Pacific Gas and
Electric Company™

Mark Krausse
Director
State Agency Relations

1415 L Street, Suite 280
Sacramento, CA 95814
(916) 386-5709
Fax: (916) 386-5720
MCKD@pge.com

May 26, 2009

DOCKET	
09-IEP-1O	
DATE	May 26 2009
RECD.	May 26 2009

Electronic Delivery

California Energy Commission
Docket Office, MS-4
1516 Ninth Street
Sacramento, CA 95814

Re: Docket No. 09-IEP-1O

Docket Office:

Please find attached PG&E's comments on the workshop held May 11, regarding "2009 IEPR - OTC".

Please contact me should you have any questions.

Sincerely,

Attachment

PG&E Comments

Preparation of the 2009 Integrated Energy Policy Report

Committee Workshop on Options for Maintaining Electric System Reliability When Eliminating Once-Through Cooling Power Plants

May 26, 2009

Pacific Gas and Electric Company appreciates the opportunity to participate in the California Energy Commission's Integrated Energy Policy Report process and the May 11, 2009, workshop on once-through cooling options. PG&E is encouraged by the participation of the energy agencies in the State Water Resources Control Board's development of an OTC policy.

PG&E believes that any policy implemented to reduce or eliminate the use of once-through cooling must do two things: 1) acknowledge that existing OTC facilities currently provide a variety of critical energy-related services and that their need must be assessed on a location-specific basis, and 2) provide for an orderly transition away from OTC that maintains the reliability of California's electric system.

Below are PG&E's written comments in response to the questions raised at the May 11, 2009, workshop.

<u>As an organization either procuring services via contract or owning some OTC facilities, what options exist for complying with the proposed mitigation policy to essentially eliminate OTC usage in the long-term?</u>

PG&E has demonstrated its commitment to eliminating once-through cooling at its owned facilities in several important ways: the retirement of the Hunters Point power plant, the currently ongoing Humboldt Bay repowering project that will eliminate OTC there by 2010, the decision in 2007 to dry cool the Gateway Generating Station at considerable expense, and the addition of the dry-cooled Colusa Generating Station, scheduled for commercial operation in 2010.

With these actions, the Diablo Canyon nuclear plant will be the only remaining OTC facility in PG&E's fleet. As base load, non-carbon-emitting sources of approximately 11% of the state's energy, Diablo Canyon and SONGS are in a separate class from the fossil facilities. These resources are absolutely critical to meeting the state's AB 32 goals – and this fact must be considered as part of any policy addressing OTC.

In the intermediate term, it is important to understand that existing OTC units currently provide a variety of services to California's electric grid including capacity and energy at the local and system level, as well as ancillary services, which include maintaining the integrity of the transmission system under a range of system and hydro conditions. While the need for OTC units is very case or location-specific, examples of the services they provide include leveling capability in the event of swings in hydro production during very wet or dry years, base load capacity in terms of the nuclear plants, surplus capacity to respond to heat waves, as well as providing replacement power for possible delays of other planned resources, particularly renewables.

Given the functions that OTC units currently perform, the phase out of OTC units must be carefully orchestrated to allow time to retrofit, rebuild or replace the OTC units, procure new resources, and/or reinforce the transmission system in the Greater Bay Area (GBA). The owners of OTC units first need to determine whether each unit will be retrofit, repowered, or retired. Given that some OTC units fall under a reliability must-run (RMR) classification, it is critical to understand the conditions necessary to allow these units to be retired.

As a load-serving entity (LSE), PG&E must consider generation and transmission solutions taking into account demand response, energy efficiency, and renewable integration in the event that OTC units within the Greater Bay Area are retired and not replaced.

Have you modified your procurement practices to reduce purchases from OTC facilities in light of energy agency policies favoring retirement or repowering of aged facilities?

On the procurement side, PG&E's Long-Term Request for Offer (LTRFO) process considers only offers to develop new facilities, and the process is structured so that offers for facilities using OTC are not eligible to participate. However, a proposal to repower an existing OTC facility with dry or closed cycle cooling would be considered. In PG&E's Intermediate-term RFOs, a deduction for once-through-cooling is taken into account under the environmental leadership scoring factor.[1]

In light of the uncertain time frame in which OTC plants might still generate power in their current configuration, how far forward is your organization prepared to contract with OTC facilities?

Existing OTC facilities are eligible to participate in PG&E's intermediate-term RFO process – which are one-to-five-year contracts. While the specific details of PG&E's selection criteria are confidential, a general description of the elements evaluated is available on PG&E's webpage: http://www.pge.com/rfo/itrfo. At this point, for the 2009 cycle, 2014 is the latest date that PG&E has authority to contract for generation in the intermediate-term RFO process. Until there are generation resources available that match the particular attributes of the OTC units (spinning reserve, renewable firming, etc.), certain of these units will continue to be needed for the reliability benefits they offer. PG&E appreciates the fact that the State Water Resources Control Board (SWRCB) recognizes the importance of grid reliability, and the Board's willingness to include the energy agencies in the development of an OTC policy. As policies and regulations change, PG&E is prepared to make further changes to its intermediate RFO process.

[1] A list of criteria evaluated by PG&E in its Intermediate-Term RFO is available online: http://www.pge.com/includes/docs/word_xls/b2b/wholesaleelectricsuppliersolicitation/ITRFO_Bid%20Protocols_v1.doc

For OTC facilities you own and operate, what plans have been publicly announced to reduce or eliminate OTC harm? If have not yet announced such plans, what processes are you following that will lead to decisions to reduce OTC harm?

As mentioned earlier, Diablo Canyon will be PG&E's only once-through cooled facility as of 2011.

PG&E has studied the marine impacts of Diablo Canyon for many years and the biological studies represent one of the largest marine biology databases on the west coast. It is important to note that the plant's intake was designed to minimize impingement (trapping of fish and invertebrates on the screens) and thus, unlike many other OTC plants, Diablo Canyon has essentially no impingement. This fact was acknowledged by the Central Coast Regional Water Quality Board in its assessment of the plant's once-through-cooling system. Additionally, studies done to assess entrainment (eggs and larvae pulled through the system) have shown that while a conservative estimate of approximately 10% of rocky reef larvae near the plant may be entrained; there is no data that demonstrates any population level effects of species in the vicinity of the plant. This must be considered when evaluating the feasibility of any retrofit of the plant.

PG&E has also evaluated alternative technologies for the OTC system on numerous occasions. The open ocean location makes various fine mesh and wedgewire screening technologies infeasible, and neither dry cooling nor natural draft cooling towers are feasible given site constraints. Closed-cycle mechanical draft cooling towers are the only option that is even potentially feasible. Given the very cursory nature of the Tetra Tech cooling tower feasibility study performed on behalf of the Ocean Protection Council, PG&E commissioned Enercon Services, Inc., to develop a thorough cooling tower feasibility evaluation for the Diablo Canyon site. This is the most detailed study performed to date and the bottom line is that a retrofit of Diablo Canyon is very likely infeasible on a number of levels. An executive summary of the study is attached as appendix A to these comments and the full study may be found in appendix B.

First, from an engineering point of view, the project simply has no precedent. There is no nuclear plant with salt water cooling towers in the world. It would be a phenomenally challenging project that would include a two-unit downtime of roughly 17 months. Along with an enormous excavation of over 2 million cubic yards of rock and soil and demolition of over 170,000 square feet of existing facilities to create a footprint for the towers, the project would involve major modifications to existing systems including the main condensers, electrical systems, and service cooling water heat exchangers. And in the end, it is quite difficult to say whether the plant would ever run at its current capacity factor of over 90%.

Second, there are many environmental challenges including salt deposition of over 15 million pounds per year which could trigger significant electrical arcing, a plume that would often be visible from San Luis Obispo and Avila Beach, as well as the need to construct an offshore diffuser to accommodate the warmer, and saltier 120-million-gallon-per-day discharge that would remain. It is unclear whether the plant could obtain all the necessary permits to build the cooling towers-particularly the air permit – as there are insufficient PM_{10} credits available from the San Luis Obispo Air Pollution Control District. The period of downtime alone would cause an additional 10 million tons of greenhouse gas (GHG) emissions, given the very high likelihood that any replacement power would be from fossil fuel sources.

Third, the evaluation identified several key nuclear safety concerns. These issues include an increased flood risk to safety-related systems from cooling tower water, accelerated aging of plant equipment and an increase in potential plant trips due to salt deposition, and the rerouting of the Independent Spent Fuel Storage Installation haul road. Further, during construction, there are security concerns due to the opening of the protected area and an increased risk of interruption to the fire protection systems.

DCPP Cooling Tower Retrofit Feasibility
Critical Issues

- Significant Permitting Obstacles
- Significant Adverse Environmental Effects
- Significant Nuclear Safety/Licensing Obstacles
- 17 Month Minimum 2-Unit Plant Shutdown
- Severe Shortage of Suitable Land Available For Cooling Towers
- Substantial Excavation
- Demolition and Relocation of Numerous Facilities
- Initial Costs Estimated at $ 4.5 Billion Dollars
- Total Annual Salt Deposition of over 15 million pounds
- Plumes Often Visible From San Luis Obispo and Avila Beach
- Greatest Loss in Plant Electric Output (70 MW per Unit) during peak demand

Finally, costs must be considered as well. The cost of a retrofit, if it were possible, would be on the order of $4.5 billion – over $2.7 billion in capital and another $1.8 billion for replacement power during the 17 month dual-unit outage. The table below provides an overview of the major capital cost components. The Diablo Canyon site presents a number of serious challenges to retrofit feasibility, as well as the inherent complexity in such a significant modification to a nuclear plant, both cause costs to be significantly higher than might be expected at a fossil-fueled facility in a different location. The costs estimated for Diablo Canyon could result in a long term rate increase of approximately 6% and an additional short-term increase of as much as 10% for replacement power during the outage -- for a plant that may not run as reliably as it currently does. This evidence suggests that a retrofit is not an effective use of ratepayer dollars and that the result would not be beneficial to the environment.

DIABLO CANYON COOLING TOWER RETROFIT ESTIMATED CAPITAL COSTS (millions)		
325	Site Work – excavation, retaining walls	
316	Demolition/Replacement of buildings, roads, parking	
298	Recirculation water/make-up water pumps, tunnels	
269	Permitting, Engineering, Project Management, Security	
242	Cooling Towers	
199	Electrical Systems, Process/Instrumentation, Utility relocation	
189	Worker Transportation, Commute Wages, Parking, etc.	
131	Upgrades – condensers, sewage treatment, SCW	
56	Blowdown water treatment, mixing station, diffuser	
50	Plant Shutdown and Start-up	
2,075	Total Direct Costs	
614	Project Indirect Costs and Contingency	
2,689	**Total Capital Costs**	
1,800	Replacement power (at $70 MWh)	
4,500	**Total Cost of Project**	

It should also be noted that the recent U. S. Supreme Court decision in Entergy Corp. v. Riverkeeper, Inc. (129 S. Ct. 1498 (2009)) allows the use of a cost benefit evaluation to set standards or variances to comply with Section 316(b) of the Clean Water Act -- the section of the Act which requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

Given the tremendous environmental, engineering, and cost challenges, PG&E does not believe that a retrofit of Diablo Canyon power plant is a reasonable, feasible alternative. And furthermore, the plant provides 2,300 MWs of reliable, baseload GHG-free generation that is a critical component to meeting the state's AB 32 goals. The closure of the plant – or the retrofit of it – would cause significant adverse environmental impacts, far in excess of any possible marine benefits due to the end of OTC at the site.

What transmission system improvements might allow existing OTC facilities to be retired and replaced with remote capacity that avoids coastal communities and the permitting complexities of new infrastructure in highly urbanized areas?

In the Greater Bay Area, transmission upgrades will likely be a key component of any long-term process to phase out OTC fossil facilities; however they should not be the only component. A study of OTC retirement scenarios commissioned by PG&E and conducted by Quanta Technology highlights the following:

- Retiring generation in the Greater Bay Area (GBA) without replacing that generation will require transmission system reinforcement, possibly new transmission lines, and an increase in local system voltage support devices within the GBA.

- Since the GBA system is already heavily compensated, numerous voltage support devices will not alleviate all constraints that would be created with the retirement of all OTC units in the area. New generation within the GBA is essential to maintain a robust transmission system.
- Quanta recommends maintaining at least 1,000 MW of generation capacity currently provided by OTC units within the GBA in order to avoid placing the GBA system in a tenuous state. Quanta does not recommend exceeding 3,900 MW of OTC generation retirement within the GBA

The Quanta study is attached as appendix C.

Diablo Canyon Power Plant

Cooling Tower Feasibility Study

March 2009

Prepared by:

Enercon Services Inc.
401 Roland Way
Oakland, CA 94621

DCPP Cooling Tower Feasibility Study

Table of Contents

Section	Page
I. Executive Summary	**1**
1. Overview	1
2. Design and Construction	1
3. Nuclear Safety	2
4. Environmental Impact and Permitting	2
5. Project Schedule and Costs	3
II. Background & Introduction	**4**
III. Conceptual Design Overview	**5**
1. Location of Cooling Towers	5
2. Conceptual Design Summary	9
3. Reduction in Electrical Output with Cooling Towers	13
IV. Construction and Engineering Assessment	**15**
1. Relocation and Excavation	15
A. Relocation of Existing Facilities	15
B. Relocation of ISFSI Haul Road	18
C. Site Civil Work	18
2. Constructability of Interconnecting Piping	19
3. Modifications to Existing Systems and Required New Systems	21
A. Condenser Modifications	21
B. Service Cooling Water Seawater Supply	22
C. Main Circulating Pumps	23
D. Circulating Water System Piping	24
E. Makeup Water Supply	25
F. Chlorination/Dechlorination of Effluent Streams	25
4. Electrical System Requirements	26
A. Electrical Design	26
B. Instrumentation and Controls	27
V. Nuclear Safety and Licensing	**29**
1. Nuclear Safety System Requirements	29
2. NRC Licensing	31
3. Security	32

DCPP Cooling Tower Feasibility Study

Table of Contents (cont.)

VI. Environmental Impacts and Permitting **32**
1. Air Quality – Plume/Salt Drift 32
2. Water Quality – Cooling Tower Blowdown 38
3. Adverse Impacts 42
4. Permitting 45

VII. Additional Studies **47**
1. Special Studies 47

VIII. Conceptual Schedule **48**
1. Introduction 48
2. Schedule Basis, Calendar, Resources 49
3. Pre-Shutdown Construction 50
4. Construction During Plant Shutdown 50
5. Plant Re-Start and Construction Completion 52

IX. Cost Estimate Summary **52**
1. Cost Estimate Overview 52
2. Capital Project Costs 53
3. Decommissioning Costs 54
4. Operation and Maintenance Costs 54
5. Replacement Power During Construction 54
6. Replacement Power due to Derated Capacity 55

Acronyms And Abbreviations **58**

Tables

Table 1	Issues that Would Threaten the Feasibility of the Project	4
Table 2	Projected Average Flow to/from Ocean (per Unit)	11
Table 3	Reduction in Plant Electrical Output	14
Table 4	Buildings/Facilities that Would Require Relocation	15
Table 5	Visible Plume Length Frequency Summary – Percent	33
Table 6	Plume Heights – Centerline Height Percent by Direction	34
Table 7	Summary of Thermal Plume Analysis	41
Table 8	Projected Direct Adverse Environmental Impacts of DCPP Retro	44
Table 9	Required Construction and Operation Permits & Licenses	47
Table 10	Cost Estimate Summary	53
Table 11	Major Equipment Procurement Cost	56

DCPP Cooling Tower Feasibility Study

Table of Contents (continued)

Figures

Figure 1	Diablo Canyon Site	6
Figure 2	Topographic Map of Site	7
Figure 3	Cooling Tower Location	8
Figure 4	50,000 Sq. Ft. Warehouse that Would Require Demolition	9
Figure 5	Cross Section Showing Required Excavation	9
Figure 6	Proposed Circulating Water Pump Pit (SK-C-8)	10
Figure 7	Decrease in Generator Output (per Unit)	14
Figure 8	Displaced Facilities	17
Figure 9	Revised Site Layout	17
Figure 10	Existing Circulating Water Conduits	19
Figure 11	Original Circulating Water Tunnel Excavation & Construction	19
Figure 12	Existing Underground Utilities West of Turbine Building	20
Figure 13	Cooling Tower Plume (Looking North)	36
Figure 14	Cooling Tower Plume (Looking Southeast)	36
Figure 15	Plumes from Nuclear Power Plant Cooling Towers	37
Figure 16	Hrs/Day that Blowdown Temp Would Exceed Discharge Limit	41
Figure 17	Conceptual Installation and Plume – Perspective From Ocean	57

Sketches

Circulating Water System Flow Diagram	SK-M-1
Auxiliary Water Systems Flow Diagram	SK-M-2
Auxiliary Water System Arrangement	SK-M-3
Sketch of Blowdown Diffuser Lines	SK-M-4
Cooling Tower Retrofit Electrical Single Line	SK-E-1
Electrical System Oneline for CT Auxiliaries	SK-E-2
Topo Layout of Cooling Towers	SK-C-1
Cooling Tower Profile Existing Ground Elevation	SK-C-2
Cooling Tower Cross Section	SK-C-3
Cooling Tower Basin Layout-1	SK-C-4
Cooling Tower Basin Layout-2	SK-C-5
Cooling Tower Basin Details	SK-C-6
Pump Pit Plan	SK-C-7
Pump Pit Section	SK-C-8
Pump Pit Walls	SK-C-9
Cooling Tower Schematic Layout	SK-C-10
Cooling Tower Layout & Access Road Relocation	SK-C-11
Cooling Tower Circulating Water Piping Layout	SK-C-12
Cooling Tower Concrete Pipe Cross Section-1	SK-C-13
Cooling Tower Concrete Pipe Cross Section-2	SK-C-14
Cooling Tower Concrete Tunnel Layout	SK-C-15
Cooling Tower Concrete Tunnel Layout Sect A-A	SK-C-16

DCPP Cooling Tower Feasibility Study

Table of Contents (continued)

Sketches (continued)

Arrangement of Underground 13.8 kV Conduit Run	SK-C-17
Before Proposed Control Board Changes	SK-J-1
After Proposed Control Board Changes	SK-J-2
DCPP Cooling Tower Control System Conceptual Block Diagram	SK-J-3
Preliminary Triconex I/O Point Count	SK-J-4
Preliminary Bently Nevada I/O Point Count	SK-J-5

Appendices

A-1 Equipment Cost Summary
A-2 Equipment List
A-3 Pre-Procurement Design Estimate
A-4 Design Change Package Estimate
A-5 Vendor Budget Quotes
A-6 I&C Detailed Cost Estimate
A-7 Plume Characteristics of Proposed Cooling Towers at DCPP
A-8 Civil Quantities Summary
A-9 Electrical Cable Tray & Conduit Estimate
A-10 Fuel Consumption Summary
A-11 Project Cost Estimate
A-12 Conceptual Schedule
A-13 Power Plant Systems Effluent Concerns

DCPP Cooling Tower Feasibility Study

I. Executive Summary

1. Overview

In response to the 2008 Tetra Tech Inc. cooling tower feasibility assessment performed for the California Ocean Protection Council, PG&E engaged Enercon Services Inc. (Enercon) to prepare a more detailed, site-specific assessment of the feasibility of cooling towers at the Diablo Canyon site. This assessment builds upon earlier work, including the 2003 study by Burns Engineering, and provides a further, more detailed analysis of the feasibility of a cooling tower retrofit. There is no precedent for mechanical draft cooling towers using saltwater makeup at a nuclear facility, and no precedent for a retrofit of the magnitude necessary at Diablo Canyon. Enercon concludes that any retrofit at Diablo Canyon is a highly speculative project with likely insurmountable permitting obstacles, substantial engineering challenges, significant adverse environmental impacts, costs exceeding $4-billion dollars, and uncertainty regarding the Power Plant's post-retrofit operating capacity factors. Further, plant downtime, reduction of average net electrical output, and a potential for ongoing reduced capacity factors would together cause a significant loss in generation, and would greatly undermine the State's ability to meet its Green House Gas (GHG) emissions reduction goals under California Assembly Bill AB 32.

2. Design and Construction Concerns

Enercon concludes, as prior reports have found, that only mechanical draft cooling towers are remotely feasible at the site. Dry cooling is not feasible due to limited space availability, and natural draft towers are not suitable for the site given space and seismic concerns. Furthermore, due to limited space, mechanical draft towers could only be non-plume abated. The conceptual layout includes four tower arrays – each 140 feet by 620 feet, with two rows of ten cells each. Key design and construction issues include:

- Demolition and relocation of over 170,000 square feet of existing structures, parking for 1,000 vehicles, and the Independent Spent Fuel Storage Installation (ISFSI) storage cask haul road.
- Excavation of over 2 million cubic yards of soil and rock.
- 250,000 diesel truck round trips to haul construction materials and excavation spoils.
- Modification of major existing systems including the main condensers, service cooling water heat exchangers, and electrical systems.
- Extremely difficult tie-in process given existing underground facilities to the west and south of the power plant.

- Construction of an offshore diffusers system for the discharge of a minimum 72-million gallons per day of high salinity cooling tower blowdown.
- Approximately 3-3/4 year construction timeframe, with a minimum of 17 months dual-unit downtime.
- An average of over 3,000 workers, requiring 7.4-million miles of bus trips.

3. Nuclear Safety Concerns

Enercon identified several significant issues that will likely require NRC review and approval of License Amendment Requests (LARs) in order to ensure acceptable safety levels during construction, as well as post retrofit operation. Further analysis of these issues is required to make determinations regarding potential conflicts with nuclear safety requirements. Key issues include:

- Increased flood risk to safety-related systems from cooling tower water.
- Accelerated aging of plant equipment and an increase in possible plant trips due to salt deposition.
- Interruption of the safety-required Auxiliary Saltwater (ASW) system during construction.
- Increased potential loss of offsite power.
- Rerouting of existing approved ISFSI haul road.
- Increased risk of interruption to the fire protection system during construction.
- Security concerns related to the opening of the protected area boundaries during construction.

4. Environmental Impact and Permitting Concerns

The installation and operation of cooling towers raises significant adverse environmental impacts concerns and poses substantial, likely insurmountable, permitting obstacles. Key issues identified include:

- PM_{10} emissions likely can not be permitted by the San Luis Obispo County Air Pollution Control District (APCD).
- Salt deposition of at least 7,500 tons per year would impact plant equipment, adjacent agricultural lands, and terrestrial habitat.
- The vapor plume from tower operations would be over 2,460 feet high 35% of the year. Although low visibility conditions may obscure the plumes, and many plumes large enough to be visible are likely to occur at night, meteorological conditions conducive to plume visibility are predicted to occur within 1 hour of sunrise or sunset on the order of 45 times per year for Avila Beach, and 300 times per year for San Luis Obispo.
- Fossil-fueled replacement power for the minimum 17 month dual-unit downtime will result in the emission of roughly 10,000,000-tons of GHGs. Derated capacity and additional auxiliary power requirements for cooling tower operations total an

average of approximately 55 MW, enough to supply power for approximately 42,000 California homes. Long term negative impacts on GHG emissions of roughly 180,000-tons per year would also result.

- Construction of a diffuser system in Patton Cove south of the power plant will directly disrupt approximately a half-acre of pristine rocky marine habitat.
- Permits for both construction and operation are required from many government agencies including: The California Coastal Commission, State Lands Commission, Central Coast Regional Water Quality Control Board, San Luis Obispo County (Building and APCD), and the U.S. Army Corps of Engineers. It is highly unlikely that all the necessary permits can be obtained.

5. Project Schedule and Costs

Enercon's assessment is that prior order-of-magnitude estimates grossly understate the cost of a cooling tower retrofit. A more detailed evaluation of project scope, design and engineering, and required construction results in the following regarding costs and schedule:

- The overall duration for construction would be approximately 3-3/4 years. The plant shutdown during the construction period would be at least 17 months:
  - Extensive excavation west of the Turbine Building in an area congested with both safety related and nonsafety related systems, piping and conduits.
  - Significant condenser modifications.
  - Need to assure continued operation of the safety related ASW system to provide cooling to the spent fuel pools even during shutdown.
  - Extensive relocation of existing systems and facilities.
  - Massive excavation for cooling tower installation.

- Total initial project costs are estimated at $4.5 billion (2008 Dollars) and would result in an estimated Utility customer rate increase of roughly 10%:
  - Capital costs estimated at $2.7 billion.
  - Cost of replacement power for the minimum 17 month downtime is estimated at $1.8 billion.
  - Increased decommissioning costs total $67 million.

- Additional on-going costs total $39 million annually:
  - Cooling tower operations and related maintenance is estimated at $7.4 million per year.
  - Replacement Power for derated capacity and cooling tower operations totals $31.6 million per year.

Ongoing costs assume that the plant would be capable of continuing to produce power at roughly current levels / capacity factors. If plant operational efficiency decreases, and net power production is reduced more than the 55 MW expected, electric rates will likely increase even more to cover the purchase of additional replacement power.

Issues that Would Seriously Threaten the Feasibility of a DCPP Cooling Tower Retrofit Project
• Significant Permitting Obstacles. • Significant Adverse Environmental Effects. • Significant Nuclear Safety/Licensing Obstacles. • 17 Month Minimum 2-Unit Plant Shutdown. • Severe Shortage of Suitable Land Available For Cooling Towers. • Substantial Excavation. • Demolition and Relocation of Numerous Facilities. • Initial Costs Estimated at 4.5 Billion Dollars. • Total Annual Salt Deposition Exceeding 7,500 Tons. • Plumes Often Visible From San Luis Obispo and Avila Beach. • Greatest Loss in Plant Electric Output (nearly 70 MW per Unit) Would Occur at Times of Peak Summer Demand.

Table 1: Issues that Would Threaten the Feasibility of the Project

II. Background and Introduction

Diablo Canyon Power Plant (DCPP) could be subject to a requirement to retrofit the existing once-through cooling system to closed-cycle cooling. Ongoing development of Federal Clean Water Act Section 316(b) regulations regarding aquatic organism Impingement and Entrainment (I&E) and a California Specific Policy for 316(b) rule implementation may require all coastal power plants to reduce Marine I&E to levels commensurate with a closed-cycle cooling system. Previous conceptual analyses of retrofitting DCPP to closed-cycle cooling have been performed by Tetra Tech Inc. (2002, 2008) and Burns Engineering (2003). These studies were limited in scope, and do not provide detailed analysis regarding existing plant operating system and site issues that influence the feasibility of such a project, and the engineering and construction challenges that would be posed by implementation of a retrofit. At the request of PG&E, Enercon Services developed the following study to expand on the previous studies, and further develop the scope, site specific feasibility, projected costs, and a conceptual implementation schedule associated with retrofitting DCPP to closed-cycle cooling.

Enercon developed a more detailed technical conceptual design of the cooling tower retrofit than was done in the previous Tetra Tech and Burns studies, including initial sizing of the equipment, electrical single line development, earthwork and concrete quantity estimation, site/equipment layout considerations, and identification of significant technical, permitting, and nuclear licensing obstacles. Cost estimates for procurement of the major mechanical and electrical equipment have been obtained from equipment suppliers. The Engineering cost estimates for the project are based on years of industry and Diablo Canyon specific experience. Enercon worked with PG&E and Cannon Associates in developing the construction cost estimate and project conceptual schedule.

Enercon Services, Inc., founded in 1983, is an engineering, environmental, technical and management services firm with a wealth of engineering design and project management experience in the nuclear power industry, including extensive design change experience at Diablo Canyon, as well as specific involvement in studies for retrofitting cooling towers at existing power plants.

Cannon Associates, established in 1976, is a multidisciplinary consulting firm composed of civil, structural, mechanical engineers and environmental and land use planners with expertise in construction management. Cannon performed civil engineering for the Diablo Canyon ISFSI, and coordinated with Granite Construction Inc. for the ISFSI construction.

III. Conceptual Design Overview

1. Location of Cooling Towers

Perhaps the most challenging aspect of this study has been selection of a suitable location for the cooling towers. There is a severe shortage of suitable land available for cooling towers at the plant due to its location on a small marine terrace sandwiched between the shoreline cliffs and the adjacent steep landslide-prone hillsides. Every potential location for the cooling towers results in significant disadvantages or insurmountable obstacles. Enercon concludes that mechanical draft cooling towers utilizing seawater as makeup are the only potential option. Enercon further concludes that the only viable mechanical draft cooling towers would consist of nonplume-abated rectangular bank cooling towers. Plume abated cooling towers cannot be installed in any workable configuration at the facility due to size/topographic constraints.

Ideally, from a piping layout viewpoint, it would be desirable to place the Unit 1 cooling towers to the northwest of the power block, and the Unit 2 cooling towers to the southeast of the power block. However, the area north of the plant is unavailable for several reasons including its classification as a sensitive archeological site incorporating an extensive Native American (Central Coast Chumash) ancestral burial ground. The Diablo Creek and associated established riparian habitat is also located between the existing power plant and all northern areas. The creek environment would have to be extensively disrupted and developed to accommodate substantial northward construction for any plant systems. Additionally, such a location would be undesirable from a salt drift viewpoint, since prevailing winds from the northwest would maximize the salt drift on the plant and the associated 500 kV and 230 kV transmission lines.

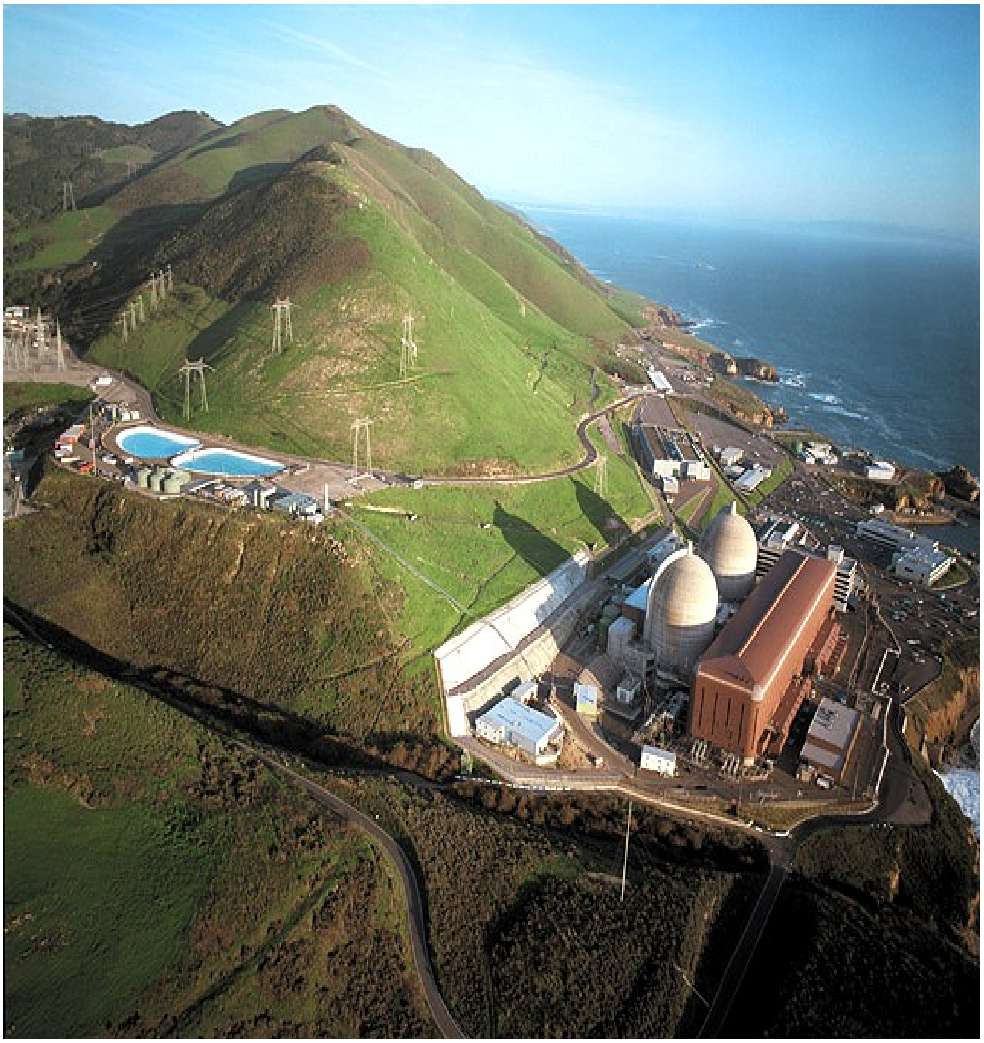

Figure 1 – Diablo Canyon Site

Consideration was given to locating the cooling towers alongside the entrance road south of the plant. This has proved unworkable due to the steep terrain of the surrounding hills which would require substantial excavation and retaining wall construction. Additionally, this area is fairly narrow, and placing the cooling towers too close to the ocean is undesirable due to the instability of the soil and the potential for future landslides. The great distance of the cooling towers at this location from the power block would also mean much greater frictional losses in pumping, driving up power requirements. Although locating the cooling towers in this area would have the least impact on existing facilities, it has been ruled out due to the reasons cited above.

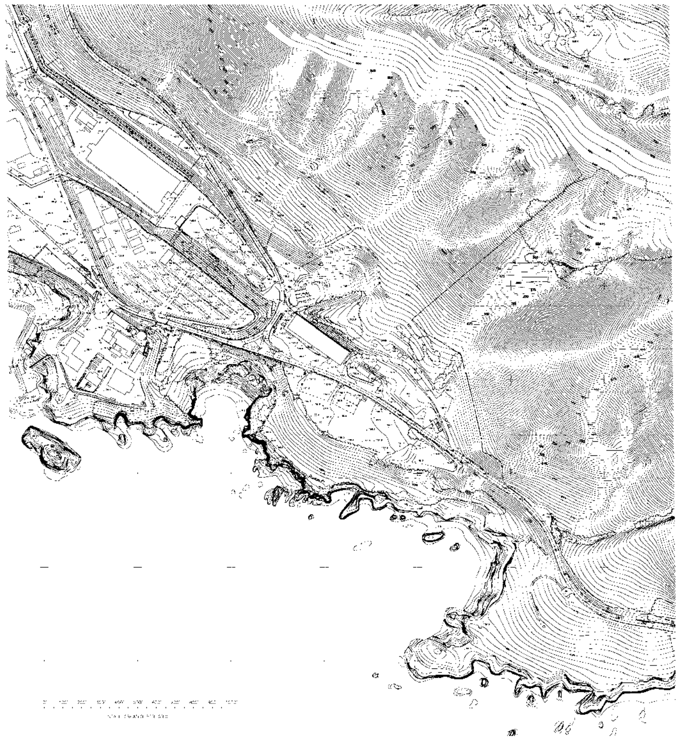

Figure 2 – Topographic Map of Site
Showing Steep Terrain and Limited Area for Cooling Towers

Other areas for the cooling towers considered were in the vicinity of Warehouse "B" and parking lot #1 as well as to the east of the plant. Again, the steep hillsides to the east and unstable soils to the west ruled out these areas. Another disadvantage of a site east of the plant would be to increase the salt buildup on the transmission lines and switchyard. Additionally, locating the cooling towers at a height significantly higher than the elevation of the condensers raises the condenser waterbox operating pressure due to the higher static head from the cooling tower risers, as well as increasing the nuclear safety related flooding hazard in the turbine building due to the cooling tower supply lines draining backwards into the building via a failed waterbox.

The only possible remaining site for the cooling towers was determined to be in the area including the main warehouse, cold machine shop, hazardous materials building, fire station, parking lots 6, 7 and 8, engineering office buildings 201 and 202, and a dozen smaller buildings (Figure 3). All of these facilities would need to be relocated with great impact on the administration and operation of the facility. The Independent Spent Fuel Storage Installation (ISFSI) haul road would require rerouting due to the excavation requirements for the cooling towers, sending the proposed route through the security firing range, necessitating its relocation as well. All four cooling tower arrays would be placed at an elevation of approximately 85' to 90', requiring a significant excavation effort as described elsewhere in this report. It is critical to place the cooling tower basins at these elevations in order to minimize the nuclear safety related threat of flooding, as well as to reduce overall pumping costs and excessive pressures in the condenser waterboxes.

As in the previous studies, a natural draft design for the cooling towers was eliminated from consideration because of seismic and other concerns. Likewise, circular arrangement mechanical draft cooling towers were eliminated from consideration due to the lack of sufficient suitable land due to the narrow site layout.

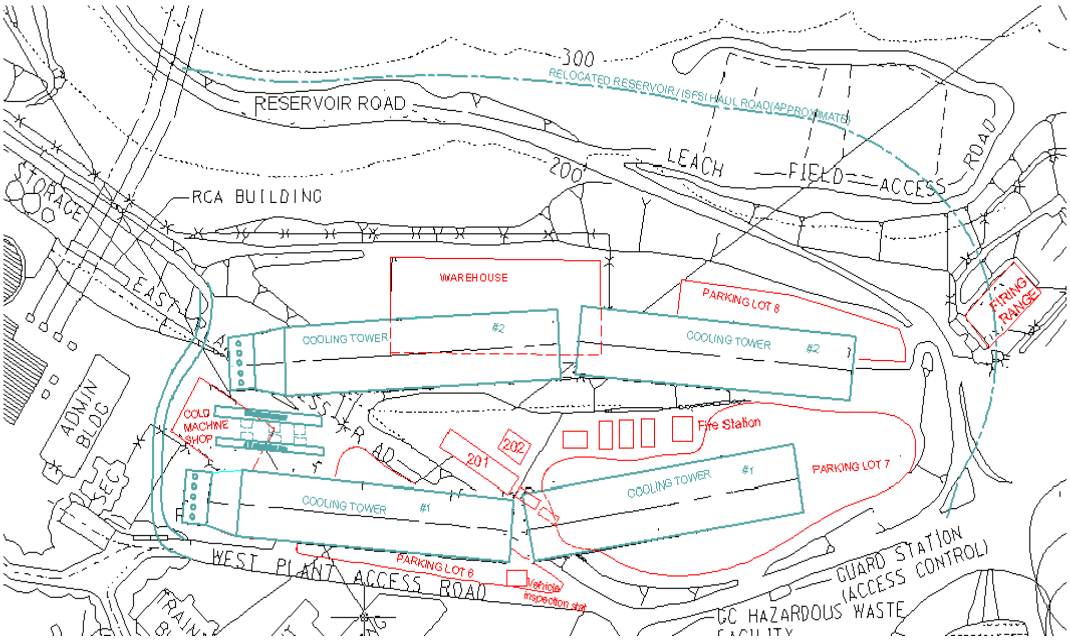

Figure 3 – Cooling Tower Location
(Displaced Facilities in Red) (SK-C-11 Rev. 0)

Based on the above evaluation, and discussions with a cooling tower supplier as to the best size, number, and configuration of cells to fit the available space, the conceptual design for each unit consists of two rectilinear arrays of mechanical draft cooling towers, 20 cells per array, arranged in two rows (side-by-side) of 10 cells each. This configuration is called "back-to-back", having hot water risers coming from the outboard side of each cell, and air coming in from the outboard side of each cell. This configuration is less desirable than a circular arrangement where cooling air can enter from inside and outside the cells, but such a configuration was ruled out at DCPP because of the lack of suitable land. The 2-Unit DCPP configuration would thus consist of 4 rectangular collections of 20 cells, having a footprint of 140' by 620' each. For each unit, a pump suction pit for the circulating water pumps would be located at the north end of the two 20 cell assemblies to take suction from the cooling tower basins (Figure 6). The cooling towers proposed are based on an approach of 17°F, with a cost estimate provided by Marley, a well known supplier.

Figure 4 – 50,000 Sq Ft Warehouse that Would Require Demolition and Relocation

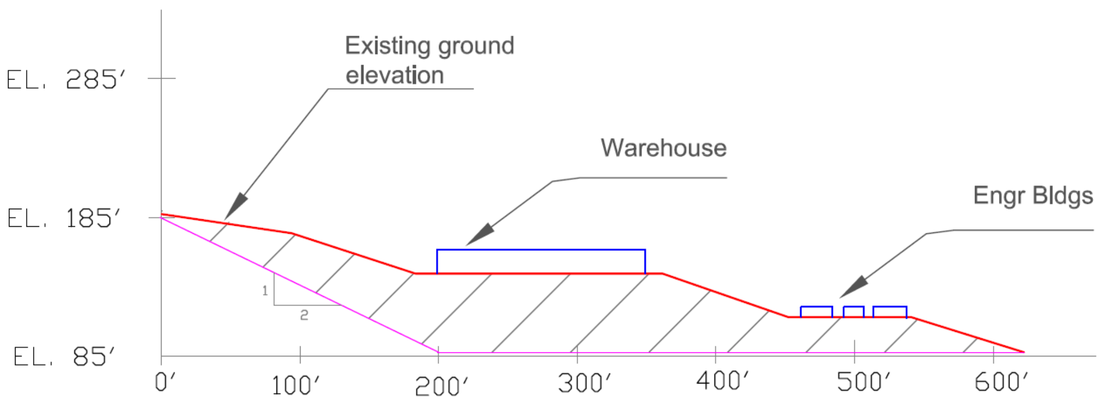

Figure 5 – Cross Section Showing Required Excavation

2. Conceptual Design Summary

Each unit would be retrofitted with two nonplume-abated rectangular configured mechanical draft cooling tower arrays. Each cooling tower would be arranged in a back-to-back array, 2 cells wide by 10 cells long.

Each operating unit's two existing 50% capacity circulating water pumps would be replaced with five 25% capacity circulating water pumps (10 total for 2 units) located in a new pump pit adjacent to the cooling towers. The use of five 25% capacity circulating water pumps (4 plus 1 installed spare) is a typical and commercially prudent and cost effective configuration that effectively eliminates downtime due to pump/motor failure or maintenance, and eliminates plant load reductions in the event of a single pump trip. The pumps would discharge into two new 10 ft square buried conduits carrying the cooling water to the west side of the turbine building where they would transition into the existing conduits on the way to the main condensers (reference SK-M-1 and SK-C-12). Likewise, the cooling flow exiting the condensers would utilize the existing conduits until it reaches the west side of turbine building where it would transition into the proposed 10 ft square conduits returning to the cooling towers.

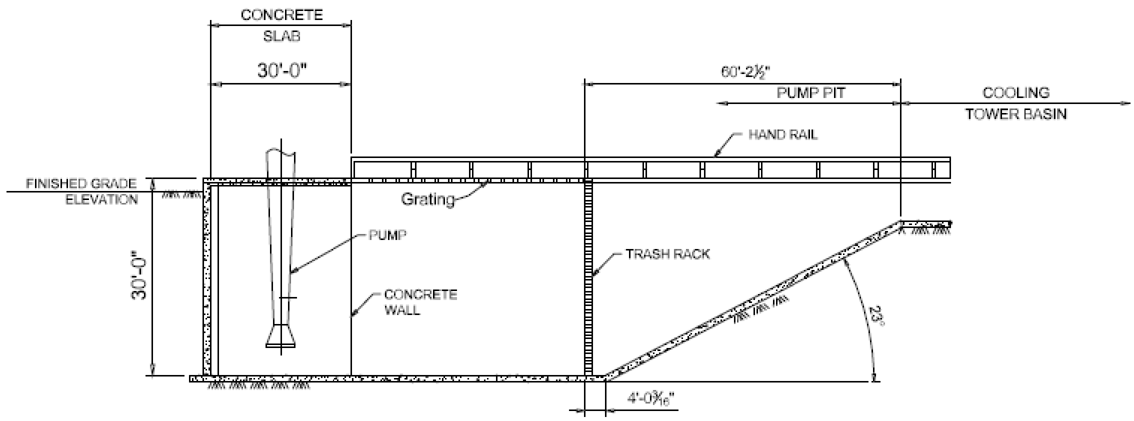

Figure 6 – Proposed Circulating Water Pump Pit (SK-C-8)

Three new 50% capacity makeup water pumps per unit (6 total for 2 units) would be installed in the intake structure near the present location of the existing circulating water pumps and intake coolers (which would be removed should the plant be retrofitted with cooling towers). The pumps would discharge into a 48" paralined steel common discharge header which would be routed up through one of the to be abandoned concrete tunnels going to the turbine building, and on to the two circulating water conduits going to the main condensers.

The present Service Cooling Water (SCW) heat exchangers are cooled by the existing once-through circulating water. As discussed below, the warmer cooling water from the cooling towers would be too warm, necessitating replacement of the two SCW heat exchangers per unit, and many of the components cooled by the SCW system. To avoid the need for this replacement and the associated significant additional costs, the SCW heat exchangers would be cooled by their own once-through cooling system. Three new 50% SCW seawater supply pumps per unit, located at the existing intake structure, would provide this cooling water for the system heat exchangers. In addition to providing an installed spare, the third 50% capacity pump would be operated to supply dilution flow for the cooling tower blowdown when needed during times of high wet bulb temperature to meet the anticipated facility effluent thermal limit of 20 F° above ambient.

The present Condensate Cooler in each unit is cooled by a side stream off the once-through circulating water, and is used when needed to reduce the main condensate temperature and thereby provide additional cooling for the main generator hydrogen cooler and stator cooler. The need for this "extra" cooling would increase since the condenser backpressure, and thus the condensate temperature, would increase with the use of closed loop cooling towers. The warmer water from the cooling towers would be insufficient to provide the required cooling. Therefore, a side stream off the proposed SCW seawater supply pumps would be used to cool the Condensate Coolers.

The present once-through cooling for the safety related ASW system would remain a once-through system by necessity, and continue to use existing dedicated intake pumps and ocean water supply. Warmer cooling tower circulating water would be insufficient to provide the necessary cooling required for the existing plant Component Cooling Water (CCW) heat exchangers that are vital equipment in an installed critical nuclear safety system. Retrofit of this plant system to function within acceptable Nuclear Operating License parameters with closed-cycle cooling is infeasible.

Flow From Ocean

Description	Flow (gpm)	
	Existing	**Cooling Towers**
Condenser Cooling (gpm)	860,000	0
ASW System (gpm)	11,500	11,500
Service Cooling Water HX (gpm)	4,300	4,300
Condensate Cooler (gpm)	n/a	2,000
Cooling Tower Makeup	n/a	37,800
Blowdown Dilution (ΔT Control)	n/a	6,400 *
Seawater Reverse Osmosis System	500	500
Total (gpm)	876,300	62,500
Percent of Existing Flow	-	**7.1%**

Discharge To Ocean

Description	Flow (gpm)	
	Existing	**Cooling Towers**
Condenser Cooling (gpm)	860,000	0
ASW System (gpm)	11,500	11,500
Service Cooling Water HX (gpm)	4,300	4,300
Condensate Cooler (gpm)	n/a	2,000
Cooling Tower Blowdown	n/a	25,200
Blowdown Dilution (ΔT Control)	n/a	6,400 *
Seawater Reverse Osmosis System	240	240
Total (gpm)	876,040	49,640
Percent of Existing Flow	-	**5.7%**

* *When needed for blowdown temperature dilution (~ 25% of the time)*

Table 2: Projected Average Flow to/from Ocean (per Unit)

Both the SCW system supply and cooling tower makeup seawater lines would require periodic chemical treatment (concentrated chlorination or chlorine/bromine treatment) to control pipeline biofouling. The ASW inlet flow is required to be continuously chlorinated to protect the vital function of the system. It would be necessary to continuously dechlorinate the effluent of the ASW system, and most likely dechlorinate

SCW system effluent during chemical treatment, since the present ability to dilute these streams prior to discharge using the high volume main condenser once-through cooling water flow would no longer be possible.

Each unit would require a steady state cooling tower circulating system blowdown flow of approximately 25,200 gpm when running at full load. The concentration of the circulating water would be 1.5x normal seawater. Thus the blowdown would have a concentration of about 52,500 ppm total dissolved solids (TDS) given an average seawater concentration of 35,000 ppm TDS. The blowdown stream is toxic to marine life due to the higher salt concentration. Therefore, it would either have to be rapidly mixed with the ambient seawater as it is introduced into the ocean, or it would have to be treated prior to discharge to reduce its TDS concentration back to that of seawater. As discussed elsewhere, treatment of this quantity of blowdown is not practical. It has been determined that the most practical means of disposal for cooling tower blowdown is discharge to an array of diffuser nozzles placed on the ocean floor offshore of the facility. The proposed location for a diffuser system is south of the existing power plant near Patton Cove. Routing high salinity cooling tower blowdown to the existing plant outfall located on the shoreline at Diablo Cove cannot be permitted, nor is it an optimal configuration for efficient cooling tower operation.

The tube side of the main condensers (waterboxes) are designed for 25 psig. Due to the height and location of the cooling towers, the new pressure in the waterboxes would be on the order of 45 psig, necessitating strengthening or replacement of the waterboxes. In addition, the existing rolled tube-to-tubesheet joints in each condenser are presently susceptible to saltwater leaks. Leaks into the condensate system can lead to damage of the safety related steam generators and/or unplanned plant shutdowns. An increase in condenser waterbox pressure would significantly increase leakage and associated chloride intrusion into the secondary system. Therefore, the condenser waterbox and tubes would be replaced with modular welded tube-to-tubesheet units.

Mechanical draft cooling towers have considerably more power requirements than the existing once-through cooling system. This additional power is primarily for the mechanical draft fans required for the tower cells. At 300 horsepower (hp) each, about 12 MVA per unit are needed at an assumed power factor of 0.88. Other new power required for the cooling tower installation would be the makeup water pumps drawing about 2,700 kVA per unit. Also, each unit would require a seawater supply to the SCW system, requiring another 170 kVA. The new circulating water pumps would have higher head requirements than the existing circulating water pumps, resulting in an increase power requirement of 2.5 MVA. The various existing auxiliary transformers at Diablo Canyon do not have sufficient capacity to provide the additional loads to power the cooling tower fans and other auxiliaries. Therefore, a new bay with circuit breakers, disconnects, and transformers would be added at the 500 kV switchyard with additional transformers and other electrical equipment added downstream to serve the new loads.

The existing sewage treatment system would most likely need to be upgraded to meet more stringent effluent limits. The high volume circulating water system would no longer be available to dilute the treated sewage effluent stream. A new packaged system would be sized for 50,000-gpd, and would consist of a flow equalization tank, aeration tank, clarifier, clearwell, pressurized multimedia filtration system, anoxic tank for nitrate reduction, and a UV light system for disinfection. The effluent could be treated by the proposed system to have 10 mg/L of biological oxygen demand (BOD), 10 mg/L of total suspended solids (TSS), 5 mg/L of total nitrogen, and 1 mg/L of ammonia. The Seawater Reverse Osmosis Unit (SWRO) brine reject and filter backwash effluent would be directed to the tower blowdown diffuser system due to high salinity.

3. Reduction in Electrical Output with Cooling Towers

Replacing the once-through cooling system using saltwater cooling towers would result in a higher backpressure in the main condensers because the cooling water temperature entering the condensers would be greater than the present once-through ocean water temperature. For purposes of this study, hourly wet bulb temperatures for the years 2003 through 2007 were taken from the National Weather Service (NWS) Station at the San Luis Obispo (SLO) Airport. This data was considered the most accurate of available local data, and therefore most appropriate for use in this study. Accurate Diablo Canyon site specific data for humidity or wet bulb temperature was not available. The airport weather station data gives lower wet bulb temperatures (due to drier inland conditions) than would actually be experienced at the Diablo Canyon site. The lower wet bulb values cause a reduced estimate of plume size, and a lower prediction of circulating water temperatures. Thus the conservative bias introduced by use of SLO rather than site specific coastline data results in smaller predicted plumes, and a decrease in the predicted loss of plant electrical output.

The once-through ocean cooling water as measured at the intake structure has an average inlet temperature of 53.9ºF, with a standard deviation of 2.5ºF. The average wet bulb temperature is 52.0ºF, with a standard deviation of 6.8ºF. With the cooling tower approach of 17ºF, it is seen that with cooling towers in service the circulating water entering the condensers would be 69.0ºF, on average. When compared with the once-through cooling water inlet temperature of 53.9ºF, this amounts to an increase of 15.1ºF on average for condenser inlet cooling water temperatures when using cooling towers.

The turbine exhaust pressure was determined using standard Heat Exchange Institute (HEI) condenser backpressure calculation methodology utilizing the DCPP turbine performance test data to determine the associated cleanliness factor. The DCPP Turbine (Alstom) Thermal Kit backpressure correction curve was then used to determine the effect on generator electrical output. (Note: The original Westinghouse low pressure turbine rotors were replaced with Alstom rotors in 2005 & 2006.)

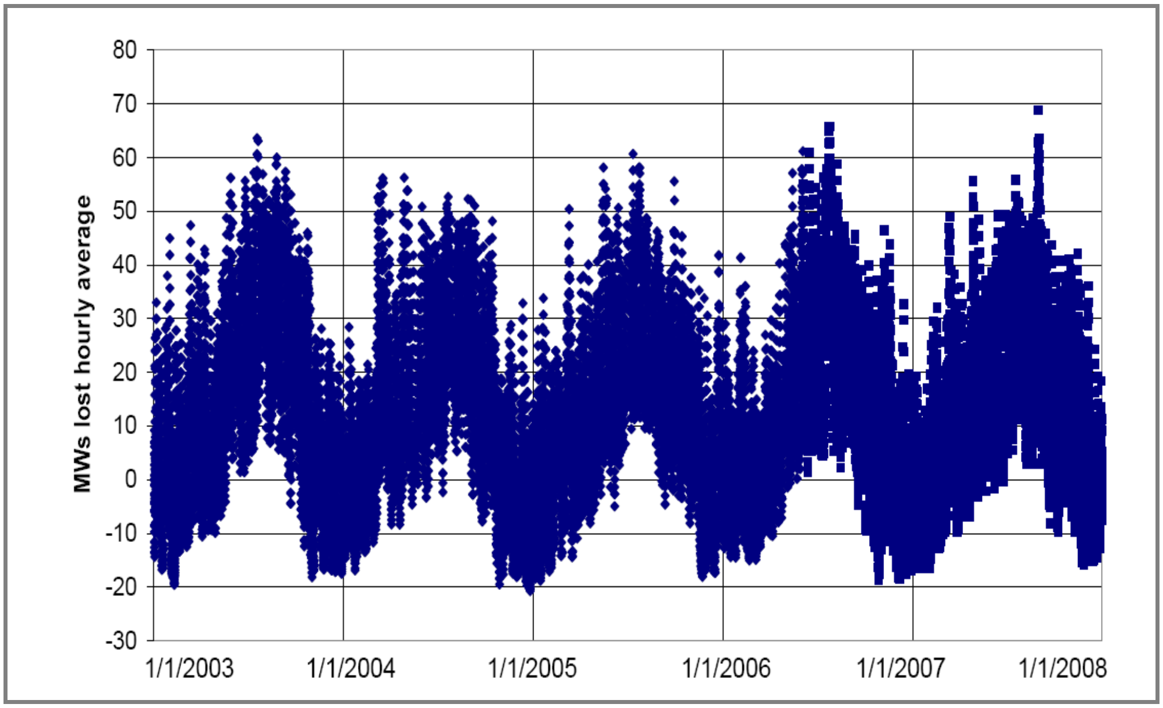

Figure 7 – Decrease in Generator Output (per Unit)

The average yearly loss in generator output due to the proposed cooling tower retrofit project (including an optimized condenser) based on a 90% capacity factor (both pre and assumed post cooling tower retrofit) would be approximately 204,000 Megawatt Hours (MWHr) for Units 1 & 2 combined. When considering the additional loads required for the cooling tower fans and pumps, the total decrease in plant electrical output would be approximately 451,000 MWHr/yr. The average decrease in generator output with retrofit cooling towers and an optimized condenser would be 12.9 MW per unit (25.8 MW for 2-units). As can be seen in Figure 7, the change in Megawatts would vary from an increase of approximately 21 MW per unit to a loss of approximately 69 MW per unit depending on the corresponding wet bulb and ocean water temperatures. The gain in MW during certain temperature conditions is due to the proposed replacement of the condenser tube bundles with new optimized bundles. Unfortunately, as can be seen in Figure 7, the greatest loss in generator output would be at the time of peak summer electric demand.

Description	MW/Unit	MW/2-Units	MWHr/year*
Circulating Water Pumps ΔMW	2.2	4.4	36,810
Makeup Water Pumps	2.4	4.8	40,157
Cooling Tower Fans	10.0	20.0	167,320
SCW Seawater Supply Pumps	0.2	0.4	3,346
Average Lost Generation	12.9	25.8	203,547
Net Loss in Plant Output	**27.7**	**55.4**	**451,180**

** 2-Units - Based on a 90% Capacity Factor & 25-Day Refueling Outages.*

Table 3: Reduction in Plant Electrical Output

Without optimized condensers, the average 2-unit decrease in generator output with retrofit cooling towers would be 59.8 MW (versus 25.8 MW with optimized condensers) with an average yearly generator loss of approximately 471,700 MWHr, and a net loss in plant output of 719,000 MWHr (versus 451,200 MWHr with installation of new optimized condensers).

For purposes of this study and associated cost estimates, it has been assumed that the plant capacity factor after the cooling tower installation would be identical to the pre-cooling tower capacity factor (approximately 90% including refueling outages). In reality, the capacity factor would likely be reduced due to the increased complexity of a saltwater tower cooling system, the corrosive effects on plant equipment due to salt deposition from the tower drift, and the potential for tripping of the 500 kV lines due to flash-over from excessive salt deposition.

IV. Construction and Engineering Assessment

1. Relocation and Excavation

A. Relocation of Existing Facilities

In order to adequately site the cooling towers, many existing facilities would need to be relocated, either onsite to a less convenient location or offsite to the surrounding community. These include parking lots 6, 7 and 8, with some 1,000 parking spots, and the main warehouse building. The cold machine shop (CMS) is presently located inside the security protected area boundary in close proximity to the power block which provides significant convenience. With the cold machine shop relocated outside of the protected area boundary, this convenience and efficiency would be lost. An even greater loss of convenience and efficiency would apply to the main warehouse which would be relocated 50% onsite but outside of the protected area and 50% offsite. Facilities such as the security firing range, design engineering offices, record storage, etc., would have to be relocated entirely offsite adding considerable cost and inconvenience. The following table is a list of buildings and facilities that would require relocation and/or demolition.

Buildings/Facilities that Would Require Relocation and/or Demolition

Blg #	Description	Impact	Relocate Onsite or Offsite?	Existing Sq Ft	Required Sq Ft Onsite	Required Sq Ft Offsite
115	Main Warehouse	Demo & Relocate	Part Onsite & Part Offsite	50,000	25,000	25,000
116	Cold Machine Shop (CMS)	Demo & Relocate	Onsite	15,000	15,000	0
506	Radwaste Offices	Demo & Relocate	Onsite	1,000	1,000	0
508	(near cold machine shop)	Demo & Relocate	Onsite	1,000	1,000	0
127	Haz Materials Warehouse	Demo & Relocate	Onsite	4,000	4,000	0
201	Design Engineering Offices	Demo & Relocate	Part Onsite & Part Offsite	12,000	6,000	6,000
202	Design Engineering Offices	Demo & Relocate	Part Onsite & Part Offsite	4,000	2,000	2,000
220	Design Engineering Offices	Demo & Relocate	Part Onsite & Part Offsite	1,000	500	500

Buildings/Facilities that Would Require Relocation and/or Demolition (cont.)

Blg #	Description	Impact	Relocate Onsite or Offsite?	Existing Sq Ft	Required Sq Ft Onsite	Required Sq Ft Offsite
248	Outage Human Resources	Demo & Relocate	Part Onsite & Part Offsite	1,000	500	500
250	Project Offices	Demo & Relocate	Part Onsite & Part Offsite	3,000	1,500	1,500
252	Project Offices	Demo & Relocate	Part Onsite & Part Offsite	3,000	1,500	1,500
217	Restrooms	Demo & Relocate	Onsite	500	500	0
253	Offices	Demo & Relocate	Part Onsite & Part Offsite	500	250	250
260	Security/Records Storage	Demo & Relocate	Part Onsite & Part Offsite	2,000	1,000	1,000
261	Records Storage/ Offices	Demo & Relocate	Part Onsite & Part Offsite	2,000	1,000	1,000
262	Telecom/Project Offices	Demo & Relocate	Part Onsite & Part Offsite	2,000	1,000	1,000
263	Training Facility	Demo & Relocate	Part Onsite & Part Offsite	2,000	1,000	1,000
264	Building Services	Demo & Relocate	Part Onsite & Part Offsite	2,000	1,000	1,000
251	Fire House	Demo & Relocate	Onsite	3,000	3,000	0
254	Storage Facility	Demo	Neither - Eliminate	8,000	0	0
255	Storage Facility	Demo	Neither - Eliminate	8,000	0	0
114	Firing Range	Demo & Relocate	Offsite	3,000	0	3,000
114A	Security Training	Demo & Relocate	Offsite	500	0	500
114B	Security Training	Demo & Relocate	Offsite	500	0	500
113	Warehouse B	Demo	Neither - Eliminate	18,000	0	0
120	Hazardous Waste	Demo & Relocate	Onsite	3,000	3,000	0
125	Fire Water Tank/ Pump House	Demo & Relocate	Onsite	2,000	2,000	0
124	Sewage Treatment Plant	Demo & Relocate	Onsite	1,000	2,000	-
165	Biology Offices/Career Ctr	Demo	Neither - Eliminate	2,000	0	0
160	Biology Laboratory	Demo	Neither - Eliminate	4,000	0	0
110	Blast and Paint Facility	Demo	Neither *	3,000	0	0
122	GC Fab Shop	Demo	Neither *	8,000	0	0
n/a	Vehicle Inspection Station	Demo & Relocate	Onsite	1,000	1,000	0
n/a	Parking Garage I	New	Onsite	-	180,000	-
n/a	Parking Garage II	New	Onsite	-	320,000	-
	Total Square Feet			**171,000**	**574,750**	**46,250**

** The Blast & Paint Facility and the GC Fab Shop would be incorporated in the new CMS.*

Table 4: Buildings/Facilities that Would Require Relocation and/or Demolition

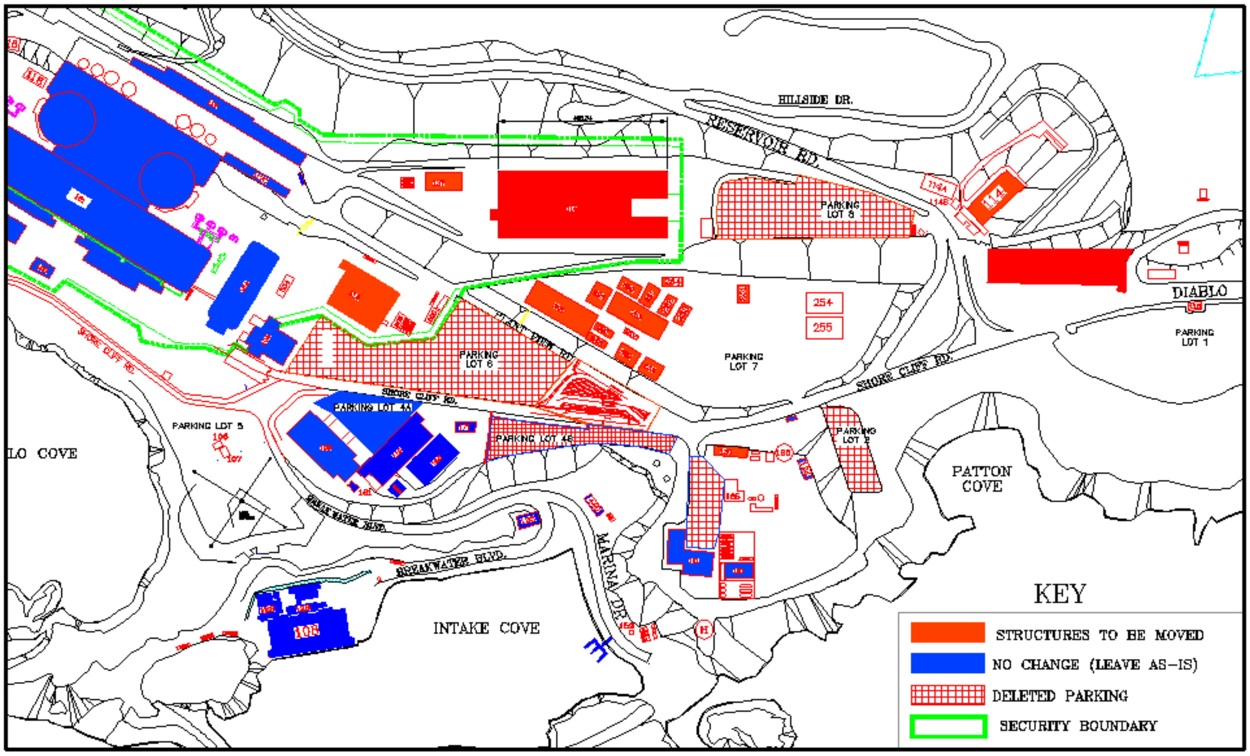

Figure 8 – Displaced Facilities

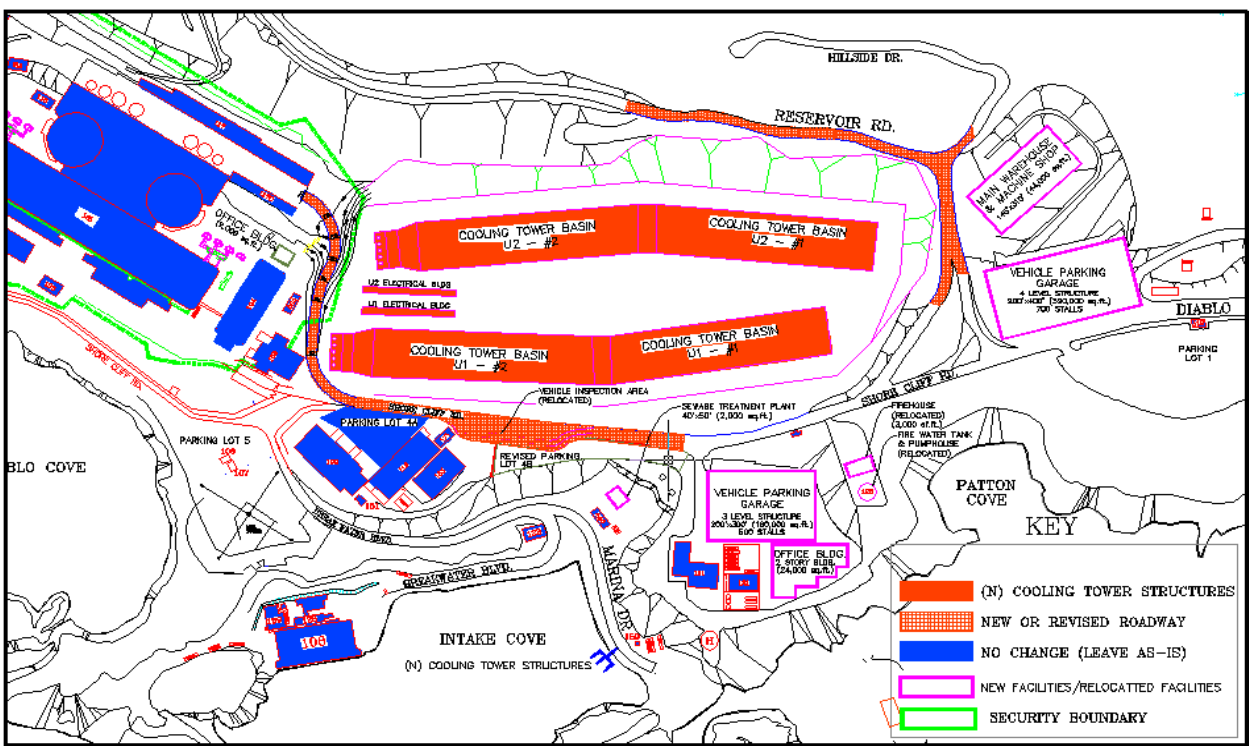

Figure 9 – Revised Site Layout

B. Relocation of ISFSI Haul Road

Location of the cooling towers would make it necessary to reroute the existing ISFSI haul road and re-engineer the subgrade for the anticipated loads. In particular, the new road would need to pass to the west of the cooling towers, just east of the Simulator Building and the Maintenance Training Building. Beneath the road would be the new circulating water concrete tunnels, each having an internal cross section of approximately 10' x 10', with reinforced concrete walls 3 feet thick. This dimension was selected in order to be able to fit all 8 tunnels (4 supply and 4 return) for both units alongside each other as they approach the western side of the turbine building. Because of the location of the cooling towers with respect to the condensers, the tunnels would have to cross over each other in certain areas, meaning deeper excavation. The tunnels would have to be engineered for the excessive loads anticipated on the road above them, not only due to the ISFSI casks but also due to normal operational/maintenance loads, as well as outage-related loads.

The revised ISFSI haul road would need to avoid the zones where the potential for landslides will exist for 75 years after the installation. This setback requirement originates from the California Coastal Commission, and is necessary in order to obtain a building permit from San Luis Obispo County. The potential for future landslides exists at the location of the existing access road near Warehouse "B" and parking lot #1. California Coastal Commission rules do not allow for reinforcement of the littoral area around landslides in order to reduce the likelihood of future landslides. These points would need to be taken into account when finalizing the new ISFSI haul road.

C. Civil Site Work

Siting the cooling towers to the southeast of the turbine building would necessitate massive excavation of the hillside to the east of the cooling towers. All four separate tower basins would be excavated to a base elevation of 85' to 90'. The excavations would leave slopes of 2 to 1 (tangent = 0.5). Although choosing a higher slope would reduce the amount of excavated fill to be removed, the higher slope would be hazardous for personnel. On the west side of the cooling towers some excavation and relocation work for the access/ISFSI haul road would be necessary (Reference Sketches SK-C-1, 2, & 3).

The volume of excavated soil and rock has been estimated at 2,011,000 bank cubic yards. This material would need to be trucked to an offsite disposal facility, requiring roughly 200,000 truckloads. The total amount of soil and rock includes an estimate that 52% is rock, based on review of the geological information in the ISFSI Final Safety Analysis Report (FSAR) Update.

2. Constructability of Interconnecting Piping

Figure 10 schematically shows the existing circulating water conduits to the main condensers. Connections would have to be made to all the supply and return conduits including those coming from the north end of the Unit 1 condensers. Review of detailed site drawings clearly shows that the excavations and routing required for these large diameter connections would quickly become an extremely complex engineering and construction task.

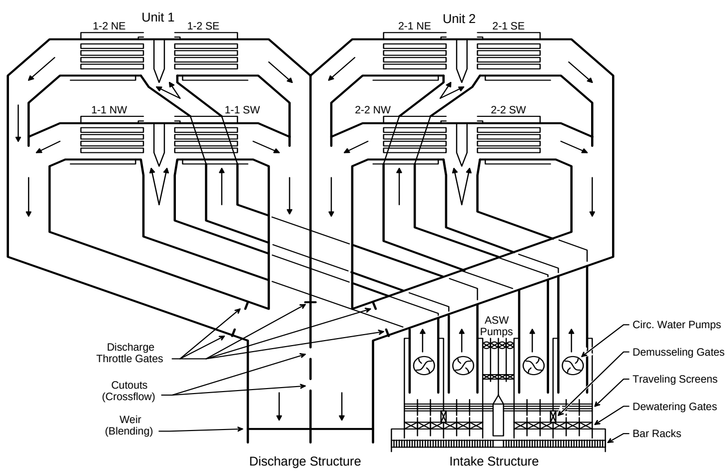

Figure 10 – Existing Circulating Water Conduits

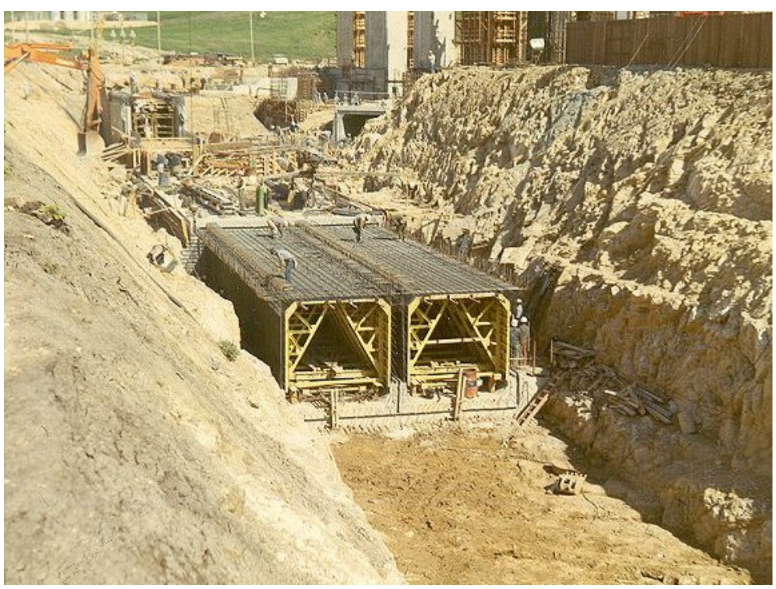

Figure 11 – Original Circulating Water Tunnel Excavation & Construction

The limited area for this intertie in front of the turbine building is extremely congested with both safety related and nonsafety related systems, piping, and conduits as shown in Figure 12.

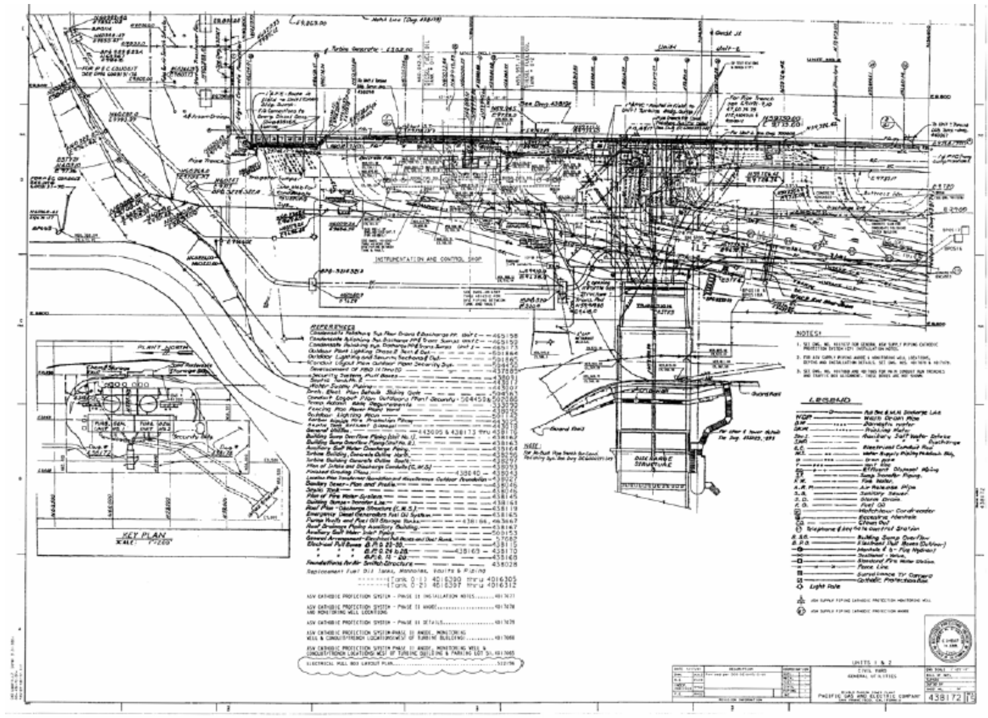

Figure 12 – Existing Underground Utilities West of Turbine Building

Constructing the large diameter concrete tunnels with the associated excavation in this area would result in the disruption of numerous systems that would have to be relocated to accomplish this construction. The safety related ASW system bisects this area, and is required to remain in operation even with both units shut down. The difficulty, time, and cost associated with these excavations, tie-ins, and system interferences are immense. The development of the details of this aspect of the retrofit would likewise be an immense task.

Those utilities which are buried in the vicinity of the proposed tunnel excavations, which would require temporary protection and/or relocation during construction and/or final relocation upon construction completion, include but are not limited to:

Seawater Reverse Osmosis Lines	I&C Conduits & Pull Boxes
Telephone Communications	Aux Saltwater Vacuum Breaker Lines
Microwave Communications	Building Roof Drains
Security Systems (undefined)	Storm Drains
Potable Water Piping	Yard Fire Loop & Branch Lines
Sewage Lines & Septic Tanks	Instrument Air & Service Air
Electrical Conduits & Pull Boxes	Outdoor Lighting
Fiber Optic Cables	Electrical Grounding Cable
12 kV Power Cables	Auxiliary Saltwater Lines (ASW)

3. Modifications to Existing Systems and Required New Systems

A. Condenser Modifications

The present condenser has a history of tube leaks which would be made worse by significantly increasing the waterbox pressures. The present condensers have 2 to 3% of their tubes plugged due to leakage. Increased tube leaks would have an adverse impact on the operation of the condensate polishers and potentially an adverse impact on transient feedwater and main steam chemistry. Secondary side water chemistry is an important aspect of nuclear safety due to potential degradation of steam generators and main turbines (missile generation) and potential plant trips. Plant trips due to chemistry excursions unnecessarily exercise plant safety systems. Transient departures from water and steam chemistry limits would, as a minimum, impact the steam generator and main turbine warranties.

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. Additionally, as noted previously in this report, the rolled tube-to-tubesheet joints in the installed condensers are currently susceptible to saltwater leaks into the condensate system (which can lead to damage of the safety related steam generators and/or unplanned unit shutdowns). The increase in condenser waterbox pressure would increase leakage. Because of these current design limitations and the high probability of significantly increased chloride salts intrusion associated with elevated system pressures, the condenser waterboxes and tubes would be replaced by necessity with modular welded tube-to tubesheet units. The transitions from the buried conduits to the waterboxes would also be upgraded to withstand the increase in pressure.

In order to optimize the performance of the new bundles and thereby minimize the lost generation due to hotter inlet cooling water, the proposed tube bundles would be composed of ¾” diameter titanium tubes (compared to the present 1” diameter tubes) resulting in increased total tube surface area.

Installation of the new condenser tube bundles would be a major undertaking. In order to provide access for the new bundles, existing equipment and large structural members would have to be removed and then reinstalled. The lower end of the large transition pieces from the waterboxes to the underground conduits are imbedded in the turbine building floor concrete, necessitating concrete excavation and replacement.

B. Service Cooling Water Seawater Supply

Inside the turbine building the circulating water presently cools not only the main condensers but also the SCW heat exchangers and the condensate cooler for the main generator hydrogen coolers (to maintain generator gas temperature within limits).

The increase of cooling water temperature to 17°F above the highest wet bulb temperatures (as well as the increase in pressure) would necessitate replacement of both the SCW heat exchangers and the condensate cooler for each unit, and many of the components cooled by the SCW system.

The SCW system removes heat from various secondary system components via a closed loop cooling cycle and rejects the heat to the main circulating water system. The closed loop SCW system presently runs with a typical cold end temperature on the order of 79°F (e.g. 54°F on average seawater inlet flow cools the service cooling water to 79°F). Even if the existing heat exchangers were replaced with much larger heat exchangers, it would not be possible to cool the SCW to 79°F using the warmer circulating water from the cooling towers during periods of highest wet bulb temperature.

The heat loads cooled by the SCW system include:

- Main Feed Pumps Turbine Lube Oil Coolers
- Condensate Booster Pumps Lube Oil Coolers
- Generator Exciter
- Fuse Wheel
- Generator Seal Oil Coolers
- Iso-Phase Bus Coolers
- Main Turbine Reservoir Lube Oil Coolers
- Post LOCA Sampling System Room Air Conditioning and Sample Panel Chiller
- Plant Air Compressors 05 and 06 (via the SCW Booster Pumps)
- Reciprocating Air Compressor Jacket Coolers and Aftercoolers
- Air System Air Dryers
- TSC Air Conditioning Units
- Personnel Access Control Room Air Conditioning Unit
- Operations Ready Room Air Conditioning Unit
- Condenser Vacuum Pump Seal Water Heat Exchanger
- Electro-Hydraulic Control Coolers
- Feedwater Sample Cooler 72
- #2 Heater Drain Pump Lube Oil Coolers and Sample Cooler
- Secondary Process Control Room Isothermal Bath Water Chiller

In addition to replacement of the SCW heat exchangers themselves, many of the above components cooled by the system would require modification or replacement due to the higher SCW closed loop circulating cooling water temperatures. To avoid the need for these extensive plant equipment upgrades, the existing SCW heat exchangers would be cooled by their own once-through cooling system. Therefore, for each unit, three new

50% SCW seawater supply pumps (6 total) sized at 3,150 gpm at 86' total differential head (TDH) would be provided. They would draw water from the intake structure and the cooling flow would be routed in new 20" paralined steel pipes up to the turbine building. The new 20" lines must be routed through an already congested area surrounding the main condensers to the SCW heat exchangers located on the east side of the turbine building. A branch to the condensate coolers would be provided even though the equipment is infrequently used at present for either unit. This routing would replace routing which presently consists of short runs from near the main condenser intake lines embedded in concrete below the 85' (ground) level. The new piping would not be embedded in the concrete, and would therefore invariably have a negative impact on operating and maintenance activities in the vicinity.

To minimize biofouling, it would be necessary to chlorinate the SCW seawater supply lines. The sodium hypochlorite injection system used for the existing main circulating water system would be used for this purpose.

C. Main Circulating Water Pumps

The proposed cooling systems new main circulating water pumps would be 25% capacity each, with one installed spare per unit. They would be rated at 215,000 gpm at 110' TDH. The motor size would be 7,600 hp and would operate at 327 rpm. The five pumps would be vertical turbine configuration, arranged in a row, taking suction from the pump pit which is adjacent to the cooling towers. The pumps would discharge into a common 8' diameter paralined steel circular cross section manifold with valves on either side of the middle pump's tee into the manifold. This would allow any 4 of the 5 pumps to be operated. At either end of the manifold, a transition is made into a 10' by 10' square cross section reinforced concrete tunnel. These two tunnels are directed side-by-side and transition into the existing 11'-9" square concrete tunnels which lead to each unit's main condensers. With this configuration, similar to the existing configuration, the plant may be operated at 50% capacity while one side of each main condenser is taken out of service. Unlike the present configuration without a spare, the spare pump would be able to serve either supply tunnel in the event of another pump's failure.

Each pump's capacity of 215,000 gpm would mean a sudden reduction of flow whenever that pump is taken out of service. This could give rise to pressure fluctuations, known as "water hammer", with possible destructive results. Thus, studies of the effects of water hammer would be recommended, in order to mitigate its detrimental effects. Another characteristic of the closed cooling tower loop being considered is the fact that upon shutdown of the circulating water pumps, some water would flow backward from the high points in the condenser waterboxes (elevation of ~104') and the cooling tower hot side distribution piping (elevation ~125') into the cooling tower basin / pump pit. The basin and pit combined capacity would be sized to accommodate this overflow, which would be routed to the ocean through the weirs discharging to the system blowdown lines.

D. Circulating Water System Piping

Piping conforming to Piping Specification "G" would be utilized. This is steel pipe with an internal coating called "paralining". It has provided excellent service for existing Diablo Canyon seawater applications such as the ASW system, and is suitable for the proposed circulating water system. Concrete coated steel pipe is inferior because of minute cracks in the concrete lining allowing chloride migration to the underlying steel with subsequent destructive corrosion.

Although Specification "G" includes pipe up to a maximum diameter of 24", the company that provided the pipe in the past, Barber-Webb, has indicated that pipe up to 8' diameter can be paralined. The coating must be applied under controlled conditions in the factory. This means it would need to be flanged as opposed to welded in the field since the coating cannot be applied reliably in the field. Sections up to 40' in length can be shipped to the jobsite. Paralined pipe would be used for the makeup water supply, cooling tower blowdown, and the SCW seawater supply. Additionally, the discharge of each of the circulating water pumps would be a paralined 78" diameter steel pipe (Reference Sketches SK-C-12 to 16). The common discharge line that all five pumps connect to would be an 8' paralined pipe.

For the long sections of buried circulating water conduit to and from the cooling towers, concrete-walled tunnels are specified. Conveying 50% of the total flow, they would be a 10' by 10' square cross section with 12" 45° fillets at the corners. The walls would be about 3' thick with steel reinforcement. This configuration and material of construction is consistent with the existing tunnels, although the existing tunnels are larger, with a cross section of 11'-9". The new tunnels would have a velocity of 9.8 feet per second (fps) vs. 7.0 fps for the existing tunnels, but the increased pressure drop is tolerable. Having the smaller cross section allows for a more compact arrangement, especially to the west of the turbine building where all 8 tunnels (4 supply and 4 return) would be buried side-by-side. The new tunnels would be built in place in excavations prepared for them. In some areas to the west of the turbine building and to the west of the cooling towers, the tunnels would need to cross underneath each other, requiring extra deep trenching. This configuration cannot be avoided since the proposed cooling towers for both units are on the south side of the plant.

In the area to the west of the turbine building the new tunnels would transition into the existing tunnels. At this interface, a barricade would be constructed in the old tunnels to isolate them from the empty sections coming from the ocean intake structure and going to the discharge structure. These empty tunnels coming up the hill from the intake structure, specifically lines 1-1 and 2-1, would have the 48" makeup water lines and the 20" SCW system lines routed inside them up to an area near the transition point where they would be routed out of the tunnel on to their respective destinations.

E. Makeup Water Supply

New makeup water pumps would be installed in the intake structure near the removed circulating water pumps. Each unit would be furnished with three, 50% capacity makeup water pumps sized at 22,500 gpm at 216' TDH. With two pumps running, a maximum makeup flow of 45,000 gpm can be delivered, providing a margin over the steady-state makeup requirement of 37,800 gpm. The individual pumps would discharge into a 36" paralined steel pipe. The common discharge header for each unit would be a 48" paralined steel pipe. This pipe would be routed through one of the existing concrete tunnels going to the turbine building that would be abandoned if the plant were retrofit with cooling towers. The 48" makeup water line would be taken through the tunnel wall near the junction point where the new 10 ft square concrete tunnels coming from the cooling towers joined the existing tunnels. The makeup water line for each unit would then branch into two 36" paralined steel pipes each going to one of the two main circulating water tunnels leading to the main condensers.

F. Chlorination and Dechlorination of Effluent Streams

As mentioned elsewhere in this report, both the service cooling water supply lines and the makeup water supply lines would be chlorinated to control pipeline marine biofouling. The ASW stream is also continuously chlorinated. It would be necessary to dechlorinate both the ASW and SCW systems downstream of the heat exchangers since the ability to dilute with main condenser flow would no longer be possible.

The existing site dechlorination system utilizes aqueous sodium bisulfite injected into the condenser discharges. This system is currently installed to service only the main condensers periodically, and would require significant modification to service other effluent streams directly, as well as operate on a continuous basis. For a combined flow of 16,000 gpm per unit (ASW and the SCW seawater supply) approximately 61 gallons of commercial bulk sodium bisulfite would be required each day to adequately dechlorinate. This would result in additional annual chemical supply costs of $150,000. The estimate is based on an initial residual chlorine level target of 1 part per million (ppm) at system heat exchanger inlets.

The blowdown stream could contain residual chlorine, however it would be expected in very low concentrations under most circumstances. Chlorine would be introduced into the main circulating water system under normal operating conditions by the makeup water supply. However, the treated influent would represent only a small percentage of the systems total circulating volume at any given time. System chemical demand, including operation of the cooling towers that would result in extensive exposure of the circulating water to the atmosphere, would likely cause rapid reduction of residual biofouling treatment chemicals. It is not anticipated that routine injection of additional sodium hypochlorite into the cooling tower circulating water would be required because the concentration of salts in the system would be toxic to most common forms of aquatic life.

If excessive organic microfouling of main condenser tube surfaces did occur under certain conditions, periodic oxidant treatment of the cooling tower circulating system may be required. In that event, the blowdown stream could be temporarily isolated until residual chlorine levels reduced below discharge limitations, the entire circulating system could be dechlorinated, or the blowdown flow could be directly dechlorinated. Main condenser circulating system effluents should not otherwise require dechlorination.

4. Electrical System Requirements

A. Electrical Design Features

Mechanical draft cooling towers have considerably more power requirements than the existing once-through cooling system. This additional parasitic power is primarily for the mechanical draft fans required for the cells. At 300 hp each, about 12 MVA per unit are needed at an assumed power factor of 0.88. Other new power required for the cooling tower installation would be the makeup water pumps drawing about 2,700 kVA per unit. Also, each unit would require a seawater supply to the service cooling water system, requiring another 170 kVA.

The new circulating water pumps would replace the existing circulating water pumps which would be abandoned and removed from the intake structure. The new circulating water power requirements are roughly equivalent to the existing requirements but would not be fed from the existing 12 kV buses. Rather, new 13.8 kV power would be brought down from the 500 kV switchyard.

The various existing auxiliary transformers at Diablo Canyon do not have nearly enough margin to provide the additional loads to power the cooling tower fans and other auxiliaries. The most practical and cost effective way to provide the new power requirements has been determined to take power from the outgoing 500 kV transmission lines, one 500 kV line source for Unit 1, the other for Unit 2. A new bay at the 500 kV switchyard would be required to locate each unit's cooling tower transformer (Reference Sketch SK-E-1). The power sent to these transformers would need to be metered in order to make corrections to the power sent out. The voltage would be first reduced from 500 kV to 13.8 kV, with the outgoing 13.8 kV conductors routed down to the cooling tower locations (Reference Sketch SK-C-17). A voltage level of 13.8 kV is selected rather than 12 kV because 13.8 kV is a more standardized high voltage level used in industry. The 500 kV/13.8 kV transformers would be rated at 64 MVA with a power factor of 0.88. At the cooling tower area, the 13.8 kV conductors would be routed to the new circulating water pumps, rated at about 7,600 hp each, five per unit. The other 13.8 kV conductors would be routed to three transformers per unit, each having a rating of 13.8 kV/4 kV, 5.4 MVA capacity. Individual 4 kV buses would be routed from each of the three transformers into an adjoining electrical equipment building where the 4 kV breakers for the 40 cooling tower fan motors would be located. Each unit's cooling tower electrical building would be approximately 16'W x 160'L x 12' H, constructed of protected coating steel, and set atop a concrete foundation.

The new service cooling water supply pumps and makeup water pumps and their transformers and switchgear would be located in the existing intake structure, placed immediately on the upstream (intake bay) side of where the existing circulating water pumps now reside. Power for the makeup water pumps would be 4 kV, from new transformers, one per unit, rated at 12 kV/4 kV with a capacity of 9 MVA each. The service cooling water seawater supply pump motors, at 100 hp nameplate each, would be stepped down to 440V, requiring additional small transformers. The 12 kV input power for the 12 kV/4 kV transformers would come from the existing 12 kV feeds to the abandoned circulating water pumps (Reference Sketch SK-E-2).

B. Instrumentation and Controls

The existing high voltage electrical bus and circulating water system controls are via hard wired relay logic. The operator interfaces for these systems consist of hardwired switches, indicators, and annunciator windows on vertical boards VB-5 and VB-4, respectively, in the main control room. There is insufficient space in the main control room to provide similar hardwired operator interfaces for the additional high voltage buses and circulating water system controls. Modern control systems reliably utilize touch screen operator interfaces and digital controls. Therefore this approach would be used.

Refer to Sketch SK-J-3 for a conceptual block diagram of the proposed control system and operator interface. The proposed control system for the new high voltage buses and the circulating water system would be the Triconex Tricon digital control system. This highly reliable, triple redundant platform already provides the main turbine controls and feed water system controls at DCPP. It has been approved for safety related applications by the NRC, and DCPP intends to use it for safety related control and protective systems in future upgrade projects (Note: Electrical protective functions such as over-current protection would be performed by equipment other than the Triconex). The Triconex control hardware (one main chassis, three expansion chassis, and associated field termination panels per unit) would be located in the electrical room at the new cooling tower location. A total of four Triconex cabinets per unit would be anticipated in this location. There would also be a remote input/output (I/O) expansion chassis per unit and associated field termination panels located in the intake structure. A total of two Triconex cabinets per unit are anticipated in this location. Reference Sketch SK-J-4 for a preliminary Triconex I/O list.

Machinery vibration monitoring would be provided by four Bently Nevada racks per unit in the cooling tower electrical room and three racks per unit in the intake structure. Three Bently Nevada cabinets are expected to be required in the former location and two in the latter per unit. Data would be transmitted to the Triconex control system via data links. Reference Sketch SK-J-5 for a preliminary Bently Nevada I/O list.

Chemistry monitoring and injection controls would be required for the new bisulfite injection system. Control would be through the Triconex.

Interface equipment would be required for a connection to the Cal ISO for monitoring power usage of the new equipment.

The main operator interface would consist of touch screen human machine interfaces (HMIs) in the main control room. Sketches SK-J-1 and 2 show that two HMIs would be installed on the bench board section of VB-4. A panel in the cooling tower electrical room would have two additional HMIs as well as backup hardwired control switches and indications for critical electrical bus controls. Existing annunciator panels in the main control room would be revised to provide alarm windows for the new equipment. Data would be provided to the plant process computer (PPC) via a data link to the plant data network (PDN). This would allow process data to be displayed on PPC HMIs on the operator control consoles in the main control room.

Communication between the Triconex main chassis and main control room HMIs, between the Triconex main chassis and the remote I/O chassis, and between the Triconex main chassis and the plant data network would be via new redundant fiber optic cables. A relatively small number of hardwired circuits would be required from the cooling tower electrical room to the intake structure or directly to the turbine building. In the former case, it is expected that existing circuits between the intake structure and the turbine building could be reused. In the latter case, the new circuits could be run with the fiber optic cables. I/O circuits from new equipment to Triconex and Bently Nevada equipment would be hardwired. By locating the Triconex I/O chassis near the equipment, circuit lengths would be reduced.

Uninterruptible Power Supplies (UPS) would be required for the new Triconex and Bently Nevada equipment. There would be a UPS in the cooling tower electrical equipment room and a UPS in the intake structure for each unit. Operating parameters and alarms would input to the Triconex and this information would be available at the main control room and HMIs in the cooling tower electrical room.

The control system would provide manual start and stop capabilities for equipment and, where appropriate, automatic sequenced operation of equipment (e.g. cooling tower fans) during startups and shutdowns. Cooling fan starts would be sequenced based on unit load via a signal from the existing main turbine control system (MTCS).

Changes would be required to the existing MTCS. A turbine load signal would be needed to the circulating water control system. Existing logic that reduces turbine load upon loss of a circulating water pump would require changes. A turbine trip upon 13.8 kV bus undervoltage may be desirable in addition to the existing turbine trip on low vacuum. The existing MTCS cannot accommodate significant additional logic since it is heavily loaded. Changes are expected to be minimal so are not expected to require an upgrade to the MTCS.

Changes to the reactor trip logic are not anticipated but would need to be investigated if this project was to be implemented. If required, this could result in changes to the solid state protective system (SSPS) inputs and changes to significant numbers of plant drawings, documents, and procedures.

V. Nuclear Safety and Licensing

1. Nuclear Safety System Requirements

Retrofitting Diablo Canyon with closed loop cooling towers creates several nuclear safety issues that would have to be addressed. It is most likely that these issues would require Nuclear Regulatory Commission (NRC) review and approval via License Amendment Requests (LARs) to insure an acceptable level of safety. There is a risk that such issues could result in LARs that would not pass the NRC review and approval process. As noted previously, retrofit of the ASW system to a closed-cycle cooling configuration is not feasible from a Nuclear Safety and Licensing perspective. The nuclear safety related issues include:

- **Flooding**
  The condenser cooling water system is a nonsafety related system and is not required for the safe shutdown of the plant. However, flooding caused by failure of the system in the area of the condensers could jeopardize safety related systems located in the turbine building (Emergency Diesel Generators, Component Cooling Water heat exchangers, safety related conduits and controls). The Diablo Canyon Final Safety Analysis Report (FSAR) discusses the possibility of flooding from the cooling water system, and the attributes of the system that lessen the risk due to flooding. Key to those attributes is the present low pressure in the condenser waterboxes and a circulating water pump trip upon high water in the turbine building sump. With the present system, after a circulating water pump trip and coastdown, the water in the large conduits would drain by gravity flow back to the ocean and not into the turbine building. Retrofitting the present system with cooling towers adversely changes both these system attributes – the waterbox pressure would approximately double, and after a pump trip, large quantities of water in the circulating water pipes (now at an elevation higher than the condensers) would gravity drain into the turbine building. This increase in flood risk would have to be addressed in the FSAR Update and may not be acceptable to the Nuclear Regulatory Commission (NRC).

- **Salt Deposition – Increase in Plant Trips**
  As discussed further under “Air Quality – Plume / Salt Drift”, there would be significant salt deposition on the power lines leaving the plant giving rise to an increase in the frequency of plant trips due to “loss of off site power”. Although the plant is designed to safely shut down after such an event, it would result in an increased reliance on the plant safety systems which increases the plant safety risk, and is a topic of interest to the NRC.

- **Salt Deposition – Accelerated Aging of Plant Equipment**
  Salt deposition from the cooling towers would have the general effect of increasing corrosion, required maintenance, and frequency of failure of exposed plant equipment. For example, with a southeasterly wind the plume could engulf the safety related Emergency Diesel Generator (EDG) ventilation intakes. This would accelerate the corrosion problems with the EDG radiators (already a problem with existing salty air), and may cause operational problems with the EDG controls. See further discussion under "Air Quality – Plume / Salt Drift"

- **ASW System Interruption**
  The massive and complex construction excavation activities west of the turbine building necessitated by the cooling tower retrofit would increase the probability of interruption of the safety related Auxiliary Saltwater (ASW) cooling system during construction. Even during plant shutdown, the ASW system is required for spent fuel pool cooling. The NRC may prohibit this increased risk of disruption of the safety related ASW cooling system, and may require an alternate means of cooling the spent fuel pools.

- **Loss of Offsite Power**
  The past plant design basis was to withstand a full load rejection without a reactor trip by running back the turbine. The plant would remain online powering the house loads off the 25 kV bus. With the recent replacement of the steam generators, the design basis of the plant has been changed to a 50% load reduction rather than a full load rejection. However, previous plant load rejection controls are still functional, and there are scenarios in which the reactor will not trip and the turbine generator will continue to supply house loads (including the reactor coolant pumps and the circulating water pumps) after both 500 kV breakers open. If cooling towers were installed, power to the circulating water pumps would no longer be from the 25 kV generator output bus but from the 500 kV system. Similarly, power to the new cooling tower fans would be provided from the 500 kV system. Therefore, unlike the existing system, condenser vacuum would be lost if both 500 kV breakers open. Existing protective systems would result in a turbine low vacuum trip and subsequent reactor trip. It may be necessary for protective logic to be implemented to immediately trip the reactor when both 500 kV breakers open rather than relying on an eventual low vacuum turbine trip. This would require changes to the SSPS inputs and changes to significant numbers of plant drawings, documents, and procedures. Further study of this issue and NRC review and approval would be required if the project were implemented.

- **ISFSI Haul Road Rerouting**
  Hauling dry casks of spent fuel from the Fuel Handling Building up to the ISFSI storage area has been described in the ISFSI FSAR, and has been reviewed/approved by the NRC. The haul road is important to safety and has several requirements including a maximum slope of 8.5%, as well as support of loadings from the dry cask transporter. The present route has avoided

existing and future landslide-prone areas and has been designed to withstand the effects of a Hosgri Fault earthquake while encumbered with a loaded transporter without the transporter being damaged (tipping over). Therefore, the new routing of this haul road due to the installation of cooling towers and their auxiliaries would require a new detailed analysis and review/approval by the NRC.

- **Landslide Potential**
  Certain areas of the site are active landslide zones. The relocation of the ISFSI haul road, as well as the location of the cooling towers and their auxiliaries, would need to be located to avoid areas of anticipated future landslides. This issue would be subject to NRC scrutiny.

- **Fire Protection System Interruptions During Construction**
  The NRC would have concerns with the possibility of any compromises to the fire protection system, such as accidental damage to the yard fire loop, which could occur during construction. This is a risk since extensive excavation would be required for the cooling towers and concrete tunnel construction.

- **Security During Construction**
  The massive excavations and disruptions of normal site security boundaries, and the large numbers of construction personnel and equipment crossings of Protected Area (PA) boundaries, would be of concern to the NRC.

2. NRC Licensing

NRC regulations 10 CFR 50.59, 10 CFR 50.90 and 10 CFR Part 51 govern proposed changes to a nuclear plant. These regulations specify when prior NRC review and approval of plant changes is necessary. As part of a cooling tower retrofit, PG&E would perform a 10 CFR 50.59 evaluation in accordance with the guidance provided in Revision 1 of NEI 96-07 and Regulatory Guide 1.187, both dated November 2000. As discussed previously in this report, retrofitting Diablo Canyon with closed loop cooling towers creates several nuclear safety issues that in accordance with 10 CFR 50.59 would require NRC review and approval via the License Amendment Request (LAR) process (10 CFR 50.90 and 10 CFR Part 51). These issues include the increased risk of flooding of safety related equipment, the increased risk of plant trips and accelerated aging of plant equipment due to salt deposition, the rerouting of the ISFSI haul road, and the risk of disruption of the ASW system during construction. There is a significant risk that that the NRC would not be willing to grant a license amendment to allow the change in design that creates or increases these nuclear safety issues. Also, the NRC will need to ensure that the National Environmental Policy Act (NEPA) is appropriately implemented for the environmental effects of the proposed cooling towers construction and operation. In order to request NRC approval, the final design must be completed, applicable State permits issued, and an LAR prepared and submitted to the NRC. The NRC review period typically takes one year after submittal of the LAR. In addition, it is anticipated that interveners would request NRC hearings. NRC hearings could take two to three additional years.

3. Security

Retrofitting cooling towers at DCPP would have a major impact on site security. The plant PA boundary would have to be ultimately relocated to accommodate the installation of the cooling towers and their auxiliaries. The boundary for this would be approximately in the same area to the southeast of the power block, with the cooling towers, circulating water pumps, and the associated electrical buildings being located outside the PA. The relocated main warehouse would also be located outside the PA.

VI. Environmental Impacts and Permitting

1. Air Quality – Plume / Salt Drift

Significant visible plumes would be generated by cooling towers at DCPP, and would be frequently visible from San Luis Obispo and/or Avila Beach. The largest plumes would have lengths exceeding 5 miles and heights exceeding 2,500 feet.

Background: When the ambient air is cooler than the moist cooling tower exhaust air, it cannot absorb all the moisture, and the excess moisture in the exhaust air stream condenses creating a visible plume. Under certain conditions, a cooling tower plume presents a significant fogging hazard to its surroundings. The water evaporated in the cooling process is "pure" water, in contrast to the drift droplets carried along with the plume. “Drift” is the water droplets that become entrained in the air stream as it passes through the cooling tower. The rate of drift loss is a function of cooling tower design and configuration, airflow rate through the cooling tower, and water loading. Drift droplets have the same or greater concentration of impurities as the water entering the cooling tower. Because the drift contains the minerals and chemicals of the makeup water, contact of these salts and chemicals with plants, building surfaces, and human activity can be detrimental and/or hazardous. Sedimentation of drift droplets downwind of the cooling towers would result in an increase in ground level concentrations of salt chemicals.

Due to their size and the limited space available at DCPP, plume-abated cooling towers could not be located at the plant site. They are larger than the nonplume-abated cooling towers being evaluated in this study, and require a significantly larger footprint. The plume-abated cooling towers have a greater height required for the cooling tubes and additional fans for the incoming hot water. For proper operation they also need to have air coming in from both sides ruling out the back-to-back rectilinear arrangement selected for the nonplume-abated cooling towers. The only layout possibilities for plume-abated cooling towers would either be circular or extended rectilinear footprints with a width of only one cell and a length necessary for 40 cells (~2,400’). Neither configuration is a possibility given the characteristics of the site discussed elsewhere. The tubes would have to be titanium for corrosion resistance. The fan power would be about double what the nonplume-abated cooling towers consume. The cost for plume-abated cooling towers is at least 150% of that for nonplume-abated cooling towers. In summary, the lack of a suitable location has ruled out plume-abated cooling towers for DCPP.

To determine the environmental impact of cooling towers at DCPP, the seasonal/annual cooling tower impact (SACTI) prediction code was utilized along with the cooling tower design data and local meteorology data. The SACTI software is described by the NRC in Section 5.3.3.1 of Standard Review Plan, NUREG-1555, as appropriate for this purpose. For purposes of this study it is assumed that both units are operating at 100% power.

As noted previously, accurate Diablo Canyon site specific data for humidity or wet bulb temperature is not available. Therefore, for purposes of this study, hourly wet bulb temperatures for the years 2003 through 2007 were taken from the National Weather Service (NWS) station at the San Luis Obispo (SLO) Airport. Site specific wind velocity and direction data for DCPP was utilized. The SLO Airport weather station data gives lower wet bulb temperatures (due to drier inland conditions) than would be experienced at the Diablo Canyon site. The use of these lower wet bulb values rather than site specific coastline data results in smaller predicted plumes (provides a conservative study bias).

A summary of visible plume lengths that would result from cooling towers at DCPP is presented in Table 5. Plumes greater than 1/3 of a mile in length would be present approximately 73% of the time during winter and 60% of the time in the fall. Plumes greater than 2 miles in length would be present approximately 35% of the time during winter and 25% of the time in the fall. In most cases, the plumes tend to lie either towards the northwest (over the plant itself, especially in the winter) or to the southeast (along the access road from Avila Beach).

	Winter	**Spring**	**Summer**	**Fall**
Most Frequent Plume Heading Directions	NW,SE	SE,ESE,SSE	SE,ESE	SE,ESE,SSE
Percent of Plumes < 1/3 miles	26.9	35.0	44.2	40.4
Percent of Plumes >1/3 to 2 mile	38.5	28.2	30.3	34.8
Percent of Plumes >2 to 5 miles	30.3	32.8	24.3	22.5
Percent of Plumes >5 Miles	4.3	4.0	1.3	2.2

Table 5: Visible Plume Length Frequency Summary – Percent

Table 6 shows the percent of time for various centerline heights of the plumes above the tops of the proposed cooling towers. The highest plumes, like the longest ones shown in Table 5, extend down the coast in the ESE to SSE direction.

	<100m (<330 ft)	100 - <500m (330 - 1640 ft)	500-<750m (1640 - 2460 ft)	750 - 810m (2460 - 2700 ft)	Total Percent
S	0.43	0.36	0.71	1.5	3
SSW	0.26	0.39	0.66	1.22	2.53
SW	0.35	0.49	0.86	1.4	3.1
WSW	0.39	0.42	0.67	1.3	2.78
W	0.38	0.4	0.83	1.6	3.21
WNW	0.23	0.78	1	2.55	4.56
NW	0.56	1.89	1.94	4	8.39
NNW	1.24	2.51	1.26	1.93	6.94
N	1.36	1.02	0.62	0.97	3.97
NNE	0.43	0.52	0.3	0.45	1.7
NE	0.36	0.44	0.27	0.37	1.44
ENE	0.43	0.42	0.22	0.31	1.38
E	1.24	0.75	0.49	0.76	3.24
ESE	7.44	2.87	1.29	2.08	13.68
SE	13.81	3.34	3.8	9.75	30.7
SSE	1.44	0.71	1.87	5.36	9.38
All	**30.35**	**17.31**	**16.79**	**35.55**	**100.00**

Table 6: Plume Heights – Centerline Height Percent by Direction

Plume visibility by calendar time is not an output of the SACTI program, but estimates can be made based on the frequency of conducive meteorological conditions. Such an estimate determined that plumes would be generated of sufficient size to be seen from Avila Beach between an hour before sunrise and an hour after sunset approximately 45 times per year, and from San Luis Obispo approximately 300 times per year. The plumes would be visible from San Luis for approximate 200 sunsets per year.

Estimates of salt, TDS, PM_{10}, and water deposits are given in Tables 9a, 9b, 9c, and 10 of Appendix A-7. Due to the use of saltwater, the salt deposition rates are notable for some distance. The five miles of plant access road along the coastline will be exposed to some amount of salt. The makeup of the total dissolved solids is over 75% sodium chloride. The total annual salt deposition would exceed 7,500 tons.

Buildup of salt on the transformers, conductors, and insulators associated with the 500 kV system would require continuous attention in the form of frequent water washings and monitoring of the system to minimize flashover incidents. The power generation industry experiences significant problems caused by salt buildup on electrical systems at plants which are less exposed to salt deposition than that which would be seen at DCPP should cooling towers be installed. Numerous plants located on coastal areas, e.g., SONGS in Southern California, Turkey Point in Florida, and Brunswick in North Carolina, have experienced flashover of high voltage equipment due to excessive accumulations of salt. (Reference Nuclear Industry OE 21874, OE 21784, and SER 10-93). To combat the problems of excessive salt buildup, operators have found it necessary to increase the frequency of water washing. Also, increased vigilance is placed on monitoring electrical measurements associated with the transmission system to obtain early warnings of flashover in order to avoid equipment damage.

At DCPP, salt drift from the cooling towers would deposit large quantities of salt in a broad radius surrounding the cooling towers (Reference Table 8 for Adverse Environmental Impacts). The amount of salt deposits on the exposed high voltage electrical components would greatly increase over the existing salt deposition rates. Frequent washings and monitoring would be required – at a minimum. Precise predictions of increased outages due to electrical flashover of equipment attributable to excessive salt buildup associated with cooling tower drift is not possible, but an increase in such outages with attendant interruption of generation would be expected. The alternative of locating high voltage transmission lines underground between the generator step up transformers and the switchyard is extremely costly and of questionable reliability, and has not been considered in this study.

Shading and fog from the plumes are given in Tables 11 and 12 of Appendix A-7. There will be some loss of sunlight near the cooling towers. The fogging is predicted to interact directly with plant components to the NW and plant worker and equipment or commercial transport vehicles approaching from the SE.

Figure 13 – Cooling Tower Plume (Looking North)

Figure 14 – Cooling Tower Plume (Looking Southeast)

Palo Verde – Mechanical Draft Towers in a Dry Environment

Palo Verde

Washington Public Power #2

Cattenom

Cattenom

Figure 15 – Plumes from Nuclear Power Plant Cooling Towers

2. Water Quality – Cooling Tower Blowdown

Each unit would require a steady state blowdown flow of approximately 25,200 gpm when running at full load. The concentration of the circulating water would be 1.5 times normal seawater. Thus the blowdown would have a concentration of about 52,500 ppm TDS given an average seawater concentration of 35,000 ppm TDS. The blowdown stream is toxic to marine life due to the higher TDS concentration, therefore it would either have to be rapidly diluted with ambient seawater as it is introduced into the ocean or it would have to be treated to reduce its TDS concentration back to that of seawater.

Technology exists for removing salt from concentrated waste streams. The technology is known as zero liquid discharge (ZLD) and typically involves successive stages of reverse osmosis, brine concentration, followed by crystallization where a salt cake is created. At DCPP the waste stream of concentrate obviously could not be put back into the ocean, so the salt cake would have to be dried and trucked offsite to a waste disposal facility. Besides this waste disposal activity, the main disadvantage of ZLD for this application is the very high cost of the equipment and the high levels of electric power required. A rule of thumb for power requirements for ZLD (per discussion with Aquatech) is 15 kW of power are required for each gpm of waste stream to be treated. Thus, for DCPP's waste stream of 25,200 gpm per unit that would mean 378 MW of power. In DCPP's case this power is overstated since not all the dissolved solids would be extracted from the blowdown, but rather just about 1/3 of them in order to achieve a TDS level equal to the ocean. However, DCPP would still require the brine concentrator and crystallizer systems since whatever salt levels removed would have to be trucked away in solid form. Brine concentrator and crystallizer engineering and operation is fraught with challenges because of scale buildup on the heat exchange surfaces as well as corrosion. Dryer operation is also problematic. Periodic acid cleaning of the systems is required.

Due to the problems associated with ZLD systems as described above, they are not considered practical for the massive application that would be required for DCPP. Rather, the blowdown stream would be mixed with receiving waters by use of diffuser arrays in order to mitigate the effects of the concentrated wastewater stream on sea life.

Plant effluent salinity within 10% of ambient has been provided (regulator guidance) as the acceptable range for discharge permit approval if the outfall configuration does not facilitate rapid diffusion in the ocean receiving water. This concentration range cannot be achieved even with dilution of cooling tower blowdown with the 51-mgd remaining once-through cooling volume proposed for the ASW/SCW systems (72-mgd at 1.5x combined with 51-mgd at 1.0x results in a discharge salinity of approximately 1.3x). Therefore, the cooling tower blowdown cannot be permitted for discharge to a single shoreline or submerged outfall point without substantial additional dilution water sources. Other plant effluent streams (including freshwater wastewater streams) do not provide enough volume to appreciably impact dilution. Additionally, use of excessive amounts of ambient seawater purposefully drawn into plant systems to achieve acceptable outfall salinity would be counter to any retrofit effort implemented to minimize seawater use.

The only practical option for rapid dilution to ambient salinity is use of a diffusion system spread across an acceptably large area in the receiving water body. For this application, a seafloor-anchored diffuser piping array placed out from the shoreline and intertidal zone would be required to reduce or eliminate potential negative impacts to receiving water quality and marine life.

Of specific concern for cooling tower blowdown (in addition to necessity for rapid dilution in receiving waters) are the Effluent Limit Guidelines (ELGs) for select constituents. These ELGs are specific for point of discharge from cooling tower systems, and not for final concentrations detected at a facility's combined wastewater outfall. Chromium (Cr) and Zinc (Zn) have blowdown ELGs of 0.2 mg/L (milligrams per liter or parts per million) and 1.0 mg/L respectively. An assessment of intake seawater (influent) samples taken monthly for DCPP during the period 2005-2007 determined that Cr was almost exclusively non-detectible with one value of 0.2 ug/L (micrograms per liter or parts per billion) concentration during the period. Zn was also routinely non-detectible; however, several instances of detection did occur with a maximum concentration of 59 ug/L during the period. For both of these constituents, concentration factors of 1.5x or even 2.0x in cooling tower blowdown would not result in an exceedance of the process specific ELGs provided available makeup at DCPP continued to exhibit low concentrations. Other cooling tower blowdown priority pollutant ELGs should likewise not be problematic provided ambient seawater chemistry off the plant site remained stable.

Closed-cycle systems tend to exhibit more alkaline pH than makeup water. For DCPP, ambient seawater normally has a pH in the range of 7.8 to 8.4. This pH range facilitates chlorine/bromine control of biological fouling in existing seawater systems. As discussed previously in this report, the high salinity projected for cooling tower system operations should reduce or eliminate macrofouling concerns (primarily marine barnacle and mussel fouling) within the system. However, fouling of main condenser tube surfaces might still occur under certain conditions due to micro-organisms capable of withstanding the high salinity. This could require periodic chlorination treatment of the main condensers. However, such treatment would be hindered by elevated pH conditions. Acid (hydrochloric or sulfuric acid) injection to depress system pH could be necessary in order to facilitate microfouling oxidation treatment within the main condensers. It is not anticipated that addition of inorganic acids to effect moderate pH depression would negatively impact overall water quality in the system, or subsequently reduce the ability to discharge the blowdown.

Chlorine treatment on an as-needed basis injected immediately upstream of the main condenser inlets could be accomplished with only a temporary increase in residual oxidants within the system. The cooling tower blowdown may require temporary isolation in the event residual chlorine was persistent. If actual operations required extended chlorination treatment, or resulted in excessive residual chemical concentrations, cooling tower blowdown dechlorination capability could be required. Actual need for pH moderation, main condenser biofouling treatment, and/or periodic cooling tower blowdown dechlorination is highly speculative. Therefore, equipment specifications and costs to implement these processes have not been considered in this study.

The blowdown stream would be taken from the cold side of the cooling towers, having a maximum temperature of 83°F given a "maximum" wetbulb temperature of 66°F (this "maximum" wetbulb represents a point 2 standard deviations to the right of the mean wetbulb value of 52.0°F, representing all but 193 hours per average year when the wetbulb is greater than 66°F).

Blowdown would be directed into a pipe from a weir gate at the pump pit to achieve the desired flow. From there the pipe would be directed to the ocean near Patton Cove, south of the intake cove. The temperature and concentration of the blowdown being higher than that of the seawater would result in a density of 64.7 lb/cu ft, as compared with a seawater density of 64.0 lb/cu ft. Being heavier, the blowdown stream would tend to sink amid the seawater, with negative effects on benthic marine communities. To counter this tendency, the blowdown stream would be channeled through diffusers at a high velocity, (5 ft/sec minimum) in order to promote mixing with the surrounding seawater. The blowdown distribution system would consist of a large distribution header, approximately 36", which would be filled from a weir at each circulating water pump pit where the flow could be set for a steady state flow of 25,200 gpm per unit, and would discharge under water on the sea floor (Reference Sketch SK-M-4). On the top of the underwater pipe would be located an array of diffuser nozzles (approximately 600 1½-inch diameter nozzles). Given equal flow they would each have a discharge velocity of 6.6 feet per second. At this velocity, the concentrated stream would be forced to mix with the less concentrated seawater as it exited the nozzle. Static head from the 85 foot elevation at the inlet of the blowdown line would provide the driving force for the flow. The nozzles would be located on 1 foot centers, two at each station, symmetrically configured pointing upward at an angle of 60° from the horizontal. The diffuser section of the piping would start 200 feet from shore and extend another 300 feet for a total of 500 feet per unit. Fiberglass would be a suitable material for the diffuser system.

The blowdown plume was modeled with CORMIX, a comprehensive software system for the analysis, prediction, and design of outfall mixing zones resulting from the discharge of aqueous pollutants into diverse water bodies. It contains mathematical models of point source discharge mixing within an intelligent computer-aided design interface. The programs focus is environmental impact assessment and regulatory management. It has been developed under several cooperative funding agreements between U.S. EPA, U.S. Bureau of Reclamation, Cornell University, Oregon Graduate Institute, University of Karlsurhe, Portland State University, and MixZon Inc. during the period 1985-2007.

CORMIX is a recommended analysis tool in the permitting of industrial, municipal, thermal, and other point source discharges to receiving waters. The system's major emphasis is on predicting the geometry and dilution characteristics of the initial mixing zone so that compliance with water quality regulatory constraints may be judged.

CORMIX was used to evaluate the thermal and total dissolved solids (TDS) plumes that would be discharged as a result of the closed-cycle cooling installation. The expected thermal plume from the diffuser array ports was found to be 0.80 meters (2.6 feet) long before reaching the 2.78°C (5°F) isotherm above the ambient. The expected TDS plume was found to be approximately 0.77 meter (2.5 feet) long. The current thermal discharge associated with the once-through cooling system is much larger, has an average thermal differential of approximately 11.1°C (20°F), and dissipates from a single shoreline outfall. An amendment would be required to the power plant's NPDES Permit to define the modified thermal discharge characteristics, including use of the entirely new offshore diffuser array. The actual plant discharge has not been designed, but the results provided would be bounding for any similar discharge. Table 7 summarizes the CORMIX results:

Plume Type	Ocean Temperature °C (°F)	Discharge Flow Rate (Per Unit) m^3/s (gpm)	Isotherm Considered °C (°F)	Plume Length m (ft)
Thermal	9.33 (48.8)	1.59 (25,200)	2.78 (5)	0.80 (2.6)
TDS	9.33 (48.8)	1.59 (25,200)	2.78 (5)	0.77 (2.5)

Table 7: Summary of Thermal Plume Analysis

DCPP is currently permitted to return wastewater to the ocean at a temperature of no more than 22°F higher than ambient seawater intake temperature. It has been assumed that a reconfigured DCPP would be required to meet the 20°F limit above ambient receiving water temperatures for a 'new' discharge in accordance with the California Thermal Plan. Since the cooling water blowdown would always be 17 °F higher than the wet bulb temperature, there would be numerous occasions when the blowdown temperature would be more than 20°F above the ocean temperature. Examination of wet bulb temperature and ocean temperature at the intake structure show that the differential temperature would exceed 20°F approximately 25% of the time. The use of SLO Airport weather station wet bulbs, which are likely lower than the wetter immediate coastal zone, adds a bias which tends to reduce the estimated hours per year that the blowdown would exceed the ocean water temperature by more than 20°F.

Figure 16 shows the hours per day that the blowdown would exceed the ocean water temperature by more than 20°F (based on data from the years 2003 – 2007). Note that the limit is rarely exceeded in winter, but often in summer.

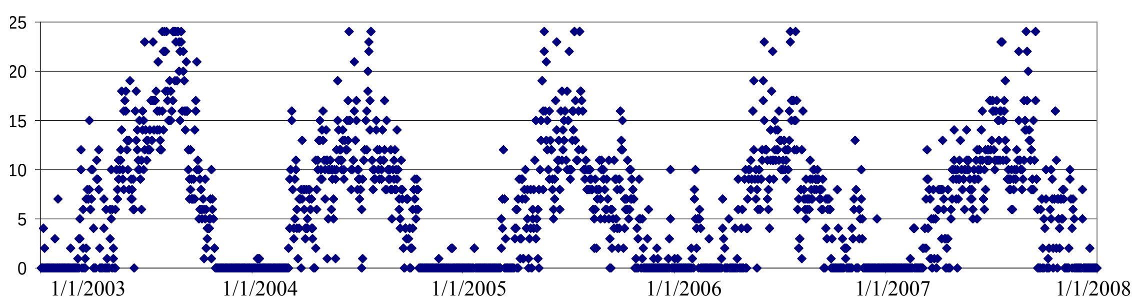

Figure 16 – Hours/Day that the Blowdown Water Temperature Would Exceed the Discharge Limit

Under such conditions it would be necessary to cool/dilute the blowdown stream with a colder stream such as the service cooling water seawater supply or the makeup water system. For purposes of this study, a 20” branch from the SCW seawater supply would be routed to the inlet of the blowdown line to achieve the desired mixing. During these periods when blowdown temperature reduction is required, it would be necessary to run the third SCW supply pump. This would result in an additional volume of raw seawater use during these periods.

3. Adverse Impacts

Retrofit of DCPP to closed-cycle cooling would create significant adverse environmental impacts. These direct adverse impacts, as discussed below, would be realized both during implementation of the project, as well as during post-retrofit operation of the facility. Additionally, the large workforce, and transportation of equipment and materials required during the construction phase, would generate negative impacts to the immediate surrounding communities. Personnel transportation to and from the facility would substantially increase light vehicular traffic in the immediate area for an extended period. Heavy equipment and materials trucking would significantly impact traffic flow and generate appreciable road noise.

The project would generate significant adverse impacts related to overall electric industry green house gas (GHG) emissions. Loss of DCPP Units 1 & 2 for an extended period of time during construction (projected at 17 months minimum) would require replacement of the entire base load generation capacity of the facility. This lost electric supply would most likely be replaced throughout the period of construction with higher utilization of available fossil fuel generation units. Additionally, the permanent loss of unit efficiency and increase in required auxiliary power for the cooling tower system operations would result in an ongoing reduction in net base load generation. This post implementation reduction in electric generation capacity would need to be replaced by other base load generation facilities (fossil units). The loss of long term capacity would effectively reduce future supply gains from planned efficient fossil and renewable resource generation projects in the State.

Demolition, construction, and transport activities associated with a retrofit project would be substantial. The very large equipment associated with these activities would rely on diesel combustion, and therefore result in substantial consumption of fuel oil as well as the associated onsite emissions of GHG and particulates. Most construction activities would occur within the existing, previously disturbed, site industrial areas. However, the placement of a discharge dispersion system on the seafloor offsite of the plant would disrupt and segment pristine rocky marine habitat, as well as disrupt transited intertidal zones during pipe placement. The large demolition and new construction projects would also generate substantial volumes of related debris. Metals, wood, concrete, and asphalt can be recycled; however they would still require offsite transport resulting in additional fossil fuel consumption. Non-recyclable fills, plastics, equipment and existing building materials would need to be transported offsite as well, and disposed in limited available landfill space.

Salt emissions from the saltwater makeup mechanical draft cooling towers would present a significant new adverse impact at the plant site. Salt drift would plague the entire industrial site and all exposed plant equipment, as well as settle on surrounding lands. The deposition of salt to the terrestrial plant and animal community on coastal bluffs southeast of the facility would dramatically increase, far in excess of the natural contamination from winds coming off the adjacent sea. Additionally, substantial vapor plumes from the cooling tower complex would be visible during certain periods to surrounding communities.

Operation of the cooling tower systems would generate large volumes of high salinity elevated temperature blowdown requiring disposal to the Pacific Ocean. Construction of the diffuser system for discharge of the blowdown would disrupt the existing seafloor community, and operation of the system could result in establishment of high salinity zones potentially toxic to microscopic organisms in the immediate vicinity of diffuser ports. Such unfavorable conditions could occur in the receiving water when currents are low and ocean conditions calm resulting in less efficient mixing and dispersion.

Since PG&E owns large acreage tracts surrounding the power plant, noise generated from the cooling towers, primarily due to the fans, should not be a significant issue at the industrial site boundary. However, the cooling towers would increase the ambient noise levels in their surrounding vicinity which would impact the occupancy of nearby offices and facilities.

The following table summarizes the projected significant adverse environmental impacts:

Adverse Impact	Cause	Projected Magnitude
Project Implementation (Construction Phase):		
Green House Gas (GHG) Emissions for Replacement Power	Unit 1 & 2 Replacement Power During Extended Outages. (Lost carbon-free generation most likely replaced by fossil-fuel generation.) See Notes 1 & 2.	**10,318,500 Tons CO_2 GHG Emissions**
Project Fossil Fuel Combustion	Transport of Construction Equipment, Construction Materials, Removal of Spoils, Debris, & Recyclable Materials, Onsite Grading & Construction Activities and Bussing of Craft Workers.	**> 4.424,000 Gallons of Diesel Fuel.** Reference Appendix A-10 ,"Fuel Consumption Summary"
Disruption of Benthic Marine Habitat	Area Preparation and Placement of Discharge Dispersion Piping on Seafloor.	**Loss of 0.35 Acres of Rocky Subtidal**
Construction Debris Disposal	Landfill of Non-Recyclable (Non-Metal or Wood) Construction and Site Debris.	**3,600 Cubic Yards Landfill Disposal** 300 roll-offs filled to 12-cubic yards
Facility Operations Post-Construction:		
Green House Gas (GHG) Emissions for Replacement Power	Generation Required to Replace Unit 1 & 2 Efficiency Loss & Increased Site Auxiliary Power Requirements. (Lost carbon-free generation most likely replaced by fossil-fuel generation.). See Notes 1 & 3.	**180,500 Tons CO2/Year GHG Emissions**.
Salt Emissions and Deposition	Cooling Tower Salt Drift	**15,000,000 Pounds per Year** Deposited on surrounding lands & equipment. Calculation based on 25 day outages, drift of 86 gpm and .0405 gm/gm fraction of salts (Reference Appendix A-7).
Vapor Plume	Cooling Tower Emissions	**Plume Lengths Exceeding 5 miles** **Plume Heights Exceeding 2,500 feet** **45+ Times/Yr Visible from Avila Beach** **300+ Times/Yr Visible from SLO**
Blowdown Discharge Dispersion Zone with High TDS	High salinity and thermal dispersion zone. Potential for negative impacts to marine organisms that come in direct contact. (Estimate of water volume affected by 1200 operating diffuser array nozzles.)	**350 Cubic Meters in Receiving Water** Estimated high TDS zone above each diffuser array: 91m long * 2.5m wide * 0.77m high = 176 cubic meters per unit
Corrosion Control Emissions	Site corrosion control initiatives would substantially increase including necessity to resurface and paint metal equipment and structures.	**> 500 lbs/year Increase in Volatile Organic Compound (VOC) Emissions**

Table 8: Projected Direct Adverse Environmental Impacts of DCPP Retrofit.

Table 8 Notes:

1. GHG calculations based on California Public Utilities Commission (CPUC) Greenhouse Gas Emissions Performance Standard Documents: 800-900 Pounds of CO2 per MW-Hr provided as emissions from efficient combined-cycle turbine natural gas fueled generation. 800 Lbs/MW-Hr used in GHG emissions estimates.

2. GHG emissions for Project Replacement Power During Construction (Unit 1 & Unit 2 Net Generation Capacity of 1155 MW/Unit with 17 Month Dual-Unit Outage):
[2310 MW * 0.9 * 517 Days/project * 24 Hrs/day] = [25,796,232 MW-Hrs] * 800 lbs. CO2/MW-Hr = 20,636,985,600 lbs. CO2 = 10,318,493 Tons C02 or 9,380,448 Metric Tons CO2.

3. GHG emissions for Annual Replacement Power Post-Project Operations (Average 55.4 MW Facility Reduction in Electric Output & Anticipated 90% Facility Capacity Including One 25-Day Unit Refueling Outage per Cycle):
451,180 MW-Hrs/Yr [Ref. Table 3] * 800 lbs. CO2/MW-Hr = 360,944,000 lbs.CO2/Yr = 180,472 Tons C02/Yr or 163,693 Metric Tons CO2/Yr.

4. Permitting

Implementation of retrofitting DCPP to a closed-cycle cooling configuration would require a substantial regulatory permitting effort. In addition, due to existing or potential restrictive requirements and conditions, the ability to acquire all key construction approval and/or post project plant system operating permits would be very difficult. One key environmental permit (air emissions permit) presents a potentially insurmountable obstacle to project feasibility. Furthermore, no single regulatory agency controls or has overriding authority over all required project permits and licenses further complicating any permitting assessment.

In accordance with power plant construction projects in the State of California within the last decade, crucial operating permits would have to be secured (or at minimum a firm legal commitment obtained from the regulatory agency responsible) before project construction could start. These include permits required for unit operations post retrofit. Without the assurance that operating permits will be obtainable/approved following construction, a power plant retrofit project would be too risky to proceed. For DCPP these key permits would include, at a minimum: 1) a substantially revised facility wastewater discharge requirements permit (National Pollution Discharge Elimination System [NPDES] Permit), and 2) an Air Emissions Permit-to-Operate (PTO) for cooling tower operations due to projected substantial PM_{10} emissions.

A Coastal Zone Coastal Development Permit (CDP) would be required for the overall project from the California Coastal Commission prior to initiating construction. Obtaining final Coastal Commission approval for such a project is highly speculative, and assurance of post project operating permit and license availability would likely be a CDP approval condition under any scenario. Additionally, the fact that plume abatement cooling towers are infeasible on the plant site, and frequent substantial vapor plumes are projected to be visible from surrounding communities, reduces the likelihood of commission approval. Conditions in a CDP would also likely include significant mitigation or offsets for environmental impacts of project implementation (construction traffic, construction pollution, site aesthetic impacts, salt plume impacts to surrounding lands, etc.), and could result in substantial additional project costs that are not included in the current estimates.

Air permitting for mechanical draft wet cooling towers, a key required post retrofit environmental operating permit, is problematic for DCPP. San Luis Obispo County is a non-attainment region for State of California PM_{10} air quality parameters. Obtaining a permit for significant new PM_{10} emissions would require substantial emissions offsets that currently are not available within the air district. With the projected growth of local and state populations, the lack of emissions offsets presents a real and potentially insurmountable obstacle to permitting a cooling tower system at DCPP.

The implementation of a retrofit would require significant modification to the Power Plant's current NPDES Permit issued by the California Regional Water Quality Control Board, Central Coast Region (CCRWQCB). Potential modifications could include more restrictive effluent limitations, as well as additional discharge and receiving water monitoring. This could add substantially to ongoing facility operation and maintenance costs. If the discharge would be considered "new" under the State Thermal Plan (likely due to the proposed installation of an offshore diffuser array for tower blowdown), the outfall limit would be set at 20°F above ambient receiving water temperatures. The thermal limit could necessitate periodic unit power reductions, and/or the use of additional raw seawater for mixing with tower blowdown (Reference Report Section III.2 Conceptual Design Summary).

As previously discussed, the only practical/viable option for discharge of the large volume of high salinity cooling tower blowdown is diffusion offshore. Construction of an offshore piping system would require a State tidal and submerged lands lease and Army Corp of Engineers permit before the overall retrofit project could begin. Additionally, approval for diffuser system installation would be a prerequisite for obtaining NPDES Permit approval. The scenario of nested regulatory approvals would necessitate significant administrative lead time for wastewater discharge system related permit and license authorizations, and to insure timely sequenced resolution.

Approval of all project related Local and State permits, or at a minimum firm agency commitments to provide final approval for fully developed draft permits, would be necessary to support NRC licensing for the extensive nuclear plant modifications. Estimates of lead time for various administrative efforts reflect allowances to adequately resolve anticipated Local and State permitting challenges prior to submittal of an NRC Operating License Amendment Request (LAR).

The following table summarizes anticipated project permit and licensing requirements:

Regulatory Agency	Permit Type & Function	Administrative Allowance (Begin Documentation and Permitting Process)	Probable Constraints & Significant Special Conditions
Project Implementation/Construction Permits:			
California Coastal Commission	Coastal Zone Development Permit (CDP). (*Overall Project Construction and Building Authorization Permit*)	3-Years prior to project NRC LAR Submittal.	Obtain key environmental operating permit commitments before overall project approval. Special conditions and offsets.
County of San Luis Obispo	Project Component Building Permits(s) & Grading Permits.	3-Years prior to project NRC LAR Submittal. (*In conjunction with CDP*)	Special conditions and offsets likely required. Scope unknown.
U.S. Army Corps of Engineers (ACE)	Section 404 Nationwide Permit (NWP) for Structural Discharge. (*Permit for seafloor dredging and materials placement for offshore wastewater diffuser array*)	5-Years prior to project NRC LAR Submittal. (*Commitment to support NPDES permitting effort*)	Seafloor damage and disruption mitigation likely required.
California State Lands Commission (SLC)	Right of Way (ROW) and Lease for Tidal and Submerged Lands at Patton Cove. (*Lease for wastewater diffuser array lands use*)	5-Years prior to project NRC LAR Submittal. (*In conjunction with ACE Section 404 permit effort*)	Unknown
State Water Resources Control Board (SWRCB)	Construction Storm Water Discharge Permit. (*Required for project >1 acre of ground disturbance*)	4-Months prior to initial construction.	None-Anticipated. Routine type project permit.
SLO County Air Pollution Control District (APCD)	Concrete Batch Plant Permit-to-Operate (PTO).	4-Months prior to batch plant operations.	Dust control measures and fuel combustion emissions restrictions (if fossil-fueled).
New/Revised Facility Operating Permits:			
Regional Water Quality Control Board (RWQCB) Central Coast Region-3	National Pollution Discharge Elimination Systems (NPDES) Permit. Facility Wastewater Discharge Requirements.	4-Years prior to project NRC LAR Submittal. (*Draft Permit and Agency commitment likely required before CDP approval*)	No variance from California Thermal Plan maximum temperature limits. More restrictive constituent limitations on equipment specific wastewater pathways (Sewage, SWRO, etc.).
SLO County Air Pollution Control District (APCD)	New Cold Machine Shop Abrasive Blasting & Painting Unit Air Emissions Permit-to-Operate (PTO)	4-Months prior to initial unit operations.	None-Anticipated. In-kind or similar equipment replacement for existing unit.
SLO County Air Pollution Control District (APCD)	Cooling Tower Air Emissions Permit-to-Operate (PTO).	4-Years prior to project NRC LAR Submittal. (*Draft Permit and Agency commitment likely required before CDP approval*)	Require procurement of PM_{10} emissions offsets. Offsets are currently unavailable and potentially unattainable.

Table 9: Required Construction and Operation Permits & Licenses
Not Including NRC Nuclear Reactor Operating License Amendments/Extensions for Units 1 & 2

VII. <u>Additional Studies</u>

1. Special Studies

Numerous technical issues would require further study at a point during the design phase of the cooling tower retrofit. These include (but are not limited to):

- **Circulating Water Pump Pit:** It is recommended that the pits be designed by modeling studies, which can be done by the circulating pump suppliers, among others.

- **Diffuser Design:** Effective diffusion of the heated and concentrated blowdown needs to be analyzed further to ensure sufficient mixing would be achieved.
- **Soils Investigations:** Additional borings and soil testing is advisable where heavy loads are anticipated due to the cooling tower basins and the pump pits.
- **Water Hammer Analyses:** Very large water flows can be subjected to high pressure spikes or low pressure vacuum formation during transient conditions. These fluctuations, known as "water hammer" require analyses to avoid or minimize the pressure fluctuations through design features.
- **Cooling Tower/Condenser/Flow Rate Optimization:** If the retrofit were to proceed, a more detailed optimization of the combined cooling tower performance, condenser design, piping size and cooling water flow rate should be performed.
- **Power Plant System Effluents:** Further design of a retrofit would require additional analyses of a variety of existing effluent streams which would remain even with a closed-cycle cooling system. Needed analyses include evaluating the capacity of the liquid radwaste system to manage smaller batch discharges, assessing the potential to redirect the reverse osmosis system to a newly constructed offshore diffuser, and the need to further treat other remaining discharges such as the steam generator blowdown, turbine building sump effluent, and makeup water treatment system blowdown. In addition, the effect of reduced seawater flows and potential for extended periods of stagnation within auxiliary system heat exchangers, would likely create challenges due to elevated copper concentrations in the remaining discharge. Reference Appendix 13, Power Plant System Effluents Concerns.

VIII. Conceptual Schedule

1. Introduction

The conceptual schedule for implementing closed-cycle cooling using mechanical draft cooling towers at Diablo Canyon was developed using current regulatory proposals. Start dates for construction were chosen to accommodate the 01/01/2021 deadline provided in the California SWRCB draft policy for implementing I&E reduction goals at operating facilities that use once-though cooling. The schedule provides that both units will be shutdown in extended closed-cycle retrofit outages prior to the deadline, with return to service and commercial power generation not occurring until after the deadline. The schedule also provides for substantial project lead time which will be necessary to facilitate extensive permitting, licensing, design, and work planning activities.

The conceptual schedule is based on both units operating as long as practical (approximately 21-22 months) during construction of new site replacement facilities, and the cooling tower/site excavation. Initial construction (10 months) involves building new site facilities to replace those displaced by the new cooling towers and related services. Permitting (SLO County Building, California Coastal Commission, NRC LAR approval, etc.) would be required prior to start of new facility construction. Demolition of displaced facilities can begin after warehouse inventories and displaced personnel have been moved. Excavation and construction of the cooling towers would then follow.

Cooling tower basin excavation, re-configuration of the Protected Area (PA) perimeter, and start of the Circulating Water Tunnel (CWT) construction between the tower basins and the tie-in inside the PA would require that major yard utilities be taken out of service. This would initiate the overall plant shutdown. Specifically, loss of service for the 480V & 4,160V (non-vital) electrical yard loops would challenge the operability of several mechanical systems needed to run the plant. Disruption of the fire loop, domestic water, circulating water and other water systems would result. The shutdown and eventual re-start would be staggered with 2 to 3 weeks between Unit 1 and Unit 2. During plant shutdown and tunnel construction (including tie-ins), both units' ASW piping would remain in service supporting CCW. Special protection measures would be in place.

Several parallel construction paths would be ongoing during plant shutdown: (a) Condenser retrofit, SCW piping and other displaced turbine building equipment rework, (b) Construction and tie-in of new/existing CW tunnels west of the turbine building, including displaced/re-routed utilities, (c) Rework/configuration of the intake structure for new makeup and SCW pumps, piping, and related services, and (d) Electrical service changes to match new equipment at the intake, the cooling tower basins, and the 500 kV switchyard.

The overall duration for construction would be approximately 3-3/4 years. The plant shutdown during the construction period would be at least 17 months. Durations assume that engineering design can be developed to support permitting, that permits can be obtained, and that the regulatory process does not extend overall construction. Anticipated Federal, State, and County (SLO) permitting are included in the schedule.

2. Schedule Basis, Calendar, Resources

The schedule assumes an average (plateau) peak work force of approximately 3,000 craft between 2nd Q, 2020 and 4th Q, 2021 (18 months). This occurs primarily during plant shutdown. Actual peaks within this timeframe could be as high as 4,000. The conceptual schedule has not been resource loaded at this level of detail. Bussing from several offsite staging areas would be required to reduce the number of automobile trips to and from the site. Prior to the plant shutdown, craft requirements would be approximately half the peak period level (1,500), and for the last 9 months of construction that number would reduce to approximately 1,000 workers.

The distribution of craft would be such that approximately 2/3 of the above hours are based upon 2 x 10 hour/day shifts and a 6 day work week. Non-critical craft would work a single 10 hour x 5 days/week shift.

The construction and engineering activity durations are based upon judgment. Input for the overall durations has been reviewed by DCPP System and Design Engineering and

Construction Planning. Many of the durations are based upon historical information from original construction or more recently completed projects.

The permanent (existing) plant staff is assumed to remain constant at about 1,250. The plant shutdown and on-going construction are expected to require support for capital improvement and maintenance projects similar in size and value to those presently being conducted during both ongoing operations and refueling outages.

3. Pre-Shutdown Construction

Permitting for anticipated Federal, State, and County agencies covers about 7 years; this can be adjusted relative to the start of engineering. Design is only shown for the replacement facilities. These are the "drivers" for early site construction. Other engineering design (cooling towers, pumps, piping, tunnels and supporting system changes, and related design) has not been shown on the schedule, but is understood to occur in the overall timeframe. Front-end engineering is precedent to the permitting process. Final engineering supports site construction and is assumed dependent on the permitting process. The initial construction would be for facilities needing to relocate before cooling tower construction: main warehouse, cold machine shop, engineering/other offices (Parking Lot #7), new sewage treatment plant, new parking structure (1,000 spaces) and the vehicle inspection station. Locations for some of these are tentative and require more engineering evaluation. Some of these may have to be located offsite, or divided to suit multiple smaller (partial) footprints.

The overall duration to construct new/displaced facilities would be approximately 10 months, plus 1 to 2 months for personnel and inventory moves. After that, cooling tower excavation could proceed (generally) from west to east. Cooling tower basins' grade would be at elevation 83' to elevation 85' and would cover approximately 40 acres (encompassing Lots #6, 7, 8, the main warehouse and southern portions of Reservoir Road).

Security changes needed to support construction are extensive. These affect the re-arrangement of the existing PA fencing, circuitry, and camera/microwave systems. During re-work and restoration of the PA, compensatory security measures will be in place (24/7) to ensure the integrity of the Plant Security PA Boundary.

During 2019 through 1st Q 2020, it would be necessary to conduct fuel cask campaign operations to ready both fuel pools for full core offloads that occur during the plant shutdown(s). Limited access during realignment of Reservoir Road (2nd/3rd Q of 2019) could impact ISFSI operations.

4. Construction During Plant Shutdown

Excavation of the cooling tower basins, the pump pits and new tunnels between the cooling towers and inside the PA would involve interruption of main plant 480V & 4 kV electrical systems. As tunnel trenching proceeds past the security building into the PA, the entire southern security boundary must be protected and eventually re-worked. Excavation for the tunnels into the PA west of the turbine building expands the number of systems to be temporarily shut down and re-configured. It is not practical to reroute or try to "jumper" the affected systems because the tunnels' path for both units covers such a large area (the planned excavation extends northward past the actual plant centerline between Unit 1 & Unit 2). Key vital systems are not allowed to be shut down, but require special protection to ensure continued operability. The main fire loop, the ASW piping, the diesel fuel oil tanks and piping are among those requiring protection.

The new circulating water tunnels would require 8 connections to existing tunnels. On the supply side, 4 of these would meet the existing inlet tunnels and penetrate them. Tie-in of the new tunnels would have to minimize the impact and exposure of the 4 ASW supply pipes. These are on the upper opposing CWT walls. The proposed routing avoids the ASW pipes on the inner walls and the 480V vital duct banks on top of the tunnels by using tie-in routing from the outside or below. Shoring and sequencing of the work in getting to the required elevation requires dedicated construction engineering to map, expose and protect all of the U/G utilities in the areas.

The excavation in front (west) of the turbine building and the corresponding reinstallation of the affected underground utilities followed by backfill need to be completed before and after movement and access of equipment for the main condenser rework and other affected equipment on elevation 85' of the turbine building. The PA west of both (especially Unit 2) buildings could not support equipment movement during much of the first half of 2020.

During plant shutdown, fuel would be offloaded and stored in each unit's spent fuel pool. Essentially, each unit would be in a 17 month refueling outage. Considerable capital and maintenance work would be planned during the shutdowns in addition to the cooling tower scope, but is not included in this conceptual schedule or estimate. The ramp down and power ascension of both units will be staggered by approximately 2 to 3 weeks.

Normal unit refuelings and cycle lengths would be utilized for the cycle preceding each unit's shutdown. The schedule for starting construction of replacement facilities in 2018 and plant shutdowns commencing in early 2020 would be preceded by 1R21 in the 4th Q of 2018, and 2R21 in the 4th Q of 2019. Refuelings would not resume until approximately 18 months and 21 months after the re-start of commercial operations or September of 2023 and February of 2024 in accordance with the conceptual schedule.

Other critical activities, needed to integrate the new cooling towers, pumps, and hardware into the plant, involve construction of a new access road into the back (east) side of the powerblock. This occurs at the bench at elevation 115' and allows cask transporter traffic between the Fuel Handling Building (FHB) and the ISFSI facility via Reservoir Road up the hill. The new road to the bench at elevation 115' must transition approximately 30 ft of elevation over almost 400 ft of length. Routing of grading, compaction and paving equipment in this area, and overall construction represent a challenge to electrical and compressor equipment southeast of the Unit 2 Turbine Building. The Radwaste maintenance and compressor facility would require relocation (related services are also affected). Tie-ins for switchgear at the 500 kV Switchyard and main buried electrical services down to the power block and the cooling tower basins would take place while the plant is shut down.

No specific line activities are included in the conceptual schedule for control room simulator changes. Engineering design and hardware order placement for affected boards would be in 2018 and 2019. Physical changes would be done in 2020 to support actual operator training in 2021 before restart.

The new makeup and blowdown lines, between the cooling towers and intake (and the cooling towers and offshore diffuser), follow the CWT work and mechanical installations at the intake; the work is not critical path. Two 36" diameter blowdown lines are routed underground from the cooling tower basins to Patton Cove and then several hundred feet offshore to the discharge (diffuser array) location. The existing CWT bores 1-2 and 2-2 will serve as a corridor for routing the makeup piping from the intake to the new tunnel tie-ins inside the PA. The blowdown lines require special engineering, permitting and installation to ensure that ocean floor and sea life protection is maximized. The schedule has very summary level of detail showing these activities over an approximate 15 months.

5. Plant Re-start and Construction Completion

The schedule assumes that Unit 1 & Unit 2 restarts are on staggered schedules (2 to 3 weeks apart) to facilitate safe startup operations for each unit. Approximately 2 months of startup and testing would precede fuel loading and restart per unit. Reloading of fuel, system tests and paralleling each unit to the grid including power ascension would require about two weeks. During this period, and the 2 to 3 months preceding, plant security must complete all of its final testing of the new, reconfigured, PA boundaries.

The post-startup duration for construction is about 4 to 6 months. Very little definition has been included for these noncritical activities. Backfilling, grading & paving outside the PA, noncritical utilities' testing and restoration, signage, painting, training and close-out of all construction packages can all complete after plant restart.

IX. Cost Estimate Summary

1. Cost Estimate Overview

The cost of retrofitting DCPP with mechanical draft cooling towers is comprised of 5 elements; 1) Capital Project Cost, 2) Decommissioning Cost, 3) Operation and Maintenance Cost, 4) Cost of Replacement Power to compensate for lost MW during construction shutdown period, and 5) Cost of Replacement Power for lost MW Capacity due to the derating of DCPP caused by the cooling system reconfiguration. A summary of these costs and a high level description of the basis for each of these estimates follows:

Capital Project Cost	$2,689,000,000*
Decommissioning Cost	$67,000,000*
Operation and Maintenance Cost	$7,400,000/Year*
Replacement Power – Lost During Construction	$1,806,000,000*
Replacement Power – Loss in Net Plant Output	$31,600,000/Year*

**2008 Dollars Excluding Escalation and AFUDC*

Table 10: Cost Estimate Summary

Unit prices used in determining capital project costs are derived using PG&E capital projects guidelines, manufacturer/vendor input, recent actual costs from other major capital projects at DCPP and input from the engineering, operations, project management and the work planning departments, as well as estimating judgment.

2. Capital Project Cost: $2,689 Million

This cost is based on the conceptual design prepared by Enercon Services and described in this report (Reference Capital Project Cost Estimate Details Appendix A-11). The estimate includes permitting, engineering, procurement and installation of the new system and re-design of existing systems to accommodate the new system. Construction cost includes relocation of the plant infrastructure to accommodate the new equipment. Reconstruction of displaced plant facilities onsite would be limited to the existing developed footprint at DCPP. Not all of the facilities which would be displaced can be fully relocated onto the existing DCPP footprint. Allowances have been included for reconstruction of those facilities at an offsite location. Equipment manufacturers have provided budgetary proposals based on the conceptual design and are incorporated into the cost estimate including applicable taxes. Based on the size of this project, its manpower requirements and recent DCPP experience, travel through the town of Avila Beach would be restricted to a limited number of 'trips' through the community. This restriction would require DCPP to provide offsite parking, bussing (transportation to and from the facility for approximately 3,000 craft personnel), as well as pay for the associated travel time. Maintenance or repairs to public roadways outside of DCPP are not included in this cost estimate. As safety and security are always a foremost concern at DCPP, the cost of maintaining and ensuring a safe and secure facility are included in the construction costs.

No allowances have been made for escalation, project financing costs and/or foreign currency exchange rate fluctuations. All costs are in present day (2008 US Dollars) and include indirect cost and corporate overhead exclusive of financing costs (Accumulated Funds Used During Construction - AFUDC). AFUDC is an estimate of PG&E's cost of capital invested in a project during construction, and is applied to all the Utility's capital orders or projects that have a construction period greater than 30 days. AFUDC is applied to a project's total direct cost, applicable taxes, and capital administrative & general (A&G). AFUDC is accrued from the first month that costs are first charged to a project and continues until the month the project is declared operational. AFUDC is included in a project's overall cost and recovered from the ratepayers. Based on the proposed schedule, it is estimated that the total capital project costs presented would double if it were to include AFUDC and escalation. Demolition cost includes an allowance for fluorescent light fixture and ballast disposal, asbestos disposal as contained in some building systems, and lead abatement at the existing security firing range. No other allowances have been made for hazardous, contaminated or environmentally adverse material abatement of any kind.

3. Decommissioning Cost: $67 Million

The project would have a significant impact on the overall decommissioning cost at the end of the useful life of DCPP. Though the current developed footprint would not be expanded, the areas currently used for parking would be replaced by structures. The new construction put in place would eventually be removed as part of the station's decommissioning process. The cost of this added removal scope must be included in the decommissioning fund. The cost estimate for the decommissioning is based on analysis of the current estimate of the cost to decommission DCPP as a percentage of the escalated cost to build the plant, and is adjusted to a lower value to reflect the non-contaminated nature of the new systems (decommissioning at 2.5% of install costs).

4. Operation and Maintenance Cost: $7.4 Million Annually

The operation and maintenance cost of maintaining the mechanical draft cooling towers is based on general vendor recommendations. The costs which have been provided include daily, weekly, monthly, quarterly, semi-annual and annual inspections and maintenance. Labor, material and chemicals are also included. Allowances have been included for the cost of increased maintenance to electrical equipment due to salt drift and for the cost of travel between onsite and offsite facilities. These costs would be in addition to costs currently incurred for operation and maintenance of the existing cooling system. Combined intake pump and electrical systems, cooling systems piping, concrete conduit, and main condenser operation and maintenance cost are assumed to be roughly equivalent (Reference Appendix A-11 Project Cost Estimates Page-2 Annual Increase to Station Operation & Maintenance Cost).

5. Replacement Power – Lost MW During Construction: $1,806 Million

In order to safely execute this project, both nuclear units would be shut down when construction activities expose main mechanical or electrical systems or jeopardize any nuclear safety related systems. During this shutdown period, power must be purchased to meet the demand of the PG&E service area. This period is expected to last a minimum of 17 months (517 days). The formula for calculating replacement power is based on an estimate of each unit's annual output priced using PG&E's current (2008) long term power procurement forecasts of $70 per MWHr, and a Plant Capacity Factor of 90%.

Construction Replacement Power Cost Estimate Calculation:
$70/MW * 1,155 MW/Hr * 24 Hr/Day * 517 Days * 2 (Units) * 0.9 (Capacity Factor)
= $1,805,736,240 (say $1,806,000,000)

6. Replacement Power – Lost MW due to Derated Capacity plus Additional Auxiliary Power: $31.6 Million Annually

After installation, the cooling towers would result in decrease in net plant output due to a decrease in generator output, and an increase in required plant auxiliary power. PG&E would meet service territory demand by purchasing an equal quantity of replacement power ongoing. The cost of replacement power is calculated using an average of $70 per MWHr based conservatively low on PG&E's 2008 replacement energy costs. Plant Capacity Factor of 0.9 assumes a one unit 25-day refueling outage during any given year.

Average Derate Annual Replacement Power Cost Estimate Calculation:
$70/MW * 451,180 MW-Hrs/Yr [Ref. Table 3]
= $31,582,600 (say $31,600,000)

.

Description	Total Price 2 Units
Mechanical Equipment:	
Cooling Towers	$80,000,000
Condenser Waterbox/Tubesheets/Tubes	$62,780,000
Circulating Water Pumps	$46,400,000
Other Pumps	$4,900,000
Valves (96”, 78”, & 36”)	$3,999,000
Electrical Equipment:	
500 kV/13.8 kV Transformers	$8,000,000
Other Transformers	$3,420,000
Cooling tower electrical building. Foundation not included	$2,870,000
500 kV substation package for cooling tower power supply (excluding transformers)	$12,000,000
Other:	
Dechlorination System	$500,000
Paralined Steel Piping	$18,222,000
Fiberglass Reinforced Plastic Piping	$1,072,000
Instrumentation and Controls	$4,254,000
Sewage Treatment Plant	$300,000
Total Major Equipment Procurement Cost	**$248,189,000**

**Excludes shipping, taxes, import fees, etc.*

Table 11: Major Equipment Procurement Cost*

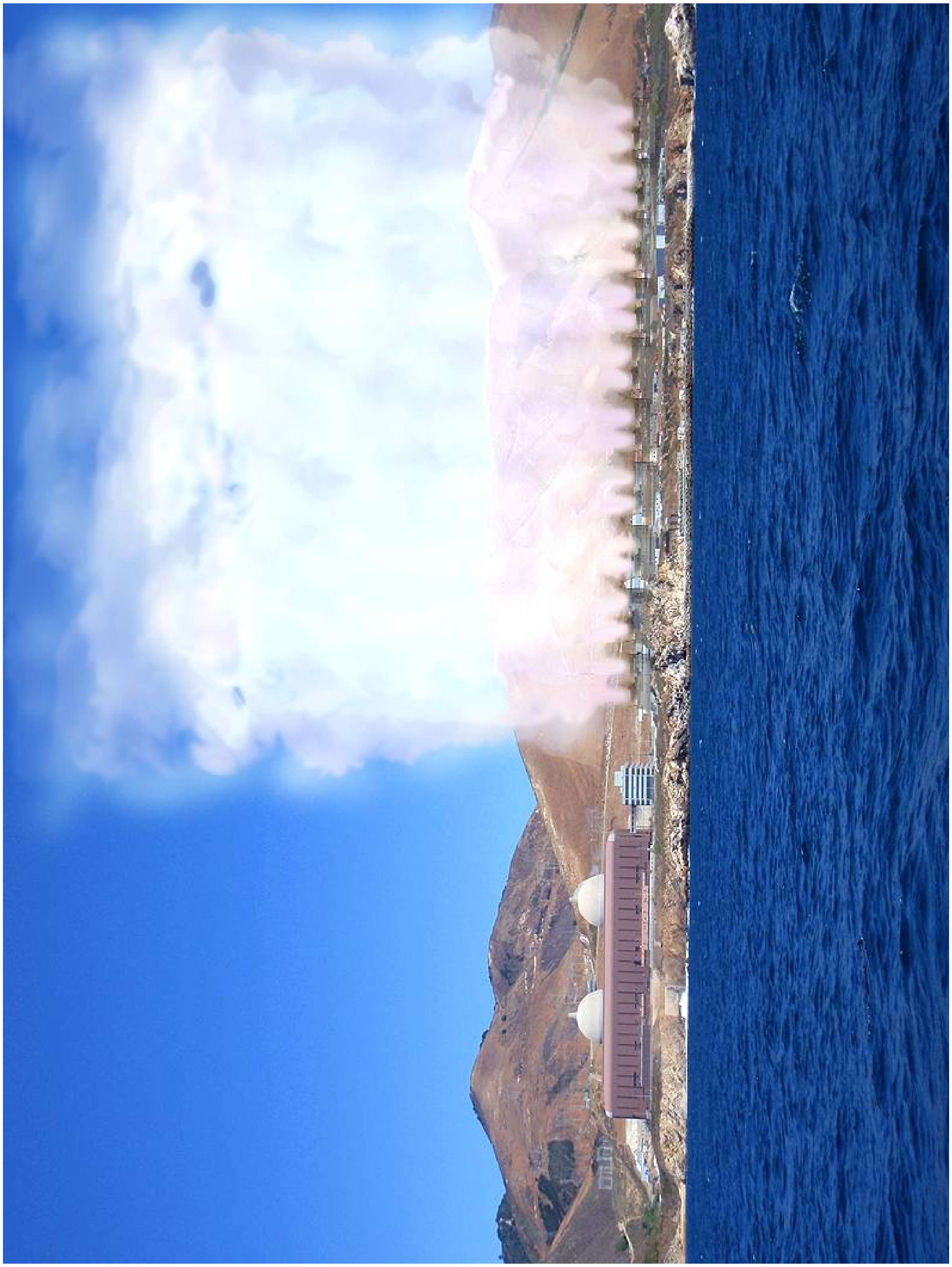

Figure 17 – Conceptual Installation and Plume – Perspective From Ocean

Acronyms and Abbreviations

A&G	Administrative & General
AFUDC	Accumulated Funds Used During Construction
APCD	Air Pollution Control District
ASW	Auxiliary Saltwater
BOD	Biological Oxygen Demand
C	Celsius
CARB	California Air Resource Board
CCW	Component Cooling Water
CDP	Coastal Development Permit
CDR	Condensate Regeneration System
CFR	Code of Federal Regulations
Cu	Copper
CWP	Circulating Water Pump
CWT	Circulating Water Tunnel
CY	Cubic Yard
DCPP	Diablo Canyon Power Plant
EDG	Emergency Diesel Generator
ELGs	Effluent Limit Guidelines
EPA	Environmental Protection Agency
F	Fahrenheit
FHB	Fuel Handling Building
FSAR	Final Safety Analysis Report
GHG	Green House Gas
GPD	Gallons per Day
GPM	Gallons per Minute
HEI	Heat Exchange Institute
HMI	Human Machine Interface
hp	Horsepower
HX	Heat Exchanger
I&C	Instrumentation & Control
I&E	Impingement and Entrainment
I/O	Input/Output
ISO	Independent System Operator
ISFSI	Independent Spent Fuel Storage Installation
kW	Kilowatt
kV	Kilovolt
kVA	Kilovolt-Amps
LAR	License Amendment Request
LRW	Liquid Radioactive Waste
MGD	Million Gallons per Day
mg/L	Milligrams per Liter (parts per million)
MTCS	Main Turbine Control System
MVA	Million Volt-Amps
MWHr	Megawatt Hour

MWTS	Makeup Water Treatment System
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NWS	National Weather Service
OE	Operating Experience
OTC	Once-Through Cooling
PA	Protected Area (inside security perimeter)
PM_{10}	Particulate Matter 10μm and smaller
PDN	Plant Data Network
PPC	Plant Process Computer
PTO	Permit to Operate
PSIG	Pounds per Square Inch Gauge
Q	Quarter
RO	Reverse Osmosis
RWQCB	Regional Water Quality Control Board
SACTI	Seasonal/Annual Cooling Tower Impact
SCW	Service Cooling Water
SER	Safety Evaluation Report
SGBD	Steam Generator Blowdown
SLO	San Luis Obispo
SONGS	San Onofre Nuclear Generating Station
SSPS	Solid State Protective System
SWRCB	State Water Resources Control Board
SWRO	Seawater Reverse Osmosis
TBS	Turbine Building Sump
TDH	Total Differential Head
TDS	Total Dissolved Solids
ug/L	Micrograms per Liter (parts per billion)
UPS	Uninterruptable Power System
UV	Ultra Violet
WB	Wet Bulb
ZLD	Zero Liquid Discharge

Diablo Canyon Power Plant

Cooling Tower Feasibility Study

March 2009

Prepared by:

Enercon Services Inc.
401 Roland Way
Oakland, CA 94621

DCPP Cooling Tower Feasibility Study

I. Executive Summary

1. Overview

In response to the 2008 Tetra Tech Inc. cooling tower feasibility assessment performed for the California Ocean Protection Council, PG&E engaged Enercon Services Inc. (Enercon) to prepare a more detailed, site-specific assessment of the feasibility of cooling towers at the Diablo Canyon site. This assessment builds upon earlier work, including the 2003 study by Burns Engineering, and provides a further, more detailed analysis of the feasibility of a cooling tower retrofit. There is no precedent for mechanical draft cooling towers using saltwater makeup at a nuclear facility, and no precedent for a retrofit of the magnitude necessary at Diablo Canyon. Enercon concludes that any retrofit at Diablo Canyon is a highly speculative project with likely insurmountable permitting obstacles, substantial engineering challenges, significant adverse environmental impacts, costs exceeding $4-billion dollars, and uncertainty regarding the Power Plant's post-retrofit operating capacity factors. Further, plant downtime, reduction of average net electrical output, and a potential for ongoing reduced capacity factors would together cause a significant loss in generation, and would greatly undermine the State's ability to meet its Green House Gas (GHG) emissions reduction goals under California Assembly Bill AB 32.

2. Design and Construction Concerns

Enercon concludes, as prior reports have found, that only mechanical draft cooling towers are remotely feasible at the site. Dry cooling is not feasible due to limited space availability, and natural draft towers are not suitable for the site given space and seismic concerns. Furthermore, due to limited space, mechanical draft towers could only be non-plume abated. The conceptual layout includes four tower arrays – each 140 feet by 620 feet, with two rows of ten cells each. Key design and construction issues include:

- Demolition and relocation of over 170,000 square feet of existing structures, parking for 1,000 vehicles, and the Independent Spent Fuel Storage Installation (ISFSI) storage cask haul road.
- Excavation of over 2 million cubic yards of soil and rock.
- 250,000 diesel truck round trips to haul construction materials and excavation spoils.
- Modification of major existing systems including the main condensers, service cooling water heat exchangers, and electrical systems.
- Extremely difficult tie-in process given existing underground facilities to the west and south of the power plant.

- Construction of an offshore diffusers system for the discharge of a minimum 72-million gallons per day of high salinity cooling tower blowdown.
- Approximately 3-3/4 year construction timeframe, with a minimum of 17 months dual-unit downtime.
- An average of over 3,000 workers, requiring 7.4-million miles of bus trips.

3. Nuclear Safety Concerns

Enercon identified several significant issues that will likely require NRC review and approval of License Amendment Requests (LARs) in order to ensure acceptable safety levels during construction, as well as post retrofit operation. Further analysis of these issues is required to make determinations regarding potential conflicts with nuclear safety requirements. Key issues include:

- Increased flood risk to safety-related systems from cooling tower water.
- Accelerated aging of plant equipment and an increase in possible plant trips due to salt deposition.
- Interruption of the safety-required Auxiliary Saltwater (ASW) system during construction.
- Increased potential loss of offsite power.
- Rerouting of existing approved ISFSI haul road.
- Increased risk of interruption to the fire protection system during construction.
- Security concerns related to the opening of the protected area boundaries during construction.

4. Environmental Impact and Permitting Concerns

The installation and operation of cooling towers raises significant adverse environmental impacts concerns and poses substantial, likely insurmountable, permitting obstacles. Key issues identified include:

- PM_{10} emissions likely can not be permitted by the San Luis Obispo County Air Pollution Control District (APCD).
- Salt deposition of at least 7,500 tons per year would impact plant equipment, adjacent agricultural lands, and terrestrial habitat.
- The vapor plume from tower operations would be over 2,460 feet high 35% of the year. Although low visibility conditions may obscure the plumes, and many plumes large enough to be visible are likely to occur at night, meteorological conditions conducive to plume visibility are predicted to occur within 1 hour of sunrise or sunset on the order of 45 times per year for Avila Beach, and 300 times per year for San Luis Obispo.
- Fossil-fueled replacement power for the minimum 17 month dual-unit downtime will result in the emission of roughly 10,000,000-tons of GHGs. Derated capacity and additional auxiliary power requirements for cooling tower operations total an

average of approximately 55 MW, enough to supply power for approximately 42,000 California homes. Long term negative impacts on GHG emissions of roughly 180,000-tons per year would also result.

- Construction of a diffuser system in Patton Cove south of the power plant will directly disrupt approximately a half-acre of pristine rocky marine habitat.
- Permits for both construction and operation are required from many government agencies including: The California Coastal Commission, State Lands Commission, Central Coast Regional Water Quality Control Board, San Luis Obispo County (Building and APCD), and the U.S. Army Corps of Engineers. It is highly unlikely that all the necessary permits can be obtained.

5. Project Schedule and Costs

Enercon's assessment is that prior order-of-magnitude estimates grossly understate the cost of a cooling tower retrofit. A more detailed evaluation of project scope, design and engineering, and required construction results in the following regarding costs and schedule:

- The overall duration for construction would be approximately 3-3/4 years. The plant shutdown during the construction period would be at least 17 months:
    - Extensive excavation west of the Turbine Building in an area congested with both safety related and nonsafety related systems, piping and conduits.
    - Significant condenser modifications.
    - Need to assure continued operation of the safety related ASW system to provide cooling to the spent fuel pools even during shutdown.
    - Extensive relocation of existing systems and facilities.
    - Massive excavation for cooling tower installation.

- Total initial project costs are estimated at $4.5 billion (2008 Dollars) and would result in an estimated Utility customer rate increase of roughly 10%:
    - Capital costs estimated at $2.7 billion.
    - Cost of replacement power for the minimum 17 month downtime is estimated at $1.8 billion.
    - Increased decommissioning costs total $67 million.

- Additional on-going costs total $39 million annually:
    - Cooling tower operations and related maintenance is estimated at $7.4 million per year.
    - Replacement Power for derated capacity and cooling tower operations totals $31.6 million per year.

Ongoing costs assume that the plant would be capable of continuing to produce power at roughly current levels / capacity factors. If plant operational efficiency decreases, and net power production is reduced more than the 55 MW expected, electric rates will likely increase even more to cover the purchase of additional replacement power.

Issues that Would Seriously Threaten the Feasibility of a DCPP Cooling Tower Retrofit Project

- Significant Permitting Obstacles.
- Significant Adverse Environmental Effects.
- Significant Nuclear Safety/Licensing Obstacles.
- 17 Month Minimum 2-Unit Plant Shutdown.
- Severe Shortage of Suitable Land Available For Cooling Towers.
- Substantial Excavation.
- Demolition and Relocation of Numerous Facilities.
- Initial Costs Estimated at 4.5 Billion Dollars.
- Total Annual Salt Deposition Exceeding 7,500 Tons.
- Plumes Often Visible From San Luis Obispo and Avila Beach.
- Greatest Loss in Plant Electric Output (nearly 70 MW per Unit) Would Occur at Times of Peak Summer Demand.

Table 1: Issues that Would Threaten the Feasibility of the Project

March 31st, 2009

Greater Bay Area Once Through Cooling Generation Retirement Study

Prepared for: **Pacific Gas & Electric**

Prepared by: **Quanta Technology, LLC**

Contacts:

Don Morrow
dmorrow@quanta-technology.com
919 334 3023

David Elizondo
delizondo@quanta-technology.com
919 334 3089

Joel M. Berry
jberry@quanta-technology.com
919 334 3074

Xiaohuan Tan
xtan@quanta-technology.com
919 334 3073

Table of Contents

LIST OF FIGURES IV

LIST OF TABLES VI

1 EXECUTIVE SUMMARY 1

2 SUMMARY 3

3 STUDY METHODOLOGY & ASSUMPTIONS 7

3.1 STUDY CRITERIA 7
3.2 STUDY METHODOLOGY 8
3.2.1 System Modeling Assumptions - Steady State 8
3.2.2 System Modeling Assumptions - Dynamics 11
3.2.3 System Modeling Assumptions – Governor Power Flow 12
3.2.4 Methods of Analysis 14

4 STUDY RESULTS 15

4.0 EXISTING SYSTEM ISSUES 15
4.1 DISCUSSION OF POTENTIAL PROJECTS 17
4.2 CASE 4 – 2015 RESULTS 22
4.2.1 Steady State Voltage Results (N-1 & L-2) 22
4.2.2 Steady State Thermal Results (N-1 & L-2) 22
4.2.3 Solutions Tested 22
4.2.4 Steady State Voltage Results (G-1 + L-1) 24
4.2.5 Additional Steady State Solutions 25
4.2.6 Fault Induced Transient Voltage Recovery Results 25
4.2.7 Governor Power Flow Results 26
4.2.8 Steady State Voltage Stability (P-V & V-Q Curves) 26
4.2.9 Review of Other Potential Solutions 27
4.3 CASE 3 – 2015 RESULTS 32
4.3.1 Steady State Voltage Results (N-1 & L-2) 32
4.3.2 Steady State Thermal Results (N-1 & L-2) 32
4.3.3 Solutions Tested 32
4.3.4 Steady State Voltage Results (G-1 + L-1) 33
4.3.5 Additional Steady State Solutions 33
4.3.6 Fault Induced Transient Voltage Recovery Results 33
4.3.7 Governor Power Flow Results 33
4.3.8 Steady State Voltage Stability (P-V & V-Q Curves) 34
4.3.9 Review of Other Potential Solutions 35
4.4 CASE 1 – 2015 RESULTS 37
4.4.1 Steady State Voltage Results (N-1 & L-2) 37
4.4.2 Steady State Thermal Results (N-1 & L-2) 37
4.4.3 Solutions Tested 37
4.4.4 Steady State Voltage Results (G-1 + L-1) 37
4.4.5 Additional Steady State Solutions 37
4.4.6 Fault Induced Transient Voltage Recovery Results 38
4.4.7 Governor Power Flow Results 39
4.4.8 Steady State Voltage Stability (P-V & V-Q Curves) 39
4.4.9 Review of Other Potential Solutions 40
4.5 CASE 4 – 2020 RESULTS 42

4.5.1 Steady State Voltage Results (N-1 & L-2) ... *42*
4.5.2 Steady State Thermal Results (N-1 & L-2) ... *42*
4.5.3 Solutions Tested ... *42*
4.5.4 Steady State Voltage Results (G-1 + L-1) ... *43*
4.5.5 Additional Steady State Solutions ... *43*
4.5.6 Fault Induced Transient Voltage Recovery Results ... *44*
4.5.7 Governor Power Flow Results ... *45*
4.5.8 Steady State Voltage Stability (P-V & V-Q Curves) ... *45*
4.5.9 Review of Other Potential Solutions ... *46*
4.6 SENSITIVITY ANALYSIS RESULTS FOR 2020 ... 48
4.6.1 Case 3.5 ... *48*
4.6.2 Case 3.5 + 1 CT (50 MW) at RCEC ... *48*
4.6.3 Case 3.5 + 1 CT (180 MW) at RCEC ... *48*
4.6.4 Case 3.5 + 2 CTs (360 MW) at RCEC ... *49*
4.6.5 Case 3.5 + Russell City Energy Center Plant (2 CTs & 1 ST) ... *49*
4.6.6 Case 1 + HVDC Terminal at Collinsville 500kV ... *49*

5 PROPOSED NETWORK UPGRADES ... 51

6 CONCLUSIONS ... 53

7 COMPLETE RESULTS ... 55

7.1 CASE 4 – 2015 STEADY STATE VIOLATIONS ... 55
7.2 CASE 3 – 2015 STEADY STATE VIOLATIONS ... 66
7.3 CASE 1 – 2015 STEADY STATE VIOLATIONS ... 71
7.4 CASE 4 – 2020 STEADY STATE VIOLATIONS ... 77
7.5 CASE 4 – 2015 FAULT SIMULATIONS ... 91
7.6 CASE 3 – 2015 FAULT SIMULATIONS ... 97
7.7 CASE 1 – 2015 FAULT SIMULATIONS ... 103
7.8 CASE 4 – 2020 FAULT SIMULATIONS ... 109
7.9 CASE 4 – 2015 GOVERNOR POWER FLOW RESULTS ... 118
7.10 CASE 3 – 2015 GOVERNOR POWER FLOW RESULTS ... 123
7.11 CASE 1 – 2015 GOVERNOR POWER FLOW RESULTS ... 128
7.12 CASE 4 – 2020 GOVERNOR POWER FLOW RESULTS ... 134
7.13 CASE 4 – 2015 CURVES ... 140
7.14 CASE 3 – 2015 CURVES ... 144
7.15 CASE 1 – 2015 CURVES ... 148
7.16 CASE 3 – 2015 SENSITIVITY WITH RUSSELL CITY ENERGY CENTER (RCEC) ONLINE ... 152
7.17 CASE 1 – 2015 SENSITIVITY WITH RUSSELL CITY ENERGY CENTER (RCEC) ONLINE ... 155
7.18 CASE 4 – 2020 CURVES ... 158
7.19 SENSITIVITY ANALYSIS – 2020 CURVES ... 162

List of Figures

FIGURE 3-1 WECC VOLTAGE PERFORMANCE PARAMETERS 8
FIGURE 4-1 COMPARISON OF COLLINSVILLE TO THE PROPOSED CAPACITOR AT PITTSBURG (DEC OUTAGE) 28
FIGURE 4-2 POTENTIAL BLACK DIAMOND 230KV SUBSTATION CONFIGURATION 29
FIGURE 7-1 CASE 4 – 2020: TRANSIENT VOLTAGE RECOVERY CURVES OF SELECTED 230KV BUSES LOCAL TO GBA WITH FAULT #B2-22 115
FIGURE 7-2 CASE 4 – 2020: TRANSIENT VOLTAGE RECOVERY CURVES OF SELECTED LOAD BUSES LOCAL TO GBA WITH FAULT #B2-22 116
FIGURE 7-3 CASE 4 – 2020: TRANSIENT VOLTAGE RECOVERY CURVES OF SELECTED LOAD BUSES LOCAL TO GBA WITH FAULT #B2-22 117
FIGURE 7-4 CASE 4 – 2015: P-V CURVES OF 230KV BUSES LOCAL TO GBA WITH DEC OUTAGE 140
FIGURE 7-5 CASE 4 – 2015: V-Q CURVES OF 230KV BUSES LOCAL TO GBA WITH DEC OUTAGE 141
FIGURE 7-6 CASE 4 – 2015: P-V CURVES OF 230KV BUSES LOCAL TO GBA WITH MEC OUTAGE 142
FIGURE 7-7 CASE 4 – 2015: V-Q CURVES OF 230KV BUSES LOCAL TO GBA WITH MEC OUTAGE 143
FIGURE 7-8 CASE 3 – 2015: P-V CURVES OF 230KV BUSES LOCAL TO GBA WITH DEC OUTAGE 144
FIGURE 7-9 CASE 3 – 2015: V-Q CURVES OF 230KV BUSES LOCAL TO GBA WITH DEC OUTAGE 145
FIGURE 7-10 CASE 3 – 2015: P-V CURVES OF 230KV BUSES LOCAL TO GBA WITH MEC OUTAGE 146
FIGURE 7-11 CASE 3 – 2015: V-Q CURVES OF 230KV BUSES LOCAL TO GBA WITH MEC OUTAGE 147
FIGURE 7-12 CASE 1 – 2015: P-V CURVES OF 230KV BUSES LOCAL TO GBA WITH DEC OUTAGE 148
FIGURE 7-13 CASE 1 – 2015: V-Q CURVES OF 230KV BUSES LOCAL TO GBA WITH DEC OUTAGE 149
FIGURE 7-14 CASE 1 – 2015: P-V CURVES OF 230KV BUSES LOCAL TO GBA WITH MEC OUTAGE 150
FIGURE 7-15 CASE 1 – 2015: V-Q CURVES OF 230KV BUSES LOCAL TO GBA WITH MEC OUTAGE 151
FIGURE 7-16 CASE 3 – 2015: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & RCEC PLANT (614 MW) IN-SERVICE 152
FIGURE 7-17 CASE 3 – 2015: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & 1 CT AT RCEC (180 MW) IN-SERVICE 153
FIGURE 7-18 CASE 3 – 2015: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & 1 CT AT RCEC (50 MW) IN-SERVICE 154
FIGURE 7-19 CASE 1 – 2015: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & RCEC PLANT (614 MW) IN-SERVICE 155
FIGURE 7-20 CASE 1 – 2015: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & 1 CT AT RCEC (180 MW) IN-SERVICE 156
FIGURE 7-21 CASE 1 – 2015: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & 1 CT AT RCEC (100 MW) IN-SERVICE 157
FIGURE 7-22 CASE 4 – 2020: P-V CURVES OF 230KV BUSES LOCAL TO GBA WITH DEC OUTAGE 158
FIGURE 7-23 CASE 4 – 2020: V-Q CURVES OF 230KV BUSES LOCAL TO GBA WITH DEC OUTAGE 159
FIGURE 7-24 CASE 4 – 2020: P-V CURVES OF 230KV BUSES LOCAL TO GBA WITH MEC OUTAGE 160
FIGURE 7-25 CASE 4 – 2020: V-Q CURVES OF 230KV BUSES LOCAL TO GBA WITH MEC OUTAGE 161
FIGURE 7-26 CASE 3.5 – 2020: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE 162
FIGURE 7-27 CASE 3.5 – 2020: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & OAKLAND LONG TERM PLAN ALTERNATIVE 163
FIGURE 7-28 CASE 3.5 – 2020: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & 1 CT AT RCEC (50 MW) IN-SERVICE 164
FIGURE 7-29 CASE 3.5 – 2020: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & 1 CT AT RCEC (180 MW) IN-SERVICE 165
FIGURE 7-30 CASE 3.5 – 2020: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & OAKLAND LONG TERM PLAN ALTERNATIVE & 1 CT AT RCEC (180 MW) IN-SERVICE 166
FIGURE 7-31 CASE 3.5 – 2020: P-V CURVES OF 230 KV BUSES LOCAL TO GBA WITH DEC OUTAGE & 2 CTS AT RCEC (360 MW) IN-SERVICE 167

Figure 7-32 Case 3.5 – 2020: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & RCEC Plant (614 MW) In-Service 168
Figure 7-33 Case 1–2020: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & HVDC at Collinsville 169

List of Tables

TABLE 3-1 PLANNING CRITERIA REQUIREMENTS 7
TABLE 3-2 GREATER BAY AREA LOAD ASSUMPTIONS FOR CASES 1, 3, & 4 9
TABLE 3-3 GREATER BAY AREA GENERATION RETIREMENT ASSUMPTIONS 9
TABLE 3-4 AUXILIARY LOAD AT RETIRED GENERATORS 11
TABLE 4-1 GREATER BAY AREA 500KV BUS VOLTAGES (N-0) 15
TABLE 4-2 GREATER BAY AREA EXISTING SHUNT COMPENSATION IN 2015 15
TABLE 4-3 GREATER BAY AREA POTENTIAL GENERATION RETIREMENTS 16
TABLE 4-4 THERMAL OVERLOADS IDENTIFIED FOR SYSTEM REINFORCEMENTS 22
TABLE 4-5 VOLTAGE VIOLATIONS FOR CATEGORY B/C EVENTS (N-1 & L-2) 30
TABLE 4-6 VOLTAGE VIOLATIONS FOR DELTA ENERGY CENTER OUTAGE PLUS L-1 30
TABLE 4-7 ZONE 322 GENERATION RE-DISPATCH 38
TABLE 4-8 TRANSMISSION LINES WITH LOW X/R RATIO 44
TABLE 4-9 VOLTAGE VIOLATIONS IN GBA WITH DELTA ENERGY CENTER OUTAGE 50
TABLE 4-10 VOLTAGE VIOLATIONS NEAR GBA WITH DELTA ENERGY CENTER OUTAGE 50
TABLE 5-1 ESTIMATED EQUIPMENT COSTS (2006 $) 51
TABLE 5-2 TOTAL ESTIMATED COST OF RECOMMENDED PROJECTS (2006 $) 52
TABLE 7-1 CASE 4 – 2015: THERMAL VIOLATIONS FOR CATEGORY A EVENTS (N-0) 55
TABLE 7-2 CASE 4 – 2015: THERMAL VIOLATIONS FOR CATEGORY B/C EVENTS (N-1 & L-2) 55
TABLE 7-3 CASE 4 – 2015: VOLTAGE VIOLATIONS FOR CATEGORY A EVENTS (N-0) 59
TABLE 7-4 CASE 4 – 2015: VOLTAGE VIOLATIONS FOR CATEGORY B EVENTS (COMBINED CYCLE PLANT CONTINGENCIES) 59
TABLE 7-5 CASE 4 – 2015: VOLTAGE VIOLATIONS FOR CATEGORY B/C EVENTS (N-1 & L-2) 59
TABLE 7-6 CASE 4 – 2015: VOLTAGE VIOLATIONS FOR CATEGORY B/C EVENTS (N-1 & L-2), THE 2ND WORST CONTINGENCY AFTER DELTA ENERGY CENTER OUTAGE 62
TABLE 7-7 CASE 4 – 2015: VOLTAGE VIOLATIONS FOR DELTA ENERGY CENTER OUTAGE PLUS L-1 64
TABLE 7-8 CASE 4 – 2015: VOLTAGE VIOLATIONS FOR METCALF ENERGY CENTER OUTAGE PLUS L-1 64
TABLE 7-9 CASE 3 – 2015: VOLTAGE VIOLATIONS FOR CATEGORY A EVENTS (N-0) 66
TABLE 7-10 CASE 3 – 2015: VOLTAGE VIOLATIONS FOR CATEGORY B EVENTS (COMBINED CYCLE PLANT CONTINGENCIES) 66
TABLE 7-11 CASE 3 – 2015: VOLTAGE VIOLATIONS FOR CATEGORY B/C EVENTS (N-1 & L-2) 68
TABLE 7-12 CASE 3 – 2015: VOLTAGE VIOLATIONS FOR DELTA ENERGY CENTER OUTAGE PLUS L-1 69
TABLE 7-13 CASE 3 – 2015: VOLTAGE VIOLATIONS FOR METCALF ENERGY CENTER OUTAGE PLUS L-1 69
TABLE 7-14 CASE 1 – 2015: VOLTAGE VIOLATIONS FOR CATEGORY A EVENTS (INTACT SYSTEM) 71
TABLE 7-15 CASE 1 – 2015: VOLTAGE VIOLATIONS FOR CATEGORY B/C EVENTS (N-1 & L-2) 71
TABLE 7-16 CASE 1 – 2015: VOLTAGE VIOLATIONS FOR DELTA ENERGY CENTER OUTAGE PLUS L-1 72
TABLE 7-17 CASE 1 – 2015: VOLTAGE VIOLATIONS FOR METCALF ENERGY CENTER OUTAGE PLUS L-1 73
TABLE 7-18 CASE 1 – 2015: VOLTAGE VIOLATIONS FOR DELTA ENERGY CENTER OUTAGE PLUS L-1 WITH ZONE 322 RE-DISPATCHED 75
TABLE 7-19 CASE 1 – 2015: VOLTAGE VIOLATIONS FOR METCALF ENERGY CENTER OUTAGE PLUS L-1 WITH ZONE 322 RE-DISPATCHED 76
TABLE 7-20 CASE 4 – 2020: THERMAL VIOLATIONS FOR CATEGORY A EVENTS (N-0) 77
TABLE 7-21 CASE 4 – 2020: THERMAL VIOLATIONS FOR CATEGORY B/C EVENTS (N-1 & L-2) 77
TABLE 7-22 CASE 4 – 2020: VOLTAGE VIOLATIONS FOR CATEGORY A EVENTS (N-0) 79
TABLE 7-23 CASE 4 – 2020: VOLTAGE VIOLATIONS FOR CATEGORY B EVENTS (COMBINED CYCLE PLANT CONTINGENCIES) 79
TABLE 7-24 CASE 4 – 2020: VOLTAGE VIOLATIONS FOR CATEGORY B/C EVENTS (N-1 & L-2) 81
TABLE 7-25 CASE 4 – 2020: THERMAL VIOLATIONS FOR CATEGORY A EVENTS (N-0) WITH COLLINSVILLE SUBSTATION 81

TABLE 7-26 CASE 4 – 2020: THERMAL VIOLATIONS FOR CATEGORY B/C EVENTS (N-1 & L-2) WITH COLLINSVILLE SUBSTATION ... 82
TABLE 7-27 CASE 4 – 2020: VOLTAGE VIOLATIONS FOR CATEGORY A EVENTS (N-0) WITH COLLINSVILLE SUBSTATION ... 84
TABLE 7-28 CASE 4 – 2020: VOLTAGE VIOLATIONS FOR CATEGORY B EVENTS (COMBINED CYCLE PLANT CONTINGENCIES) WITH COLLINSVILLE SUBSTATION ... 84
TABLE 7-29 CASE 4 – 2020: VOLTAGE VIOLATIONS FOR CATEGORY B/C EVENTS (N-1 & L-2) WITH COLLINSVILLE SUBSTATION ... 84
TABLE 7-30 CASE 4 – 2020: VOLTAGE VIOLATIONS FOR DELTA ENERGY CENTER OUTAGE PLUS L-1 WITH COLLINSVILLE SUBSTATION ... 84
TABLE 7-31 CASE 4 – 2020: VOLTAGE VIOLATIONS FOR METCALF ENERGY CENTER OUTAGE PLUS L-1 WITH COLLINSVILLE SUBSTATION ... 87
TABLE 7-32 CASE 4 – 2020: THERMAL VIOLATIONS FOR DELTA ENERGY CENTER OUTAGE PLUS L-1 WITH COLLINSVILLE SUBSTATION ... 89
TABLE 7-33 CASE 4 – 2020: THERMAL VIOLATIONS FOR METCALF ENERGY CENTER OUTAGE PLUS L-1 WITH COLLINSVILLE SUBSTATION ... 89
TABLE 7-34 CASE 4 – 2015: FAULT SIMULATION RESULTS ... 91
TABLE 7-35 CASE 3 – 2015: FAULT SIMULATION RESULTS ... 97
TABLE 7-36 CASE 1 – 2015: FAULT SIMULATION RESULTS ... 103
TABLE 7-37 CASE 4 – 2020: FAULT SIMULATION RESULTS ... 109
TABLE 7-38 CASE 4 – 2015: VOLTAGE VIOLATIONS FOR GOVERNOR POWER FLOW SIMULATION ... 118
TABLE 7-39 CASE 4 – 2015: THERMAL VIOLATIONS FOR GOVERNOR POWER FLOW SIMULATION ... 120
TABLE 7-40 CASE 3 – 2015: VOLTAGE VIOLATIONS FOR GOVERNOR POWER FLOW SIMULATION ... 123
TABLE 7-41 CASE 3 – 2015: THERMAL VIOLATIONS FOR GOVERNOR POWER FLOW SIMULATION ... 125
TABLE 7-42 CASE 1 – 2015: VOLTAGE VIOLATIONS FOR GOVERNOR POWER FLOW SIMULATION ... 128
TABLE 7-43 CASE 1 – 2015: THERMAL VIOLATIONS FOR GOVERNOR POWER FLOW SIMULATION ... 130
TABLE 7-44 CASE 4 – 2020: VOLTAGE VIOLATIONS FOR GOVERNOR POWER FLOW SIMULATION ... 134
TABLE 7-45 CASE 4 – 2020: THERMAL VIOLATIONS FOR GOVERNOR POWER FLOW SIMULATION ... 136

1 Executive Summary

This study looked at several levels of generation retirement within the Greater Bay Area. Results of the study show that a retirement scenario with approximately 3,900 MW of aging and once through cooling generation retired is the maximum generation retirement scenario that Quanta Technology would consider to be acceptable without new, local real power resources from generation or HVDC or construction of long distance 500kV transmission lines.

For the 3,900 MW retirement scenario (Case 4 in the table below), three 230 kV substations (Pittsburg, Moraga, and Stagg) were identified as being critical locations where large, shunt reactive support will be required to help support Greater Bay Area voltages. With 225 MVAR mechanically switched capacitor banks installed at each of these three substations, and smaller capacitor banks installed to address local sub-transmission system issues, the 2015 Greater Bay Area system was found to be adequate for each of the tests investigated.

However, there are concerns with adding these large capacitors to the system. The Greater Bay Area is already heavily compensated with shunt reactive power devices, and it will lose substantial real power and dynamic reactive power capability with the retirement of local generation. One can see this in the steady-state voltage stability analysis: the P-V curves show a voltage collapse occurring with Greater Bay Area voltages above 0.90 per unit. This is a concern, because it will be extremely difficult to operate the system with the point of collapse being so close to normal operating voltages.

In 2020, the Greater Bay Area system required more support and, given the highly compensated state of the system, the Collinsville 500/230kV Substation was recommended. This substation is an adequate alternative to additional capacitor installations, but it is limited in effect for mitigating the low voltages in the surrounding 500 kV substations. One of the major benefits of Collinsville is that some of the thermal loading issues on the Tesla 500/230 kV transformers are eliminated.

One of the concerns with the proposed layout of Collinsville is the emergency loading on either of the two submarine cables to be installed between Collinsville and Pittsburg. The cables were assumed to be rated at 800 MVA (normal) and 900 MVA (emergency). Recent communications with ABB suggest that actual cable ratings with the largest available cables would likely be in the range of 600 – 800 MVA. To eliminate overload problems, an additional cable would need to be constructed, which could be problematic for both permitting and the total cost of the project.

If the system configuration at Collinsville is modified to include either a HVDC terminal or the interconnection of Solano area generation that is presently within the CAISO interconnection queue, then Collinsville will have a substantially improved impact on the Greater Bay Area system. Either of these modifications reduces long distance power being imported to the general region and therefore would improve system voltages throughout the Greater Bay Area.

Quanta Technology also performed limited analysis of the Russell City Energy Center, a proposed combined cycle generating plant that interconnects into Eastshore Substation. This analysis showed that new generation sited at a centrally located substation would substantially improve the steady state voltage stability margins or allow for additional generation retirement.

Other Concerns

The lack of detailed load modeling in the dynamic data and base case is a concern. Quanta Techonology's experience in performing similar studies for other clients shows that the use of detailed load models at the distribution level for the fault induced voltage recovery analysis may result in slower recovery or even transient voltage collapse scenarios due to motor stalling. Based on this, the large static reactive compensation projects recommended may not be the optimal size or location. It is possible that smaller dynamic reactive devices may be required to support the system for faults near load serving substations. The Oakland and San Jose areas are the major concern due to the concentration of load and the distance from existing dynamic reactive support.

A potential voltage collapse scenario was identified in the governor power flow analysis. The outage of the Delta Energy Center resulted in a voltage collapse outside of PG&E's service territory. The analysis showed that the collapse may be avoided by reducing the flow on the California – Oregon Intertie by approximately 350 MW. While this is not a problem local to the Greater Bay Area, any new restrictions on major import paths will require more generation to replace the previously assumed imports. This may be especially problematic if once through cooling generation is retired in the Greater Bay Area and the other regions within California.

Potential Once Through Cooling Retirement Scenarios Investigated

Generation	Online?		
	Case 1	Case 3	Case 4
Oakland Units 1, 2, & 3	No	Yes	Yes
Alameda Units 1 & 2	No	Yes	Yes
Moss Landing Units 1 & 2	No	No	Yes
Potrero Unit 3	No	No	No
Potrero Units 4, 5 & 6	No	No	No
Contra Costa Unit 6 & 7	No	No	No
Pittsburg Units 5, 6 & 7	No	No	No
Moss Landing Units 6 & 7	No	No	No

Complete Analyses Performed
Steady State Thermal & Voltage Analysis (N-1 & L-2)
Steady State Voltage Analysis (G-1 + L-1)
Transient Stability Simulations of Fault Induced Voltage Recovery
Governor Power Flow Analysis of Post-Transient Fault Recovery
Steady State Voltage Stability Analysis (P-V & V-Q Curves)

2 Summary

This report documents the impact of retirement of various generating stations in the Greater Bay Area utilizing once through cooling systems. The steady-state thermal and voltage impacts along with the transient and dynamic stability impacts are identified. This report also identifies the system improvements required to eliminate all steady state voltage violations, all transient voltage recovery violations, and specific thermal loading violations identified in the analysis.

Given the results presented in this report, Quanta Technology recommends that PG&E investigate the ability to convert the recently installed Duke Moss Landing Units 1 & 2 (1,060 MW combined) from once through cooling to dry or hybrid cooling systems instead of retiring the plants or, alternatively, to eliminate the common mode of failure for the Delta Energy Center and the Metcalf Energy Center. Either of these recommendations would result in the most direct solution to the problem which is the increasing of real power imports to the Greater Bay Area. Based on this result, it is recommended that PG&E consider the scenario referred to as "Case 4" as defining the maximum amount of allowable generation retirement of approximately 3,900 MW.

Because PG&E doesn't own the Delta Energy Center, Metcalf Energy Center, or any of the generation that could be retired because of the once through cooling systems, this report recommends specific transmission projects to eliminate steady state and transient voltage violations. All recommendations were developed based on the study plan goal to "Identify critical 230kV substations where voltage support may be required, the amount of reactive support required to reliably serve electric customers and the type of technology to use." Using this goal, Quanta Technology focused on shunt reactive resources. This solution constraint leads to suggested solutions that eliminate all violations in the Case 3 and Case 1 analysis but the steady state voltage stability analysis results in P-V Curves with the point of collapse within 5% of the base case load level and above 0.90 per unit voltage. Power electronic based shunt devices can be used to extend the point of collapse but not to effectively reduce the voltage at the point of collapse. The ultimate problem with a system designed in this manner is that it will be extremely difficult to operate because the point of collapse is very close to normal operating voltages.

The results of the 2015 analysis show that static reactive power sources, i.e. mechanically switched capacitors ("MSC") are sufficient to maintain the Greater Bay Area system voltage in transient, post-transient, and steady state timeframes. The lack of necessity for high-speed, continuously controllable reactive power sources, such as Static VAR Compensators ("SVC") or Static synchronous compensators ("STATCOM") is likely due to the lack of detailed load modeling provided by P&E in the transient portion of this analysis. Composite load models were previously discussed but not used in the transient simulations. <u>Quanta Technology strongly recommends that PG&E perform additional analysis for fault simulations near load centers with explicit modeling of Greater Bay Area T/D transformers, distribution level capacitors, and detailed composite load models.</u> However, the adequacy of static reactive power sources may also be related to the support from existing SVCs at Potrero and Newark Substations and Voltage Source Converters ("VSC") at Potrero and Pittsburg Substations. The VSCs are the terminals of the TransBay Cable and are essentially STATCOMs in terms of reactive power capabilities plus the ability to transfer real power via the TransBay HVDC Cable.

The 2015 Case 4 projects consist of almost 1 GVAR of static reactive power sources. The foremost concern is that the transmission system, while compliant with all recognized planning standards, will be overcompensated with capacitors. The over-compensated system using these MSCs may mask the voltage collapse scenario. A general principle that could alleviate this concern to some extent would be to replace the retiring dynamic VARs from the once through cooling generators with a mix of static and dynamic VARs. As previously noted, detailed dynamic load modeling would be required to define this mix appropriately but 80 – 90% static and 10 – 20% dynamic mix appears to be warranted based upon Quanta Technology's experience with similar studies performed for other clients. The dynamic VAR resources, such as a STATCOM, can also effectively control the slower switching VAR resources like MSCs. The other concern is that highly compensated transmission systems can reduce the system resonance closer to the lower characteristic frequencies like 5th, 7th, and 11th resulting in Temporary Over-voltages ("TOV") and may require resonance mitigation which has not been reviewed in this study.

Series compensation was not reviewed in this study due to the small geographic footprint of the Greater Bay Area. More specifically, there are no major transmission lines with a large inductance value that would justify series capacitors.

HVDC lines were also not reviewed in detail in this study. A VSC based HVDC terminal injecting real power into the Greater Bay Area would be equivalent in most aspects to a new generator. As noted previously, new generation or preventing the retirement of generation is preferable to the numerous MSC installations proposed.

The final set of recommended transmission only projects by PG&E defined scenarios follows.

The 2015 Case 4 results:

- Many steady state voltage violations were identified with no transient voltage recovery violations identified. The major problem is that the Delta Energy Center, a combined cycle generating plant that is injecting 880 MW to Greater Bay Area system, has a common mode of failure resulting in the loss of all combustion turbines and the only steam turbine at the plant.
- Recommended solutions include three large MSC installations, two transmission line loop-in projects, an additional outlet at the Gateway generating plant, and numerous small, low voltage capacitor bank installations to relieve local voltage violations.

The 2020 Case 4 results:

- Similar to the 2015 results, the outage of the Delta Energy Center caused low voltages across the GBA system.
- Recommended solutions, in addition to the 2015 recommendations, include the Collinsville 500/230kV Substation, improved protection of the Los Esteros Critical Energy Facility, and small capacitor bank installations to relieve local voltage violations.
- Additional recommendation to perform fault induced voltage recovery simulations near load centers with detailed load modeling to further define the adequacy of the recommended MSC installations.

The total estimated cost of all projects recommended for Case 4 ranges from $375 million to $450 million based on previous estimates from PG&E. The Collinsville Substation accounts for more than 90% of the cost.

The 2015 Case 3 results:

- More steady state voltage violations were observed in the regions bordering and outside of the Greater Bay Area. It is apparent that the problem of generation retirement is more directly related to the lack of real power within the Greater Bay Area compared to the lack of local voltage support. Quanta Technology was unable to achieve valid solutions for the 5% GBA load scaling used on the P-V and V-Q curve computation.
- The Delta Energy Center outage remains the most critical issue.
- No major transient voltage recovery violations were identified. However, some wind turbines were observed to trip for certain fault scenarios. These wind turbines are modeled using voltage thresholds that are not compliant with FERC Order 661-A which specifies the ability of wind turbine low voltage ride-through.
- Solutions tested include additional large MSC installations at Vaca Dixon 500kV, Moss Landing 500kV, and Moss Landing 230kV. Some of the violations observed at the lower base voltage levels (60kV or 115kV) were not addressed due to main focus of the study to determine region wide voltage issues and the observed voltage stability issues.
- <u>Overall recommendation is to not proceed to this level of generation retirement unless new generation is sited within the Greater Bay Area.</u>

The 2015 Case 1 results:

- Some non-convergent cases were observed with the recommended projects from Case 3 for G-1 + L-1.
- The Delta Energy Center outage remains the most critical issue.
- Quanta Technology and PG&E agreed to increase the real power generated at all online units in Zone 322 (near Sacramento). No other solutions were recommended.
- <u>Overall recommendation is to not proceed to this level of generation retirement unless new generation is sited within the Greater Bay Area.</u>

Alternatives to the recommended projects included the Black Diamond 230kV substation – a conceptual project developed in this study, the Sunol 230kV substation (500kV was not considered), additional generation within the Greater Bay Area, one alternative of the Oakland Long Term Project, a HVDC terminal at the Collinsville Substation, limited testing of improved load power factor as measured at the transmission point of interconnection, and a reduced transfer capability limit on the California-Oregon Intertie.

The Black Diamond substation was suggested as an alternative because of the physical space constraints that limit the installation of any new equipment. The substation would be located where multiple 230kV lines cross paths south of Pittsburg. The general concept is to reduce the system impedance between major substations and site a centrally located reactive power source. This substation, with a 225 MVAR capacitor, was to be an adequate alternative to both the 225 MVAR capacitor installations at Pittsburg and Moraga.

The Sunol 230kV substation was tested as a southern GBA equivalent but it was found to be unnecessary in terms of voltage in the Case 4 scenario and provided no thermal benefit.

Given the steady state voltage stability results in Case 3 and Case 1 showing the point of collapse occurring at bus voltages greater than 0.90 per unit and less than 105% of the 2015 base case load, limited testing of the proposed Russell City Energy Center ("RCEC") combined cycle plant was performed.

From the RCEC analysis a generation retirement scenario with Case 4 plus the retirement of all three Oakland units and both Alameda was investigated. This analysis found that retirement of these generators (~200 MW) results in a substantial reduction in the real power margin (~600 MW). The RCEC units were found to improve the margin but the point of injection distant from Oakland load requires more real power to achieve the same levels of real power margin. One alternative of the Oakland Long Term Project was tested in combination with the RCEC and was found to provide no additional benefit.

A 3,000 MW HVDC terminal was tested at the Collinsville 500kV substation. The results show that the full retirement scenario of more than 5,000 MW is likely achievable and would probably even require less transmission upgrades within the Greater Bay Area.

A region wide policy of improving all load power factors to unity was tested. The results show that this policy could be used in place of some of the larger capacitor installations recommended.

A voltage collapse outside of the PG&E service territory was identified in the governor power flow analysis for outages of the Delta Energy Center. This was addressed by reducing the flow on the California – Oregon Intertie by approximately 350 MW. While this is not a problem local to the Greater Bay Area, any new restrictions on major import paths will require more generation to replace the previously assumed imports.

3 Study Methodology & Assumptions

3.1 Study Criteria

The planning criteria used in this study are based on the applicable Western Electricity Coordinating Council ("WECC") Planning Criteria and NERC Reliability Standards. The applicable requirements are shown in Table 3-1. Also, there is a requirement for a 5% real power margin for the worst contingency in the steady state voltage stability analysis.

Table 3-1 Planning Criteria Requirements

System Event	Steady State		Transient Voltage Dip[1]
	Thermal	Voltage	
Category A Intact System	All transmission facilities <100% of Normal Seasonal Rating (Rate 1)	$0.950 \leq v \leq 1.050$	N/A
Category B Single Contingency	All transmission facilities <100% of Emergency Seasonal Rating (Rate 2)	$0.950 \leq v \leq 1.050$	Not to exceed 25% at load buses or 30% at non-load buses. Not to exceed 20% for more than 20 cycles at load buses
Category C Selected Multiple Contingencies[2]	All transmission facilities <100% of Emergency Seasonal Rating (Rate 2)	$0.950 \leq v \leq 1.050$ Post-Transient: $0.950 \leq v \leq 1.050$	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.
Category D Extreme Events	Violations of Category C criteria will be noted.		

1. All generators must also maintain synchronism with the transmission system unless intentionally tripped or tripped as a direct result of the contingency (i.e. lose of radial connection).
2. Can use Special Protection Systems including generation and load shedding for Category C and D.

Angular instabilities are defined as any machine losing synchronism with the transmission system unless it is intentionally tripped by a Special Protection System or forcibly tripped as a direct consequence of the fault (i.e. lose of radial lines). Transient Voltage Dip is further defined by the WECC in Figure 3-1.

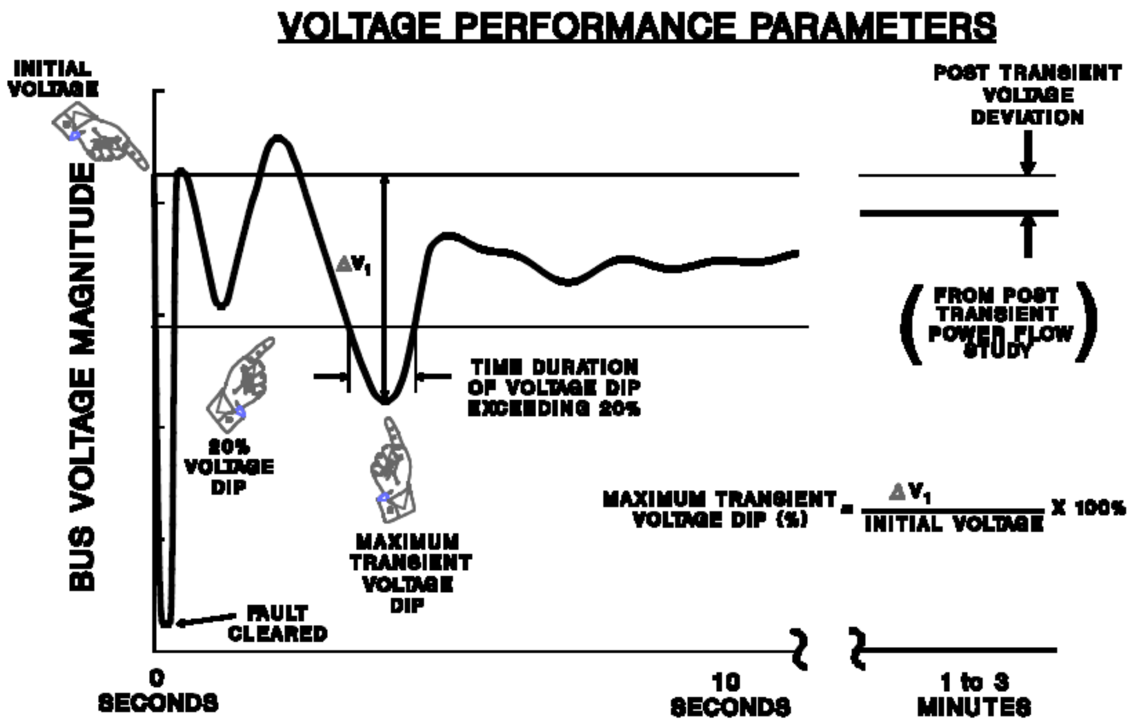

Figure 3-1 WECC Voltage Performance Parameters

3.2 Study Methodology

3.2.1 System Modeling Assumptions - Steady State

All analysis performed in this study was based on the PG&E provided base cases for 2015 and 2020 summer peak one in ten year heat wave load forecasts, shown in Table 3-2 with the generator dispatch also provided by PG&E, shown in Table 3-3.

PG&E initially provided seven cases for each year to represent different levels of generation retirement. However, PG&E and Quanta Technology agreed to begin the analysis on the 2015 version of Case 4, based on engineering judgment that the steady state voltage profile of the GBA system was expected to have minimal violations in Cases 5-7. Also, it was agreed to skip Case 2 because it was identical to Case 1 except that it included the proposed Collinsville 500/230kV substation. Given that the Collinsville substation was previously identified as a potential long term reinforcement, it was considered as an alternative for each case analyzed in this study.

Table 3-2 Greater Bay Area Load Assumptions for Cases 1, 3, & 4

Greater Bay Area Regions	2015 Demand (MW)	2020 Demand (MW)
San Francisco	1,010	1,055
Peninsula Division	1,123	1,192
East Bay Division	1,093	1,115
Diablo Division	1,860	1,961
Mission Division	1,432	1,496
San Jose Division	1,935	2,032
De Anza Division	1,023	1,070
Silicon Valley Power	615	663
Greater Bay Area Total	**10,095**	**10,584**

Table 3-3 Greater Bay Area Generation Retirement Assumptions

Generation	Online?		
	Case 1	Case 3	Case 4
Delta Energy Center	Y	Y	Y
Los Medanos Energy Center	Y	Y	Y
Gateway Generation (Contra Costa 8)	Y	Y	Y
Metcalf Energy Center	Y	Y	Y
Oakland Units 1, 2, & 3	N	Y	Y
Alameda Units 1 & 2	N	Y	Y
Moss Landing Units 1 & 2	N	N	Y
Potrero Unit 3	N	N	N
Potrero Units 4, 5 & 6	N	N	N
Contra Costa Unit 6 & 7	N	N	N
Pittsburg Units 5, 6 & 7	N	N	N
Moss Landing Units 6 & 7	N	N	N

After receiving the load flow cases from PG&E, Quanta Technology further modified the cases as follows.

1. The Pittsburg VSC, the sending end of the TransBay HVDC Cable, was set to regulate the terminal 180.5kV bus of the VSC instead of the Pittsburg 230kV bus. The maximum reactive capability was lowered to 120 MVAR so that the assumed capability of the VSC, 430 MVA, was respected.
2. The Potrero VSC, the receiving end of the TransBay HVDC Cable, was set to regulate the terminal 180.5kV bus of the VSC instead of the Potrero 115kV bus. The voltage set point was selected such that the reactive power injected into the transmission system was near 0 MVAR. This is the most economically efficient mode of operation because the real power capability of the VSC is not diminished by the in-

jection of reactive power. It is also the ideal initial condition for all fault scenarios because the VSC has the full dynamic range available.

3. All fixed capacitors (i.e. shunts with no control) at the Potrero 115kV bus were modeled as in-service.
4. The Potrero SVC was modeled as a static VAR device operating at the maximum inductive mode. This is the ideal initial condition for all fault scenarios because the SVC has the full dynamic capacitive range available.
5. The Newark SVC was modeled as a static VAR device regulating the Newark 230kV bus voltage.
6. Set the scheduled voltage of each of the three Oakland generating unit terminal buses to 1.05 per unit.

Preliminary contingency analysis revealed numerous clusters of voltage and thermal violations in the same regions. Following discussions with PG&E, Quanta Technology modeled projects 7-12 as assumed facilities in all cases. Each of these projects has already attained approval by the CAISO.

7. The 350 MVAR capacitor at the Metcalf 500kV bus was switched in-service. PG&E verified that this is an existing facility.
8. Replacement of thermally limiting line switches on the Jefferson – Stanford – Cooley Landing 60kV path.
9. Replacement of the existing Jefferson 230/60kV transformer that is presently out-of-service due to gassing issues. The assumed no load tap setting on each of the parallel 230/60kV transformers was set to eliminate circulating reactive power and maintaining both the 230kV and 60kV bus voltages within the required ranges.
   a. Cases 3 and 4 – Both transformer taps set to 0.98125.
10. South of San Mateo Capacity Increase Project 2010: Reconductor of Ravenswood – San Mateo, Newark – Ames circuits 1, 2, and 3, and Newark – Ames (dist-Ames) 115 kV with 477 ACSS conductor.
11. Reconductor of Newark – Ravenswood and Tesla – Ravenswood 230kV lines with bundled 954 ACSS conductors.
12. Installation of a 10 MVAR capacitor at Half Moon Bay 60kV substation.

Preliminary contingency analysis also revealed several non-converging contingencies that were found to easily converge when solved manually. This problem was traced back to the Sylmar HVDC terminals near Los Angeles. Modeling assumptions 13 and 14 were implemented to drastically reduce the number of non-converged contingencies that were required to be checked post-contingency processing.

13. The Newton Solution Tolerance was increased to 0.25 MVA.
14. Fake synchronous condensers were added at both of the Sylmar HVDC. It is the opinion of Quanta Technology that modeling these facilities has a negligible effect on the GBA system and is necessary to expedite the study.

Also, it was observed that the buses in Table 3-4 have auxiliary load modeled even though the generator is assumed to be retired. The total load that was removed from the case is almost equivalent to the GBA yearly load growth.

Table 3-4 Auxiliary Load at Retired Generators

Bus Name	Bus Number	Load (MW)	Load (MVAR)	Case #s
Pittsburg 7	30000	17.1	8.8	All Cases
Pittsburg 5	33105	7.7	4.0	All Cases
Pittsburg 6	33106	7.7	4.0	All Cases
Contra Costa 6	33116	5.0	2.6	All Cases
Contra Costa 7	33117	5.0	2.6	All Cases
Duke Moss Landing 6	36405	6.7	5.4	All Cases
Duke Moss Landing 7	36406	6.7	5.4	All Cases
Case 4 Totals		**55.9**	**32.8**	
Duke Moss Landing 1	36221	6.6	3.3	3, 2, & 1
Duke Moss Landing 2	36222	6.6	3.3	3, 2, & 1
Duke Moss Landing 4	36224	6.6	3.3	3, 2, & 1
Duke Moss Landing 5	36225	6.6	3.3	3, 2, & 1
Case 3, 2, & 1 Totals		**82.3**	**46.0**	

3.2.2 System Modeling Assumptions - Dynamics

The dynamics base cases were modified in a similar manner except for the following issues with the SVCs and VSCs.

1. The Potrero and Newark SVCs were modeled as generators with a fixed reactive capability (Qmax = Qmin). This modeling is required due to the user model EPCL file which represents the SVCs with SMES1 models. Initially, the fixed reactive capability was set to be equivalent to the Static VAR Devices ("SVD") modeled in the load flow base cases (described above) but modified so that a "flat start" or "no bump" simulation was achievable. The modified values were -100.0 MVAR at Potrero and -41.5 MVAR at Newark.
2. Initialization errors were observed when the Pittsburg VSC was set to regulate the terminal bus voltage. To avoid any changes in the user model EPCL file, the Pittsburg VSC was left to regulate the Pittsburg 230kV bus. The maximum reactive capability was still reduced to 120 MVAR.
3. Initialization errors were observed when the Potrero VSC was set to regulate the terminal bus voltage. To avoid any changes in the user model EPCL file, the Potrero VSC was left to regulate the Potrero 115kV bus but the scheduled voltage was changed from 1.03500 to 1.02916 to match the Potrero SVC scheduled voltage.
4. To achieve a "flat start" simulation with no faults modeled it was necessary to remove the Potrero SVC control of the three mechanically switched capacitors at the Potrero 115kV bus. This was done by changing all switching thresholds for the MSCs to arbitrarily large numbers as described below. This change is acceptable

for the purposes of this study but a more in-depth study should be performed to coordinate the control of the VSC, SVC, and MSCs at the Potrero substation.

   a. PG&E Supplied Parameters: @Bin1 = 160, @Bin2 = 80
   b. Quanta Modification: @Bin1 = 1000, @Bin2 = 1000
   c. PG&E Supplied Parameter: @Bout1 = -80, @Bout2 = -40
   d. Quanta Modification: @Bout1 = -1000, @Bout2 = -1000

5. Other simulation tests show reactive power output at both Metcalf Energy Center combustion turbines (Buses #35881 and #35882) varies without disturbance. Quanta Technology reviewed the dynamic data and observed that the parameters after Tf in the exciter model "exst1" at these two buses are originally set to be (0, 0, 999.0, -999.0, 0.04, 2.80, 5.00), which are different from the default values suggested in the PSLF user manual. In order to get a "flat start" simulation, the parameters of the model "exst1" after Tf were set to the PSLF default values as (0, 0, 99, -99, 0, 99, 0). This modification of dynamic data was discussed with and agreed to by PG&E.

The dynamics data was also modified by "netting" the generators at the following buses because each of them had angular drift greater than 5° over a 10 second simulation with no faults modeled. Netting generation causes the dynamic models to be ignored and the machine to be represented as a negative load. This list was reviewed with PG&E on October 10th, 2008. The Gianera CT (Bus #36858) in the city of Santa Clara was noted as having modeling problems by PG&E and it was agreed that netting this machine was the appropriate short term solution to continue with this study.

- Bus #32496, near Rio Oso
- Bus #35050, near Midway
- Bus #36207, near Moss Landing
- Bus #34553, near Gates
- Bus #48516, near Coyote
- Bus #36858, near Newark

The last base case modification was to switch in the capacitor at the Highwinds 34.5kV bus (#32172) to support the wind farm voltage.

Finally, before each fault simulation the PG&E supplied "BASELOAD.p" EPCL file was run to initialize governor and exciter models within the limits shown in the dynamics data file.

Composite load models were discussed but not used for this analysis. Quanta Technology strongly recommends that PG&E perform a sensitivity study for the worst fault simulations identified in this study with detailed composite load models.

3.2.3 System Modeling Assumptions – Governor Power Flow

Additional assumptions included all case modifications previously stated in Section 3.2.1 and the following.

1. Removed the fake synchronous condensers that were placed at the Sylmar HVDC terminals.
2. Assumed all recommended projects are in-service. This requires that all switched capacitors are assumed to have the full susceptance switched in prior to the contingency. This assumption should be reviewed once the appropriate number of steps at each MSC installation is determined.
3. Changed the control area of the Potrero and Newark SVCs from 30 to 64. This allows continuous control of the SVCs during the governor power flow solution. All mechanically switched capacitors and SVCs are modeled in PSLF as SVD with either discrete or continuous control. The PG&E provided EPCL code doesn't allow switching of any SVDs unless the device control area is 64.
4. Changed the Base Load flags of the Pittsburg and Potrero VSCs from 0 to 1 so that the real power output of the VSCs doesn't change during the governor power flow solution.
5. Changed the Base Load flags of each unit in the following combined cycle plants from 1 to 0 so that the real power output of each unit is changed relative to the amount of generation tripped during the contingency.
    a. Delta Energy Center (Pittsburg 230kV)
    b. Los Medanos Energy Center (Pittsburg 115kV)
    c. Duke Moss Landing 1 & 2 (Moss Landing 230kV)
    d. Cosumnes (Rancho Seco 230kV)
    e. Texaco Sunrise(Midway 230kV)
    f. Sutter (O'Banion 230kV)
    g. Elk Hills (Midway 230kV)
    h. La Paloma (Midway 230kV)
6. Reduced COI loading from 4,800 MW to 4,450 MW by reducing power transfers from Area 40 (Northwest) to Area 30 (PG&E). Only the area slack buses participated in the power transfer to insure that machines local to the Greater Bay Area were not affected. See below for more detail.

The initial steady state voltage stability (P-V Curves) and Governor Power Flow solution attempts resulted in solution divergence in areas distant from the PG&E Greater Bay Area. Review of the Case 4 base case and governor power flow iterations showed that an area outside of PG&E's system consistently collapses for governor power flow solutions of Delta Energy Center outages. Multiple solutions were tested in order to refocus the study on the Greater Bay Area including large synchronous condensers in that area. However, the only system modification that resulted in consistently converging solutions was to reduce the flow on the California-Oregon Intertie ("COI") from 4,800 MW, the maximum capability, to 4,450 MW. The reduction in flow was made by reducing interchange from Area 40 (Northwest) to Area 30 (PG&E) 400 MW. PG&E approved this modification due to known voltage issues emanating outside of PG&E's service territory

3.2.4 Methods of Analysis

The analysis started with the least severe retirement scenario in 2015, Case 4, and continued to Case 3 and finally Case 1. All projects recommended in Case 4 were included in Case 3 and all projects recommended in Cases 4 and 3 were included in Case 1.

After all 2015 analysis was completed then Case 4 in 2020 was analyzed assuming that all Case 4, 2015 projects were in-service.

Within each case, the analysis was performed in the same order:

Step 1 – Steady State Thermal & Voltage Analysis (N-1 & L-2)
- Full Newton Raphson Solutions for steady state contingencies.

Step 2 – Initial Steady State Solution Development
Step 3 – Steady State Voltage Analysis (G-1 + L-1)
- Full Newton Raphson Solutions for steady state contingencies.

Step 4 – Initial Steady State Solution Development
Step 5 – Transient Stability Simulations of Fault Induced Voltage Recovery
- Single phase-to-ground and three-phase-to-ground fault simulations with primary clearing (i.e. normal clearing times) and delayed clearing scenarios as advised by PG&E.

Step 6 – Review of Adequacy of Solutions for Voltage Recovery
Step 7 – Governor Power Flow Analysis of Post-Transient Fault Recovery
- Full Newton Raphson Solutions with modeling of post-transient response of speed governors. Analysis is performed using a PG&E provided EPCL program.

Step 8 – Review of Adequacy of Solutions for Post-Transient Recovery
Step 9 – Steady State Voltage Stability Analysis (P-V & V-Q Curves)
- Full Newton Raphson Solutions using a PSLF provided EPCL program to create the curves.

Step 10 – Final Solution Development & Project Sensitivities

4 Study Results

4.0 Existing System Issues

The general result of retiring generation without commissioning new local generating plants is the increased thermal loading on regional transmission ties and lower voltages due to the loss of reactive resources and the increased imports. Table 4-1 shows a general indication of the voltage profile of the area by review of 500kV buses close to the GBA system. The voltage profile was recorded prior to the inclusion of any projects recommended by Quanta Technology.

Table 4-1 Greater Bay Area 500kV Bus Voltages (N-0)

Monitored Bus	Voltage (p.u.)						
	Scheduled	2015			2020		
		Case 4	Case 3	Case 1	Case 4	Case 3[3]	Case 1[4]
Moss Landing 500kV	1.060	1.037	0.999	0.986	1.023	-	-
Metcalf 500kV[1]	1.037	1.034	1.009	0.997	1.021	-	-
Tesla 500kV	1.049	1.018	0.995	0.983	1.004	-	-
Tracy 500kV[2]	1.070	1.028	1.005	0.993	1.014	-	-
Vaca Dixon 500kV	1.053	1.020	1.000	0.989	1.007	-	-

1. An existing 350 MVAR capacitor is modeled at this bus.
2. An existing 600 MVAR capacitor is modeled at this bus.
3. Case 3-2020 didn't solve without new projects. The case was able to solve with Moss Landing 1 off and two CTs at Moss Landing 2 off. The resulting 500kV voltages range between 0.965 and 0.980.
4. Case 1-2020 was not reviewed because Case 3-2020 didn't solve.

As shown in Table 4-2 and Table 4-3, the existing GBA transmission system in 2015 will already be heavily compensated with shunt reactive power devices with the potential for a loss of 1,900 to 2,700 dynamic MVAR through the retirement of local generation. The GBA system will be 36% compensated (3.6 GVAR/10 GW) without any of the recommended projects from this analysis.

Table 4-2 Greater Bay Area Existing Shunt Compensation in 2015

Greater Bay Area Regions	Demand (MW)	Demand (MVAR)	Existing Shunt Compensation (MVAR)
San Francisco	1,010	168	890
Peninsula Division	1,127	243	550
East Bay Division	1,093	292	10
Diablo Division	1,860	451	10
Mission Division	1,432	304	890
San Jose Division	1,935	425	880
De Anza Division	1,023	229	380
Silicon Valley Power	615	107	0
Greater Bay Area Total	10,095	2,219	3,610

Table 4-3 Greater Bay Area Potential Generation Retirements

Generating Unit Name	Bus Number	Pmax (MW)	Qmax (MVAR)
Potrero 3	33252	210	140
Potrero 4	33253	52	33
Potrero 5	33254	52	33
Potrero 6	33255	52	33
Pittsburg 5	33105	325	176
Pittsburg 6	33106	325	130
Pittsburg 7	30000	710	370
Contra Costa 6	33116	340	165
Contra Costa 7	33117	340	165
Duke Moss Landing 6	36405	750	340
Duke Moss Landing 7	36406	750	340
Case 4 Totals		**3,906**	**1,925**
Duke Moss Landing 1	36221	176	110
Duke Moss Landing 2	36222	176	110
Duke Moss Landing 3	36223	198	124
Duke Moss Landing 4	36224	176	110
Duke Moss Landing 5	36225	176	110
Duke Moss Landing 6	36226	198	124
Case 3 Totals		**1,100**	**688**
Oakland 1	32901	55	32
Oakland 2	32902	55	32
Oakland 3	32903	55	37
Alameda CT 1	38118	25	12
Alameda CT 2	38119	25	12
Case 1 Totals		**215**	**125**
Total Retirement of Dynamic VAR =		**5,221**	**2,738**

4.1 Discussion of Potential Projects

Given the results presented in this report, Quanta Technology recommends that PG&E investigate the ability to convert the recently installed Duke Moss Landing Units 1 & 2 (1,060 MW combined) from once through cooling to dry or hybrid cooling systems instead of retiring the plants or to eliminate the common mode of failure for the Delta Energy Center and the Metcalf Energy Center. Either of these recommendations would result in the most direct solution to the problem which is the increasing of real power imports to the Greater Bay Area. Specifically, it is recommended that the scenario referred to as "Case 4" define the maximum amount of allowable generation retirement of approximately 3,900 MW.

Because PG&E doesn't own the Delta Energy Center, Metcalf Energy Center, or any of the generation that could be retired because of the once through cooling systems, this report recommends specific transmission projects to eliminate steady state and transient voltage violations. All recommendations were developed based on the study plan goal to "Identify critical 230kV substations where voltage support may be required, the amount of reactive support required to reliably serve electric customers and the type of technology to use." Using this goal, Quanta Technology focused on shunt reactive resources. This solution constraint leads to suggested solutions that eliminate all violations in the Case 3 and Case 1 analysis but would not be considered as Good Utility Practice because the steady state voltage stability analysis results in P-V Curves with the point of collapse within 5% of the base case load level and above 0.90 per unit voltage. Power electronic based shunt devices can be used to extend the point of collapse but not to effectively reduce the voltage at the point of collapse. The ultimate problem with a system designed in this manner is that it will be extremely difficult to operate because the point of collapse is very close to normal operating voltages.

The results of the 2015 analysis show that static reactive power sources, i.e. mechanically switched capacitors ("MSC") are sufficient to maintain the Greater Bay Area system voltage in transient, post-transient, and steady state timeframes. The lack of necessity for high-speed, continuously controllable reactive power sources, such as Static VAR Compensators ("SVC") or Static synchronous compensators ("STATCOM") is likely due to the lack of detailed load modeling in the transient portion of this analysis. Composite load models were previously discussed but not used in the transient simulations. Quanta Technology strongly recommends that PG&E perform additional analysis for fault simulations near load centers with explicit modeling of Greater Bay Area T/D transformers, distribution level capacitors, and detailed composite load models. However, the adequacy of static reactive power sources may also be related to the support from existing SVCs at Potrero and Newark Substations and Voltage Source Converters ("VSC") at Potrero and Pittsburg Substations. The VSCs are the terminals of the TransBay Cable and are essentially STATCOMs in terms of reactive power capabilities plus the ability to transfer real power via the TransBay HVDC Cable.

During the study, PG&E noted that customer complaints of voltage sags below 0.7 per unit for up 7 cycles were a problem for the customer owned equipment. Local voltage performance may be most efficiently resolved by distributed non-transmission solutions such as Dynamic Sag Correctors, a three-phase series device located at the customer's plant, or a local distribution level SVC or STATCOM, or even distributed energy storage resources. Given the lack of distribution level load modeling, Quanta Technology can't verify that any distribution level loads experience these voltage sags for regional faults. Most load buses are modeled down to only 60 kV.

While no power electronic based reactive sources are specifically recommended, there are concerns with the recommended set of projects. The 2015 Case 4 projects consist of almost 1 GVAR of static reactive power sources. The foremost concern is that the transmission system, while compliant with all recognized planning standards, will be overcompensated with capacitors. The over-compensated system using these MSCs may mask the voltage collapse scenario. A general principle that could alleviate this concern to some extent would be to replace the retiring dynamic VARs with a mix of static and dynamic VARs. As previously noted, detailed dynamic load modeling would be required to define this mix appropriately but 80 – 90% static and 10 – 20% dynamic mix is recommended. The dynamic VAR resources, such as a STATCOM, can also effectively control the slower switching VAR resources like MSCs. The other concern is that highly compensated transmission systems can reduce the system resonance closer to the lower characteristic frequencies like 5th, 7th, and 11th resulting in Temporary Over-voltages ("TOV") and may require resonance mitigation which has not been reviewed in this study.

Typical dynamic reactive sources are SVCs and STATCOMs. SVCs are combinations of shunt capacitors and inductors controlled by thyristor switching. The thyristor switching allows for continuous control of susceptance but the VAR injected into the system is still proportional to the square of the voltage. STATCOMs are inverters consisting of Insulated Gate Bipolar Transistors ("IGBT") connected to a DC capacitor bank and controlled using Pulse Width Modulation ("PWM"). The PWM control results in a higher speed of response compared to SVCs and the use of the inverter and DC capacitor results in the VAR injected being linearly proportional to the voltage. The overall footprint of a STATCOM is also much smaller than a SVC.

The relative costs of SVCs are typically three times the cost of MSCs and STATCOMs are typically two times the cost of SVCs. These cost comparisons consider only the actual equipment installed; real estate and other related costs are not considered. Also, the full dynamic range, maximum capacitive to maximum inductive capability, of SVCs and STATCOMs should be used when comparing costs.

A retiring generator could also be used to supply dynamic reactive support by being converted to a synchronous condenser. This potential solution was discussed with PG&E but not investigated in detail due to multiple issues including:

1. PG&E doesn't own any of the potentially retiring generating units. If PG&E purchased the generating assets then maintenance of rotating machines would be required. Existing PG&E maintenance staff doesn't specialize in this area.
2. If the existing Generation Owners continued to own and operate the synchronous condensers then an unknown method of financial compensation would need to be negotiated.
3. Operating costs of synchronous condensers is expected to be significantly higher than other reactive support devices.

Series compensation was not reviewed in this study due to the small geographic footprint of the Greater Bay Area. More specifically, there are no major transmission lines with a large inductance value that would justify series capacitors.

HVDC lines were also not reviewed in detail in this study. A VSC based HVDC terminal injecting real power into the Greater Bay Area would be equivalent in most aspects to a new generator. As noted previously, new generation or preventing the retirement of generation is preferable to the numerous MSC installations proposed.

The final set of recommended transmission only projects by PG&E defined scenarios follows.

The 2015 Case 4 results:

- Many steady state voltage violations were identified with no transient voltage recovery violations identified. The major problem is that the Delta Energy Center, a combined cycle generating plant that is injecting 880 MW to Greater Bay Area system, has a common mode of failure resulting in the loss of all combustion turbines and the only steam turbine at the plant.
- Recommended solutions include three large MSC installations, two transmission line loop-in projects, an additional outlet at the Gateway generating plant, and numerous small, low voltage capacitor bank installations to relieve local voltage violations.

The 2020 Case 4 results:

- Similar to the 2015 results, the outage of the Delta Energy Center caused low voltages across the GBA system.
- Recommended solutions, in addition to the 2015 recommendations, include the Collinsville 500/230kV Substation, improved protection of the Los Esteros Critical Energy Facility, and small capacitor bank installations to relieve local voltage violations.
- <u>Additional recommendation to perform fault induced voltage recovery simulations near load centers with detailed load modeling to further define the adequacy of the recommended MSC installations.</u>

The total estimated cost of all projects recommended for Case 4 ranges from $375 million to $450 million based on previous estimates from PG&E. The Collinsville Substation accounts for more than 90% of the cost.

The 2015 Case 3 results:
<u>Overall recommendation is to not proceed to this level of generation retirement unless new generation is sited within the Greater Bay Area.</u>

- More steady state voltage violations were observed in the regions bordering and outside of the Greater Bay Area. It is apparent that the problem of generation retirement is more directly related to the lack of real power within the Greater Bay Area compared to the lack of local voltage support. Quanta Technology was unable to achieve valid solutions for the 5% GBA load scaling used on the P-V and V-Q curve computation.
- The Delta Energy Center outage remains the most critical issue.
- No major transient voltage recovery violations were identified. However, some wind turbines were observed to trip for certain fault scenarios. These wind turbines are

modeled using voltage thresholds that are not compliant with FERC Order 661-A which specifies the ability of wind turbine low voltage ride-through.

- Solutions tested include additional large MSC installations at Vaca Dixon 500kV, Moss Landing 500kV, and Moss Landing 230kV. Some of the violations observed at the lower base voltage levels (60kV or 115kV) were not addressed due to main focus of the study to determine region wide voltage issues and the observed voltage stability issues.

The 2015 Case 1 results:
<u>Overall recommendation is to not proceed to this level of generation retirement unless new generation is sited within the Greater Bay Area.</u>

- Some non-convergent cases were observed with the recommended projects from Case 3 for G-1 + L-1.
- The Delta Energy Center outage remains the most critical issue.
- Quanta Technology and PG&E agreed to increase the real power generated at all online units in Zone 322 (near Sacramento). No other solutions were recommended.

Alternatives to the recommended projects included the Black Diamond 230kV substation – a conceptual project developed in this study, the Sunol 230kV substation (500kV was not considered), additional generation within the Greater Bay Area, one alternaive of the Oakland Long Term Project, a HVDC terminal at the Collinsville Substation, limited testing of improved load power factor as measured at the transmission point of interconnection, and a reduced transfer capability limit on the California-Oregon Intertie.

The Black Diamond substation was suggested as an alternative because of the physical space constraints that limit the installation of any new equipment. The substation would be located where multiple 230kV lines cross paths south of Pittsburg. The general concept is to reduce the system impedance between major substations and site a centrally located reactive power source. This substation, with a 225 MVAR capacitor, was to be an adequate alternative to both the 225 MVAR capacitor installations at Pittsburg and Moraga.

The Sunol substation was tested as a southern GBA equivalent but it was found to be unnecessary in terms of voltage in the Case 4 scenario and provided no thermal benefit.

Given the steady state voltage stability results in Case 3 and Case 1 showing the point of collapse occurring at bus voltages greater than 0.90 per unit and less than 105% of the 2015 base case load, limited testing of the proposed Russell City Energy Center ("RCEC") combined cycle plant was performed.

From the RCEC analysis a generation retirement scenario with Case 4 plus the retirement of all three Oakland units and both Alameda was investigated. This analysis found that retirement of these generators (~200 MW) results in a substantial reduction in the real power margin (~600 MW). The RCEC units were found to improve the margin but the point of injection distant from Oakland load requires more real power to achieve the same levels of real power margin. One alternative of the Oakland Long Term Project was tested in combination with the RCEC and was found to provide no additional benefit.

A 3,000 MW HVDC terminal was tested at the Collinsville 500kV substation. The results show that the full retirement scenario of more than 5,000 MW is likely achievable and would probably even require less transmission upgrades within the Greater Bay Area.

A region wide policy of improving all load power factors to unity was tested. The results show that this policy could be used in place of some of the larger capacitor installations recommended.

A potential voltage collapse was identified in the governor power flow analysis. The outage of the Delta Energy Center resulted in a voltage collapse outside of the PG&E service territory. This was addressed by reducing the flow on the California – Oregon Intertie by approximately 350 MW. While this is not a problem local to the Greater Bay Area, any new restrictions on major import paths will require more generation to replace the previously assumed imports.

4.2 Case 4 – 2015 Results

4.2.1 Steady State Voltage Results (N-1 & L-2)

As shown in Table 7-3, Table 7-4, and Table 7-5 in the Section 7.1, numerous voltage violations were identified. The following list is a summary of regional voltage issues.

1. No Intact System (Category A) voltage violations were identified.
2. The outage of the Delta Energy Center interconnected to the Pittsburg 230kV substation caused 60 bus voltage violations including 44 violations at 230kV buses.
3. The Oakland area 115kV system bus voltages were barely above 0.95 per unit with an intact system and were below 0.95 per unit for approximately 100 contingencies.
4. Minor voltage issues were observed near the 115kV system north of Sobrante, from Newark to San Jose to Metcalf areas, and at 60kV buses near Las Positas.

4.2.2 Steady State Thermal Results (N-1 & L-2)

As shown in the Table 7-1 and Table 7-2 in Section 7.1, numerous thermal loading violations were identified. Local system thermal overloads were only addressed when specifically requested by PG&E to do so. Table 4-4 shows the lines selected by PG&E for review of potential solutions.

Table 4-4 Thermal Overloads Identified for System Reinforcements

Monitored Element	Worst Contingency[1]	Post-Cont. Loading (p.u.)	Emergency Rating (MVA)
Metcalf – Hicks 230kV line[2]	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	1.15	637.4
Hicks – Monta Vista 230kV line		1.14	499.0
Vasona – Saratoga 230kV line		1.20	499.0
Saratoga – Monta Vista 230kVline		1.13	420.0

1. Worst and Only Contingency causing an overload of these lines
2. Metcalf – Hicks 230kV terminal equipment will be replaced with an ultimate line rating of 694 MVA, which would still be overloaded in this analysis.

Quanta Technology tested the existing SPS at Monta Vista Substation, which open-ends the Monta Vista – Jefferson 230 kV lines at Monta Vista for this contingency. It was found that this tripping scheme does relieve the overload. This tripping scheme was not tested for any sensitivity in system load or generation dispatch. It is recommended that the line tripping scheme be re-evaluated and/or the affected transmission lines be re-rated or reconductored.

4.2.3 Solutions Tested

The following set of projects was developed by considering clusters of local upgrades for each sub region of the GBA system. All capacitor installations need to be studied in more detail to determine the necessary MVAR steps to minimize the Δv during switching operations.

Projects 1-4 are proposed to improve the 230kV bus voltages across the GBA system for the worst contingency; the outage of the whole Delta Energy Center combined cycle natural gas generating plant (880 MW). If future stability analysis shows the need for dynamic compensation then one of Projects 1-3 should be tested as an SVC installation instead of a MSC.

1. Install a new 225 MVAR MSC with 3 steps of 75 MVAR at the Pittsburg 230kV substation.
2. Install a new 225 MVAR MSC with 3 steps of 75 MVAR at the Moraga 230kV substation.
3. Install a new 225 MVAR MSC with 3 steps of 75 MVAR at the Stagg 230kV substation.
4. Raise the scheduled voltage at the Metcalf 230kV bus from 1.00 per unit to 1.02 per unit. This forces more of the 400 MVAR of capacitors at the Metcalf 230kV bus to be switched in and raises the voltage on the local 230kV and 115kV system.

Projects 5-12 are proposed to improve local voltage on 115kV and 60kV subsystems. Most of the MSC installations are proposed to be placed at the same location as the bus voltage violation.

5. Install a new 20 MVAR capacitor bank at the Belmont 115kV substation. Note that the Belmont – Bair 115kV line has an unusually low X/R ratio (0.0207/0.0576 = 0.3594). If the line resistance is actually lower then this project may be unnecessary.
6. Install a new 40 MVAR capacitor bank at the Dixon Landing 115kV substation.
7. Install a new 20 MVAR capacitor bank at the San Jose B 115kV substation. An adjacent substation may be an alternative site for the proposed project.
8. Install a new 30 MVAR capacitor bank at the El Cerrito 115kV substation. The double contingency that causes the low voltage at El Cerrito also results in local line overloads. Transmission line rebuilds, reconductoring, or load shedding may be preferred alternatives.

The Projects 9-11 may be combined into a single project at a nearby substation or completely replaced by the Oakland Long Term Project which is looking at the possibility of installing a new 115kV cable from Oakland C 115kV substation to Oakland J 115kV substation.

9. Install a new 20 MVAR capacitor bank at the Owens Brockway 115kV substation.
10. Install a new 20 MVAR capacitor bank at the San Leandro 115kV substation.
11. Install a new 20 MVAR capacitor bank at the Oakland Station J 115kV substation.

12. Install a new 20 MVAR capacitor bank at the Las Positas 60kV substation.

Projects 13-15 are proposed to improve the 230kV bus voltage at the Eastshore and San Ramon substations without adding more capacitors or new transmission lines to the system.

13. Loop the Pittsburg – San Mateo 230kV line into the Eastshore substation. This will require physical substation space to accommodate two new bus positions.
14. Modify the tap settings on the Eastshore 230/115kV transformers to boost the 230kV voltage. The taps on transformer ID 1 were locked at 0.9939 and the taps on transformer ID 2 were locked at 1.000.
15. Loop one of the Pittsburg – Eastshore circuits into the San Ramon 230kV substation. This will require physical substation space to accommodate two new bus positions.

Finally, the Lakewood 115kV substation was found to have severe thermal and voltage violations but was not reviewed for system improvements. These violations should be considered as candidates for Special Protection Systems that directly trip load to reduce the line loading and improve the local voltage profile.

4.2.4 Steady State Voltage Results (G-1 + L-1)

After developing solutions to the violations discovered in Sections 4.2.1 and 4.2.2, additional analysis was performed to determine the ability of the system to operate with the coincident outage of the most critical generating plant and any single transmission line. Transformer, generator, and all other multiple contingencies (double circuit, breaker failure, etc.) are not considered in this analysis.

The Delta Energy Center, an 880 MW combined cycle natural gas fueled generating plant, was selected as the most critical generator outage in the Northern section of the GBA system. The Metcalf Energy Center, an 560 MW combined cycle natural gas fueled generating plant, was selected as the most critical generator outage in the Southern section of the GBA system.

As shown in Table 7-7 and Table 7-8 in Section 7.1, some of the voltage violations discovered and eliminated in the initial contingency analysis were aggravated by the combination of contingencies.

The only major issue discovered in this analysis was that the combination of an outage of the Delta Energy Center with the outage of the Contra Costa – Gateway 230kV line results in divergent solutions, this single line contingency is equivalent to the outage of the whole Gateway Generating Station (590 MW).

4.2.5 Additional Steady State Solutions

In addition to the fifteen projects tested in Section 4.2.3, the following projects were developed in order to meet the voltage requirements for the G-1 + L-1 analysis.

16. Construct a second 230kV line from Gateway Generating Station to Contra Costa. The system one-line diagrams show what appear to be two existing lines between Gateway and Contra Costa that are protected as a single line. If that is the case then the existing lines can be protected separately.
17. Increase the voltage schedule at all Moss Landing units from 1.03 per unit to 1.05 per unit.

A. The 450 MVAR capacitor at the Table Mountain 500kV bus was switched in-service.
B. The 200 MVAR capacitor at the Olinda 500kV bus was switched in-service.
C. The two 197.3 MVAR capacitors at the Malin 500kV bus were switched in-service.

PG&E requested that Projects A, B, and C only be noted in the report but not used as fully recommended projects in the ongoing analysis. If Projects A, B, and C are not included then voltage violations will still be observed for specific L-1 + G-1 contingencies in the following locations:

- North and East of the Tesla substation, which is outside of the GBA system. Re-dispatch of the Rancho Seco generation works to restore voltage to this area and given the low probability of a complete plant outage this is considered to be the best alternative.
- Loyola 60kV and Los Gatos 60kV buses. Both of these violations occur only for a single contingency which causes both voltage and thermal violations. Due to the low base voltage and isolated nature of the violations both are presently ignored.

4.2.6 Fault Induced Transient Voltage Recovery Results

No transient voltage recovery violations were identified in the Case 4 analysis with the recommended steady state projects. However, wind turbines at the Shiloh substation were observed to trip due to a 0.75 per unit voltage threshold. The Shiloh wind turbines do not meet FERC Order 661-A Low Voltage Ride Through criteria and therefore solutions to the tripping are not developed.

Also, some distant wind farms were observed to trip but this is not considered to be associated with the GBA system.

The complete list of transient simulations is in Table 7-34 in Section 7.5.

4.2.7 Governor Power Flow Results

Governor power flow analysis is conducted to simulate the ability of the system to recover during the post-transient timeframe following a major contingency. All governor power flow analysis was performed with the Case 4 recommended steady state projects modeled.

Table 7-38 and Table 7-39 in Section 7.9 list all voltage and thermal violations in the governor power flow analysis. As shown in Table 7-38, no voltage violations were identified in the GBA system.

As described in Section 3.2.3, the loss of the Delta Energy Center resulted in non-convergent governor power flow solutions until COI loading was reduced to approximately 4,450 MW. The point of collapse is initiated in a region geographically and electrically distant from the GBA system. However, it is the opinion of Quanta Technology that these issues need to be considered in region wide study to evaluate the effect of generation retirements on the North to South power transfer capability of the Western Interconnection. These power transfer or regional capacity issues will be even more problematic if other once through cooling generation is retired in other areas in California.

4.2.8 Steady State Voltage Stability (P-V & V-Q Curves)

Two separate cases were created with the single worst contingency modeled; one with the outage of the whole Delta Energy Center generating plant and the other with the outage of the whole Metcalf Energy Center generating plant. The P-V curves were created with each of these cases by scaling the GBA system conforming loads (zones 307-310, 316-318, and 321) with a constant power factor to the point of collapse. The Diablo Nuclear Generating Station was used as the source of the power transfer, requiring that the maximum real power capability be increased. The source is considered a proxy for imports from the south. Then V-Q curves were created with each base case by scaling the conforming loads up 5% with a constant power factor. These analyses are intended to show that the solutions proposed are sufficient to handle uncertainty in load forecast beyond the one in ten year extreme weather event and uncertainty in transmission topology.

The initial curves showed the point of collapse was occurring at the system swing machine at Morro Bay. In order to eliminate the distant collapse, the area interchange was disabled and the Southern California load (Area 24) was reduced by 5% at a constant power factor. The final curves shown in Figure 7-4 are based on the base case with these modifications. The curves show the GBA 230kV buses at voltages above 0.90 per unit at the point of collapse but with the required 5% real power margin.

The modified base case and fully scaled case were then used for the V-Q analysis. Fake synchronous condensers were set at each of the monitored buses while the voltage schedule was modified by 0.0025 per unit steps.

As seen in Figure 7-5, all of the monitored buses in the GBA system have positive reactive margin at the point of collapse (i.e. $dV/dQ = 0$ at $Q < 0$) for both the base and the 105% load case.

An additional review of the outage of the Metcalf Energy Center was performed to ensure that the outage of the Delta Energy Center is the worst contingency even for the southern region of the GBA system. Figure 7-6 and Figure 7-7 show the P-V and V-Q curves associated with the outage of the Metcalf Energy Center. It is apparent from the curves that the outage of the Delta Energy Center is more severe than the outage of the Metcalf Energy Center.

Note that the bumps in the P-V curves are a result of the Potrero SVC injection. It was observed that the Potrero SVC and VSC reactive power injections can vary in each real power step of the curve calculation. Usually the variation is minimal but can result in bumps or spikes on the curves. It was also found that adjusting the SVC voltage deadband from 0.01 per unit to either 0.00 per unit or 0.02 per unit didn't result in smoother curves.

4.2.9 Review of Other Potential Solutions

Both the Collinsville 500/230kV Substation and the 230kV Black Diamond Way Substation were compared to recommended projects to determine if either substation would be an adequate replacement for individual projects.

4.2.9.1 Collinsville 500/230kV Substation

At the request of PG&E, a potential 500/230kV substation with connections to the Pittsburg substation was tested for comparison to the projects recommended in Sections 4.2.3 and 4.2.5. The Collinsville substation is preliminarily planned as a new facility north of the Sacramento River that would loop in the existing 500kV line from Vaca Dixon to Tesla (with the existing series capacitor bypassed), have two 500/230kV transformers, and two 5.3 mile long 230kV submarine cables connected to the existing Pittsburg 230kV substation.

Given the location and planned transmission interconnections, Collinsville was compared only to the recommended capacitor bank installation at the Pittsburg 230kV substation for only the worst contingency, the loss of the Delta Energy Center. As shown in Figure 4-1 below, the Collinsville substation and the capacitor installation are nearly equivalent for the steady state voltage violations caused by the outage of the whole Delta Energy Center. From left to right, Figure 4-1 shows the local system with Collinsville assuming the existing normal and emergency ratings of the submarine cables as defined as 800/900 MVA and 9.0 Ω series reactors on each cable to prevent thermal overloads under contingency, the local system with Collinsville as defined by PG&E but assuming that the cables have an increased capability to avoid thermal overloads, and without the Collinsville substation but with the recommended 225 MVAR capacitor bank at the Pittsburg 230kV bus.

While local thermal overloads were not reviewed in detail, it should be noted that Collinsville also eliminated the N-0 overload of the Tesla 2M 500/230kV transformer.

Given these results and the cost to construct this substation, the Collinsville substation is not included as an assumed in-service facility in the Case 3 contingency analysis.

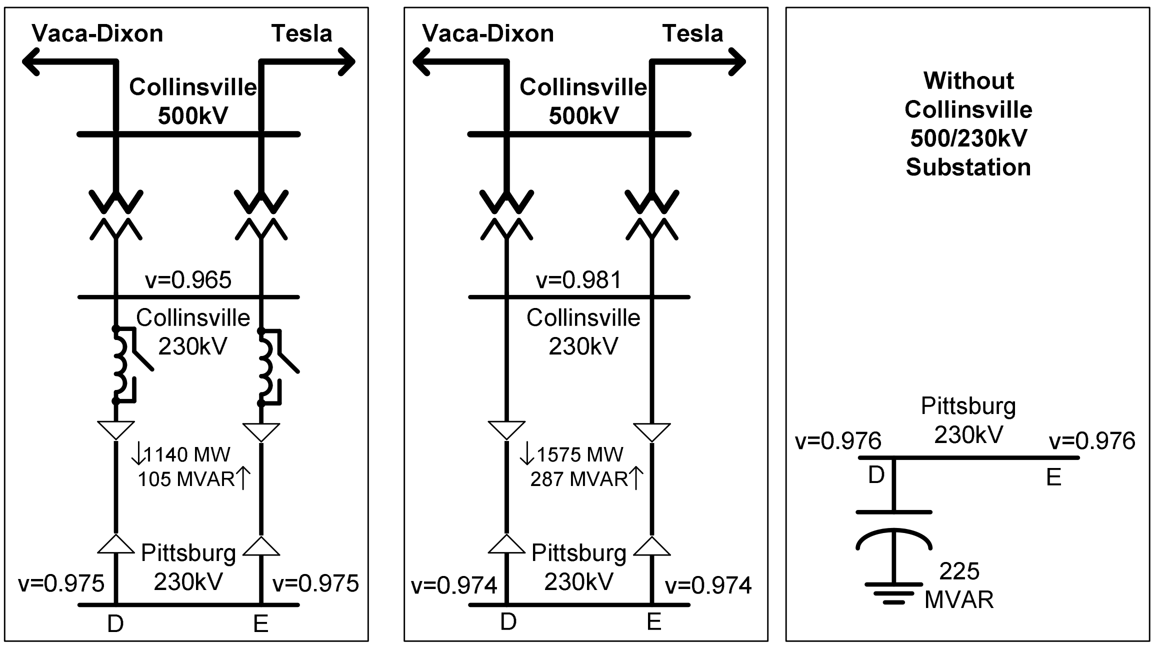

Figure 4-1 Comparison of Collinsville to the Proposed Capacitor at Pittsburg (DEC Outage)

4.2.9.2 Black Diamond 230kV Substation

Due to physical space constraints at existing substations and the desire for a centrally located reactive resource, a potential 230kV substation south of the Pittsburg substation and northeast of the Clayton substation was reviewed. This location is observed on the PG&E provided geographic transmission map as the crossing of eight 230kV transmission lines. The proximity of the lines was also verified using Google Maps where multiple transmission towers are easily seen near a road named Black Diamond Way (+37° 57' 43.20" N, -121° 53' 22.20" W).

A limited number of local contingencies were tested to determine the necessity of terminating each of the eight existing lines into the potential Black Diamond substation. The results indicate, as shown in Figure 4-2, that the following lines should be terminated in the new substation:

1. Pittsburg – Tassajara 230kV line
2. Pittsburg – Tres Vaqueros 230kV line
3. Pittsburg – San Ramon 230kV line
4. Contra Costa – Rossmoor Tap 1 230kV line
5. Contra Costa – Rossmoor Tap 2 230kV line

In addition, each of the Contra Costa – Black Diamond 230kV lines will require the installation of a 10 Ω series reactor to directly prevent thermal overloads under N-1 scenarios.

All projects recommended in Section 4.2.3 would still be required except for the following modifications.

1. The 225 MVAR capacitor bank installation originally planned at the Pittsburg substation will be moved to the Black Diamond substation.
2. The 225 MVAR capacitor bank installation planned at the Moraga 230kV substation doesn't appear to be necessary with the limited contingency analysis performed.

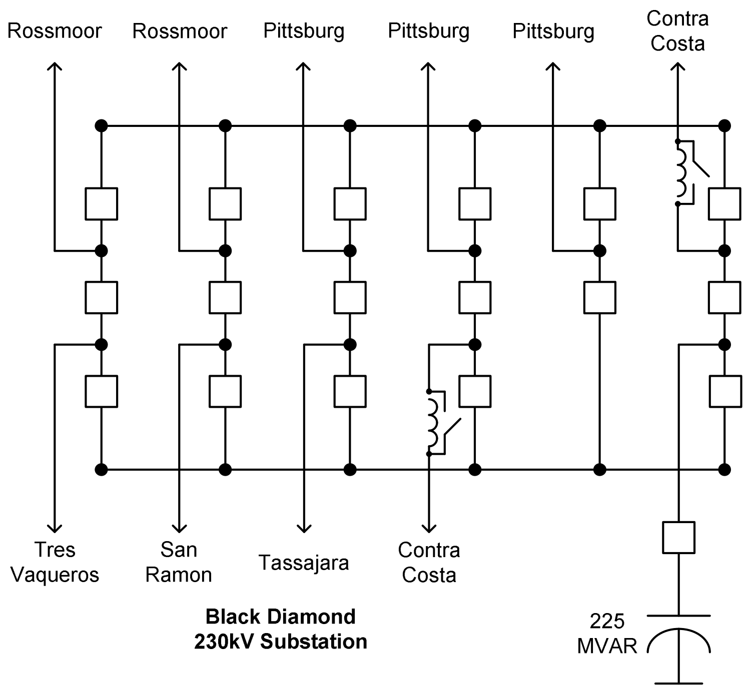

Figure 4-2 Potential Black Diamond 230kV Substation Configuration

After this initial design of the Black Diamond Substation, the complete contingency analysis was performed. As shown in Table 4-5, the Lakewood violations were previously identified and considered good candidates for load shedding systems. The other violations are close to the minimum acceptable voltage of 0.95 per unit so minor adjustments of recommended projects may eliminate these issues. As shown in Table 4-6, the results of the L-1 + G-1 contingencies are similar to the recommended projects once the Stagg capacitor bank is installed.

The major conclusion of the complete contingency analysis is that the Black Diamond Way substation is a suitable technical alternative to the Moraga and Pittsburg capacitor installations previously recommended.

Table 4-5 Voltage Violations for Category B/C Events (N-1 & L-2)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)
Brighton 230kV	Delta Energy Center (Pittsburg 230kV) 880 MW, 400 MVAR	0.960	0.948
Lakewood C 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	1.005	0.924
Lakewood M 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	1.005	0.924
Plainfield 60kV	Delta Energy Center (Pittsburg 230kV) 880 MW, 400 MVAR	0.969	0.947
Herdlyn 70kV	Delta Energy Center (Pittsburg 230kV) 880 MW, 400 MVAR	0.965	0.945

Table 4-6 Voltage Violations for Delta Energy Center Outage plus L-1

Monitored Bus	Worst Line Contingency	Vbase (p.u.)	Vcont (p.u.)
Lockford 230kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.958	0.945
Eastshore 230kV[1]	Eastshore – San Mateo 230kV line	0.981	0.927
Jameson 115kV	Christie – Martinez 115kV line Martinez – Oleum 115kV line Martinez – North Tower 115kV line Switch IN North Tower – N.Tower Jct 115kV line	0.987	0.949
Plainfield Jct 60kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 92.5 MVAR)	0.952	0.937
Middle River 60kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.955	0.936
Livermore 60kV	Livermore – Las Positas 60kV line	0.986	0.943

Monitored Bus	Worst Line Contingency	Vbase (p.u.)	Vcont (p.u.)
Radum 60kV	Livermore – Las Positas 60kV line	0.979	0.946
Livermore2 60kV	Livermore – Las Positas 60kV line	0.986	0.943
Vineyard 60kV	Livermore – Las Positas 60kV line	0.979	0.946
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV	1.044	0.944
Los Gatos	Monta Vista – Los Gatos 60kV line Switch IN Almaden – Los Gatos 60kV line	1.011	0.945

1. Project 13, the loop-in of the Pittsburg – San Mateo 230kV line at the Eastshore substation was not modeled in this analysis but does eliminate this violation.

4.2.9.3 Collinsville 500kV & Black Diamond 230kV Substation

Limited contingency analysis of constructing both the Collinsville 500/230kV Substation and the Black Diamond 230kV Substation was also reviewed for Case 4. The general impression from this limited analysis is that the amount of shunt compensation recommended at Black Diamond could be reduced due to the increase in real power injected at Pittsburg from Collinsville.

Constructing both the Black Diamond and Collinsville substations would be extremely expensive and doesn't appear to be justified by the results of the 2015 Case 4 analysis.

4.3 Case 3 – 2015 Results

4.3.1 Steady State Voltage Results (N-1 & L-2)

As shown in Table 7-9, Table 7-10, and Table 7-11 and in Section 7.2, numerous voltage violations were identified. The following list is a summary of regional voltage issues.

1. Two Intact System (Category A) voltage violations were identified. This shows that the recommended projects for Case 4 slightly underestimated the reactive resources required for the region east of the GBA system.
2. The outage of the Delta Energy Center interconnected to the Pittsburg 230kV substation caused numerous bus voltage violations.
3. The outage of the Metcalf Energy Center connected to a 230kV line from Metcalf to Monta Vista substations caused numerous bus voltage violations.

4.3.2 Steady State Thermal Results (N-1 & L-2)

Thermal overloads were not reviewed in detail for the Case 3 analysis. The following general observations were made.

1. The overloads near Monta Vista and Metcalf, previously noted in Section 4.2.2, are still a problem in Case 3 and signal the need for local transmission reinforcement.
2. There are no overloads of facilities ≥230kV for Category B contingencies (G-1, L-1, or T-1) though some lines are loaded ≥95% of the applicable rating.
3. The newly created San Ramon – Eastshore 230kV line is overloaded for the double circuit outage of the Newark – Ravenswood and Tesla – Ravenswood 230kV lines.

4.3.3 Solutions Tested

The following set of projects was developed by recognizing that the identified voltage violations are occurring mainly in the southern portion of the GBA system as a result of the retirement of two generating plants in the southern portion of the study region. All capacitor installations need to be studied in more detail to determine the necessary MVAR steps to minimize the Δv during switching operations. The identification of project numbers is continued from the Case 4 analysis.

18. Install a new 225 MVAR capacitor bank with 3 steps of 75 MVAR at the Moss Landing 230kV substation.
19. Install a new 350 MVAR capacitor bank with 2 steps of 175 MVAR at the Moss Landing 500kV substation.

Projects 20 and 21 were developed to provide general support near Contra Costa and Vaca Dixon substations. The installation of capacitors on the 500kV system results in lower active and reactive losses on the near the 500/230kV substations.

20. Install a new 350 MVAR capacitor bank with 2 steps of 175 MVAR at the Vaca Dixon 500kV substation.
21. Increase the scheduled voltage at the Gateway Generating Station from 1.00 per unit to 1.03 per unit.

4.3.4 Steady State Voltage Results (G-1 + L-1)

After developing solutions to the violations discovered in Sections 4.3.1 and 4.3.2, additional analysis was performed to determine the ability of the system to operate with the coincident outage of the most critical generating plant and any single transmission line. Transformer, generator, and all other multiple contingencies (double circuit, breaker failure, etc.) are not considered in this analysis.

The Delta Energy Center, an 880 MW combined cycle natural gas fueled generating plant, was selected as the most critical generator outage in the Northern section of the GBA system. The Metcalf Energy Center, a 560 MW combined cycle natural gas fueled generating plant, was selected as the most critical generator outage in the Southern section of the GBA system.

As shown in Table 7-12 and Table 7-13 in Section 7.14, no major issues were discovered in this analysis. Some of the contingencies resulted in bus voltages slightly below 0.95 per unit at the 115kV and 60kV level.

4.3.5 Additional Steady State Solutions

No additional projects are recommended because only minor voltage violations were identified in Section 4.3.4.

4.3.6 Fault Induced Transient Voltage Recovery Results

No transient voltage recovery violations were identified in the Case 4 analysis with the recommended steady state projects. However, wind turbines at the Shiloh substation were observed to trip due to a 0.75 per unit voltage threshold. The Shiloh wind turbines do not meet FERC Order 661-A Low Voltage Ride Through criteria and therefore solutions to the tripping are not developed.

Also, some distant wind farms were observed to trip but this is not considered to be associated with the GBA system.

The complete list of transient simulations is in Table 7-35 in Section 7.6.

4.3.7 Governor Power Flow Results

Similar to Case 4, governor power flow analysis is conducted to simulate the ability of the system to recover during the post-transient timeframe following a major contingency. Adjustments in Southern California load to account for the retirement of the

Moss Landing units resulted in slightly increased North to South flow on COI. In order to keep consistent flow on COI between Case 4 and Case 3, the interchange from Area 40 (Northwest) to Area 30 (PG&E) was further reduced from Case 4 levels by 100 MW.

As shown in Table 7-40 in Section 7.10, no voltage violations occur in the GBA system. As shown in Table 7-41, overloads local to the GBA system include the Tracy 500/230kV transformers, the Los Banos 500/230kV transformer, and the Moss Landing – Los Banos 500kV line.

4.3.8 Steady State Voltage Stability (P-V & V-Q Curves)

Two separate cases were created and modified as the same way as described in Section 4.2.8 for P-V & V-Q analysis at a group of selected 230kV buses in and around the GBA system.

The P-V curves in Figure 7-8 show the point of collapse occurring with GBA 230kV buses at voltages above 0.90 per unit at less than 105% load with the Delta Energy Center contingency.

The modified base case and scaled case with 103.5% load were then used for the V-Q analysis. The Case 4 analysis used a 105% load level for comparative V-Q curves but this load level was unattainable with the projects proposed for Case 3. As previously noted, power electronic based reactive power sources can extend this curve but can't effectively increase the steepness of slope of the curve.

As seen in Figure 7-9, all the monitored buses in the GBA system have positive reactive margin at the point of collapse (i.e. $dV/dQ = 0$ at $Q < 0$) for both the base and the 103.5% load case. However, it is observed that the Metcalf 230kV bus collapse at a voltage above 0.95 per unit. The occurrence of voltage collapse greater than the low voltage limit is a concern because operations may require additional tools to recognize impending collapse while system voltages still appear to be strong.

An additional review of the outage of the Metcalf Energy Center was performed to ensure that the outage of the Delta Energy Center is the worst contingency even for the southern region of the GBA system. Figure 7-10 shows that the system is able to support up to 105% load with the outage of the Metcalf Energy Center. Figure 7-11 shows the V-Q curves associated with the outage of the Metcalf Energy Center. It is observed that the Pittsburg D 230kV bus voltage is greater than 0.95 per unit at the point of collapse.

A sensitivity analysis was performed with the Russell City Energy Center ("RCEC") combined cycle plant at various levels of real power output with the outage of the Delta Energy Center in order to show the need for real power in the GBA system. As shown in Figure 7-16, dispatching the plant to full capability of approximately 610 MW will support up to 110.7% of the load modeled in the 2015 summer peak 90/10 case with the single worst contingency. Figure 7-17 shows that even with only one combustion turbine in-service and dispatched to 180 MW, the system is able to sustain over 106% load. Figure 7-18 further shows that even a small amount of real power generation will enhance the system to support up to 105% of the base load level. Only a single combustion turbine was in-service and dispatched to 50 MW for this final sensitivity.

The RCEC is a proposed combined cycle plant with maximum capabilities of 614 MW and 347 MVAR and a point of interconnection at the Eastshore 230kV substation. The sensitivities performed were intended to show the proof of concept that generation sited within the GBA system is a more robust option compared to shunt reactive power sources.

Note that the bumps in the P-V curves are a result of the Potrero SVC injection. It was observed that the Potrero SVC and VSC reactive power injections can vary in each real power step of the curve calculation. Usually the variation is minimal but can result in bumps or spikes on the curves. It was also found that adjusting the SVC voltage deadband from 0.01 per unit to either 0.00 per unit or 0.02 per unit didn't result in smoother curves.

4.3.9 Review of Other Potential Solutions

Both the Collinsville 500/230kV Substation and the 230kV Black Diamond Way Substation were compared to recommended projects. Only a limited review of single and double contingencies is performed for Case 3 because the additional generation retirement is at the Moss Landing Substation, which is south of the GBA system and distant from both alternatives.

4.3.9.1 Collinsville 500/230kV Substation

Similar results were observed in the Case 3 and Case 4 analysis. The Collinsville Substation with two 230kV cables connecting to Pittsburg is an adequate alternative to the recommended 225 MVAR capacitor bank at Pittsburg. The Collinsville project actually results in an improved voltage in Case 3 at Pittsburg with the outage of the Delta Energy Center because of the recommended 300 MVAR capacitor bank at Vaca-Dixon 500kV. The Pittsburg voltage was 0.975 per unit in Case 4 and 0.980 per unit in Case 3.

While thermal violations were not reviewed in detail, it was observed that either of the submarine cables from Collinsville to Pittsburg is slightly overloaded for the L-1 + G-1 scenario of the outage of the Delta Energy Center plus the outage of the other submarine cable. Each cable is modeled with an emergency thermal rating of 900 MVA and a 9 Ω series reactor with identical thermal ratings. The overloads on the submarine cables could be relieved by increasing either the capacity of the cables or the impedance of the series reactor.

The Collinsville Substation is not considered an adequate alternative to any project recommended in the Case 3 analysis.

4.3.9.2 Black Diamond 230kV Substation

Similar results were observed in the Case 3 and Case 4 analysis. The Black Diamond Substation is an adequate alternative to the 225 MVAR MSC installation at Pittsburg and Moraga.

The Black Diamond Substation is not considered an adequate alternative to any project recommended in the Case 3 analysis.

4.3.9.3 Collinsville 500kV & Black Diamond 230kV Substation

Limited contingency analysis of constructing both the Collinsville 500/230kV Substation and the Black Diamond 230kV Substation was also reviewed for Case 3. The general impression from this limited analysis is that the amount of shunt compensation recommended at Black Diamond could be reduced due to the increase in real power injected at Pittsburg from Collinsville.

Constructing both the Black Diamond and Collinsville substations would be extremely expensive and doesn't appear to be justified by the results of the 2015 Case 3 analysis.

4.4 Case 1 – 2015 Results

4.4.1 Steady State Voltage Results (N-1 & L-2)

As shown in Table 7-14 and Table 7-15 in Section 7.3, two voltage violations were identified. The following list is a summary of regional voltage issues.

1. No Intact System (Category A) voltage violations were identified. This shows that the recommended projects for Case 3 and Case 4 address the voltage problems in GBA system appropriately.
2. The double circuit outage of Lakewood – Clayton 115kV line and Lakewood – Meadow Lane – Clayton 115 kV line caused voltage violations at Lakewood C bus and Lakewood M bus. The contingency was previously identified as a candidate for a Special Protection System due to the combination of voltage and thermal violations.

4.4.2 Steady State Thermal Results (N-1 & L-2)

Thermal overloads were not reviewed in detail for the Case 1 analysis.

4.4.3 Solutions Tested

No solutions were required for the N-1 or L-2 analysis.

4.4.4 Steady State Voltage Results (G-1 + L-1)

As shown in Table 7-16 and Table 7-17 in Section 7.3, the major issues discovered in the initial G-1 + L-1 analysis with only projects suggested in Sections 4.2.3, 4.2.5, and 4.3.3 modeled in the case were that three line outages force generation offline result in divergent solutions when combined with Delta Energy Center outage.

The non-convergent contingencies are:

1. Nortech – Los Esteros 115kV line also trips the Los Esteros Critical Energy Facility
2. Llagas – Gilroy Foods 115kV line also trips the Gilroy Cogen Plant
3. Sobrante – Ignacio 230kV line also trips Crockett Cogen Plant

4.4.5 Additional Steady State Solutions

No additional projects were required for the N-1 or L-2 analysis but the G-1 + L-1 analysis shows non-convergent solutions. As agreed to by PG&E, generation re-dispatch outside of the GBA system was used as the solution to these three contingencies.

As shown in Table 7-18 and Table 7-19 in Section 7.3, increasing real power generation between Table Mountain and Los Banos Substations results in lower thermal loading on the 500kV system, slightly higher 500kV bus voltages which draw less reactive power from the 230kV system ultimately resulting in an improved voltage profile in the GBA lower voltage system consisting of 60kV – 230kV buses.

Project 22 was developed by recognizing that the identified non-converging contingencies are occurring mainly due to the lack of real power as a result of the retirement of approximately 5 GW of generating capability in the GBA system.

22. Re-dispatch generation outside of GBA system by increasing the real power generation of certain units to their maximum capacity as shown in Table 4-7.

Table 4-7 Zone 322 Generation Re-dispatch

Bus #	Unit Name	Pgen (MW)	Pmax (MW)	ΔP (MW)
37320	UCDMC	25.0	27.0	2.0
37301	CAMINO 1	50.0	75.0	25.0
37302	CAMINO 2	50.0	75.0	25.0
37304	CAMPBEL2	50.0	52.0	2.0
37303	CAMPBEL1	100.0	105.0	5.0
37305	JAYBIRD1	60.0	77.0	17.0
37306	JAYBIRD2	60.0	77.0	17.0
37308	LOON LK	70.0	77.0	7.0
37309	MCCLELLN	60.0	74.0	14.0
37310	PROCTER1	40.0	41.0	1.0
37311	PROCTER2	30.0	41.0	11.0
37312	PROCTER3	40.0	41.0	1.0
37313	PROCTER4	40.0	43.0	3.0
37314	ROBBS PK	20.0	24.5	4.5
37315	SRWTPA	10.0	13.0	3.0
37315	SRWTPA	40.0	41.0	1.0
37316	SRWTPB	40.0	42.0	2.0
37317	UNIONVLY	40.0	46.0	6.0
37318	WHITERK1	80.0	120.0	40.0
37319	WHITERK2	80.0	125.0	45.0
Total		985.0	1216.5	231.5

4.4.6 Fault Induced Transient Voltage Recovery Results

No transient voltage recovery violations were identified in the Case 4 analysis with the recommended steady state projects. However, wind turbines at the Shiloh substation were observed to trip due to a 0.75 per unit voltage threshold. The Shiloh wind turbines do not meet FERC Order 661-A Low Voltage Ride Through criteria and therefore solutions to the tripping are not developed.

Also, some distant wind farms were observed to trip but this is not considered to be associated with the GBA system.

The complete list of transient simulations is in Table 7-36 in Section 7.7.

4.4.7 Governor Power Flow Results

No voltage violations were identified in the GBA system as shown in Table 7-40 in Section 7.10.

As shown in Table 7-41, the Tracy – Tesla 500kV line is overloaded for a bus fault at the Round Mt. 500kV bus, the Table Mt. – Vaca Dixon 500kV line is overloaded for a bus fault at the Tesla 500kV bus, and the thermal overloads identified in Case 3 are also identified in Case 1.

Note that the loss of the Table Mt. – Vaca Dixon 500kV line plus the loss of the Delta Energy Center did not converge with the Case 1 base case. In order to achieve a solution, the COI loading was further reduced from 4,450 MW to 4,370 MW by reducing power transfers from Area 40 (Northwest) to Area 30 (PG&E) by an additional 100 MW.

4.4.8 Steady State Voltage Stability (P-V & V-Q Curves)

Similar to Case 4 and Case 3, two separate cases were created and modified in the same manner described in Section 4.2.8 for steady state voltage stability analysis at a group of selected 230kV buses in and around the GBA system.

The P-V curves in Figure 7-12 show the point of collapse occurring with GBA 230kV buses at voltages greater than 0.95 per unit and the load less than 105% with the single worst contingency.

The modified base case and scaled case with 103.5% load were then used for the V-Q analysis. The Case 4 analysis used a 105% load level for comparative V-Q curves but this load level was unattainable with the projects proposed for Case 1. As previously noted, power electronic based reactive power sources can extend this curve but can't effectively increase the steepness of slope of the curve.

As seen in Figure 7-13, all the monitored buses in the GBA system have positive reactive margin at the point of collapse (i.e. $dV/dQ = 0$ at $Q < 0$) for both the base case and the 103.5% load case. However, it is observed that the Metcalf 230kV bus collapses at a voltage above 0.96 per unit with a very small reactive margin. A collapse at voltages greater than the low voltage limit is a sign that the system is over-compensated.

An additional review of the outage of the Metcalf Energy Center was performed to ensure that the outage of the Delta Energy Center is the worst contingency even for the southern region of the GBA system. The P-V curves in Figure 7-14 show that the system is able to support 105% load with the outage of the Metcalf Energy Center. The V-Q curves in Figure 7-15 show the Pittsburg D 230kV bus collapse at a voltage above 0.95 per unit.

Similar to Case 3, a sensitivity analysis was conducted using a real power injection at the Eastshore substation from the proposed RCEC combined cycle plant with the outage of the Delta Energy Center in order to show the need for real power in the GBA system.

As shown in Figure 7-19, dispatching the plant to full capability of approximately 610 MW will support up to 110.3% of the load modeled in the 2015 summer peak 90/10 case with the single worst contingency. Figure 7-20 shows that even with only one combustion turbine in-service and dispatched to 180 MW, the system is able to sustain over 105.5% load. Figure 7-21 further shows that even a small amount of real power generation will enhance the system to support up to 105% of the base load level. Only a single combustion turbine was in-service and dispatched to 100 MW for this final sensitivity.

Note that the bumps in the P-V curves are a result of the Potrero SVC injection. It was observed that the Potrero SVC and VSC reactive power injections can vary in each real power step of the curve calculation. Usually the variation is minimal but can result in bumps or spikes on the curves. It was also found that adjusting the SVC voltage deadband from 0.01 per unit to either 0.00 per unit or 0.02 per unit didn't result in smoother curves.

4.4.9 Review of Other Potential Solutions

Both the Collinsville 500/230kV Substation and the 230kV Black Diamond Way Substation were compared to recommended projects. The review performed for Case 1 focused on the buses directly connected to Moraga because the additional generation retirement is near Oakland.

4.4.9.1 Collinsville 500/230kV Substation

The Collinsville Substation with two 230kV cables connecting to Pittsburg is still an adequate alternative to the recommended 225 MVAR capacitor bank at Pittsburg.

The thermal violations noted in Section 4.3.9.1 were found to be aggravated in Case 1. The overloads on the submarine cables could still be relieved by increasing either the capacity of the cables or the impedance of the series reactor.

4.4.9.2 Black Diamond 230kV Substation

The Black Diamond Substation is still an adequate alternative to the 225 MVAR MSC capacitor bank at Pittsburg and Moraga. The system immediately surrounding

Moraga didn't appear to be heavily stressed from the Oakland and Alameda retirements.

4.4.9.3 Collinsville 500kV & Black Diamond 230kV Substation

Limited contingency analysis of constructing both the Collinsville 500/230kV Substation and the Black Diamond 230kV Substation was also reviewed for Case 1. The general impression from this limited analysis is that the amount of shunt compensation recommended at Black Diamond could be reduced due to the increase in real power injected at Pittsburg from Collinsville.

Constructing both the Black Diamond and Collinsville substations would be extremely expensive and doesn't appear to be justified by the results of the 2015 Case 1 analysis.

4.5 Case 4 – 2020 Results

4.5.1 Steady State Voltage Results (N-1 & L-2)

The results in Table 7-22, Table 7-23, and Table 7-24 show that the outage of the Delta Energy Center is still the worst contingency in 2020.

4.5.2 Steady State Thermal Results (N-1 & L-2)

The results in Table 7-20 and Table 7-21 show thermal overloads at Tesla and near the Metcalf substation.

4.5.3 Solutions Tested

The following project was developed with consideration of the Case 3 and Case 1 results in the 2015 analysis. The previous results exhibited features of an overcompensated transmission system so shunt compensation was only reviewed for voltage violations at load serving substations. Regional voltage violations were addressed through the construction of a 500/230kV substation. Note that this recommended project represents a significant increase in the total cost to support the retirement of generating plants that utilize once through cooling systems. The total cost should be considered in comparison to the cost to convert the once through cooling to hybrid or dry cooling systems or to eliminate the common mode of failure at the Delta Energy Center.

Project 23 is proposed to improve the 230kV bus voltages across the GBA system for the worst contingency; the outage of the whole Delta Energy Center combined cycle natural gas generating plant (880 MW). Project 23 also improves the thermal violations at the Tesla substation. However, the Tesla 500/230kV transformers are still highly loaded.

23. Construct the Collinsville 500/230kV substation. The Collinsville substation was modeled as a new facility north of the Sacramento River that would loop in the existing 500kV line from Vaca Dixon to Tesla (with the existing series capacitor bypassed), have two 500/230kV transformers, and two 5.3 mile long 230kV submarine cables connected to the existing Pittsburg 230kV substation. Each submarine cable is assumed to have a summer normal rating of 800 MVA and a summer emergency rating of 900 MVA. Due to the low impedance of the cables, a 9 Ω reactor was modeled as installed at Collinsville in series with each cable.

No projects were developed to address the voltage violations at the Brighton, Herdlyn, or Plainfield buses because each of these buses is outside of the GBA system. Also, the voltage violations at Lakewood buses were previously identified in the 2015 analysis.

The recommendation to utilize a load shedding scheme at Lakewood for specific double contingencies is still valid in the 2020 analysis.

4.5.4 Steady State Voltage Results (G-1 + L-1)

After developing solutions to the violations discovered in Sections 4.5.1 and 4.5.2, additional analysis was performed to determine the ability of the system to operate with the coincident outage of the most critical generating plant and any single transmission line. Transformer, generator, and all other multiple contingencies (double circuit, breaker failure, etc.) are not considered in this analysis.

The Delta Energy Center, an 880 MW combined cycle natural gas fueled generating plant, was selected as the most critical generator outage in the Northern section of the GBA system. The Metcalf Energy Center, an 560 MW combined cycle natural gas fueled generating plant, was selected as the most critical generator outage in the Southern section of the GBA system.

The only major issue discovered in this analysis was that the combination of an outage of the Delta Energy Center with the outage of the Los Esteros – LECEF Tap – Nortech 115kV line results in many voltage violations, as shown in Table 7-30. This single line contingency is equivalent to the outage of the whole Los Esteros Critical Energy Facility (200 MW).

4.5.5 Additional Steady State Solutions

In addition to the projects tested in Section 4.5.3, the following projects were developed in order to meet the voltage requirements for the G-1 + L-1 analysis.

Projects 24-27 are proposed to improve local voltage on 115kV and 60kV subsystems. Most of the MSC installations are proposed to be placed at the same location as the bus voltage violation. As previously noted with the Oakland Long Term Project, some of these local load serving voltage issues are best addressed by transmission line upgrades that result in a lower system impedance. In general, it is recommended that lower impedance system designs be utilized when practical and that shunt capacitors be installed directly at the load serving substation, preferably at the distribution voltage.

Based on G-1 + L-1 results, projects 24 – 26 are proposed to improve local voltage on 115kV and 60kV subsystems.

24. Install a new 20 MVAR capacitor bank at the Swift 115kV substation.
25. Install a new 20 MVAR capacitor bank at the Livermore 60kV substation.
26. Install a new 20 MVAR capacitor bank at the Glenwood 60kV substation.
27. Loop the existing Los Esteros Critical Energy Facility into the Los Esteros – Nortech 115kV line. It is assumed that the length of the transmission tap line to the Los Esteros – Nortech 115kV line is negligible and not considered in L-1 contingency analysis (i.e. the line is equivalent to the GSU).

No projects were developed to address the following voltage violations identified in the G-1 + L-1 analysis.

- Tassajara 230kV. The violation is borderline (v = 0.949) so it is assumed that minor adjustments of previously recommended projects will sufficiently address this.
- Collinsville 230kV. The Collinsville substation design is considered to be conceptual in nature and may eventually include additional 230kV outlets or capacitor banks to regulate the voltage.
- Travis 60kV. The substation is not within the borders of the GBA system.
- Loyola 60kV and Los Gatos 60kV. The 2015 analysis recommended load shedding schemes. This recommendation is still valid for the 2020 analysis.
- Belmont 115kV and Middle River 60kV. See the notes below.

It is observed that the resistance of each branch listed in Table 4-8 is higher than the reactance, resulting in a low X/R ratio. The high resistance of the Belmont – Bair 115kV line results in a voltage violation at the Belmont 115kV bus with the simultaneous outage of the Belmont – San Mateo 115kV line and the Delta Energy Center or Metcalf Energy Center. Similarly, the high resistance of Bixler – Middle River 60kV line causes voltage violations at Middle River 60kV bus for numerous contingencies. Quanta Technology recommends that PG&E verify these parameters before proposing any solutions.

Table 4-8 Transmission Lines with Low X/R Ratio

Branch	R (p.u.)	X (p.u.)	X/R Ratio
Belmont – Bair 115kV line	0.0576	0.0207	0.3594
Parks Tap – Parks 60kV line	0.0355	0.0219	0.6169
Bixler – Middle River 60kV line	0.1758	0.1296	0.7372

4.5.6 Fault Induced Transient Voltage Recovery Results

No transient voltage recovery violations were identified in the Case 4 analysis with the recommended steady state projects. However, wind turbines at the High Wind 3 and both the Shiloh substations were observed to trip due to a 0.75 per unit voltage threshold. The High Wind and Shiloh wind turbines do not meet FERC Order 661-A Low Voltage Ride Through criteria and therefore solutions to the tripping are not developed.

Also, some distant wind farms were observed to trip but this is not considered to be associated with the GBA system.

The complete list of transient simulations is in Table 7-37 in Section 7.8.

4.5.7 Governor Power Flow Results

Governor power flow analysis is conducted to simulate the ability of the system to recover during the post-transient timeframe following a major contingency. All governor power flow analysis was performed with the Case 4 recommended steady state projects modeled. Similar to the 2015 analysis, the loss of the Delta Energy Center resulted in non-convergent governor power flow solutions until COI loading was reduced to approximately 4,450 MW.

Table 7-38 in Section 7.12 lists all voltage and thermal violations in the governor power flow analysis. As shown in Table 7-44, no voltage violations occur in the GBA system. As shown in Table 7-45, both Metcalf – Moss Landing 1 230kV line and Metcalf – Moss Landing 2 230kV line are overloaded as the result of various contingencies. This thermal loading is consistent with the G-1 + L-1 analysis.

4.5.8 Steady State Voltage Stability (P-V & V-Q Curves)

Two separate cases were created with the single worst contingency modeled; one with the outage of the whole Delta Energy Center generating plant and the other with the outage of the whole Metcalf Energy Center generating plant. The P-V curves were created with each of these cases by scaling the GBA system conforming loads (zones 307-310, 316-318, and 321) with a constant power factor to the point of collapse. The Diablo Nuclear Generating Station was used as the source of the power transfer, requiring that the maximum real power capability be increased. The source is considered a proxy for imports from the south. Then V-Q curves were then created with each base case by scaling the conforming loads up 5% with a constant power factor. These analyses are intended to show that the solutions proposed are sufficient to handle uncertainty in load forecast beyond the one in ten year extreme weather event and uncertainty in transmission topology.

The initial curves showed the point of collapse was occurring at the system swing machine at Morro Bay. In order to eliminate the distant collapse, the area interchange was disabled and the Southern California load (Area 24) was reduced by 5% at a constant power factor. In addition, one fake synchronous condenser injecting around 50 MVAR was installed at "STA. D 1" 22kV (Bus #37208) and another synchronous condenser injecting around 30 MVAR was installed at "North CST" 69kV (Bus #45408) in order to improve the voltage in regions distant from the GBA system. With the fake synchronous condensers and projects 23-27, the 5% real power margin with the worst contingency was achieved. The final curves shown in Figure 7-22 are based on the base case with these modifications.

The P-V curves show the GBA 230kV buses at voltages above 0.90 per unit at the point of collapse. As noted in the 2015 analysis, voltage collapse above 0.90 per unit is an indication of a highly compensated system.

The modified base case and the fully scaled case with the conforming loads increased by 5% at a constant power factor were then used for the V-Q analysis. Fake synchronous condensers were set at each of the monitored buses while the voltage schedule was modified by 0.0025 per unit steps.

As seen in Figure 7-23, all of the monitored buses in the GBA system have positive reactive margin at the point of collapse (i.e. $dV/dQ = 0$ at $Q < 0$) for both the base and the 105% load case.

An additional review of the outage of the Metcalf Energy Center was performed to ensure that the outage of the Delta Energy Center is the worst contingency even for the southern region of the GBA system. Figure 7-24 and Figure 7-25 show the P-V and V-Q curves associated with the outage of the Metcalf Energy Center. It is apparent from the curves that the outage of the Delta Energy Center is more severe than the outage of the Metcalf Energy Center.

Note that the bumps in the P-V curves are a result of the Potrero SVC injection. It was observed that the Potrero SVC and VSC reactive power injections can vary in each real power step of the curve calculation. Usually the variation is minimal but can result in bumps or spikes on the curves. It was also found that adjusting the SVC voltage deadband from 0.01 per unit to either 0.00 per unit or 0.02 per unit didn't result in smoother curves.

4.5.9 Review of Other Potential Solutions

Two other conceptual projects were reviewed but not recommended due to concerns cost and performance.

4.5.9.1 Sunol 230kV Substation

A potential 230kV substation with connections to the Newark, Castro Valley, Tassajara, Metcalf, Los Esteros, Las Positas, Vineyard, and Tesla substations was tested for a general review of performance of a centrally located substation for the southern portion of the GBA system.

A centrally located substation in the southern portion of the GBA system doesn't appear to be necessary from the Case 4 results but could be useful if the Moss Landing retirements are pursued instead of other units. Also, if the change in system impedance resulted in reduced thermal loading near Metcalf, Moss Landing, or Tesla then the project could be justified without consideration of voltage. However, the results show that the change in thermal loading is negligible for the critical contingencies.

Previous studies performed by PG&E examined this location plus the construction of a 500kV double circuit connecting Sunol to the existing Tesla – Los Banos 500kV line.

4.5.9.2 Power Factor Correction on the Distribution System

Implementing a region wide policy of correcting all load power factors to unity was reviewed due to physical space constraints at existing transmission substations and the general desire to minimize the total shunt compensation.

This analysis was performed by installing a bus shunt equal to the MVAR component at all conforming and non-conforming loads in the GBA system (Zones 307-310, 316-318, 321, 337-340, and 346-348). This analysis is conceptual in nature because neither the distribution system nor the T/D transformers are modeled in the base case. Also, no regard was given to existing compensation at or near the load serving buses.

After setting all loads to unity power factor and removing the three 225 MVAR MSCs recommended in the 2015 analysis, the outage of the Delta Energy Center was reviewed and the only identified voltage violations were high voltages on the 60kV system and low voltages in Zone 311, the Stockton load zone which covers Tesla and further East. Also, dynamic compensation can be used at the distribution level to address the concerns due to distribution level voltage sags. Distribution level SVCs, STATCOMs, and Dynamic Sag Correctors are commercially available and may be the best alternative for local voltage sag or transient voltage recovery issues. In particular, distribution level SVCs are available in a pad-mount enclosure that doesn’t require substation space.

The drawbacks of this policy would be the potential work resource and budgeting constraints for the distribution group. Also, this policy is still adding substantial shunt capacitance to the system and could still contribute to operational problems related to flatter P-V curves.

4.6 Sensitivity Analysis Results for 2020

Given that the recommendation of not proceeding to the Case 3 retirement scenario of Case 4 plus retirement of the Moss Landing Units 1 and 2 in the 2015 analysis, Case 3 in 2020 is not reviewed. Instead, a set of sensitivities were reviewed using P-V curves because the major limitation observed in each case with the real power margin and the regional voltages near the point of collapse.

4.6.1 Case 3.5

Case 3.5 is defined as the Case 4 retirement scenario plus recommended transmission projects and the additional retirement of all three of the Oakland generators and both of the Alameda generators for an additional retirement of approximately 200 MW local to Oakland.

As shown in Figure 7-26, the GBA system has only a 1% real power margin to the point of collapse with the worst contingency of the Delta Energy Center plant. This sensitivity shows the value of real and reactive power sources close to large load serving areas as the retirement of 200 MW resulted in a real power margin reduced by 600 MW.

A sensitivity study was conducted using an alternative being proposed for the Oakland Long Term Plan. As shown in Figure 7-27, this alternative doesn't help to improve the real power margin.

4.6.2 Case 3.5 + 1 CT (50 MW) at RCEC

This sensitivity was tested to show a proof of concept that a centrally located real power source provides an increase in the real power margin. The real power source is modeled as a single combustion turbine generating 50 MW at the proposed Russell City Energy Center plant, which is interconnected to the Eastshore 230kV substation.

As shown in Figure 7-28, the GBA system has only a 2.5% real power margin to the point of collapse with the worst contingency of the Delta Energy Center plant. This small increase in real power doesn't result in an acceptable real power margin.

4.6.3 Case 3.5 + 1 CT (180 MW) at RCEC

This sensitivity was tested to show a proof of concept that a centrally located real power source provides an increase in the real power margin. The real power source is modeled as a single combustion turbine generating 180 MW at the proposed Russell City Energy Center plant, which is interconnected to the Eastshore 230kV substation.

As shown in Figure 7-29, the GBA system has a 4.5% real power margin to the point of collapse with the worst contingency of the Delta Energy Center plant. This sensitivity shows that the Eastshore substation is a slightly worse location for generation compared to being closer to the Oakland load. This scenario could likely be achievable with limited reactive support at the lower voltage levels in the Oakland area.

As shown in Figure 7-30, the Oakland Long Term Plan alternative doesn't help to improve the real power margin.

4.6.4 Case 3.5 + 2 CTs (360 MW) at RCEC

This sensitivity was tested to show a proof of concept that a centrally located real power source provides an increase in the real power margin. The real power source is modeled as two combustion turbines each generating 180 MW at the proposed Russell City Energy Center plant, which is interconnected to the Eastshore 230kV substation.

As shown in Figure 7-31, the GBA system has a 6.75% real power margin to the point of collapse with the worst contingency of the Delta Energy Center plant. This sensitivity shows that the Eastshore substation is almost equivalent to the locations closer to the Oakland load.

4.6.5 Case 3.5 + Russell City Energy Center Plant (2 CTs & 1 ST)

This sensitivity was tested to show a proof of concept that a centrally located combined cycle plant can provide a substantial increase in the real power margin. The real power source is modeled as two combustion turbines each generating 180 MW and a single steam turbine generating 254 MW at the proposed Russell City Energy Center plant, which is interconnected to the Eastshore 230kV substation.

As shown in Figure 7-32, the GBA system has a 9.75% real power margin to the point of collapse with the worst contingency of the Delta Energy Center plant. This sensitivity shows that a typical combined cycle plant located within the GBA system could allow for additional retirement of generation, an improved margin to collapse, or deferral and potential elimination of recommended transmission projects.

4.6.6 Case 1 + HVDC Terminal at Collinsville 500kV

At the request of PG&E, a 3,000 MW HVDC terminal was modeled at the Collinsville 500kV bus. This sensitivity is intended to represent a potential HVDC line connecting BC Hydro and PG&E.

The project is assumed to use conventional HVDC technology instead of the VSC technology due to the amount of power being transferred. Conventional HVDC requires reactive support so this sensitivity modeled a generator injecting 3,000 MW at unity power factor, assuming that appropriate resources would be installed to support the reactive requirements of the HVDC terminal. This sensitivity also includes two new 500kV lines connecting Collinsville to Tracy using the existing Collinsville – Tesla 500kV line parameters.

The initial steady state review showed that the previously recommended capacitor installations at Pittsburg, Moraga, and Stagg were not required for G-1 as previously defined. The Pittsburg and Moraga 225 MVAR capacitors were completely removed and the Stagg 225 MVAR capacitor was reduced to 75 MVAR. Also, the Collinsville 9 Ω series reactors were not appropriately sized for a project of this magnitude. The series reactors may need to have larger impedances, in the range of 15 to 20 Ω depending on the cable ratings for L-1 + G-1 contingencies.

Using these modeling updates and the original series reactors, the voltage violations observed are listed in Table 4-9 and Table 4-10. The full set of contingencies was not reviewed for this sensitivity.

Table 4-9 Voltage Violations in GBA with Delta Energy Center Outage

Monitored Bus	Voltage (p.u.)
Tassajara 230kV	0.9491
EDES 115kV	0.9417
EDES Tap 115kV	0.9422
Domtar SL 115kV	0.9437
Oakland Station J 115kV	0.9440
Owens Tap 115kV	0.9440
Owens Brockway 115kV	0.9445
San Leandro 115kV	0.9455

Table 4-10 Voltage Violations near GBA with Delta Energy Center Outage

Monitored Bus	Voltage (p.u.)
Atlantic 230kV	0.9318
Procter I 230kV	0.9330
Procter J 230kV	0.9332
Natomas 230kV	0.9388
Goldhill 230kV	0.9411
Brighton 230kV	0.9436
Rio Oso 230kV	0.9450
Hurley S 230kV	0.9453
Elverta S 230kV	0.9488
Elverta W 230kV	0.9494
Herdlyn 70kV	0.9454

As shown in Figure 7-33, the GBA system has a 5.5% real power margin to the point of collapse with the worst contingency of the Delta Energy Center plant. This sensitivity shows that a large HVDC terminal in or near the GBA system could allow for additional retirement of generation, an improved margin to collapse, or deferral and potential elimination of recommended transmission projects.

5 Proposed Network Upgrades

The final proposed network upgrades are based on the recommendation that Case 4, the retirement of approximately 3,900 MW of local generating capability be the maximum retirement scenario. Also, it is assumed that no new generation will be sited in or near the Greater Bay Area nor will any major AC or DC transmission projects be constructed in the region.

The final proposed upgrades consist of:

- A 500/230kV substation at Collinsville or a similar electrical location.
- Three large shunt mechanically switched capacitor installations (Pittsburg, Moraga, and Stagg).
- Two improvements to generator Points of Interconnection (Gateway and Los Esteros Critical Energy Facility) to eliminate major G-2 outages as a result of L-1 + G-1 contingencies.
- Two line loop-ins of existing transmission lines that are physically adjacent to existing substations (Eastshore and San Ramon 230kV Substations).
- Shunt mechanically switched capacitor installations at 60kV and 115kV base voltages for local load serving violations (250 MVAR in total).

The estimated cost of each recommended project is based on the "Greater San Francisco Bay Area Long-Term Transmission Planning Study, Preliminary Feasibility and Economic Analysis" dated January 7, 2008. From the original report, all estimates are in 2006 dollars. The estimated cost of individual pieces of equipment is shown in Table 5-1.

The total estimated cost of the recommended projects ranges from approximately $375 million to $450 million dollars. Over 90% of the total project cost is due to the Collinsville Substation. The estimated cost of each project is shown in Table 5-2.

Table 5-1 Estimated Equipment Costs (2006 $)

Equipment		Cost
230kV Breaker-and-a-Half Bay (3 Circuit Breakers)		$3,000,000
230kV Circuit Breaker and Bay		$1,000,000
Shunt Capacitor		$25,000/MVAR
Collinsville Substation	(low)	$342,000,000
	(high)	$414,000,000

Table 5-2 Total Estimated Cost of Recommended Projects (2006 $)

Project	Cost ($1,000s)
Collinsville Substation	342,000 to 414,000
225 MVAR Shunt MSC at Pittsburg 230kV	5,625
225 MVAR Shunt MSC at Moraga 230kV	5,625
225 MVAR Shunt MSC at Stagg 230kV	5,625
Loop Pittsburg – San Mateo 230kV Line Into the Eastshore 230kV Substation (1 BAAH Bay)	3,000
Loop Pittsburg – Eastshore 230kV Line Into the San Ramon 230kV Substation (1 BAAH Bay)	3,000
Construct Single Bus Substation at the LECEF Tap on Los Esteros – Nortech 115kV Line (1 BAAH Bay) Assumes line length is negligible	3,000
Construct 2nd Gateway – Contra Costa 230kV Line (1 Circuit Breaker and Bay) Assumes line length is negligible	1,000
40 MVAR Shunt MSC at Dixon Landing 115kV	1,000
30 MVAR Shunt MSC at El Cerrito 115kV	750
20 MVAR Shunt MSC at Belmont 115kV	500
20 MVAR Shunt MSC at San Jose A or B 115kV	500
20 MVAR Shunt MSC at Owens Brockway 115kV	500
20 MVAR Shunt MSC at San Leandro 115kV	500
20 MVAR Shunt MSC at Oakland J 115kV	500
20 MVAR Shunt MSC at Swift 115kV	500
20 MVAR Shunt MSC at Livermore 115kV	500
20 MVAR Shunt MSC at Las Positas 60kV	500
20 MVAR Shunt MSC at Glenwood 60kV	500
Modify Tap Settings on the Eastshore 230/115kV Transformers	-
Raise Voltage Schedule at Moss Landing 230kV	-
Raise Voltage Schedule at Metcalf 230kV	-
Total (Collinsville Low) =	**375,125**
Total (Collinsville High) =	**447,125**

6 Conclusions

Given the results presented in this report, Quanta Technology recommends that PG&E investigate the following non-transmission system upgrades.

- Convert the Duke Moss Landing Units 1 and 2 from once through cooling to dry or hybrid cooling systems instead of retiring the plants. The Moss Landing Units are large (1,060 MW in total) and recently installed in 2002. The continued operation of these two Moss Landing plants is assumed in the Case 4 analysis and the final recommended projects.
- Determine the common modes of failure for the Delta Energy Center because it is the worst contingency in all scenarios analyzed. Given the total estimated cost of the recommended projects of at least $375 million, eliminating the common modes of failure may be a lower cost solution.

Quanta Technology also recommends that PG&E perform additional analysis as follows to define the recommended projects in more detail.

- Dynamic simulations with detailed load modeling and faults modeled on the lower voltage facilities closer to load serving substations. This analysis would be required to determine if dynamic compensation is needed at or near the local load serving areas or if the centrally located capacitor banks are sufficient.
- Sensitivity analysis to consider the effect of requests in the CAISO generation interconnection queue. Requests at Pittsburg, Contra Costa, and in Solano County may allow for additional retirements or the elimination of the need for projects recommended in this report.
- Detailed design of the Collinsville Substation.
    - Submarine Cable Issues: During the study it was discovered that the assumed cable ratings may actually be closer to 600 MVA per cable instead of the 800 MVA normal rating used. Normal ratings of 600 MVA may limit the ability of Collinsville to relieve the thermal loading at Tesla. To fully utilize the Collinsville Substation for redistribution of power flow either a third 600 MVA cable might be needed. An overhead 230kV line to Birds Landing or a nearby substation could also be tested for this purpose. The major disadvantages of an additional cable are the permitting issues, the direct cost of the cable, the additional series reactor, and the additional substation space and equipment at both Collinsville and Pittsburg substations. The overhead line to Birds Landing may be less expensive but may also have physical space constraints and could create loop flow overloads.
    - Sizing of Series Reactors: This study assumed that each submarine cable would be installed in series with a 9 Ω reactor. The impedance of the reactor was selected based on the number of cables and the ampacity of each cable. Also, if Collinsville will ultimately include more 500kV terminals or HVDC then the series reactors will not be optimally sized. Given the uncertainty in the ultimate design of Collinsville, switchable steps with an approximate range from 10 to 20 Ω might be an effective solution.

- Sizing of Series Capacitor: This study assumed the existing series capacitor at Vaca Dixon on the Vaca Dixon – Tesla 500kV line would be completely bypassed. The existing series capacitor would compensate the Vaca Dixon – Collinsville 500kV line by more than 100%. A practical level of compensation, likely between 30 and 70% should be determined along with the other design considerations.

7 Complete Results

7.1 Case 4 – 2015 Steady State Violations

The following tables show the worst contingencies for each of the monitored facilities. The *worst* contingency is defined as the contingency causing the lowest bus voltage or the highest thermal loading. Voltage Hits are defined as the number of contingencies causing a voltage violation – this number includes the non-converged contingencies solved by hand. Note that the monitored element in the Thermal Violations was taken directly from the auto-contingency output files and doesn't imply a direction of flow.

Table 7-1 Case 4 – 2015: Thermal Violations for Category A Events (N-0)

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
CP-V Colusa – Cortina 230kV line	868	N/A	1.04	N/A
Tesla 500/14kV transformer ID 2	1164 MVA	N/A	1.03	N/A
Tesla 230/14kV transformer ID 2	1153 MVA	N/A	1.02	N/A
Malin – Round Mountain 500kV line	1800	N/A	1.00	N/A

Table 7-2 Case 4 – 2015: Thermal Violations for Category B/C Events (N-1 & L-2)

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Saratoga – Vasona 230kV line	1253	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.74	1.20
Hicks – Metcalf 230kV line	1600	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.69	1.15
Monta Vista – Hicks 230kV line	1252	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.63	1.14
Monta Vista – Saratoga 230kV line	1055	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.57	1.13
Newark D – Newark E 230kV line	1600	Tesla E – Newark D 230kV line Tesla E – Ravenswood 230kV line	0.22	1.02

Table 7-2 Case 4 – 2015: Thermal Violations for Category B/C Events (N-1 & L-2)

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Moraga – San Leandro 115kV ckt 2	557	Moraga – Oakland Station J 115 kV line Moraga – San Leandro 115 kV ckt 3	0.75	1.52
Moraga – San Leandro 115kV ckt 1	557	Moraga – Oakland Station J 115 kV line Moraga – San Leandro 115 kV ckt 3	0.74	1.51
Ravenswood – Cooley Landing 115kV ckt 2	883	Ravenswood – Palo Alto 115kV ckt 1 Ravenswood – Palo Alto 115kV ckt 2	0.72	1.50
Moraga – San Leandro 115kV ckt 3	712	Moraga – San Leandro 115kV ckt 1 Moraga – San Leandro 115 kV ckt 2	0.64	1.33
Lakewood M – Lakewood Reactor 115kV ckt 9	798	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	0.24	1.31
Mission – Potrero 115kV line	699	Larkin E – Potrero 115kV ckt 2	0.81	1.24
Pittsburg – Clayton 115kV line	1600	Pittsburg – Clayton 115kV ckt 3 Pittsburg – Clayton 115kV ckt 4	0.56	1.23
Christie – Sobrante 115kV	523	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.41	1.22
San Leandro – Domtar SL 115kV line	947	Moraga – Oakland Station J 115 kV line Moraga – San Leandro 115 kV ckt 3	0.74	1.19
Cooley Landing – Palo Alto 115kV line	883	Ravenswood – Palo Alto 115kV ckt 1 Ravenswood – Palo Alto 115kV ckt 2	0.31	1.19
El Patio SJ2 – El Patio 115kV line	1225	Newark – Los Esteros 230 kV line Los Esteros – Metcalf 230kV line	0.90	1.18
El Patio SJ1 – San Jose A 115kV line	1225	Newark – Los Esteros 230 kV line Los Esteros – Metcalf 230kV line	0.90	1.18
Lakewood Reactor – Moraga 115kV line	894	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	0.25	1.17
EDES Tap – Domtar SL 115kV line	947	Moraga – Oakland Station J 115 kV line Moraga – San Leandro 115 kV ckt 3	0.71	1.17
Martinez D – Alhambra Tap 2 115kV line	486	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.49	1.14
El Cerrito – Sobrante 115kV ckt 2	600	El Cerrito J1 – Sobrante 115kV line	0.64	1.12
El Cerrito J1 – Sobrante 115kV line	600	El Cerrito – Sobrante 115kV ckt 2	0.64	1.12

Table 7-2 Case 4 – 2015: Thermal Violations for Category B/C Events (N-1 & L-2)

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Ravenswood – Palo Alto 115kV ckt 2	948	Ravenswood – Palo Alto 1 115 kV line Cooley Landing – Palo Alto 115 kV line	0.47	1.11
Ravenswood E – Ames BS2 115kV ckt 2	1144	Newark – Ravenswood 230 kV line Tesla – Ravenswood 230 kV line	0.23	1.08
Ravenswood E – Ames BS1 115kV ckt 2	1144	Newark – Ravenswood 230 kV line Tesla – Ravenswood 230 kV line	0.23	1.08
Oleum – Valley View Tap 1 115kV line	471	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.21	1.08
San Mateo – Belmont 115kV line	557	Ravenswood – Bair 115kV ckt 1 Ravenswood – Bair 115kV ckt 2	0.62	1.06
Oakland Station J – Moraga 115kV line	708	EDES Tap 1 – EDES 115kV line Oakland Station J – EDES Tap 1 115kV line EDES Tap 1 – Domtar SL 115kV line San Leandro – Domtar SL 115kV line Domtar SL 115kV load ID 1 Switch IN EDS Grant – EDES 115kV line	0.69	1.07
Christie – Martinez Junction 115kV line	522	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.27	1.06
Oleum – Alhambra Tap 2 115kV line	522	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.44	1.06
Markham J – Evergreen 1 115kV line	1054	Metcalf – El Patio 115kV ckt 1 Metcalf – El Patio 115kV ckt 2	0.64	1.06
Metcalf – Piercy 115kV line	1144	Newark F – Dixon Landing 115kV line	0.89	1.05
Swift – Metcalf E 115kV line	1200	Tesla – Newark 230kV ckt 2 Metcalf – Los Esteros 230 kV line	0.87	1.04
Newark – Dixon Landing 115kV line	1144	Metcalf – Piercy 115kV line	0.23	1.04
San Jose B-F – Markham J 115kV line	1054	Metcalf – El Patio 115kV ckt 1 Metcalf – El Patio 115kV ckt 2	0.61	1.03
Larkin E – Potrero 115kV ckt 2	800	Mission – Potrero 115kV line	0.66	1.02

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Table 7-2 Case 4 – 2015: Thermal Violations for Category B/C Events (N-1 & L-2)

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Herdlyn 70/60kV transformer ckt 2	60 MVA	Las Positas – Vasco 60kV line Vasco – US Wind Power Frick Green Ridge 60kV line US Wind Power FGR – Flowind 60kV line Flowind – Zond Wind 60kV line Zond Wind – Seawest 60kV line	0.90	1.01
Senter J – Almaden 60kV line	500	Monta Vista 230/60kV transformer ckt 5 Switch IN Los Altos – Los Altos J 60kV line Loyola – Monta Vista 60kV line Monta Vista – Los Gatos 60kV line Switch IN Almaden – Los Gatos 60kV line	0.41	1.16
Watershed Tap – Jefferson E 60kV line	602	Newark – Ravenswood 230 kV line Tesla – Ravenswood 230 kV line	0.74	1.07
Hillsdale 49 – Ralston 35 60kV line	602	Newark – Ravenswood 230 kV line Tesla – Ravenswood 230 kV line	0.73	1.06
Watershed Tap – Ralston 35 60kV line	602	Newark – Ravenswood 230 kV line Tesla – Ravenswood 230 kV line	0.73	1.06
Emerald Lake – Jefferson D 60kV line	801	Jefferson D – Woodside 60kV line Switch IN Las Pulgas – Las Pulgas Junction 60kV line Switch IN Las Pulgas – Woodside 60kV line	0.78	1.07
Cooley Landing – Westing Junction 60kV line	557	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	0.14	1.07
Evergreen – Senter J 60kV line	558	Monta Vista 230/60kV transformer ckt 5 Switch IN Los Altos – Los Altos Junction 60kV line Loyola – Monta Vista 60kV line Monta Vista – Los Gatos 60kV line Switch IN Almaden – Los Gatos 60kV line	0.37	1.04
San Mateo – Oracle 60 60kV line	557	Belmont – Bair 115 kV line San Carlos – Bair 60 kV line	0.64	1.01
Emerald Lake – Las Pulgas Junction 60kV line	801	Jefferson D – Woodside 60kV line Switch IN Las Pulgas – Las Pulgas Junction 60kV line Switch IN Las Pulgas – Woodside 60kV line	0.71	1.01

Table 7-3 Case 4 – 2015: Voltage Violations for Category A Events (N-0)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
None				

Table 7-4 Case 4 – 2015: Voltage Violations for Category B Events (Combined Cycle Plant Contingencies)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
60 buses[1] with voltage ≤ 0.95 per unit	Delta Energy Center (Pittsburg 230kV) 880 MW, 400 MVAR	N/A	N/A	N/A

1. No other contingencies cause violations on 42 of these 60 buses. The buses range in base voltage level as follows
    a. 500kV: 1 bus voltage violation at Table Mountain 1M, v = 0.948 p.u.
    b. 230kV: 44 bus voltage violations
    c. 115kV: 5 bus voltage violations
    d. 70kV: 1 bus voltage violation at Herdlyn, v = 0.918 p.u.
    e. 60kV: 9 bus voltage violations

Table 7-5 Case 4 – 2015: Voltage Violations for Category B/C Events (N-1 & L-2)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Eastshore 230kV	Eastshore – San Mateo 230kV line Pittsburg – San Mateo 230kV line	0.996	0.908	3
Oakland Station J 115kV	Moraga – San Leandro 115kV ckt 3 Moraga – Oakland Station J 115kV line	0.951	0.893	97
Owens Tap 115kV	Moraga – San Leandro 115kV ckt 3 Moraga – Oakland Station J 115kV line	0.951	0.893	100
Lakewood C 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	0.994	0.895	1
Lakewood M 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	0.994	0.896	1
EDES 115kV	Moraga – San Leandro 115kV ckt 3	0.952	0.897	91

Table 7-5 Case 4 – 2015: Voltage Violations for Category B/C Events (N-1 & L-2)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
	Moraga – Oakland Station J 115kV line			
EDES Tap 1 115kV	Moraga – San Leandro 115kV ckt 3 Moraga – Oakland Station J 115kV line	0.952	0.898	75
San Leandro 115kV	Moraga – San Leandro 115kV ckt 3 Moraga – Oakland Station J 115kV line	0.960	0.915	13
El Cerrito 115kV	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.981	0.924	2
Dixon Landing 115kV	Newark – Dixon Landing 115 kV line Newark – Milpitas 1 115 kV line	1.001	0.928	3
Valley View 115kV	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.980	0.932	2
Valley View Tap 1 115kV	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.981	0.933	2
FMC 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.983	0.933	1
Piercy 115kV	Metcalf – Swift 115kV line Metcalf – Piercy 115kV line	1.009	0.934	2
Valley View Tap 2 115kV	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.983	0.935	2
San Jose B-E 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.982	0.935	1
Lakewood Reactor 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	0.985	0.936	1
San Jose B-F 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.982	0.936	1
Mabury 115kV	Newark – Dixon Landing 115 kV line Newark – Milpitas 1 115 kV line	0.992	0.937	4
San Jose A 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.981	0.938	2
Mabury J 115kV	Newark – Dixon Landing 115 kV line Newark – Milpitas 1 115 kV line	0.994	0.939	4

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Table 7-5 Case 4 – 2015: Voltage Violations for Category B/C Events (N-1 & L-2)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
El Patio SJ1 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.982	0.941	1
McKee 115kV	Metcalf – Swift 115kV line Metcalf – Piercy 115kV line	0.993	0.941	5
Markham J 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.983	0.941	1
El Patio SJ2 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.982	0.942	1
Belmont 115kV	San Mateo – Belmont 115 kV line Ravenswood – San Mateo 115 kV line	0.998	0.945	3
Montague 115kV	Los Esteros – Trimble 115 kV line Los Esteros – Montague 115kV line	0.992	0.945	1
El Patio 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.984	0.947	1
Stone J 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.980	0.947	2
Stone 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.980	0.947	2
Markham J2 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.981	0.948	2
Swift 115kV	Metcalf – Swift 115kV line Metcalf – Piercy 115kV line	0.997	0.950	1
Seawest 60kV	Las Positas 230/60kV transformer	0.975	0.916	2
Vasco 60kV	Las Positas 230/60kV transformer	0.975	0.916	2
Zond Wind 60kV	Las Positas 230/60kV transformer	0.975	0.916	2
US Wind Power Frick Green Ridge 60kV	Las Positas 230/60kV transformer	0.975	0.916	2
Vasco Junction 60kV	Las Positas 230/60kV transformer	0.975	0.916	2
Flowind 1 60kV	Las Positas 230/60kV transformer	0.975	0.916	2
Las Positas 60kV	Las Positas 230/60kV transformer	0.976	0.917	2
Livermore 60kV	Las Positas 230/60kV transformer	0.968	0.921	4
Livermore 2 60kV	Las Positas 230/60kV transformer	0.968	0.921	4

Table 7-5 Case 4 – 2015: Voltage Violations for Category B/C Events (N-1 & L-2)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Sunol 60kV	Newark D 115/115/60kV transformer	0.974	0.934	2
Decoto Junction 60kV	Newark D 115/115/60kV transformer	0.982	0.936	2
Newark 60kV	Newark D 115/115/60kV transformer	0.996	0.940	1
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.043	0.947	2
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.009	0.947	2

Table 7-6 Case 4 – 2015: Voltage Violations for Category B/C Events (N-1 & L-2), the 2nd Worst Contingency After Delta Energy Center Outage

Monitored Bus	2nd Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
San Ramon 230kV	Pittsburg – San Ramon 230 kV line Pittsburg – Tassajara 230 kV line	0.960	0.924	11
Stagg E 230kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.954	0.939	21
Stagg D 230kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.953	0.939	25
Stagg F 230kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.953	0.939	25
Stagg H 230kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.953	0.939	22
Stagg 230kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.954	0.940	16
Stagg J2 230kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.955	0.941	10
Brighton 230kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.953	0.941	16
Eight Mile 230kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.959	0.945	6

Table 7-6 Case 4 – 2015: Voltage Violations for Category B/C Events (N-1 & L-2), the 2nd Worst Contingency After Delta Energy Center Outage

Monitored Bus	2nd Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Herdlyn 70kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.953	0.940	27
Radum 60kV	Las Positas 230/60kV transformer	0.964	0.927	9
Vineyard 60kV	Las Positas 230/60kV transformer	0.964	0.928	9
Parks 60kV	Las Positas 230/60kV transformer	0.969	0.939	6
Parks Tap 60kV	Las Positas 230/60kV transformer	0.969	0.939	6
San Ramon 60kV	San Ramon 230/60kV transformer	0.976	0.943	5
Plainfield 60kV	Peabody – Contra Costa 230 kV line Lambie – Contra Costa 230 kV line	0.958	0.944	6
INE PRSN 60kV	Gateway – Contra Costa 230kV line	0.955	0.947	7
Middle River 60kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.964	0.949	2
Plainfield Junction 60kV	Peabody – Contra Costa 230 kV line Lambie – Contra Costa 230 kV line	0.963	0.949	4

Table 7-7 Case 4 – 2015: Voltage Violations for Delta Energy Center Outage plus L-1

Monitored Bus	Worst Single Line Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Herdlyn 70kV	N/A – Intact System	0.945	N/A	N/A
INE PRSN 60kV	N/A – Intact System	0.948	N/A	N/A
Plainfield 60kV	N/A – Intact System	0.948	N/A	N/A
Brighton 230kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.951	0.938	42
Lockford 230kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.961	0.947	2
Piercy 115kV	Morgan Hill – Llagas 115kV line	1.006	0.949	1
Middle River 60kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.955	0.938	9
Plainfield Junction 60kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.954	0.941	10
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.042	0.943	1
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.009	0.944	1
Livermore 2 60kV	Livermore – Las Positas 60kV line	0.987	0.946	1
Livermore 60kV	Livermore – Las Positas 60kV line	0.987	0.946	1
Vineyard 60kV	Livermore – Las Positas 60kV line	0.981	0.950	1
Radum 60kV	Livermore – Las Positas 60kV line	0.981	0.950	1

Table 7-8 Case 4 – 2015: Voltage Violations for Metcalf Energy Center Outage plus L-1

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Brighton 230kV	Gateway – Contra Costa 230kV line	0.956	0.943	1
Herdlyn 70kV	Gateway – Contra Costa 230kV line	0.951	0.935	24
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.011	0.941	1
Plainfield 60kV	Gateway – Contra Costa 230kV line	0.959	0.943	1
Middle River 60kV	Gateway – Contra Costa 230kV line	0.962	0.944	1
INE PRSN 60kV	Gateway – Contra Costa 230kV line	0.955	0.947	2
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.045	0.947	1
Plainfield Junction 60kV	Gateway – Contra Costa 230kV line	0.965	0.948	1

7.2 Case 3 – 2015 Steady State Violations

Thermal violations were not reviewed in detail.

The following tables show the worst contingencies for each of the monitored facilities. The *worst* contingency is defined as the contingency causing the lowest bus voltage. Voltage Hits are defined as the number of contingencies causing a voltage violation – this number includes the non-converged contingencies solved by hand. The Case 3 automated contingency analysis was performed with the recommended projects 1 – 18 (Sections 4.2.3, 4.2.5, and 4.3.3) fully modeled in the case. Note that the monitored element in the Thermal Violations was taken directly from the auto-contingency output files and doesn't imply a direction of flow.

Table 7-9 Case 3 – 2015: Voltage Violations for Category A Events (N-0)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Herdlyn 70kV	N/A	0.946	N/A	1
Brighton 230kV	N/A	0.947	N/A	1

Table 7-10 Case 3 – 2015: Voltage Violations for Category B Events (Combined Cycle Plant Contingencies)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
N/A – Voltage Collapse[1]	**Delta Energy Center (Pittsburg 230kV) 880 MW, 400 MVAR**	**N/A**	**N/A**	**N/A**
Los Banos M 500kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.976	0.942	1
Table Mt 1M 500kV		0.970	0.948	1
Lockford 230kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.960	0.935	4
Hicks 230kV		0.992	0.937	1
Cal Mec 230kV		0.999	0.939	1
Vasona 230kV		0.994	0.939	1
Metcalf 230kV		0.997	0.941	1
Saratoga 230kV		0.996	0.942	1
Weber 230kV		0.970	0.942	1

Table 7-10 Case 3 – 2015: Voltage Violations for Category B Events (Combined Cycle Plant Contingencies)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Tesla E 230kV		0.977	0.947	1
Stone 115kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.977	0.932	2
Stone Junction 115kV		0.977	0.933	2
Markham J2 115kV		0.978	0.933	2
Evergreen J 115kV		0.982	0.938	2
Evergreen 1 115kV		0.982	0.938	2
Evergreen 2 115kV		0.982	0.938	2
El Patio 115kV		0.981	0.939	2
Ames J1B 115kV		0.999	0.948	1
Ames J1A 115kV		0.999	0.948	1
Mountain View 115kV		0.999	0.948	1
Whisman 115kV		0.999	0.948	1
Middle River 60kV	Metcalf Energy Center (560 MW, 396 MVAR)	0.956	0.923	6
Plainfield 60kV		0.955	0.923	13
Plainfield Junction 60kV		0.960	0.935	4
BXLR TAP 60kV		0.979	0.947	1

1. The voltage collapse persisted even after disabling area interchange and reducing Southern California (Area 24) load to relieve the swing machine at Morro Bay. The recommended projects 18-21 were necessary to achieve solution convergence.

Table 7-11 Case 3 – 2015: Voltage Violations for Category B/C Events (N-1 & L-2)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Lakewood C 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	1.004	0.924	1
Lakewood M 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	1.004	0.924	1
FMC 115kV	Trimble – San Jose B 115 kV line FMC – Kifer (KRS) 115 kV line	0.982	0.931	2
San Jose B-E 115kV		0.981	0.933	3
San Jose B-F 115kV		0.981	0.934	3
San Jose A 115kV		0.979	0.935	2
Markham J 115kV		0.981	0.938	2
El Patio SJ1 115kV		0.980	0.938	2
El Patio SJ2 115kV		0.980	0.939	2
Montague 115kV	Los Esteros – Trimble 115 kV line Los Esteros – Montague 115kV line	0.990	0.945	1
Piercy 115kV	Metcalf – Swift 115kV line Metcalf – Piercy 115kV line	1.006	0.946	1
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.009	0.943	2
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.042	0.949	1

Table 7-12 Case 3 – 2015: Voltage Violations for Delta Energy Center Outage plus L-1

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Herdlyn 70kV	N/A – Intact System	0.945	N/A	N/A
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.046	0.947	1
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.013	0.946	1
Livermore 2 60kV	Livermore – Las Positas 60kV line	0.988	0.946	1
Livermore 60kV	Livermore – Las Positas 60kV line	0.988	0.947	1
Plainfield 60kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 92.5 MVAR)	0.955	0.945	3
Middle River 60kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.955	0.942	5

Table 7-13 Case 3 – 2015: Voltage Violations for Metcalf Energy Center Outage plus L-1

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Herdlyn 70kV	N/A – Intact System	0.944	N/A	N/A
Stone 115kV	Los Esteros – LECEF 115kV line LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.972	0.947	1
Stone Junction 115kV	Los Esteros – LECEF 115kV line LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.972	0.947	1
San Jose A 115kV	Los Esteros – LECEF 115kV line	0.975	0.949	1

Table 7-13 Case 3 – 2015: Voltage Violations for Metcalf Energy Center Outage plus L-1

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
	LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)			
Markham J2 115kV	Los Esteros – LECEF 115kV line LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.973	0.947	2
Piercy 115kV	Piercy – Metcalf E 115kV line	1.003	0.943	1
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.048	0.948	1
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.015	0.937	1
Middle River 60kV	Los Esteros – LECEF 115kV line LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.954	0.940	9
Plainfield 60kV	Los Esteros – LECEF 115kV line LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.951	0.940	39
Plainfield Junction 60kV	Los Esteros – LECEF 115kV line LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.956	0.946	3

7.3 Case 1 – 2015 Steady State Violations

Thermal violations are not reviewed in detail.

The following tables show the worst contingencies for each of the monitored facilities. The *worst* contingency is defined as the contingency causing the lowest bus voltage. Voltage Hits are defined as the number of contingencies causing a voltage violation – this number includes the non-converged contingencies solved by hand.

Table 7-14 Case 1 – 2015: Voltage Violations for Category A Events (Intact System)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
None				

Table 7-15 Case 1 – 2015: Voltage Violations for Category B/C Events (N-1 & L-2)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Lakewood C 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	1.006	0.920	1
Lakewood M 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	1.006	0.921	1

Table 7-16 Case 1 – 2015: Voltage Violations for Delta Energy Center Outage plus L-1

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
N/A – Voltage Collapse[1]	**Los Esteros – LECEF 115kV line LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)**	**N/A**	**N/A**	**N/A**
N/A – Voltage Collapse[1]	**Llagas – Gilroy Foods 115kV line Gilroy Cogen (146 MW, -7.5 MVAR)**	**N/A**	**N/A**	**N/A**
N/A – Voltage Collapse[1]	**Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 92.5 MVAR)**	**N/A**	**N/A**	**N/A**
Herdlyn 70kV	N/A – Intact System	0.936	N/A	N/A
Middle River 60kV	N/A – Intact System	0.945	N/A	N/A
Plainfield 60kV	N/A – Intact System	0.945	N/A	N/A
Brighton 230kV	Tesla E – Newark D 230kV line	0.956	0.949	2
Tassajara 230kV	Tassajara – Newark E 230kV line	0.962	0.949	1
Jameson 115kV	Christie – Martinez 115kV line Martinez – Oleum 115kV line Martinez – North Tower 115kV line Switch IN North Tower – N.Tower Jct 115kV line	0.986	0.948	1
Oakland Station J 115kV	Moraga – Oakland Station X 115kV line ckt ID 1	0.964	0.948	1
Owens Tap 115kV	Moraga – Oakland Station X 115kV line ckt ID 1	0.964	0.948	1
EDES 115kV	Moraga – Oakland Station X 115kV line ckt ID 1	0.962	0.947	2
EDES Tap 115kV	Moraga – Oakland Station X 115kV line ckt ID 1	0.962	0.947	2
Swift 115kV	Metcalf E – Swift 115kV line	0.990	0.948	1
Piercy 115kV	Piercy – Metcalf E 115kV line	1.003	0.943	1
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.046	0.944	1

Table 7-16 Case 1 – 2015: Voltage Violations for Delta Energy Center Outage plus L-1

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.012	0.939	1
Livermore 2 60kV	Livermore – Las Positas 60kV line	0.983	0.940	1
Livermore 60kV	Livermore – Las Positas 60kV line	0.983	0.940	1
Vineyard 60kV	Livermore – Las Positas 60kV line	0.976	0.943	1
Radum 60kV	Livermore – Las Positas 60kV line	0.976	0.943	1

1. The voltage collapse persisted even after disabling area interchange and reducing Southern California (Area 24) load to relieve the swing machine at Morro Bay.

Table 7-17 Case 1 – 2015: Voltage Violations for Metcalf Energy Center Outage plus L-1

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Herdlyn 70kV	N/A – Intact System	0.936	N/A	N/A
Middle River 60kV	N/A – Intact System	0.943	N/A	N/A
Plainfield 60kV	N/A – Intact System	0.946	N/A	N/A
Plainfield Junction 60kV	N/A – Intact System	0.948	N/A	N/A
Los Banos M 500kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 92.5 MVAR)	0.963	0.945	3
Brighton 230kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 92.5 MVAR)	0.956	0.944	3
Lockford 230kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 92.5 MVAR)	0.960	0.946	3

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Table 7-17 Case 1 – 2015: Voltage Violations for Metcalf Energy Center Outage plus L-1

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Weber 230kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 92.5 MVAR)	0.965	0.949	1
Tassajara 230kV	Pittsburg D – Tassajara 230kV line	0.976	0.948	1
Jameson 115kV	Christie – Martinez 115kV line Martinez – Oleum 115kV line Martinez – North Tower 115kV line Switch IN North Tower – N.Tower Jct 115kV line	0.983	0.946	1
Jameson Junction 115kV	Christie – Martinez 115kV line Martinez – Oleum 115kV line Martinez – North Tower 115kV line Switch IN North Tower – N.Tower Jct 115kV line	0.986	0.949	1
Dixon Landing 115kV	Newark F – Dixon Landing 115kV line	1.002	0.948	1
Markham J2 115kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 92.5 MVAR)	0.967	0.946	4
McKee 115kV	Newark F – Dixon Landing 115kV line	0.985	0.948	1
Mabury 115kV	Newark F – Dixon Landing 115kV line	0.989	0.947	1
Mabury Junction 115kV	Newark F – Dixon Landing 115kV line	0.987	0.945	1
Stone 115kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 92.5 MVAR)	0.966	0.945	4
Stone Junction 115kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 92.5 MVAR)	0.966	0.946	4
Piercy 115kV	Piercy – Metcalf E 115kV line	0.993	0.945	1

Table 7-17 Case 1 – 2015: Voltage Violations for Metcalf Energy Center Outage plus L-1

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.047	0.945	1
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.014	0.920	1

Table 7-18 Case 1 – 2015: Voltage Violations for Delta Energy Center Outage plus L-1 with Zone 322 Re-Dispatched

Monitored Bus	Worst Single Line Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Herdlyn 70kV	N/A – Intact System	0.945	N/A	N/A
Piercy 115kV	Morgan Hill – Llagas 115kV line	1.008	0.949	1
Middle River 60kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.955	0.938	5
Plainfield Junction 60kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.957	0.943	3
Plainfield 60kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.951	0.937	19
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.045	0.946	1
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.011	0.945	1
Livermore 2 60kV	Livermore – Las Positas 60kV line	0.985	0.942	1
Livermore 60kV	Livermore – Las Positas 60kV line	0.985	0.942	1
Vineyard 60kV	Livermore – Las Positas 60kV line	0.978	0.946	1
Radum 60kV	Livermore – Las Positas 60kV line	0.978	0.946	1

Table 7-19 Case 1 – 2015: Voltage Violations for Metcalf Energy Center Outage plus L-1 with Zone 322 Re-Dispatched

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Piercy 115kV	Piercy – Metcalf 115kV line	1.007	0.947	1
Herdlyn 70kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.954	0.946	6
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.014	0.944	1
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.047	0.948	1

7.4 Case 4 – 2020 Steady State Violations

The following tables show the worst contingencies for each of the monitored facilities. The *worst* contingency is defined as the contingency causing the lowest bus voltage or the highest thermal loading. Voltage Hits are defined as the number of contingencies causing a voltage violation – this number includes the non-converged contingencies solved by hand. Note that the monitored element in the Thermal Violations was taken directly from the auto-contingency output files and doesn't imply a direction of flow.

Table 7-20 Case 4 – 2020: Thermal Violations for Category A Events (N-0)

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
CPV Colusa – Cortina 230kV line	831	N/A	1.06	N/A
Tesla 500/14kV transformer ID 2	1131 MVA	N/A	1.06	N/A
Tesla 230/14kV transformer ID 2	1093 MVA	N/A	1.05	N/A

Table 7-21 Case 4 – 2020: Thermal Violations for Category B/C Events (N-1 & L-2)

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Saratoga – Vasona 230kV line	1253	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.77	1.26
Hicks – Metcalf 230kV line	1600	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.72	1.21
Monta Vista – Hicks 230kV line	1252	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.66	1.19
Monta Vista – Saratoga 230kV line	1055	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.59	1.18
San Ramon – Eastshore 230kV line	1162	Newark – Ravenswood 230kV line Tesla – Ravenswood 230kV line	0.67	1.09
Newark D – Newark E 230kV line	1599	Tesla E – Newark D 230kV line Tesla E – Ravenswood 230kV line	0.21	1.04
Ravenswood – Cooley Landing 115kV ckt 2	883	Ravenswood – Palo Alto 115 kV ckt 1 Ravenswood – Palo Alto 115kV ckt 2	0.75	1.53

Table 7-21 Case 4 – 2020: Thermal Violations for Category B/C Events (N-1 & L-2)

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Lakewood M – Lakewood Reactor 115kV ckt 9	798	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	0.26	1.37
Moraga – San Leandro 115kV ckt 3	712	Moraga – San Leandro 115 kV ckt 1 Moraga – San Leandro 115 kV ckt 2	0.63	1.30
Pittsburg – Clayton 115kV line	1600	Pittsburg – Clayton 115kV ckt 3 Pittsburg – Clayton 115kV ckt 4	0.58	1.28
Christie – Sobrante 115kV line	523	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.44	1.25
Lakewood Reactor – Moraga 115kV line	894	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	0.27	1.22
Cooley Landing – Palo Alto 115kV line	883	Ravenswood – Palo Alto 115kV ckt 1 Ravenswood – Palo Alto 115kV ckt 2	0.29	1.19
El Cerrito – Sobrante 115kV line	600	El Cerrito J1 – Sobrante 115kV line	0.65	1.13
El Cerrito J1 – Sobrante 115kV line	600	El Cerrito – Sobrante 115kV ckt 2	0.65	1.13
San Leandro – Domtar SL 115kV line	947	Moraga – Oakland Station J 115 kV line	0.73	1.12
San Mateo – Belmont 115kV line	557	Ravenswood – Bair 115kV ckt 1 Ravenswood – Bair 115kV ckt 2	0.56	1.11
Martinez D – Alhambra Tap 2 115kV line	486	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.42	1.10
EDES Tap – Domtar SL 115kV line	947	Moraga – Oakland Station J 115 kV line	0.71	1.10
Ravenswood – Palo Alto 115kV ckt 2	948	Ravenswood – Palo Alto 115kV line Cooley Landing – Palo Alto 115kV line	0.48	1.10
Christie – Martinez Junction 115kV line	516	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.26	1.09
San Jose B-F – Markham J 115kV line	1054	Metcalf – El Patio 115kV ckt 1 Metcalf – El Patio 115kV ckt 2	0.64	1.09
Ravenswood E – Ames BS1 115kV ckt 1	1144	Newark – Ravenswood 230 kV line Tesla – Ravenswood 230 kV line	0.23	1.07
Ravenswood E – Ames BS2 115kV ckt 2	1144	Newark – Ravenswood 230 kV line Tesla – Ravenswood 230 kV line	0.23	1.07

Table 7-21 Case 4 – 2020: Thermal Violations for Category B/C Events (N-1 & L-2)

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Oleum – Valley View Tap 1 115kV line	471	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.19	1.06
Newark – Dixon Landing 115kV line	1144	Metcalf – Piercy 115kV line	0.14	1.05
Larkin E – Potrero 115kV ckt 2	800	Mission – Potrero 115kV line	0.68	1.05
Oleum – Alhambra Tap 2 115kV line	522	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.38	1.03
El Patio SJ1 – El Patio SJ2 115kV	803	Newark – Los Esteros 230kV line Metcalf – Los Esteros 230 kV line	0.77	1.02
San Jose A – San Jose B F 115kV line	1220	Newark – Los Esteros 230 kV Los Esteros – Metcalf 230kV	0.78	1.02
Herdlyn 70/60kV transformer ckt 2	60 MVA	Las Positas – Vasco 60kV line Vasco – US Wind Power Frick Green Ridge 60kV line US Wind Power FGR – Flowind 60kV line Flowind – Zond Wind 60kV line Zond Wind – Seawest 60kV line	0.90	1.02

Table 7-22 Case 4 – 2020: Voltage Violations for Category A Events (N-0)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
None				

Table 7-23 Case 4 – 2020: Voltage Violations for Category B Events (Combined Cycle Plant Contingencies)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Los Banos M 500kV	Delta Energy Center (Pittsburg 230kV) (880 MW, 400 MVAR)	0.992	0.948	1
Table Mt. 1M 500kV		0.977	0.949	1
Brighton 230kV	Delta Energy Center (Pittsburg 230kV) (880 MW, 400 MVAR)	0.954	0.924	21
Peabody 230kV		0.954	0.924	1

Table 7-23 Case 4 – 2020: Voltage Violations for Category B Events (Combined Cycle Plant Contingencies)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Weber 230kV		0.977	0.939	1
Los Positas 230kV		0.978	0.941	1
Tassajara 230kV		0.984	0.943	1
Research 230kV		0.985	0.943	1
TES Junction 230kV		0.985	0.944	1
Flowind 230kV		0.991	0.944	1
Tres Vaqueros 230kV		0.991	0.944	1
Tesla E 230kV		0.987	0.945	1
ADCC 230kV		0.991	0.945	1
Telsa C 230kV		0.992	0.946	1
Lockeford 230kV		0.981	0.948	1
Brentwood 230kV		0.981	0.948	1
US Wind Power RLF 230kV		0.988	0.948	1
Alta Land 230kV		0.989	0.948	1
Tesla D 230kV		0.991	0.948	1
Stone 115kV		0.984	0.940	1
Stone Junction 115kV		0.985	0.940	1
Markham J2 115kV		0.985	0.942	1
San Jose A 115kV		0.987	0.943	2
El Patio SJ1 115kV		0.988	0.944	2
El Patio SJ2 115kV	Delta Energy Center (Pittsburg 230kV) (880 MW, 400 MVAR)	0.988	0.944	2
El Patio 115kV		0.989	0.945	1
Markham J 115kV		0.988	0.945	2
Evergreen 1 115kV		0.989	0.945	1
Evergreen 2 115kV		0.989	0.945	1
Evergreen Junction 115kV		0.989	0.946	1
Warnerville 115kV		0.978	0.946	1
Herdlyn 70kV	Delta Energy Center (Pittsburg 230kV)	0.956	0.916	19

Table 7-23 Case 4 – 2020: Voltage Violations for Category B Events (Combined Cycle Plant Contingencies)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
	(880 MW, 400 MVAR)			
Plainfield 60kV	Delta Energy Center (Pittsburg 230kV) (880 MW, 400 MVAR)	0.963	0.923	6
Middle River 60kV		0.968	0.923	3
Plainfield Junction 60kV		0.968	0.929	3
Bixler Tap 60kV		0.990	0.947	1

Table 7-24 Case 4 – 2020: Voltage Violations for Category B/C Events (N-1 & L-2)

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Lakewood C 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	1.002	0.918	1
Lakewood M 115kV		1.002	0.918	1
Montague 115kV	Los Esteros – Trimble 115kV line Los Esteros – Montague 115kV line	0.999	0.948	1
FMC 60kV	Trimble – San Jose B 115kV line FMC – Kifer 115kV line	0.989	0.940	2
San Jose B E 60kV		0.988	0.941	2
San Jose B F 60kV		0.988	0.942	2
Loyola 60kV	Monta Vista 230/60kV transformer ckt 5 Switch IN Los Altos – Los Altos J 60kV line Loyola – Monta Vista 60kV line Monta Vista – Los Gatos 60kV line Switch IN Almaden – Los Gatos 60kV line	1.044	0.942	2
Los Gatos 60kV		1.009	0.943	2

Table 7-25 Case 4 – 2020: Thermal Violations for Category A Events (N-0) with Collinsville Substation

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
CP-V Colusa – Cortina 230kV line	831	N/A	1.01	N/A
Malin – Round Mountain 500kV line	1800	N/A	0.99	N/A
Tesla 500/14kV transformer ID 2	1131 MVA	N/A	0.97	N/A

Table 7-25 Case 4 – 2020: Thermal Violations for Category A Events (N-0) with Collinsville Substation

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Tesla 230/14kV transformer ID 2	1093 MVA	N/A	0.97	N/A

Table 7-26 Case 4 – 2020: Thermal Violations for Category B/C Events (N-1 & L-2) with Collinsville Substation

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Saratoga – Vasona 230kV line	1253	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.73	1.19
Hicks – Metcalf 230kV line	1600	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.69	1.15
Monta Vista – Hicks 230kV line	1252	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.62	1.13
Monta Vista – Saratoga 230kV line	1055	Metcalf – Monta Vista 230kV ckt 3 Cal Mec – Monta Vista 230kV ckt 4	0.55	1.11
Newark D – Newark E 230kV line	1599	Tesla E – Newark D 230kV line Tesla E – Ravenswood 230kV line	0.28	1.03
Ravenswood – Cooley Landing 115kV ckt 2	883	Ravenswood – Palo Alto 115 kV ckt 1 Ravenswood – Palo Alto 115kV ckt 2	0.75	1.52
Moraga – San Leandro 115kV ckt 1	557	Moraga – Oakland Station J 115 kV line Moraga – San Leandro 115 kV ckt 3	0.73	1.45
Lakewood M – Lakewood Reactor 115kV ckt 9	798	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	0.06	1.35
Pittsburg – Clayton 115kV line	1600	Pittsburg – Clayton 115kV ckt 3 Pittsburg – Clayton 115kV ckt 4	0.62	1.35
Moraga – San Leandro 115kV ckt 3	712	Moraga – San Leandro 115 kV ckt 1 Moraga – San Leandro 115 kV ckt 2	0.63	1.29
Lakewood Reactor – Moraga 115kV line	894	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	0.06	1.21
Martinez D – Alhambra Tap 2 115kV line	486	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.57	1.19

Table 7-26 Case 4 – 2020: Thermal Violations for Category B/C Events (N-1 & L-2) with Collinsville Substation

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Cooley Landing – Palo Alto 115kV line	883	Ravenswood – Palo Alto 115kV ckt 1 Ravenswood – Palo Alto 115kV ckt 2	0.29	1.18
Christie – Sobrante 115kV line	523	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.41	1.16
Oleum – Alhambra Tap 2 115kV line	522	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.51	1.11
San Leandro – Domtar SL 115kV line	947	Moraga – Oakland Station J 115 kV line	0.72	1.11
San Mateo – Belmont 115kV line	557	Ravenswood – Bair 115kV ckt 1 Ravenswood – Bair 115kV ckt 2	0.54	1.11
EDES Tap – Domtar SL 115kV line	947	Moraga – Oakland Station J 115 kV line	0.70	1.09
Ravenswood – Palo Alto 115kV ckt 2	948	Ravenswood – Palo Alto 115kV line Cooley Landing – Palo Alto 115kV line	0.47	1.09
El Cerrito – Sobrante 115kV ckt 2	600	El Cerrito J1 – Sobrante 115kV line	0.61	1.07
El Cerrito J1 – Sobrante 115kV line	600	El Cerrito – Sobrante 115kV ckt 2	0.61	1.07
Oleum – Valley View Tap 1 115kV line	471	El Cerrito – Sobrante 115kV ckt 1 El Cerrito – Sobrante 115kV ckt 2	0.25	1.05
Markham J – Evergreen 1 115kV line	1054	Metcalf – El Patio 115kV ckt 1 Metcalf – El Patio 115kV ckt 2	0.61	1.04
Larkin E – Potrero 115kV ckt 2	800	Mission – Potrero 115kV line	0.67	1.04
Newark – Dixon Landing 115kV line	1144	Metcalf – Piercy 115kV line	0.16	1.03
Trimble – San Jose B E 115kV line	923	Metcalf – El Patio 115kV ckt 1 Metcalf – El Patio 115kV ckt 2	0.44	1.02
Monta Vista 115/60kV transformer ckt 5	161MVA	Monta Vista 115/60kV transformer ckt 6	0.59	1.00
San Jose B-F – Markham J 115kV line	1057	Metcalf – El Patio 115kV ckt 1 Metcalf – El Patio 115kV ckt 2	0.58	1.00

Table 7-27 Case 4 – 2020: Voltage Violations for Category A Events (N-0) with Collinsville Substation

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
None				

Table 7-28 Case 4 – 2020: Voltage Violations for Category B Events (Combined Cycle Plant Contingencies) with Collinsville Substation

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Brighton 230kV	Delta Energy Center (Pittsburg 230kV) 880 MW, 400 MVAR	0.960	0.947	1
Herdlyn 70kV	Delta Energy Center (Pittsburg 230kV) 880 MW, 400 MVAR	0.969	0.945	1
Plainfield 60kV	Delta Energy Center (Pittsburg 230kV) 880 MW, 400 MVAR	0.969	0.945	1

Table 7-29 Case 4 – 2020: Voltage Violations for Category B/C Events (N-1 & L-2) with Collinsville Substation

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Lakewood C 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	1.008	0.925	1
Lakewood M 115kV	Lakewood – Clayton 115kV line Lakewood – Meadow Lane – Clayton 115 kV line	1.008	0.925	1

Table 7-30 Case 4 – 2020: Voltage Violations for Delta Energy Center Outage plus L-1 with Collinsville Substation

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Brighton 230kV	N/A – Intact System	0.946	N/A	N/A
Herdlyn 70kV	N/A – Intact System	0.945	N/A	N/A

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Table 7-30 Case 4 – 2020: Voltage Violations for Delta Energy Center Outage plus L-1 with Collinsville Substation

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Plainfield 60kV	N/A – Intact System	0.947	N/A	N/A
Lockeford 230kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.958	0.942	3
Collinsville 230kV		0.962	0.946	2
Tassajara 230kV	Pittsburg D – Tassajara 230kV line	0.966	0.947	2
Research 230kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.967	0.947	1
Los Positas 230kV		0.968	0.948	1
TES Junction 230kV		0.968	0.948	1
Piercy 115kV	Piercy – Metcalf E 115kV line	1.002	0.934	1
San Jose A 115kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.974	0.940	1
Stone 115kV		0.971	0.940	1
Stone Junction 115kV		0.972	0.940	1
Markham J2 115kV		0.972	0.940	1
Belmont 115kV	San Mateo – Belmont 115kV line	0.992	0.940	1
San Jose B E 115kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.975	0.941	1
San Jose B F 115kV		0.976	0.941	1
El Patio SJ1 115kV		0.975	0.942	1
El Patio SJ2 115kV		0.975	0.942	1
Markham J 115kV		0.975	0.942	1
McKee 115kV	Piercy – Metcalf E 115kV line	0.990	0.942	1
FMC 115kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.976	0.943	1
Swift 115kV	Swift – Metcalf E 115kV line	0.989	0.943	1
FMC Junction 115kV	Los Esteros – LECEF 115kVline	0.979	0.944	1

Table 7-30 Case 4 – 2020: Voltage Violations for Delta Energy Center Outage plus L-1 with Collinsville Substation

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
El Patio 115kV	LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.976	0.944	1
Evergreen 1 115kV		0.976	0.945	1
Evergreen 2 115kV		0.976	0.945	1
Evergreen Junction 115kV		0.976	0.945	1
Montague 115kV		0.986	0.946	1
Trimble 115kV		0.985	0.947	1
Mabury 115kV	Piercy – Metcalf E 115kV line	0.991	0.947	1
Mabury Junction 115kV	Piercy – Metcalf E 115kV line	0.993	0.949	1
Los Gatos 60kV	Loyola – Monta Vista 60kV line Switch IN Almaden – Los Gatos 60kV line	1.008	0.927	1
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.044	0.930	1
Plainfield 60kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 81.6 MVAR)	0.952	0.938	17
Middle River 60kV	Llagas – Gilroy Foods 115kV line Gilroy Cogen (268.1 MW, 38.9 MVAR)	0.955	0.938	8
Travis 60kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 81.6 MVAR)	0.956	0.941	3
Los Altos 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.034	0.942	1
Livermore 2 60kV	Livermore – Las Positas 60kV line	0.985	0.943	1
Livermore 60kV	Livermore – Las Positas 60kV line	0.985	0.943	1
Travis HPT 60kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 81.6 MVAR)	0.960	0.945	2

Table 7-30 Case 4 – 2020: Voltage Violations for Delta Energy Center Outage plus L-1 with Collinsville Substation

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Glenwood 60kV	Glenwood – SRI – Cooley Landing 60kV line Cardinal Units ID 1 &2 (45.3 MW, 19.5 MVAR)	1.007	0.946	1
Radum 60kV	Livermore – Las Positas 60kV line	0.979	0.946	1
Travis Junction 60kV	Ignacio – Crockett 230kV line Crockett – Sobrante 230kV line Crockett Cogen (240.0 MW, 81.6 MVAR)	0.961	0.947	1
Vineyard 60kV	Livermore – Las Positas 60kV line	0.979	0.947	1

Table 7-31 Case 4 – 2020: Voltage Violations for Metcalf Energy Center Outage plus L-1 with Collinsville Substation

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Brighton 230kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.951	0.944	21
Tassajara 230kV	Pittsburg D – Tassajara 230kV line	0.978	0.949	1
Stone 115kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.971	0.941	1
Stone Junction 115kV		0.971	0.941	1
Piercy 115kV	Piercy – Metcalf E 115kV line	1.001	0.942	1
San Jose A 115kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.975	0.943	1
San Jose B E 115kV		0.976	0.944	1
El Patio SJ1 115kV		0.975	0.944	1
San Jose B F 115kV		0.976	0.945	1
El Patio SJ2		0.975	0.945	1
Markham J 115kV		0.976	0.945	1

Table 7-31 Case 4 – 2020: Voltage Violations for Metcalf Energy Center Outage plus L-1 with Collinsville Substation

Monitored Bus	Worst Contingency	Vbase (p.u.)	Vcont (p.u.)	Voltage Hits
Belmont 115kV	San Mateo – Belmont 115kV line	0.996	0.945	1
El Patio 115kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.976	0.946	1
Evergreen 1 115kV		0.976	0.946	1
Evergreen 2 115kV		0.976	0.946	1
Evergreen Junction 115kV		0.976	0.946	1
FMC 115kV		0.978	0.947	1
Swift 115	Swift – Metcalf E 115kV line	0.989	0.948	1
McKee 115kV	Piercy – Metcalf E 115kV line	0.991	0.949	1
Herdlyn 70kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.952	0.942	35
Los Gatos 60kV	Monta Vista – Los Gatos 60kVline Switch IN Almaden – Los Gatos 60kV line	1.011	0.927	1
Loyola 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.047	0.934	1
Glenwood 60kV	Glenwood – SRI – Cooley Landing 60kV line Cardinal Units ID 1 &2 (45.3 MW, 19.5 MVAR) Load at Stanford 60kV bus (34.95 MW, 7.10 MVAR)	1.010	0.944	1
Los Altos 60kV	Loyola – Monta Vista 60kV line Switch IN Los Altos – Los Altos Junction 60kV line	1.037	0.946	1
Plainfield 60kV	Los Esteros – LECEF 115kVline LECEF – Nortech 115kV line Los Esteros Critical Energy Facility (200.0 MW, 148.0 MVAR)	0.957	0.948	1

Table 7-32 Case 4 – 2020: Thermal Violations for Delta Energy Center Outage plus L-1 with Collinsville Substation

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Collinsville – Pittsburg D 230kV cable	2259	Collinsville – Pittsburg E 230kV cable	0.80	1.09
Collinsville – Pittsburg E 230kV cable	2259	Collinsville – Pittsburg D 230kV cable	0.78	1.08
Metcalf – Moss Landing 2 230kV line	1072	Metcalf – Moss Landing 1 230kV line	0.99	1.05
Metcalf – Moss Landing 1 230kV line	1072	Metcalf – Moss Landing 2 230kV line	0.99	1.05
Mission – Potrero 115kV line	700	Larkin E – Potrero 115kV line	0.85	1.30
San Leandro – Domtar SL 115kV line	947	Moraga – Oakland Station J 115 kV line	0.73	1.13
El Cerrito J1 – Sobrante 115kV line	600	El Cerrito – Sobrante 115kV ckt 2	0.64	1.12
El Cerrito – Sobrante 115kV ckt 2	600	El Cerrito J1 – Sobrante 115kV line El Cerrito – El Cerrito J1 115kV line	0.64	1.12
EDES Tap – Domtar SL 115kV line	947	Moraga – Oakland Station J 115 kV line	0.71	1.11
Oakland Station J – Moraga 115kV line	709	San Leandro – Domtar – EDES Tap 115kV line EDES Tap – Oakland Station J 115kV line EDES Tap – EDES 115kV line Switch IN EDES – EDES Grant 115kV line	0.69	1.07
Larkin E – Potrero 115kV line	799	Mission – Potrero 115kV line	0.69	1.07
Metcalf E – Piercy 115kV line	1144	Newark – Dixon Landing 115kV line	0.93	1.06

Table 7-33 Case 4 – 2020: Thermal Violations for Metcalf Energy Center Outage plus L-1 with Collinsville Substation

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
Metcalf – Moss Landing 1 230kV line	1072	Metcalf – Moss Landing 2 230kV line	1.02	1.09
Metcalf – Moss Landing 2 230kV line	1072	Metcalf – Moss Landing 1 230kV line	1.02	1.09
San Ramon – Eastshore 230kV line	1162	Eastshore – Pittsburg E 230kV line	0.91	1.03
Mission – Potrero 115kV line	700	Larkin E – Potrero 115kV line	0.84	1.28
San Leandro – Domtar SL 115kV line	947	Moraga – Oakland Station J 115 kV line	0.73	1.12
EDES Tap – Domtar SL 115kV line	947	Moraga – Oakland Station J 115 kV line	0.71	1.10
El Cerrito J1 – Sobrante 115kV line	600	El Cerrito – Sobrante 115kV ckt 2	0.61	1.07

Table 7-33 Case 4 – 2020: Thermal Violations for Metcalf Energy Center Outage plus L-1 with Collinsville Substation

Monitored Element	Rating (Amps)	Worst Contingency	BaseFlow (p.u.)	ContFlow (p.u.)
El Cerrito – Sobrante 115kV ckt 2	600	El Cerrito J1 – Sobrante 115kV line El Cerrito – El Cerrito J1 115kV line	0.62	1.07
Metcalf E – Piercy 115kV line	1144	Newark – Dixon Landing 115kV line	0.84	1.07
Oakland Station J – Moraga 115kV line	709	San Leandro – Domtar – EDES Tap 115kV line EDES Tap – Oakland Station J 115kV line EDES Tap – EDES 115kV line Switch IN EDES – EDES Grant 115kV line	0.69	1.06
Newark – Dixon Landing 115kV line	1144	Piercy – Metcalf E 115kV line	0.21	1.06
Larkin E – Potrero 115kV line	799	Mission – Potrero 115kV line	0.68	1.05

7.5 Case 4 – 2015 Fault Simulations

All fault simulations performed included the recommended projects that were developed based on the results of the steady state N-1, L-2, and G-1 + L-1.

Table 7-34 Case 4 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatB_01	3Ø Fault at Tesla E on Tesla – Newark 230kV line	6.0	6.0	None	None
CatB_02	3Ø Fault at Tesla E on Tesla – Ravenswood 230kV line	6.0	6.0	None	None
CatB_03	3Ø Fault at Tesla D on Tesla 230115kV transformer ID 3	6.0	6.0	None	None[10]
CatB_04	3Ø Fault at Moss Landing on Moss Landing – Metcalf 230kV line	6.0	6.0	None	None
CatB_05	3Ø Fault at Tesla C on Tesla – ADCC – Newark 230kV line ID 2	6.0	6.0	None	None
CatB_06	3Ø Fault at Eastshore on Eastshore – Pittsburg 230kV line	6.0	6.0	None	None
CatC_01	3Ø Bus Fault at Metcalf 230kV Bus Section 1D results in loss of Metcalf 230kV Capacitors Metcalf 230/115kV transformer ID #2 Metcalf – Vasona 230kV line	6.0	6.0	None	None
CatC_02	3Ø Bus Fault at Newark 230kV Bus Section 1D results in loss of Newark D – Ravenswood 230kV line Newark D – Las Positas 230kV line Newark D – Tesla E 230kV line Newark D/7M 230/13.2kV transformer	6.0	6.0	None	None
CatC_03	3Ø Bus Fault at San Mateo 230kV Bus Section 1E results in loss of Martin C 115kV Capacitors San Mateo – Ravenswood 230kV line	6.0	6.0	None	None

Table 7-34 Case 4 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_04	3Ø Bus Fault at Tesla 230kV Bus Section 2D results in loss of Tesla D – Altamont Midway 230kV line Altamont Midway – Delta Pump 230kV line Tesla D – Tracy Pump 230kV line ID 2 Tesla D 230/115kV transformer ID 3 Tesla D 230kV Capacitors	6.0	6.0	None	None[10]
CatC_05	3Ø Bus Fault at Tesla 230kV Bus Section 1E results in loss of Tesla E – Newark D 230kV line Tesla E – Eight Mile 230kV line Tesla E – Weber 230kV line	6.0	6.0	None	None
CatC_06	3Ø Bus Fault at Pittsburg 230kV Bus Section 1D results in loss of Pittsburg D – Tassajara 230kV line Pittsburg D 230/115kV transformer ID 13 Pittsburg VSC 230/181kV transformer (no change made at Potrero)	6.0	6.0	None	None
CatC_07	3Ø Bus Fault at Moraga 230kV Bus Section 2 Moraga – RossTap2 230kV line Moraga – Bahia 230kV line Moraga – Castro Valley 230kV line Moraga 230/115kV transformer ID 1 Moraga 230/115kV transformer ID 2	6.0	6.0	None	None
CatC_08	SLG Fault at MossLanding on MossLanding – Metcalf 230kV line CB #XXX fails at MossLanding and results in loss of MossLanding – Duke ML 230kV line (radial line to plant) MossLanding 230/115kV transformer ID 1 MossLanding 230/115kV transformer ID 8	15.0	6.0	None	None
CatC_09	SLG Fault at Eastshore on Eastshore – San Mateo 230kV line CB #242 fails at Eastshore and results in loss of Pittsburg – San Mateo 230kV line	15.0	6.0	None	None

Table 7-34 Case 4 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_10	SLG Fault at Newark on Newark – Ravenswood 230kV line CB #610 fails at Newark Bus Section 1D and results in loss of Newark D – Las Positas 230kV line Newark D – Tesla E 230kV line Newark D/7M 230/13.2kV transformer	15.0	6.0	None	None
CatC_11	SLG Fault at Metcalf on Metcalf – Vasona 230kV line CB #212 fails at Metcalf Bus Section 1D and results in loss of Metcalf 230kV Capacitors Metcalf 230/115kV transformer ID #2	15.0	6.0	None	None
CatC_12	SLG Fault at Tesla on Tesla – ADCC – Newark 230kV line ckt 2 CB #XXX fails at Tesla Bus Section C and results in loss of Tesla – Flowind – Pittsburg 230kV line	15.0	6.0	None	None
CatC_13	SLG Fault at Tesla on Tesla – Tracy Pump 230kV line ID 2 CB #XXX fails at Tesla Bus Section 2D and results in loss of Tesla D – Altamont Midway 230kV line Altamont Midway – Delta Pump 230kV line Tesla D 230/115kV transformer ID 3 Tesla D 230kV Capacitors	15.0	6.0	None	None
CatC_14	SLG Fault at Tesla on Tesla – Newark 230kV line CB #XXX fails at Tesla Bus Section 1E and results in loss of Tesla E – Eight Mile 230kV line Tesla E – Weber 230kV line	15.0	6.0	None	None
CatC_15	SLG Fault at Pittsburg on Pittsburg – Tassajara 230kV line CB #432 fails at Pittsburg Bus Section 1D and results in loss of Pittsburg D 230/115kV transformer ID 13 Pittsburg VSC 230/181kV transformer Pittsburg VSC terminal (represented by a generator) (no changes made at Potrero)	15.0	6.0	None	None

Table 7-34 Case 4 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_16	SLG Fault at Moraga on Moraga – Bahia 230kV line CB #222 fails at Moraga Bus Section 2 and results in loss of Moraga – RossTap2 230kV line Moraga – Castro Valley 230kV line Moraga 230/115kV transformer ID 1 Moraga 230/115kV transformer ID 2	15.0	6.0	None	None
CatC_17	Mechanical Failure at Delta Energy Center (No Fault)	N/A	N/A	None	None
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[11]
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[11]
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[11]
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[11]
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	4.0	4.0	None	None
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	N/A	N/A	None	None[12]
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	4.0	4.0	None	None[13]
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	4.0	4.0	None	None[11]
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	4.0	4.0	None	None

Table 7-34 Case 4 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	4.0	4.0	None	None[13]
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Vaca Dixon 500kV line	4.0	4.0	None	None[13]
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	N/A	N/A	None	None
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	12.0	12.0	None	None
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Vaca Dixon 500kV line	12.0	12.0	None	None
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	12.0	12.0	None	None
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	12.0	12.0	None	None
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	12.0	12.0	None	None
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	12.0	12.0	None	None
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	12.0	12.0	None	None

Table 7-34 Case 4 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None

0. All 3Ø Fault Impedances: r = 0.0 p.u., x = 0.0 p.u.
1. CatC_08: SLG Fault Impedance: r = 1.192 p.u., x = 12.942 p.u.
2. CatC_09: SLG Fault Impedance: r = 0.109 p.u., x = 2.146 p.u.
3. CatC_10: SLG Fault Impedance: r = 0.968 p.u., x = 8.493 p.u.
4. CatC_11: SLG Fault Impedance: r = 0.042 p.u., x = 2.412 p.u.
5. CatC_12: SLG Fault Impedance: r = 0.380 p.u., x = 3.832 p.u.
6. CatC_13: SLG Fault Impedance: r = 0.0465 p.u., x = 1.846 p.u.
7. CatC_14: SLG Fault Impedance: r = 0.155 p.u., x = 3.601 p.u.
8. CatC_15: SLG Fault Impedance: r = 0.177 p.u., x = 2.841 p.u.
9. CatC_16: SLG Fault Impedance: r = 0.142 p.u., x = 2.432 p.u.
10. Generator at Shilo 34.5kV bus (#32176) and Shiloh 34.5kV bus (#32177) tripped on Under-voltage at t = 1.0958 second.
11. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
12. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
    GEWTG trip due to voltage violation of dV = 0.1500 for unit 1 at bus 47326 [KLON W12] 34.50
    GEWTG trip due to voltage violation of dV = 0.1500 for unit 3 at bus 47323 [KLON W3] 34.50
    GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47829 [GDNOE W1] 34.50
13. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
    GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47829 [GDNOE W1] 34.50

7.6 Case 3 – 2015 Fault Simulations

All fault simulations performed included the recommended projects that were developed based on the results of the steady state N-1, L-2, and G-1 + L-1.

Table 7-35 Case 3 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatB_01	3Ø Fault at Tesla E on Tesla – Newark 230kV line	6.0	6.0	None	None
CatB_02	3Ø Fault at Tesla E on Tesla – Ravenswood 230kV line	6.0	6.0	None	None
CatB_03	3Ø Fault at Tesla D on Tesla 230115kV transformer ID 3	6.0	6.0	None	None[1]
CatB_04	3Ø Fault at Moss Landing on Moss Landing – Metcalf 230kV line	6.0	6.0	None	None
CatB_05	3Ø Fault at Tesla C on Tesla – ADCC – Newark 230kV line ID 2	6.0	6.0	None	None
CatB_06	3Ø Fault at Eastshore on Eastshore – Pittsburg 230kV line	6.0	6.0	None	None
CatC_01	3Ø Bus Fault at Metcalf 230kV Bus Section 1D results in loss of Metcalf 230kV Capacitors Metcalf 230/115kV transformer ID #2 Metcalf – Vasona 230kV line	6.0	6.0	None	None
CatC_02	3Ø Bus Fault at Newark 230kV Bus Section 1D results in loss of Newark D – Ravenswood 230kV line Newark D – Las Positas 230kV line Newark D – Tesla E 230kV line Newark D/7M 230/13.2kV transformer	6.0	6.0	None	None
CatC_03	3Ø Bus Fault at San Mateo 230kV Bus Section 1E results in loss of Martin C 115kV Capacitors San Mateo – Ravenswood 230kV line	6.0	6.0	None	None

Table 7-35 Case 3 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_04	3Ø Bus Fault at Tesla 230kV Bus Section 2D results in loss of Tesla D – Altamont Midway 230kV line Altamont Midway – Delta Pump 230kV line Tesla D – Tracy Pump 230kV line ID 2 Tesla D 230/115kV transformer ID 3 Tesla D 230kV Capacitors	6.0	6.0	None	None[1]
CatC_05	3Ø Bus Fault at Tesla 230kV Bus Section 1E results in loss of Tesla E – Newark D 230kV line Tesla E – Eight Mile 230kV line Tesla E – Weber 230kV line	6.0	6.0	None	None
CatC_06	3Ø Bus Fault at Pittsburg 230kV Bus Section 1D results in loss of Pittsburg D – Tassajara 230kV line Pittsburg D 230/115kV transformer ID 13 Pittsburg VSC 230/181kV transformer (no change made at Potrero)	6.0	6.0	None	None
CatC_06_v2	3Ø Bus Fault at Pittsburg 230kV Bus Section 1D results in loss of Pittsburg D – Tassajara 230kV line Pittsburg D 230/115kV transformer ID 13 Pittsburg VSC 230/181kV transformer Potrero VSC 115/181kV transformer	6.0	6.0	None	None
CatC_07	3Ø Bus Fault at Moraga 230kV Bus Section 2 Moraga – RossTap2 230kV line Moraga – Bahia 230kV line Moraga – Castro Valley 230kV line Moraga 230/115kV transformer ID 1 Moraga 230/115kV transformer ID 2	6.0	6.0	None	None

Table 7-35 Case 3 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_08	SLG Fault at MossLanding on MossLanding – Metcalf 230kV line CB #XXX fails at MossLanding and results in loss of MossLanding – Duke ML 230kV line (radial line to plant) MossLanding 230/115kV transformer ID 1 MossLanding 230/115kV transformer ID 8	15.0	6.0	None	None
CatC_09	SLG Fault at Eastshore on Eastshore – San Mateo 230kV line CB #242 fails at Eastshore and results in loss of Pittsburg – San Mateo 230kV line	15.0	6.0	None	None
CatC_10	SLG Fault at Newark on Newark – Ravenswood 230kV line CB #610 fails at Newark Bus Section 1D and results in loss of Newark D – Las Positas 230kV line Newark D – Tesla E 230kV line Newark D/7M 230/13.2kV transformer	15.0	6.0	None	None
CatC_11	SLG Fault at Metcalf on Metcalf – Vasona 230kV line CB #212 fails at Metcalf Bus Section 1D and results in loss of Metcalf 230kV Capacitors Metcalf 230/115kV transformer ID #2	15.0	6.0	None	None
CatC_12	SLG Fault at Tesla on Tesla – ADCC – Newark 230kV line ckt 2 CB #XXX fails at Tesla Bus Section C and results in loss of Tesla – Flowind – Pittsburg 230kV line	15.0	6.0	None	None
CatC_13	SLG Fault at Tesla on Tesla – Tracy Pump 230kV line ID 2 CB #XXX fails at Tesla Bus Section 2D and results in loss of Tesla D – Altamont Midway 230kV line Altamont Midway – Delta Pump 230kV line Tesla D 230/115kV transformer ID 3 Tesla D 230kV Capacitors	15.0	6.0	None	None
CatC_14	SLG Fault at Tesla on Tesla – Newark 230kV line CB #XXX fails at Tesla Bus Section 1E and results in loss of Tesla E – Eight Mile 230kV line Tesla E – Weber 230kV line	15.0	6.0	None	None

Table 7-35 Case 3 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_15	SLG Fault at Pittsburg on Pittsburg – Tassajara 230kV line CB #432 fails at Pittsburg Bus Section 1D and results in loss of Pittsburg D 230/115kV transformer ID 13 Pittsburg VSC 230/181kV transformer Pittsburg VSC terminal (represented by a generator) (no changes made at Potrero)	15.0	6.0	None	None
CatC_16	SLG Fault at Moraga on Moraga – Bahia 230kV line CB #222 fails at Moraga Bus Section 2 and results in loss of Moraga – RossTap2 230kV line Moraga – Castro Valley 230kV line Moraga 230/115kV transformer ID 1 Moraga 230/115kV transformer ID 2	15.0	6.0	None	None
CatC_17	Mechanical Failure at Delta Energy Center (No Fault)	N/A	N/A	None	None
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[2]
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[2]
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[2]
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[2]
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	4.0	4.0	None	None
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	N/A	N/A	None	None[3]
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	4.0	4.0	None	None[4]

Table 7-35 Case 3 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	4.0	4.0	None	None[4]
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	4.0	4.0	None	None
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	4.0	4.0	None	None[4]
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Vaca Dixon 500kV line	4.0	4.0	None	None[4]
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	N/A	N/A	None	None
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	12.0	12.0	None	None
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Vaca Dixon 500kV line	12.0	12.0	None	None
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	12.0	12.0	None	None
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	12.0	12.0	None	None
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	12.0	12.0	None	None

Table 7-35 Case 3 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	12.0	12.0	None	None
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	12.0	12.0	None	None
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None

1. Generator at bus Shiloh (#32176) and bus Shilo (#32177) tripped on under-voltage at t = 1.0958 second.
2. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
3. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
   GEWTG trip due to voltage violation of dV = 0.1500 for unit 1 at bus 47326 [KLON W12] 34.50
   GEWTG trip due to voltage violation of dV = 0.1500 for unit 3 at bus 47323 [KLON W3] 34.50
   GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47829 [GDNOE W1] 34.50
4. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
   GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47829 [GDNOE W1] 34.50

7.7 Case 1 – 2015 Fault Simulations

All fault simulations performed included the recommended projects that were developed based on the results of the steady state N-1, L-2, and G-1 + L-1.

Table 7-36 Case 1 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatB_01	3Ø Fault at Tesla E on Tesla – Newark 230kV line	6.0	6.0	None	None
CatB_02	3Ø Fault at Tesla E on Tesla – Ravenswood 230kV line	6.0	6.0	None	None
CatB_03	3Ø Fault at Tesla D on Tesla 230115kV transformer ID 3	6.0	6.0	None	None[1]
CatB_04	3Ø Fault at Moss Landing on Moss Landing – Metcalf 230kV line	6.0	6.0	None	None
CatB_05	3Ø Fault at Tesla C on Tesla – ADCC – Newark 230kV line ID 2	6.0	6.0	None	None
CatB_06	3Ø Fault at Eastshore on Eastshore – Pittsburg 230kV line	6.0	6.0	None	None
CatC_01	3Ø Bus Fault at Metcalf 230kV Bus Section 1D results in loss of Metcalf 230kV Capacitors Metcalf 230/115kV transformer ID #2 Metcalf – Vasona 230kV line	6.0	6.0	None	None
CatC_02	3Ø Bus Fault at Newark 230kV Bus Section 1D results in loss of Newark D – Ravenswood 230kV line Newark D – Las Positas 230kV line Newark D – Tesla E 230kV line Newark D/7M 230/13.2kV transformer	6.0	6.0	None	None
CatC_03	3Ø Bus Fault at San Mateo 230kV Bus Section 1E results in loss of Martin C 115kV Capacitors San Mateo – Ravenswood 230kV line	6.0	6.0	None	None

Table 7-36 Case 1 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_04	3Ø Bus Fault at Tesla 230kV Bus Section 2D results in loss of Tesla D – Altamont Midway 230kV line Altamont Midway – Delta Pump 230kV line Tesla D – Tracy Pump 230kV line ID 2 Tesla D 230/115kV transformer ID 3 Tesla D 230kV Capacitors	6.0	6.0	None	None[1]
CatC_05	3Ø Bus Fault at Tesla 230kV Bus Section 1E results in loss of Tesla E – Newark D 230kV line Tesla E – Eight Mile 230kV line Tesla E – Weber 230kV line	6.0	6.0	None	None
CatC_06	3Ø Bus Fault at Pittsburg 230kV Bus Section 1D results in loss of Pittsburg D – Tassajara 230kV line Pittsburg D 230/115kV transformer ID 13 Pittsburg VSC 230/181kV transformer (no change made at Potrero)	6.0	6.0	None	None
CatC_07	3Ø Bus Fault at Moraga 230kV Bus Section 2 Moraga – RossTap2 230kV line Moraga – Bahia 230kV line Moraga – Castro Valley 230kV line Moraga 230/115kV transformer ID 1 Moraga 230/115kV transformer ID 2	6.0	6.0	None	None
CatC_08	SLG Fault at MossLanding on MossLanding – Metcalf 230kV line CB #XXX fails at MossLanding and results in loss of MossLanding – Duke ML 230kV line (radial line to plant) MossLanding 230/115kV transformer ID 1 MossLanding 230/115kV transformer ID 8	15.0	6.0	None	None
CatC_09	SLG Fault at Eastshore on Eastshore – San Mateo 230kV line CB #242 fails at Eastshore and results in loss of Pittsburg – San Mateo 230kV line	15.0	6.0	None	None

Table 7-36 Case 1 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_10	SLG Fault at Newark on Newark – Ravenswood 230kV line CB #610 fails at Newark Bus Section 1D and results in loss of Newark D – Las Positas 230kV line Newark D – Tesla E 230kV line Newark D/7M 230/13.2kV transformer	15.0	6.0	None	None
CatC_11	SLG Fault at Metcalf on Metcalf – Vasona 230kV line CB #212 fails at Metcalf Bus Section 1D and results in loss of Metcalf 230kV Capacitors Metcalf 230/115kV transformer ID #2	15.0	6.0	None	None
CatC_12	SLG Fault at Tesla on Tesla – ADCC – Newark 230kV line ckt 2 CB #XXX fails at Tesla Bus Section C and results in loss of Tesla – Flowind – Pittsburg 230kV line	15.0	6.0	None	None
CatC_13	SLG Fault at Tesla on Tesla – Tracy Pump 230kV line ID 2 CB #XXX fails at Tesla Bus Section 2D and results in loss of Tesla D – Altamont Midway 230kV line Altamont Midway – Delta Pump 230kV line Tesla D 230/115kV transformer ID 3 Tesla D 230kV Capacitors	15.0	6.0	None	None
CatC_14	SLG Fault at Tesla on Tesla – Newark 230kV line CB #XXX fails at Tesla Bus Section 1E and results in loss of Tesla E – Eight Mile 230kV line Tesla E – Weber 230kV line	15.0	6.0	None	None
CatC_15	SLG Fault at Pittsburg on Pittsburg – Tassajara 230kV line CB #432 fails at Pittsburg Bus Section 1D and results in loss of Pittsburg D 230/115kV transformer ID 13 Pittsburg VSC 230/181kV transformer Pittsburg VSC terminal (represented by a generator) (no changes made at Potrero)	15.0	6.0	None	None

Table 7-36 Case 1 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_16	SLG Fault at Moraga on Moraga – Bahia 230kV line CB #222 fails at Moraga Bus Section 2 and results in loss of Moraga – RossTap2 230kV line Moraga – Castro Valley 230kV line Moraga 230/115kV transformer ID 1 Moraga 230/115kV transformer ID 2	15.0	6.0	None	None
CatC_17	Mechanical Failure at Delta Energy Center (No Fault)	N/A	N/A	None	None
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[2]
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[2]
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[2]
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[2]
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	4.0	4.0	None	None
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	N/A	N/A	None	None[3]
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	4.0	4.0	None	None[4]
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	4.0	4.0	None	None[4]
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	4.0	4.0	None	None

Table 7-36 Case 1 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	4.0	4.0	None	None[4]
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Vaca Dixon 500kV line	4.0	4.0	None	None[4]
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	N/A	N/A	None	None
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	12.0	12.0	None	None
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Vaca Dixon 500kV line	12.0	12.0	None	None
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	12.0	12.0	None	None
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	12.0	12.0	None	None
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	12.0	12.0	None	None
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	12.0	12.0	None	None
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	12.0	12.0	None	None

Table 7-36 Case 1 – 2015: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None

1. Generator at bus Shiloh (#32176) and bus Shilo (#32177) tripped on Under-voltage at t = 1.0958 second.
2. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
3. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
   GEWTG trip due to voltage violation of dV = 0.1500 for unit 1 at bus 47326 [KLON W12] 34.50
   GEWTG trip due to voltage violation of dV = 0.1500 for unit 3 at bus 47323 [KLON W3] 34.50
   GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47829 [GDNOE W1] 34.50
4. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
   GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47829 [GDNOE W1] 34.50

7.8 Case 4 – 2020 Fault Simulations

All fault simulations performed included the recommended projects that were developed based on the results of the steady state N-1, L-2, and G-1 + L-1.

Table 7-37 Case 4 – 2020: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatB_01	3Ø Fault at Tesla E on Tesla – Newark 230kV line	6.0	6.0	None	None
CatB_02	3Ø Fault at Tesla E on Tesla – Ravenswood 230kV line	6.0	6.0	None	None
CatB_03	3Ø Fault at Tesla D on Tesla 230115kV transformer ID 3	6.0	6.0	None	None[10]
CatB_04	3Ø Fault at Moss Landing on Moss Landing – Metcalf 230kV line	6.0	6.0	None	None
CatB_05	3Ø Fault at Tesla C on Tesla – ADCC – Newark 230kV line ID 2	6.0	6.0	None	None
CatB_06	3Ø Fault at Eastshore on Eastshore – Pittsburg 230kV line	6.0	6.0	None	None
CatC_01	3Ø Bus Fault at Metcalf 230kV Bus Section 1D results in loss of Metcalf 230kV Capacitors Metcalf 230/115kV transformer ID #2 Metcalf – Vasona 230kV line	6.0	6.0	None	None
CatC_02	3Ø Bus Fault at Newark 230kV Bus Section 1D results in loss of Newark D – Ravenswood 230kV line Newark D – Las Positas 230kV line Newark D – Tesla E 230kV line Newark D/7M 230/13.2kV transformer	6.0	6.0	None	None
CatC_03	3Ø Bus Fault at San Mateo 230kV Bus Section 1E results in loss of Martin C 115kV Capacitors San Mateo – Ravenswood 230kV line	6.0	6.0	None	None

Table 7-37 Case 4 – 2020: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_04	3Ø Bus Fault at Tesla 230kV Bus Section 2D results in loss of Tesla D – Altamont Midway 230kV line Altamont Midway – Delta Pump 230kV line Tesla D – Tracy Pump 230kV line ID 2 Tesla D 230/115kV transformer ID 3 Tesla D 230kV Capacitors	6.0	6.0	None	None[10]
CatC_05	3Ø Bus Fault at Tesla 230kV Bus Section 1E results in loss of Tesla E – Newark D 230kV line Tesla E – Eight Mile 230kV line Tesla E – Weber 230kV line	6.0	6.0	None	None
CatC_06	3Ø Bus Fault at Pittsburg 230kV Bus Section 1D results in loss of Pittsburg D – Tassajara 230kV line Pittsburg D 230/115kV transformer ID 13 Pittsburg VSC 230/181kV transformer (no change made at Potrero)	6.0	6.0	None	None
CatC_07	3Ø Bus Fault at Moraga 230kV Bus Section 2 Moraga – RossTap2 230kV line Moraga – Bahia 230kV line Moraga – Castro Valley 230kV line Moraga 230/115kV transformer ID 1 Moraga 230/115kV transformer ID 2	6.0	6.0	None	None
CatC_08[1]	SLG Fault at MossLanding on MossLanding – Metcalf 230kV line CB #XXX fails at MossLanding and results in loss of MossLanding – Duke ML 230kV line (radial line to plant) MossLanding 230/115kV transformer ID 1 MossLanding 230/115kV transformer ID 8	15.0	6.0	None	None
CatC_09[2]	SLG Fault at Eastshore on Eastshore – San Mateo 230kV line CB #242 fails at Eastshore and results in loss of Pittsburg – San Mateo 230kV line	15.0	6.0	None	None

Table 7-37 Case 4 – 2020: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_10[3]	SLG Fault at Newark on Newark – Ravenswood 230kV line CB #610 fails at Newark Bus Section 1D and results in loss of Newark D – Las Positas 230kV line Newark D – Tesla E 230kV line Newark D/7M 230/13.2kV transformer	15.0	6.0	None	None
CatC_11[4]	SLG Fault at Metcalf on Metcalf – Vasona 230kV line CB #212 fails at Metcalf Bus Section 1D and results in loss of Metcalf 230kV Capacitors Metcalf 230/115kV transformer ID #2	15.0	6.0	None	None
CatC_12[5]	SLG Fault at Tesla on Tesla – ADCC – Newark 230kV line ckt 2 CB #XXX fails at Tesla Bus Section C and results in loss of Tesla – Flowind – Pittsburg 230kV line	15.0	6.0	None	None
CatC_13[6]	SLG Fault at Tesla on Tesla – Tracy Pump 230kV line ID 2 CB #XXX fails at Tesla Bus Section 2D and results in loss of Tesla D – Altamont Midway 230kV line Altamont Midway – Delta Pump 230kV line Tesla D 230/115kV transformer ID 3 Tesla D 230kV Capacitors	15.0	6.0	None	None
CatC_14[7]	SLG Fault at Tesla on Tesla – Newark 230kV line CB #XXX fails at Tesla Bus Section 1E and results in loss of Tesla E – Eight Mile 230kV line Tesla E – Weber 230kV line	15.0	6.0	None	None
CatC_15[8]	SLG Fault at Pittsburg on Pittsburg – Tassajara 230kV line CB #432 fails at Pittsburg Bus Section 1D and results in loss of Pittsburg D 230/115kV transformer ID 13 Pittsburg VSC 230/181kV transformer Pittsburg VSC terminal (represented by a generator) (no changes made at Potrero)	15.0	6.0	None	None

Table 7-37 Case 4 – 2020: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
CatC_16[9]	SLG Fault at Moraga on Moraga – Bahia 230kV line CB #222 fails at Moraga Bus Section 2 and results in loss of Moraga – RossTap2 230kV line Moraga – Castro Valley 230kV line Moraga 230/115kV transformer ID 1 Moraga 230/115kV transformer ID 2	15.0	6.0	None	None
CatC_17[10]	Mechanical Failure at Delta Energy Center (No Fault)	N/A	N/A	None	None
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[11]
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[11]
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Collinsville 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[11]
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[11]
B2-new	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None[13]
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	4.0	4.0	None	None
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	N/A	N/A	None	None[12]
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	4.0	4.0	None	None[12]
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	4.0	4.0	None	None[11]

Table 7-37 Case 4 – 2020: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	4.0	4.0	None	None
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	4.0	4.0	None	None[12]
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Collinsville 500kV line	4.0	4.0	None	None[11]
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	N/A	N/A	None	None
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	12.0	12.0	None	None
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Collinsville 500kV line	12.0	12.0	None	None
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	12.0	12.0	None	None
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	12.0	12.0	None	None
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	12.0	12.0	None	None
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	12.0	12.0	None	None

Table 7-37 Case 4 – 2020: Fault Simulation Results

Fault ID	Description	Clearing Time (cycles)		Angular Instabilities	Transient Voltage Recovery
		Near End	Far End		
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	12.0	12.0	None	None
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	4.0	4.0	None	None

0. All 3Ø Fault Impedances: r = 0.0 p.u., x = 0.0 p.u.
1. CatC_08: SLG Fault Impedance: r = 1.192 p.u., x = 12.942 p.u.
2. CatC_09: SLG Fault Impedance: r = 0.109 p.u., x = 2.146 p.u.
3. CatC_10: SLG Fault Impedance: r = 0.968 p.u., x = 8.493 p.u.
4. CatC_11: SLG Fault Impedance: r = 0.042 p.u., x = 2.412 p.u.
5. CatC_12: SLG Fault Impedance: r = 0.380 p.u., x = 3.832 p.u.
6. CatC_13: SLG Fault Impedance: r = 0.0465 p.u., x = 1.846 p.u.
7. CatC_14: SLG Fault Impedance: r = 0.155 p.u., x = 3.601 p.u.
8. CatC_15: SLG Fault Impedance: r = 0.177 p.u., x = 2.841 p.u.
9. CatC_16: SLG Fault Impedance: r = 0.142 p.u., x = 2.432 p.u.
10. Generator at Shilo 34.5kV bus (#32176) tripped on Under-voltage at t = 1.0917 second.
    Generator at Shiloh 34.5kV bus (#32177) tripped on Under-voltage at t = 1.0958 second.
11. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
12. GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47846 [7MILE W1] 34.50
    GEWTG trip due to voltage violation of dV = 0.1500 for unit Z1 at bus 47829 [GDNOE W1] 34.50
13. Generator at High Wind 34.5kV bus (#32171) tripped on Under-voltage at t = 1.5875 second.
    Generator at Shilo 34.5kV bus (#32176) tripped on Under-voltage at t = 1.5917 second.
    Generator at Shiloh 34.5kV bus (#32177) tripped on Under-voltage at t = 1.6084 second.

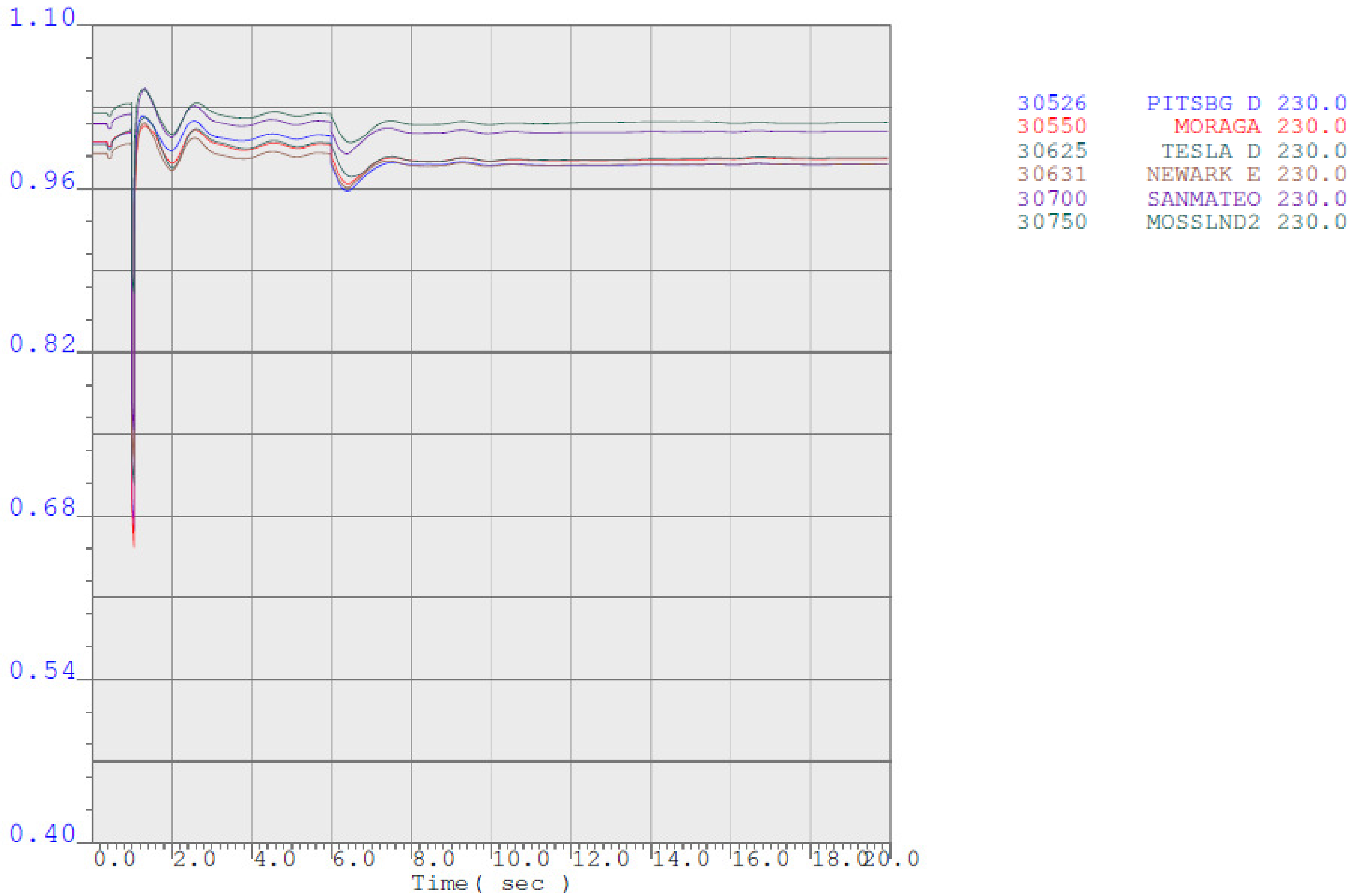

Figure 7-1 Case 4 – 2020: Transient Voltage Recovery Curves of Selected 230kV Buses Local to GBA with Fault #B2-22

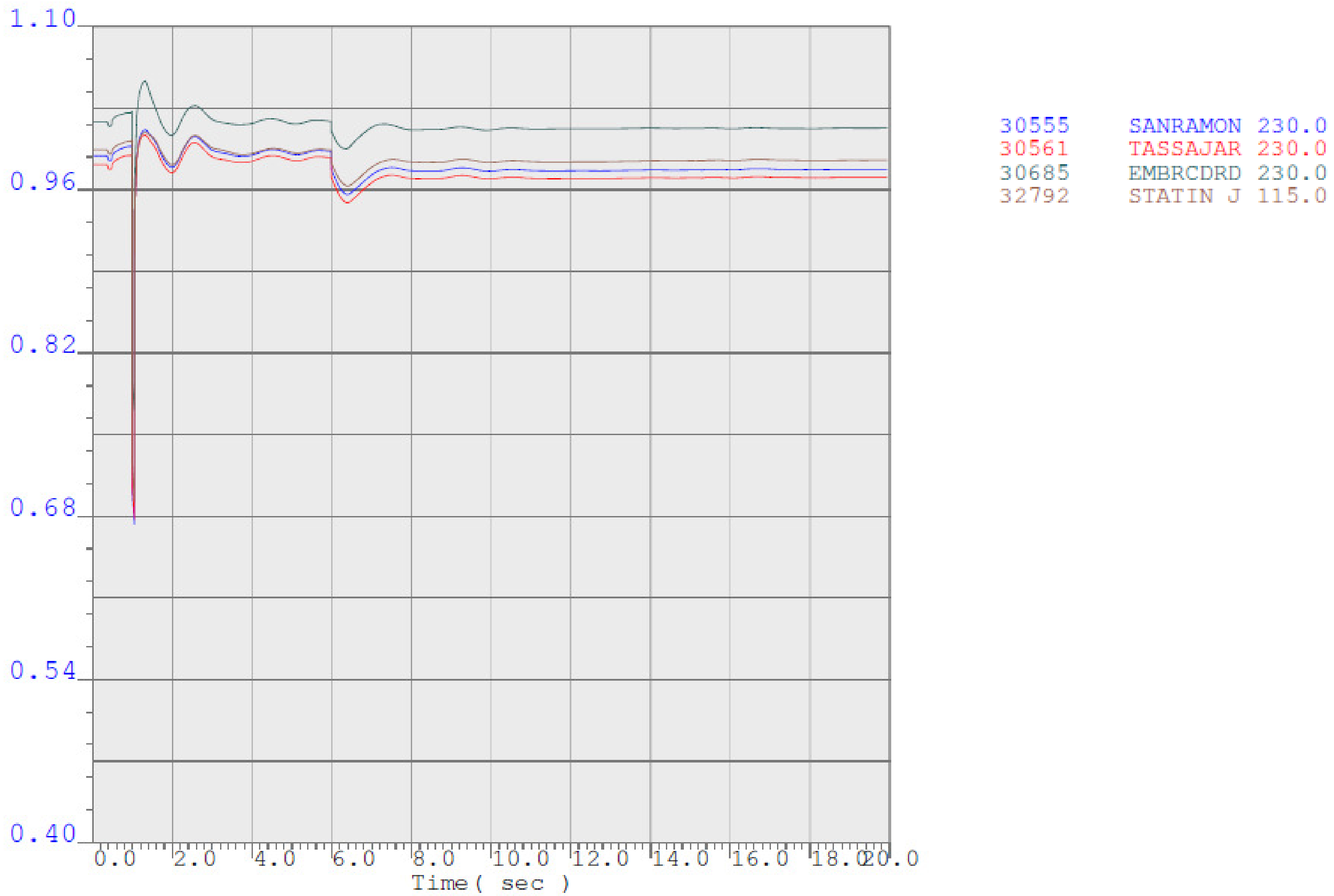

Figure 7-2 Case 4 – 2020: Transient Voltage Recovery Curves of Selected Load Buses Local to GBA with Fault #B2-22

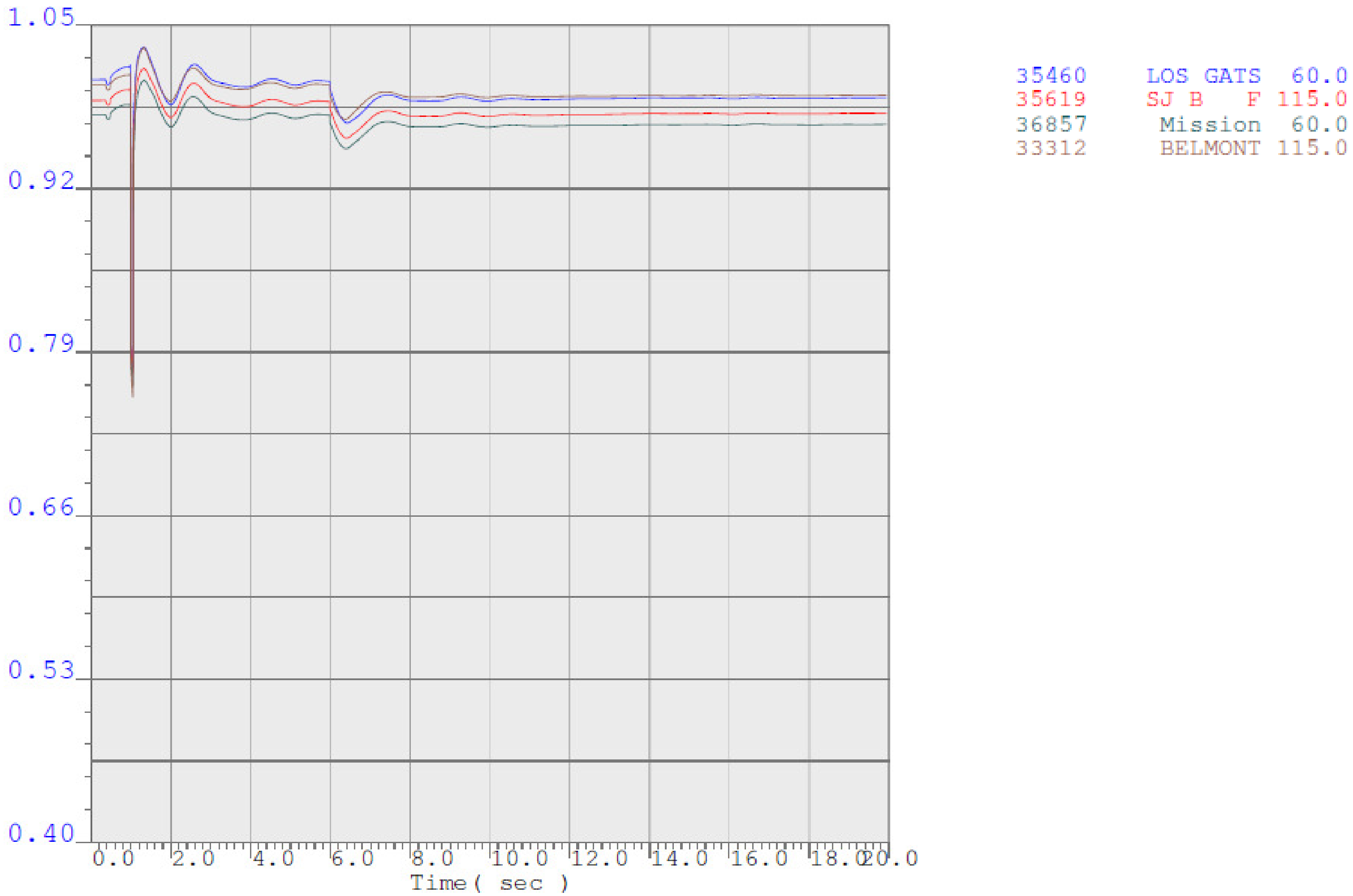

Figure 7-3 Case 4 – 2020: Transient Voltage Recovery Curves of Selected Load Buses Local to GBA with Fault #B2-22

7.9 Case 4 – 2015 Governor Power Flow Results

Table 7-38 Case 4 – 2015: Voltage Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus[1]	Vbase (p.u.)	Vcont (p.u.)	Area
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-new	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	None			
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	None			
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	None			
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	None			
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	None			
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	None			
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	None			

Table 7-38 Case 4 – 2015: Voltage Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus[1]	Vbase (p.u.)	Vcont (p.u.)	Area
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Vaca Dixon 500kV line	None			
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	None			
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	None			
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Vaca Dixon 500kV line	None			
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	None			
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	None			
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	None			
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	None			
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	None			
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	None			

1. Voltage violations outside the Greater Bay Area are not identified.

Table 7-39 Case 4 – 2015: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.21	1.08	PG&E
		Borden – Gregg 230kV	1.38	1.19	PG&E
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.21	1.31	PG&E
		Metcalf – Moss Landing 2 230kV	0.87	1.28	PG&E
		Metcalf – Moss Landing 1 230kV	0.87	1.28	PG&E
		Borden – Gregg 230kV	1.38	1.26	PG&E
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	CP-V Colusa – Cortina 230kV	1.02	0.98	PG&E
		Westley – Los Banos 230kV	1.21	1.16	PG&E
		Borden – Gregg 230kV	1.38	1.21	PG&E
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	CP-V Colusa – Cortina 230kV	1.02	0.99	PG&E
		Westley – Los Banos 230kV	1.21	1.15	PG&E
		Borden – Gregg 230kV	1.38	1.21	PG&E
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	CP-V Colusa – Cortina 230kV	1.02	1.10	PG&E
		Westley – Los Banos 230kV	1.21	1.20	PG&E
		Borden – Gregg 230kV	1.38	1.22	PG&E
B2-new	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.21	1.15	PG&E
		Borden – Gregg 230kV	1.38	1.21	PG&E
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	Westley – Los Banos 230kV	1.21	1.06	PG&E
		Borden – Gregg 230kV	1.38	1.17	PG&E
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	Borden – Gregg 230kV	1.38	1.08	PG&E
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	CP-V Colusa – Cortina 230kV	1.02	1.10	PG&E
		Westley – Los Banos 230kV	1.21	1.25	PG&E
		Borden – Gregg 230kV	1.38	1.24	PG&E
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	MDN500 – ING500 500kV	0.91	1.01	BCHydro
		CP-V Colusa – Cortina 230kV	1.02	1.10	PG&E
		Westley – Los Banos 230kV	1.21	1.28	PG&E

Table 7-39 Case 4 – 2015: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
		Borden – Gregg 230kV	1.38	1.23	PG&E
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	Warnreville – Wilson 230kV	0.74	0.98	PG&E
		Westley – Los Banos 230kV	1.21	1.79	PG&E
		Metcalf – Moss Landing 2 230kV	0.87	0.99	PG&E
		Metcalf – Moss Landing 1 230kV	0.87	0.99	PG&E
		Storey 1 – Gregg 230kV	0.97	1.05	PG&E
		Borden – Gregg 230kV	1.38	1.37	PG&E
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	Westley – Los Banos 230kV	1.21	1.24	PG&E
		Borden – Gregg 230kV	1.38	1.24	PG&E
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Vaca Dixon 500kV line	MDN500 – ING500 500kV	0.91	1.01	BCHydro
		Westley – Los Banos 230kV	1.21	1.27	PG&E
		Borden – Gregg 230kV	1.38	1.25	PG&E
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	MDN500 – ING500 500kV	0.91	0.99	BCHydro
		Borden – Gregg 230kV	1.38	1.10	PG&E
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	Westley – Los Banos 230kV	1.21	1.13	PG&E
		Borden – Gregg 230kV	1.38	1.20	PG&E
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Vaca Dixon 500kV line	Borden – Gregg 230kV	1.38	1.23	PG&E
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	Table Mt – Vaca Dixon 500kV	0.83	1.08	PG&E
		Westley – Los Banos 230kV	1.21	1.07	PG&E
		Borden – Gregg 230kV	1.38	1.00	PG&E
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	Westley – Los Banos 230kV	1.21	1.16	PG&E
		Borden – Gregg 230kV	1.38	1.20	PG&E
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line	Westley – Los Banos 230kV	1.21	1.20	PG&E
		Metcalf – Moss Landing 2 230kV	0.87	1.20	PG&E

Table 7-39 Case 4 – 2015: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
	Metcalf 500/230kV transformer ID 11	Metcalf – Moss Landing 1 230kV	0.87	1.20	PG&E
		Borden – Gregg 230kV	1.38	1.21	PG&E
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	CP-V Colusa – Cortina 230kV	1.02	1.03	PG&E
		Westley – Los Banos 230kV	1.21	1.10	PG&E
		Borden – Gregg 230kV	1.38	1.18	PG&E
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	CP-V Colusa – Cortina 230kV	1.02	1.09	PG&E
		Westley – Los Banos 230kV	1.21	1.10	PG&E
		Borden – Gregg 230kV	1.38	1.19	PG&E
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.21	1.39	PG&E
		Borden – Gregg 230kV	1.38	1.27	PG&E

7.10 Case 3 – 2015 Governor Power Flow Results

Table 7-40 Case 3 – 2015: Voltage Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus[1]	Vbase (p.u.)	Vcont (p.u.)	Area
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	Table Mt. 1M 500kV	0.999	0.944	PG&E
B2-new	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	None			
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	None			
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	None			
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	None			
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	None			
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	Wilson 230kV	0.979	0.939	PG&E
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	None			

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Table 7-40 Case 3 – 2015: Voltage Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus[1]	Vbase (p.u.)	Vcont (p.u.)	Area
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Vaca Dixon 500kV line	None			
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	None			
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	None			
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Vaca Dixon 500kV line	None			
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	None			
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	None			
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	None			
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	None			
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	None			
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	None			

1. Voltage violations outside the Greater Bay Area are not identified.

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Table 7-41 Case 3 – 2015: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.27	1.12	PG&E
		Borden – Gregg 230kV	1.41	1.22	PG&E
		Templeton – Morro Bay 230kV	1.10	0.97	PG&E
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.27	1.35	PG&E
		Borden – Gregg 230kV	1.41	1.28	PG&E
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	CP-V Colusa – Cortina 230kV	1.01	0.98	PG&E
		Westley – Los Banos 230kV	1.27	1.22	PG&E
		Borden – Gregg 230kV	1.41	1.24	PG&E
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	CP-V Colusa – Cortina 230kV	1.01	0.99	PG&E
		Westley – Los Banos 230kV	1.27	1.21	PG&E
		Borden – Gregg 230kV	1.41	1.25	PG&E
		Tracy 500/230kV MP1[1] (As viewed in .drw file)	-	1.02	PG&E
		Tracy 500/230kV MP2[1] (As viewed in .drw file)	-	1.02	PG&E
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	Table Mt – Tesla 500kV	0.55	0.98	PG&E
		CP-V Colusa – Cortina 230kV	1.01	1.11	PG&E
		Westley – Los Banos 230kV	1.27	1.26	PG&E
		Borden – Gregg 230kV	1.41	1.26	PG&E
		Templeton – Morro Bay 230kV	1.10	0.98	PG&E
		Gleaf TP – Rio Oso 115kV	1.00	1.00	PG&E
B2-new	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.27	1.21	PG&E
		Borden – Gregg 230kV	1.41	1.24	PG&E
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	Westley – Los Banos 230kV	1.27	1.10	PG&E
		Borden – Gregg 230kV	1.41	1.20	PG&E
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	MDN500 – ING500 500kV	0.91	0.98	BCHydro
		Borden – Gregg 230kV	1.41	1.09	PG&E

Table 7-41 Case 3 – 2015: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	MDN500 – ING500 500kV	0.91	0.97	BCHydro
		CP-V Colusa – Cortina 230kV	1.01	1.10	PG&E
		Westley – Los Banos 230kV	1.27	1.31	PG&E
		Borden – Gregg 230kV	1.41	1.28	PG&E
		Templeton – Morro Bay 230kV	1.10	1.00	PG&E
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	MDN500 – ING500 500kV	0.91	1.01	BCHydro
		CP-V Colusa – Cortina 230kV	1.01	1.11	PG&E
		Westley – Los Banos 230kV	1.27	1.35	PG&E
		Borden – Gregg 230kV	1.41	1.28	PG&E
		Templeton – Morro Bay 230kV	1.10	1.01	PG&E
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	Moss Landing – Los Banos 500kV	0.71	1.06	PG&E
		Los Banos 500/230kV Xfmr (As viewed in .drw file)	-	1.03	PG&E
		Warnerville – Wilson 230kV	0.79	1.10	PG&E
		Westley – Los Banos 230kV	1.27	2.01	PG&E
		Storey 1 – Gregg 230kV	1.01	1.14	PG&E
		Borden – Gregg 230kV	1.41	1.46	PG&E
		Templeton – Morro Bay 230kV	1.10	0.99	PG&E
		Le Grand – Wilson A 115kV	0.98	1.08	PG&E
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	MDN500 – ING500 500kV	0.91	0.97	BCHydro
		Westley – Los Banos 230kV	1.27	1.30	PG&E
		Borden – Gregg 230kV	1.41	1.27	PG&E
		Templeton – Morro Bay 230kV	1.10	0.99	PG&E
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Vaca Dixon 500kV line	MDN500 – ING500 500kV	0.91	1.01	BCHydro
		Westley – Los Banos 230kV	1.27	1.33	PG&E
		Borden – Gregg 230kV	1.41	1.29	PG&E

Table 7-41 Case 3 – 2015: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
		Templeton – Morro Bay 230kV	1.10	1.00	PG&E
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	Borden – Gregg 230kV	1.41	1.13	PG&E
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	Westley – Los Banos 230kV	1.27	1.17	PG&E
		Borden – Gregg 230kV	1.41	1.23	PG&E
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Vaca Dixon 500kV line	Westley – Los Banos 230kV	1.27	1.37	PG&E
		Borden – Gregg 230kV	1.41	1.28	PG&E
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	Table Mt – Vaca Dixon 500kV	0.84	1.09	PG&E
		Westley – Los Banos 230kV	1.27	1.12	PG&E
		Borden – Gregg 230kV	1.41	1.21	PG&E
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	Westley – Los Banos 230kV	1.27	1.03	PG&E
		Borden – Gregg 230kV	1.41	1.18	PG&E
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	Westley – Los Banos 230kV	1.27	1.23	PG&E
		Borden – Gregg 230kV	1.41	1.23	PG&E
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	CP-V Colusa – Cortina 230kV	1.01	1.03	PG&E
		Westley – Los Banos 230kV	1.27	1.15	PG&E
		Borden – Gregg 230kV	1.41	1.21	PG&E
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	CP-V Colusa – Cortina 230kV	1.01	1.08	PG&E
		Westley – Los Banos 230kV	1.27	1.15	PG&E
		Borden – Gregg 230kV	1.41	1.22	PG&E
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.27	1.50	PG&E
		Borden – Gregg 230kV	1.41	1.32	PG&E
		Storey 1 – Gregg 230kV	1.01	0.99	PG&E
		Templeton – Morro Bay 230kV	1.10	0.98	PG&E

1. This overload is eliminated by switching out two steps of the 4 x 150 MVAR capacitor at the Tracy 500kV bus.

7.11 Case 1 – 2015 Governor Power Flow Results

Table 7-42 Case 1 – 2015: Voltage Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus[1]	Vbase (p.u.)	Vcont (p.u.)	Area
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	***** Non-Converged Solution ***** The North to South flow on COI is reduced from 4,450 MW to 4,370 MW to achieve a solution and the following voltage violations None			
B2-new	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	None			
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	None			
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	None			
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	None			
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	None			
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	None			

Table 7-42 Case 1 – 2015: Voltage Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus[1]	Vbase (p.u.)	Vcont (p.u.)	Area
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	None			
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Vaca Dixon 500kV line	None			
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	None			
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Vaca Dixon 500kV line	None			
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	None			
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	None			
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	None			
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	None			
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	None			
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	None			

1. Voltage violations outside the Greater Bay Area are not identified.

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Table 7-43 Case 1 – 2015: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	CP-V Colusa – Cortina 230kV	1.03	1.00	PG&E
		Westley – Los Banos 230kV	1.26	1.11	PG&E
		Borden – Gregg 230kV	1.39	1.21	PG&E
		Moraga – Claremont 115kV ckt 1	0.99	1.04	PG&E
		Moraga – Claremont 115kV ckt 2	0.99	1.04	PG&E
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	CP-V Colusa – Cortina 230kV	1.03	0.99	PG&E
		Westley – Los Banos 230kV	1.26	1.34	PG&E
		Borden – Gregg 230kV	1.39	1.27	PG&E
		Moraga – Claremont 115kV ckt 1	0.99	1.04	PG&E
		Moraga – Claremont 115kV ckt 2	0.99	1.04	PG&E
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	CP-V Colusa – Cortina 230kV	1.03	1.00	PG&E
		Westley – Los Banos 230kV	1.26	1.22	PG&E
		Borden – Gregg 230kV	1.39	1.23	PG&E
		Moraga – Claremont 115kV ckt 1	0.99	1.04	PG&E
		Moraga – Claremont 115kV ckt 2	0.99	1.04	PG&E
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	CP-V Colusa – Cortina 230kV	1.03	1.01	PG&E
		Westley – Los Banos 230kV	1.26	1.20	PG&E
		Borden – Gregg 230kV	1.39	1.23	PG&E
		Moraga – Claremont 115kV ckt 1	0.99	1.05	PG&E
		Moraga – Claremont 115kV ckt 2	0.99	1.05	PG&E
		Tracy 500/230kV MP1[1] (As viewed in .drw file)	-	1.02	PG&E
		Tracy 500/230kV MP2[1] (As viewed in .drw file)	-	1.02	PG&E
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	***** Non-Converged Solution ***** The North to South flow on COI is reduced from 4,450 MW to 4,370 MW to achieve a solution and the following thermal violations			

Table 7-43 Case 1 – 2015: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
		Table Mt – Tesla 500kV	0.55	0.97	PG&E
		CP-V Colusa – Cortina 230kV	1.02	1.12	PG&E
		Westley – Los Banos 230kV	1.27	1.26	PG&E
		Borden – Gregg 230kV	1.40	1.25	PG&E
		Templeton – Morro Bay 230kV	1.15	1.02	PG&E
		Gleaf TP – Rio Oso 115kV	0.98	0.98	PG&E
		Moraga – Claremont 115kV ckt 1	0.99	1.05	PG&E
		Moraga – Claremont 115kV ckt 2	0.99	1.05	PG&E
B2-new	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.26	1.20	PG&E
		Borden – Gregg 230kV	1.39	1.22	PG&E
		Moraga – Claremont 115kV ckt 1	0.99	1.04	PG&E
		Moraga – Claremont 115kV ckt 2	0.99	1.04	PG&E
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	Westley – Los Banos 230kV	1.26	1.09	PG&E
		Borden – Gregg 230kV	1.39	1.18	PG&E
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	MDN500 – ING500 500kV	0.91	0.98	BCHydro
		Borden – Gregg 230kV	1.39	1.08	PG&E
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	MDN500 – ING500 500kV	0.91	0.97	BCHydro
		Tracy – Tesla 500kV	0.51	0.97	PG&E
		CP-V Colusa – Cortina 230kV	1.03	1.12	PG&E
		Westley – Los Banos 230kV	1.26	1.30	PG&E
		Borden – Gregg 230kV	1.39	1.26	PG&E
		Templeton – Morro Bay 230kV	1.07	0.97	PG&E
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	MDN500 – ING500 500kV	0.91	1.01	BCHydro
		CP-V Colusa – Cortina 230kV	1.03	1.14	PG&E
		Westley – Los Banos 230kV	1.26	1.35	PG&E
		Borden – Gregg 230kV	1.39	1.26	PG&E
		Templeton – Morro Bay 230kV	1.07	0.99	PG&E

Table 7-43 Case 1 – 2015: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	Moss Landing – Los Banos 500kV	0.71	1.06	PG&E
		Los Banos 500/230kV Xfmr (As viewed in .drw file)	-	1.02	PG&E
		Warnerville – Wilson 230kV	0.75	1.07	PG&E
		Westley – Los Banos 230kV	1.26	1.99	PG&E
		Storey 1 – Gregg 230kV	0.99	1.12	PG&E
		Borden – Gregg 230kV	1.39	1.44	PG&E
		Le Grand – Wilson A 115kV	0.96	1.06	PG&E
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	MDN500 – ING500 500kV	0.91	0.97	BCHydro
		Westley – Los Banos 230kV	1.26	1.29	PG&E
		Borden – Gregg 230kV	1.39	1.26	PG&E
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Vaca Dixon 500kV line	MDN500 – ING500 500kV	0.91	1.01	BCHydro
		Westley – Los Banos 230kV	1.26	1.33	PG&E
		Borden – Gregg 230kV	1.39	1.28	PG&E
		Templeton – Morro Bay 230kV	1.07	0.97	PG&E
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	MDN500 – ING500 500kV	0.91	0.99	BCHydro
		Borden – Gregg 230kV	1.39	1.11	PG&E
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	Westley – Los Banos 230kV	1.26	1.15	PG&E
		Borden – Gregg 230kV	1.39	1.20	PG&E
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Vaca Dixon 500kV line	Westley – Los Banos 230kV	1.26	1.36	PG&E
		Borden – Gregg 230kV	1.39	1.26	PG&E
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	Table Mt – Vaca Dixon 500kV	0.85	1.11	PG&E
		CP-V Colusa – Cortina 230kV	1.03	0.98	PG&E
		Westley – Los Banos 230kV	1.26	1.11	PG&E
		Borden – Gregg 230kV	1.39	1.19	PG&E
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of	Westley – Los Banos 230kV	1.26	1.02	PG&E

Table 7-43 Case 1 – 2015: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
	Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	Borden – Gregg 230kV	1.39	1.16	PG&E
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	Westley – Los Banos 230kV	1.26	1.22	PG&E
		Borden – Gregg 230kV	1.39	1.22	PG&E
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	CP-V Colusa – Cortina 230kV	1.03	1.05	PG&E
		Westley – Los Banos 230kV	1.26	1.14	PG&E
		Borden – Gregg 230kV	1.39	1.19	PG&E
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	CP-V Colusa – Cortina 230kV	1.03	1.11	PG&E
		Westley – Los Banos 230kV	1.26	1.14	PG&E
		Borden – Gregg 230kV	1.39	1.20	PG&E
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	CP-V Colusa – Cortina 230kV	1.03	0.98	PG&E
		Westley – Los Banos 230kV	1.26	1.49	PG&E
		Borden – Gregg 230kV	1.39	0.31	PG&E
		Storey 1 – Gregg 230kV	0.99	0.98	PG&E
		Moraga – Claremont 115kV ckt 1	0.99	1.04	PG&E
		Moraga – Claremont 115kV ckt 2	0.99	1.04	PG&E

1. This overload is eliminated by switching out two steps of the 4 x 150 MVAR capacitor at the Tracy 500kV bus.

7.12 Case 4 – 2020 Governor Power Flow Results

Table 7-44 Case 4 – 2020: Voltage Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus[1]	Vbase (p.u.)	Vcont (p.u.)	Area
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Collinsville 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	None			
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	Table Mt. 1M 500kV	0.993	0.945	PG&E
B2-new	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	None			
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	None			
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	None			
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	None			
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	None			
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	Storey 2 230kV	0.966	0.938	PG&E
		Borden 230kV	0.966	0.939	PG&E
		Storey 1 230kV	0.972	0.944	PG&E
		Wilson 230kV	0.975	0.944	PG&E
		Figarden 230kV	0.971	0.945	PG&E
		Ashlan 230kV	0.971	0.945	PG&E

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Table 7-44 Case 4 – 2020: Voltage Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus[1]	Vbase (p.u.)	Vcont (p.u.)	Area
		Figarden Tap2 230kV	0.971	0.945	PG&E
		Gallo 115kV	0.971	0.935	PG&E
		Livingston 115kV	0.975	0.939	PG&E
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1 Malin – Round Mt. 500kV line ID 2	None			
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Collinsville 500kV line	None			
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	None			
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	None			
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Collinsville 500kV line	None			
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	None			
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	None			
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	None			
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	None			
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	None			

Table 7-44 Case 4 – 2020: Voltage Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus[1]	Vbase (p.u.)	Vcont (p.u.)	Area
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	None			

1. Voltage violations outside the Greater Bay Area are not identified.

Table 7-45 Case 4 – 2020: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
B2-20	3Ø Fault at Tesla on Tesla – Metcalf 500kV line plus Mechanical Failure at Delta Energy Center	Borden – Gregg 230kV	1.41	1.21	PG&E
		Westley – Los Banos 230kV	1.28	1.14	PG&E
		Templeton – Morro Bay 230kV	1.20	1.04	PG&E
B2-21	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.28	1.37	PG&E
		Metcalf – Moss Landing 2 230kV	0.91	1.33	PG&E
		Metcalf – Moss Landing 1 230kV	0.91	1.33	PG&E
		Borden – Gregg 230kV	1.41	1.28	PG&E
		Templeton – Morro Bay 230kV	1.20	1.04	PG&E
B2-22	3Ø Fault at Vaca Dixon on Vaca Dixon – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	Borden – Gregg 230kV	1.41	1.23	PG&E
		Westley – Los Banos 230kV	1.28	1.21	PG&E
		Templeton – Morro Bay 230kV	1.20	1.04	PG&E
B2-23	3Ø Fault at Tracy on Tracy – Tesla 500kV line plus Mechanical Failure at Delta Energy Center	Borden – Gregg 230kV	1.41	1.24	PG&E
		Westley – Los Banos 230kV	1.28	1.20	PG&E
		Templeton – Morro Bay 230kV	1.20	1.04	PG&E
		Tracy 500/230kV MP1[1] (As viewed in .drw file)	-	1.00	PG&E
		Tracy 500/230kV MP2[1] (As viewed in .drw file)	-	1.00	PG&E
B2-24	3Ø Fault at Table Mt. on Table Mt. – Vaca Dixon 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.28	1.27	PG&E
		Borden – Gregg 230kV	1.41	1.25	PG&E
		CP-V Colusa – Cortina 230kV	0.99	1.15	PG&E

Table 7-45 Case 4 – 2020: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
		Templeton – Morro Bay 230kV	1.20	1.06	PG&E
B2-new	3Ø Fault at Metcalf on Metcalf – Moss Landing 500kV line plus Mechanical Failure at Delta Energy Center	Borden – Gregg 230kV	1.41	1.23	PG&E
		Westley – Los Banos 230kV	1.28	1.20	PG&E
		Templeton – Morro Bay 230kV	1.20	1.04	PG&E
B3-5	3Ø Fault at Vaca Dixon on Vaca Dixon 500/230kV transformer	Borden – Gregg 230kV	1.41	1.20	PG&E
		Westley – Los Banos 230kV	1.28	1.11	PG&E
		Templeton – Morro Bay 230kV	1.20	1.01	PG&E
B4-1	Loss of Pacific HVDC Intertie (Sylmar – Celilo) (No Fault)	Borden – Gregg 230kV	1.41	1.10	PG&E
C3-1	3Ø Bus Fault at Round Mt. 500kV results in loss of Round Mt. – Table Mt. 500kV line ID 1 Round Mt. – Table Mt. 500kV line ID 2 Round Mt. 500/230kV transformer	Westley – Los Banos 230kV	1.28	1.32	PG&E
		Borden – Gregg 230kV	1.41	1.28	PG&E
		CP-V Colusa – Cortina 230kV	0.99	1.11	PG&E
		Templeton – Morro Bay 230kV	1.20	1.07	PG&E
C3-2	3Ø Bus Fault at Table Mt. 500kV results in loss of Table Mt. – Tesla 500kV line Table Mt. – Vaca Dixon 500kV line	MDN500 – ING500 500kV	0.91	1.01	BC Hydro
		Westley – Los Banos 230kV	1.28	1.37	PG&E
		Borden – Gregg 230kV	1.41	1.28	PG&E
		CP-V Colusa – Cortina 230kV	0.99	1.14	PG&E
		Templeton – Morro Bay 230kV	1.20	1.09	PG&E
C3-3	3Ø Bus Fault at Los Banos 500kV results in loss of Los Banos – Tesla 500kV line Los Banos – Tracy 500kV line	Westley – Los Banos 230kV	1.28	1.99	PG&E
		Borden – Gregg 230kV	1.41	1.44	PG&E
		Storey 1 – Gregg 230kV	1.01	1.12	PG&E
		Warnreville – Wilson 230kV	0.78	1.08	PG&E
		Metcalf – Moss Landing 2 230kV	0.91	1.07	PG&E
		Metcalf – Moss Landing 1 230kV	0.91	1.07	PG&E
		Templeton – Morro Bay 230kV	1.20	1.06	PG&E
C3-8	3Ø Bus Fault at Malin 500kV results in loss of Malin – Round Mt. 500kV line ID 1	Westley – Los Banos 230kV	1.28	1.31	PG&E
		Borden – Gregg 230kV	1.41	1.28	PG&E

Table 7-45 Case 4 – 2020: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
	Malin – Round Mt. 500kV line ID 2	Templeton – Morro Bay 230kV	1.20	1.06	PG&E
C3-9	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Vaca Dixon 500kV line	MDN500 – ING500 500kV	0.91	1.01	BC Hydro
		Westley – Los Banos 230kV	1.28	1.35	PG&E
		Borden – Gregg 230kV	1.41	1.29	PG&E
		Templeton – Morro Bay 230kV	1.20	1.07	PG&E
C3-12	Loss of Both Palo Verde Nuclear Generators (No Fault)	Borden – Gregg 230kV	1.41	1.13	PG&E
C3-new1	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Metcalf 500kV line Tesla E/2M 500/230kV transformer ID 2	Borden – Gregg 230kV	1.41	1.22	PG&E
		Westley – Los Banos 230kV	1.28	1.18	PG&E
		Templeton – Morro Bay 230kV	1.20	1.02	PG&E
C3-a	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Los Banos 500kV line Tesla – Vaca Dixon 500kV line	Westley – Los Banos 230kV	1.28	1.37	PG&E
		Borden – Gregg 230kV	1.41	1.27	PG&E
		Templeton – Morro Bay 230kV	1.20	1.02	PG&E
C3-b	3Ø Bus Fault at Tesla 500kV results in loss of Tesla – Table Mt. 500kV line Tesla – Tracy 500kV line	Table Mt – Vaca Dixon 500kV	0.81	1.03	PG&E
		Borden – Gregg 230kV	1.41	1.20	PG&E
		Westley – Los Banos 230kV	1.28	1.11	PG&E
		Templeton – Morro Bay 230kV	1.20	1.02	PG&E
		Tracy 500/230kV MP1[1] (As viewed in .drw file)	-	1.00	PG&E
		Tracy 500/230kV MP2[1] (As viewed in .drw file)	-	1.00	PG&E
C3-c	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Tesla 500kV line Metcalf 500/230kV transformer ID 13	Borden – Gregg 230kV	1.41	1.19	PG&E
		Westley – Los Banos 230kV	1.28	1.06	PG&E
		Templeton – Morro Bay 230kV	1.20	1.02	PG&E
C3-d	3Ø Bus Fault at Metcalf 500kV results in loss of Metcalf – Moss Landing 500kV line Metcalf 500/230kV transformer ID 11	Westley – Los Banos 230kV	1.28	1.26	PG&E
		Metcalf – Moss Landing 2 230kV	0.91	1.26	PG&E
		Metcalf – Moss Landing 1 230kV	0.91	1.26	PG&E

Table 7-45 Case 4 – 2020: Thermal Violations for Governor Power Flow Simulation

Fault ID	Description	Monitored Bus	BaseFlow (p.u.)	ContFlow (p.u.)	Area
		Borden – Gregg 230kV	1.41	1.24	PG&E
		Westley – Los Banos 230kV	1.28	1.02	PG&E
C3-e	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon – Table Mt. 500kV line Vaca Dixon 500/230/13.8kV transformer ID 11	Borden – Gregg 230kV	1.41	1.21	PG&E
		Westley – Los Banos 230kV	1.28	1.17	PG&E
		CP-V Colusa – Cortina 230kV	0.99	1.06	PG&E
		Templeton – Morro Bay 230kV	1.20	1.03	PG&E
C3-f	3Ø Bus Fault at Vaca Dixon 500kV results in loss of Vaca Dixon 500/230/13.8kV transformer ID 11 Vaca Dixon 500/230/13.8kV transformer ID 12	Borden – Gregg 230kV	1.41	1.21	PG&E
		Westley – Los Banos 230kV	1.28	1.14	PG&E
		CP-V Colusa – Cortina 230kV	0.99	1.02	PG&E
		Templeton – Morro Bay 230kV	1.20	1.02	PG&E
C3-g	3Ø Fault at Tesla on Tesla – Los Banos 500kV line plus Mechanical Failure at Delta Energy Center	Westley – Los Banos 230kV	1.28	1.48	PG&E
		Borden – Gregg 230kV	1.41	1.31	PG&E
		Templeton – Morro Bay 230kV	1.20	1.05	PG&E

1. This overload is eliminated by switching a single step of the 4 x 150 MVAR capacitor at the Tracy 500kV bus.

7.13 Case 4 – 2015 Curves

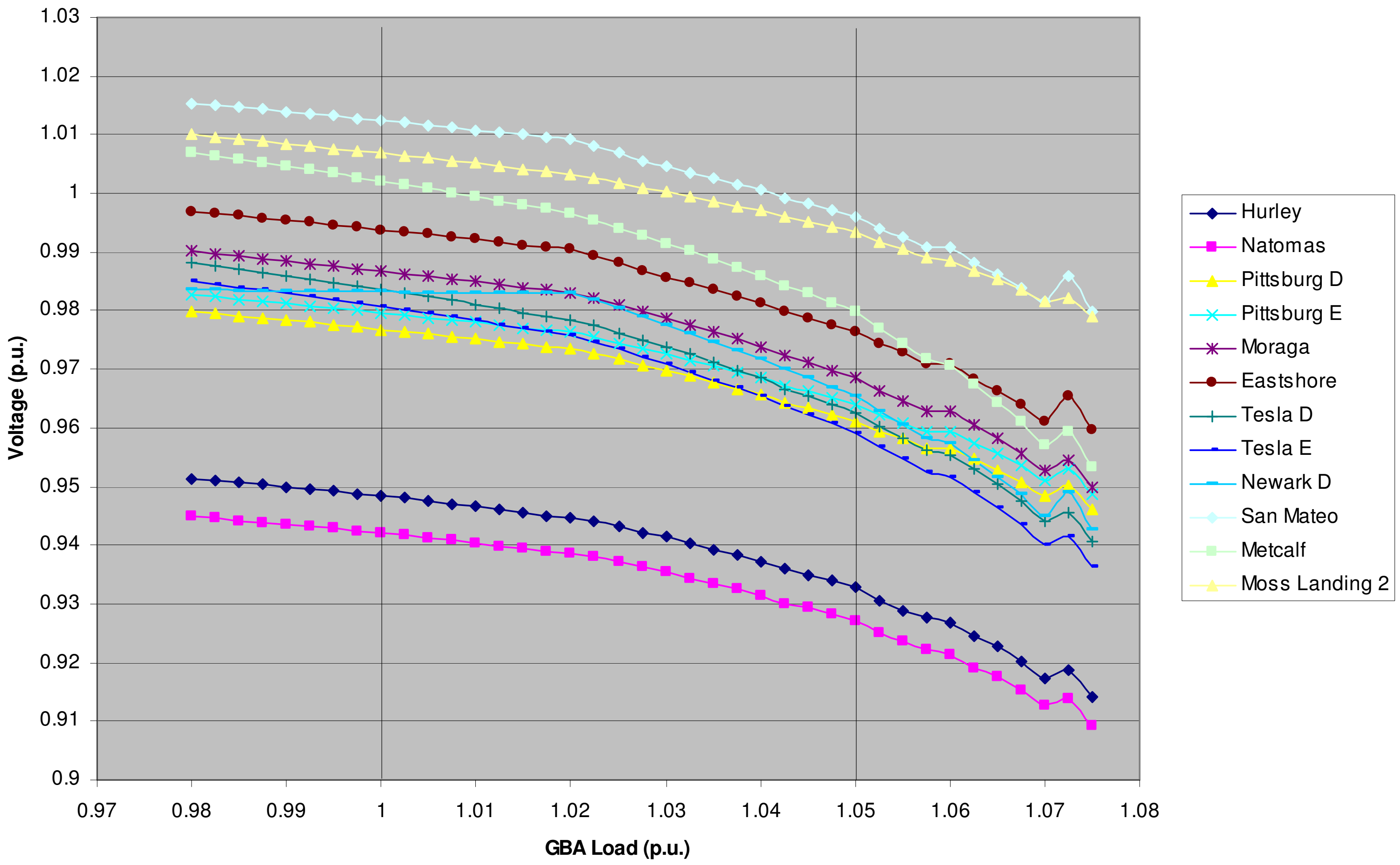

Figure 7-4 Case 4 – 2015: P-V Curves of 230kV Buses Local to GBA with DEC Outage

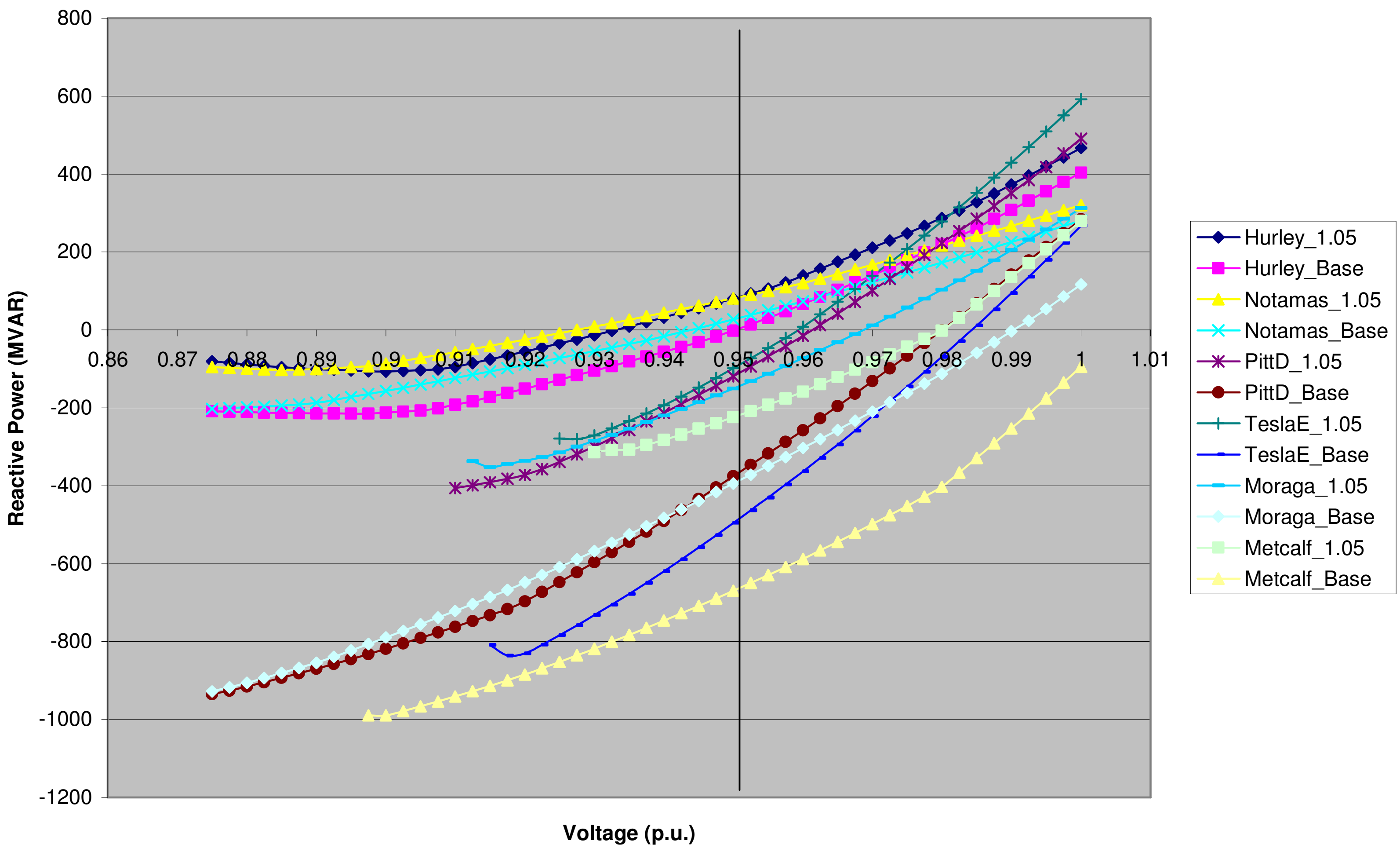

Figure 7-5 Case 4 – 2015: V-Q Curves of 230kV Buses Local to GBA with DEC Outage

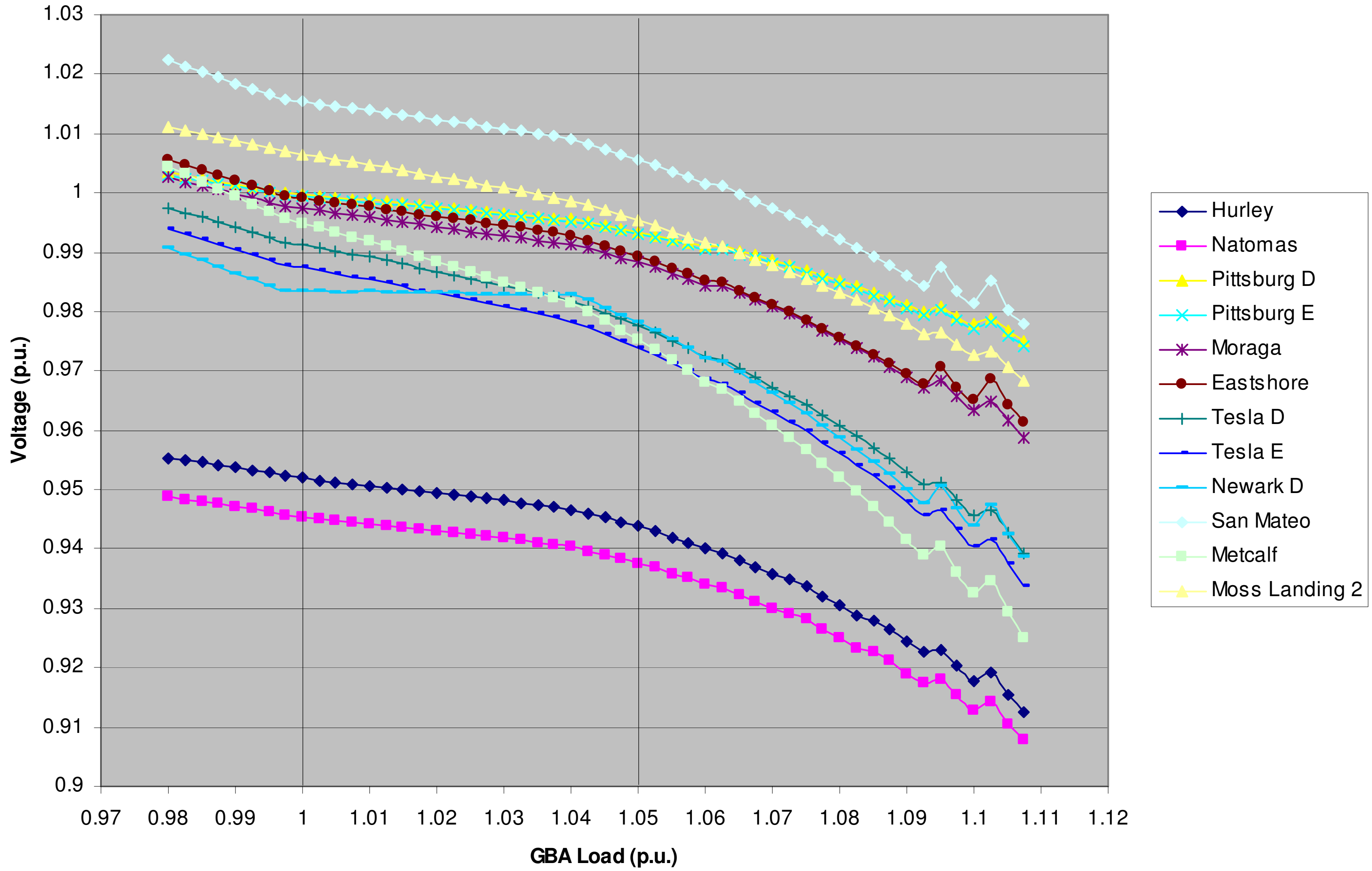

Figure 7-6 Case 4 – 2015: P-V Curves of 230kV Buses Local to GBA with MEC Outage

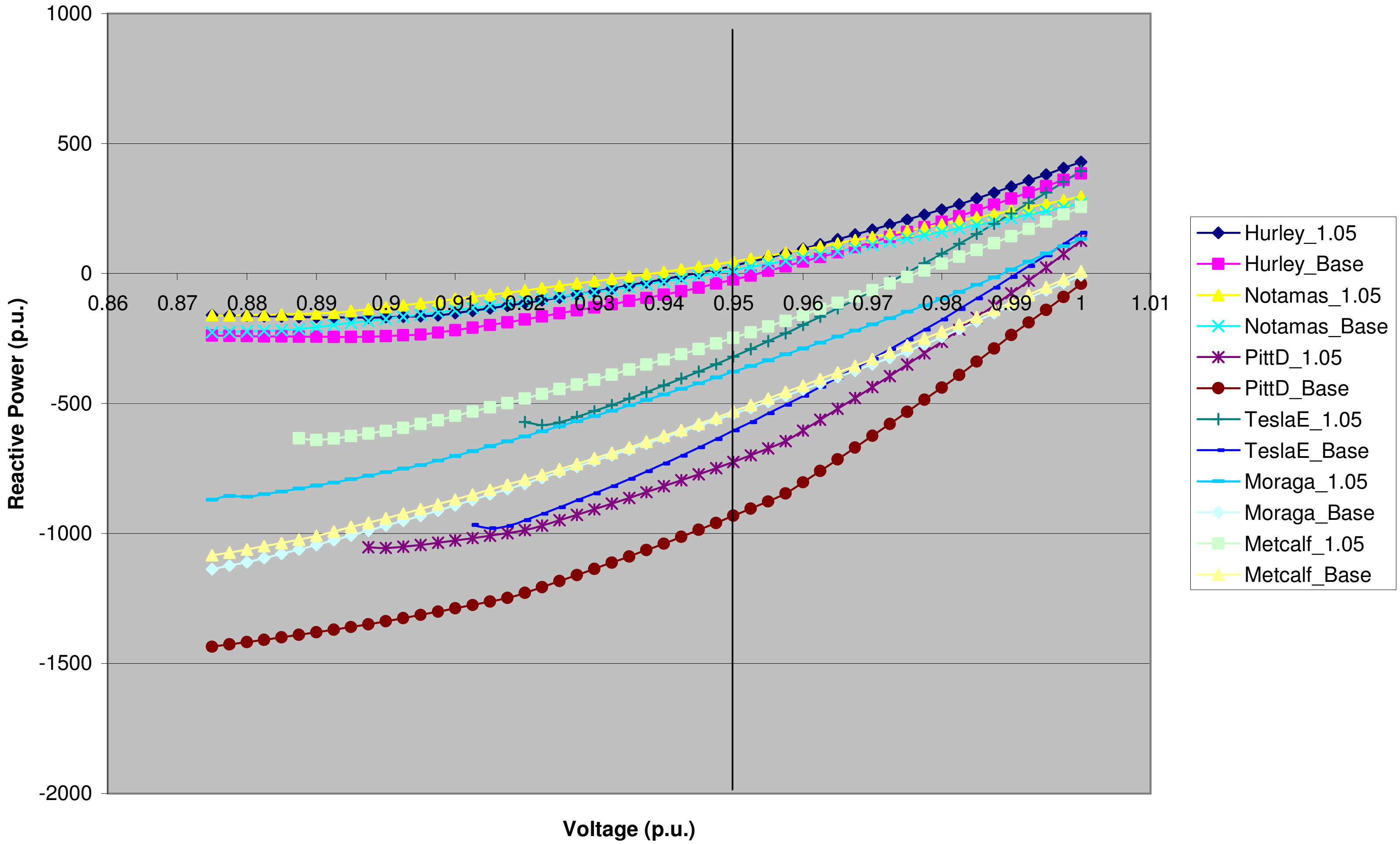

Figure 7-7 Case 4 – 2015: V-Q Curves of 230kV Buses Local to GBA with MEC Outage

7.14 Case 3 – 2015 Curves

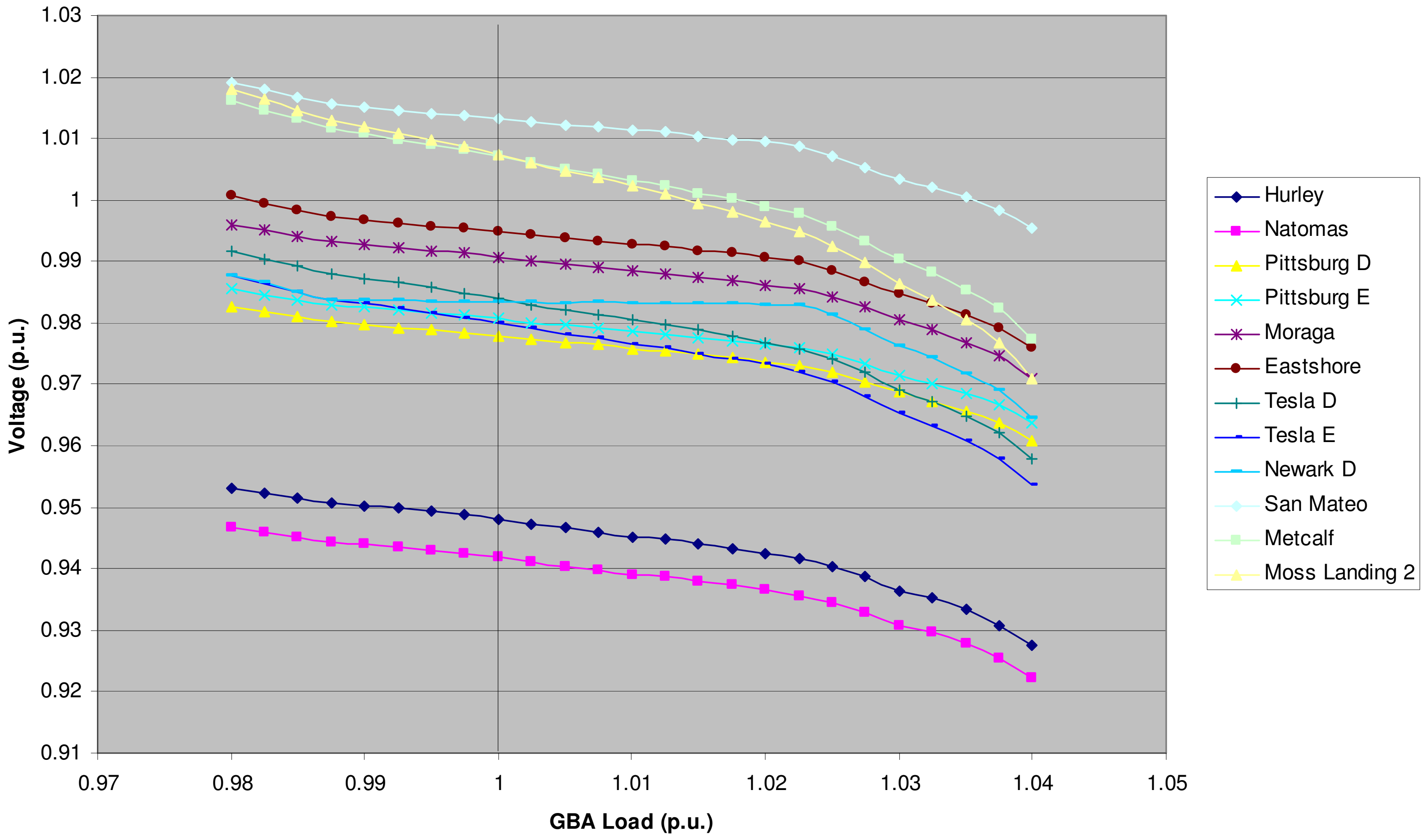

Figure 7-8 Case 3 – 2015: P-V Curves of 230kV Buses Local to GBA with DEC Outage

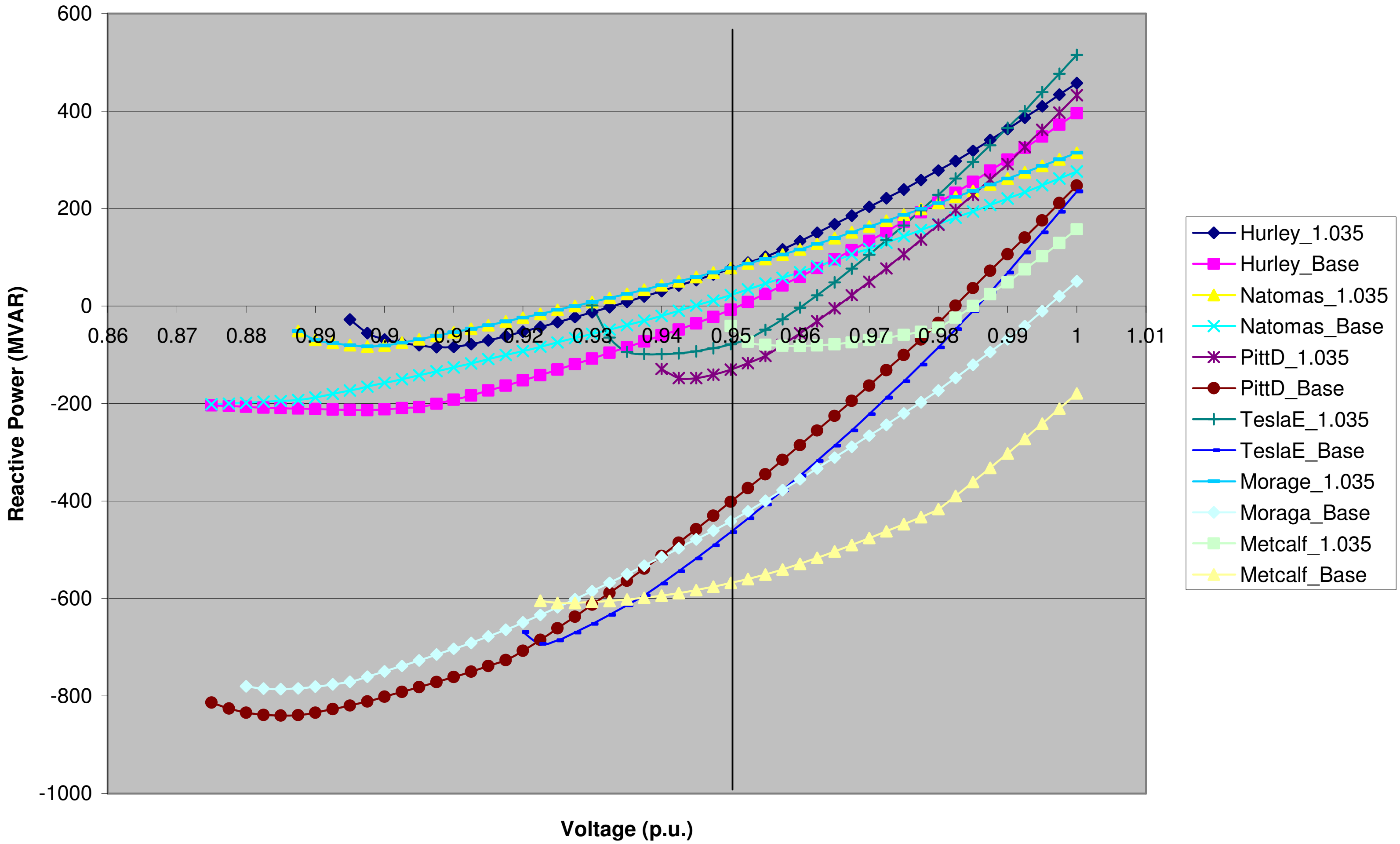

Figure 7-9 Case 3 – 2015: V-Q Curves of 230kV Buses Local to GBA with DEC Outage

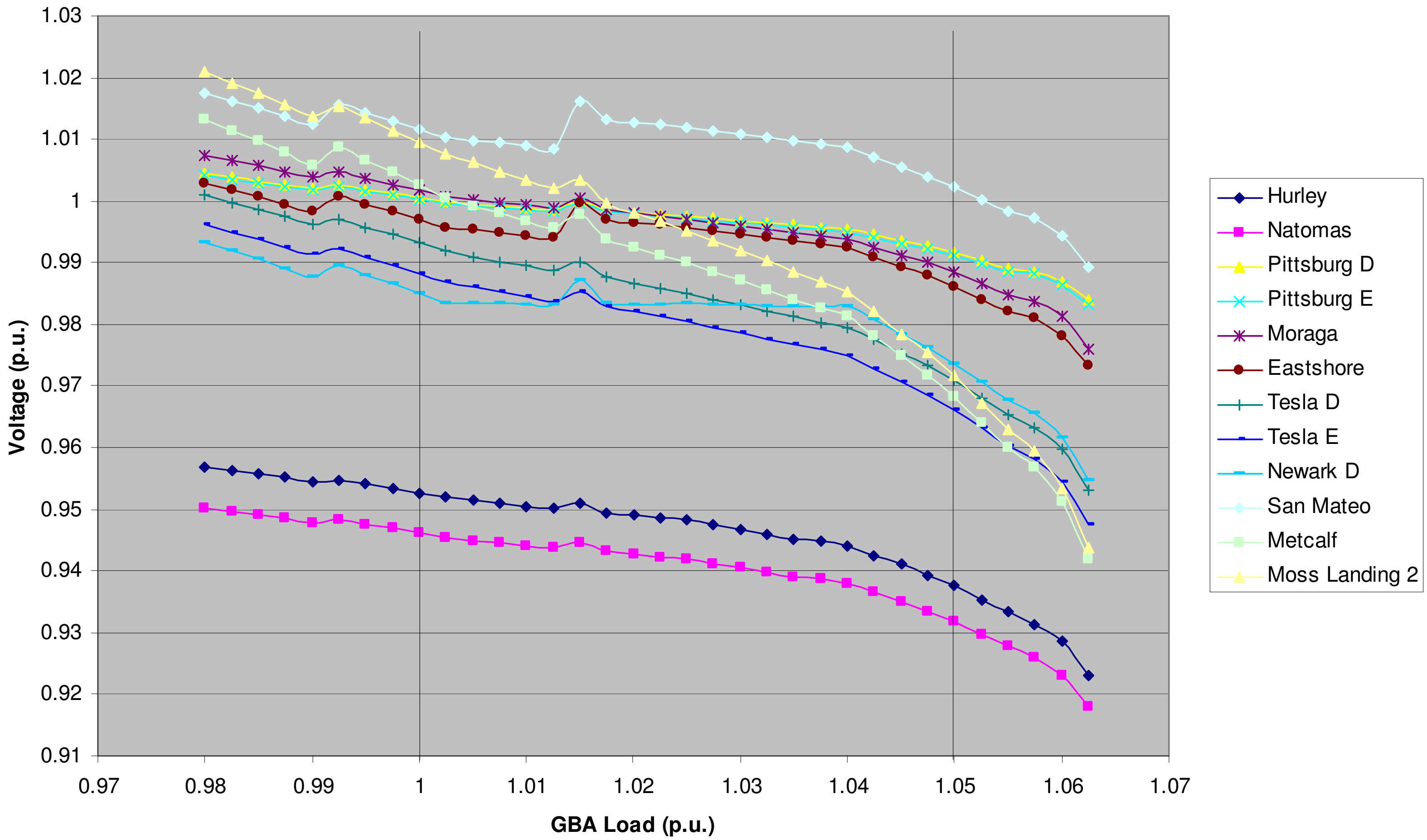

Figure 7-10 Case 3 – 2015: P-V Curves of 230kV Buses Local to GBA with MEC Outage

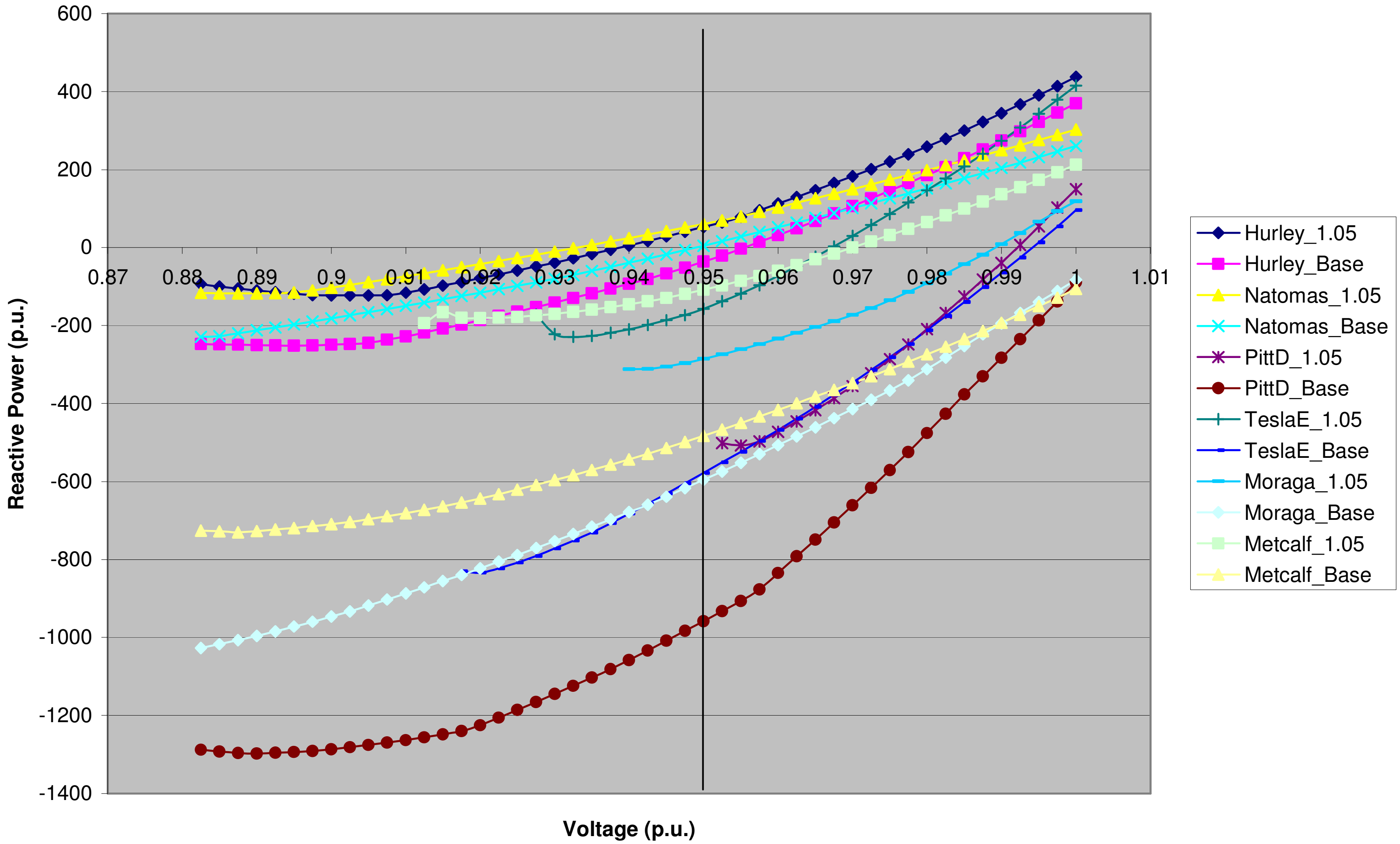

Figure 7-11 Case 3 – 2015: V-Q Curves of 230kV Buses Local to GBA with MEC Outage

7.15 Case 1 – 2015 Curves

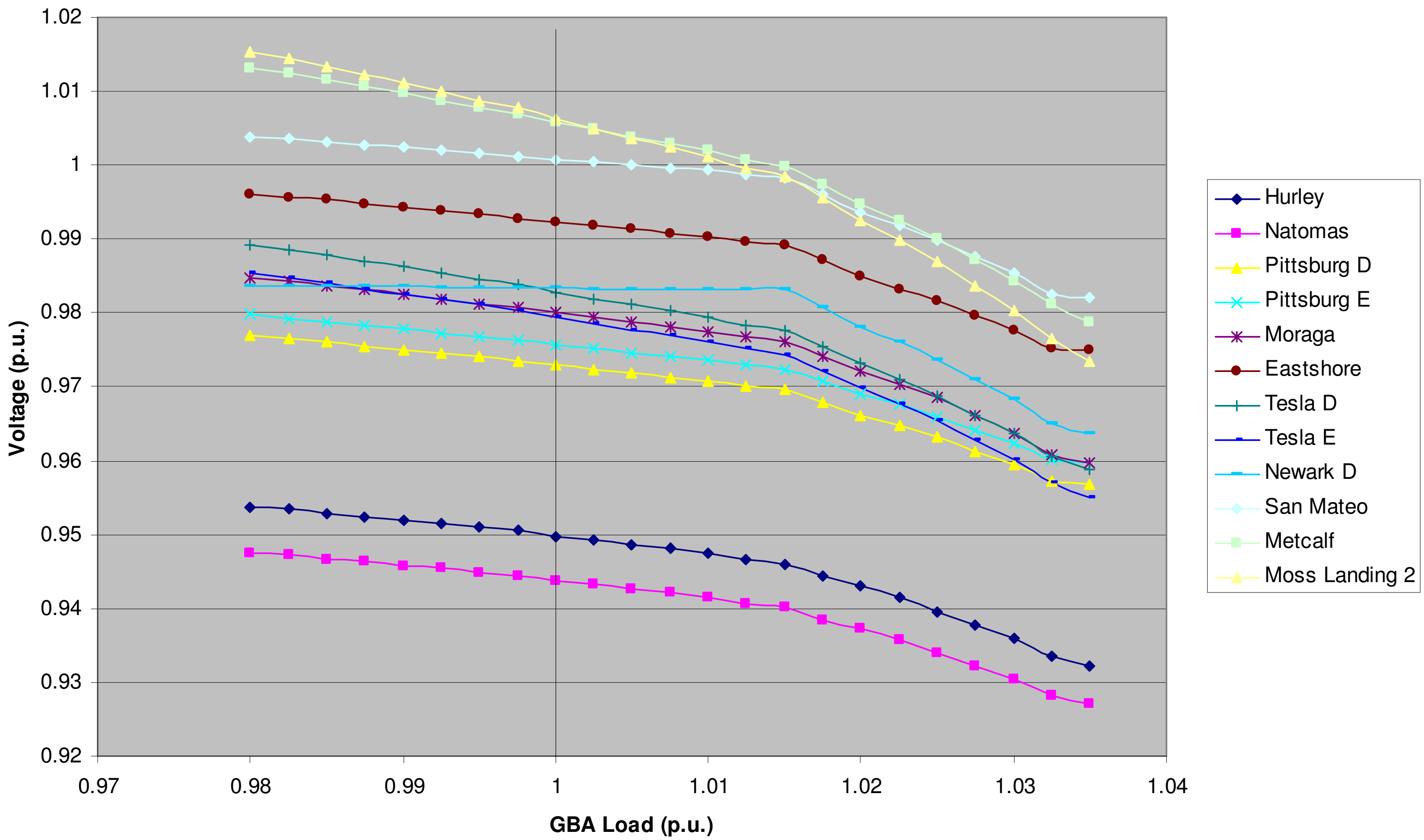

Figure 7-12 Case 1 – 2015: P-V Curves of 230kV Buses Local to GBA with DEC Outage

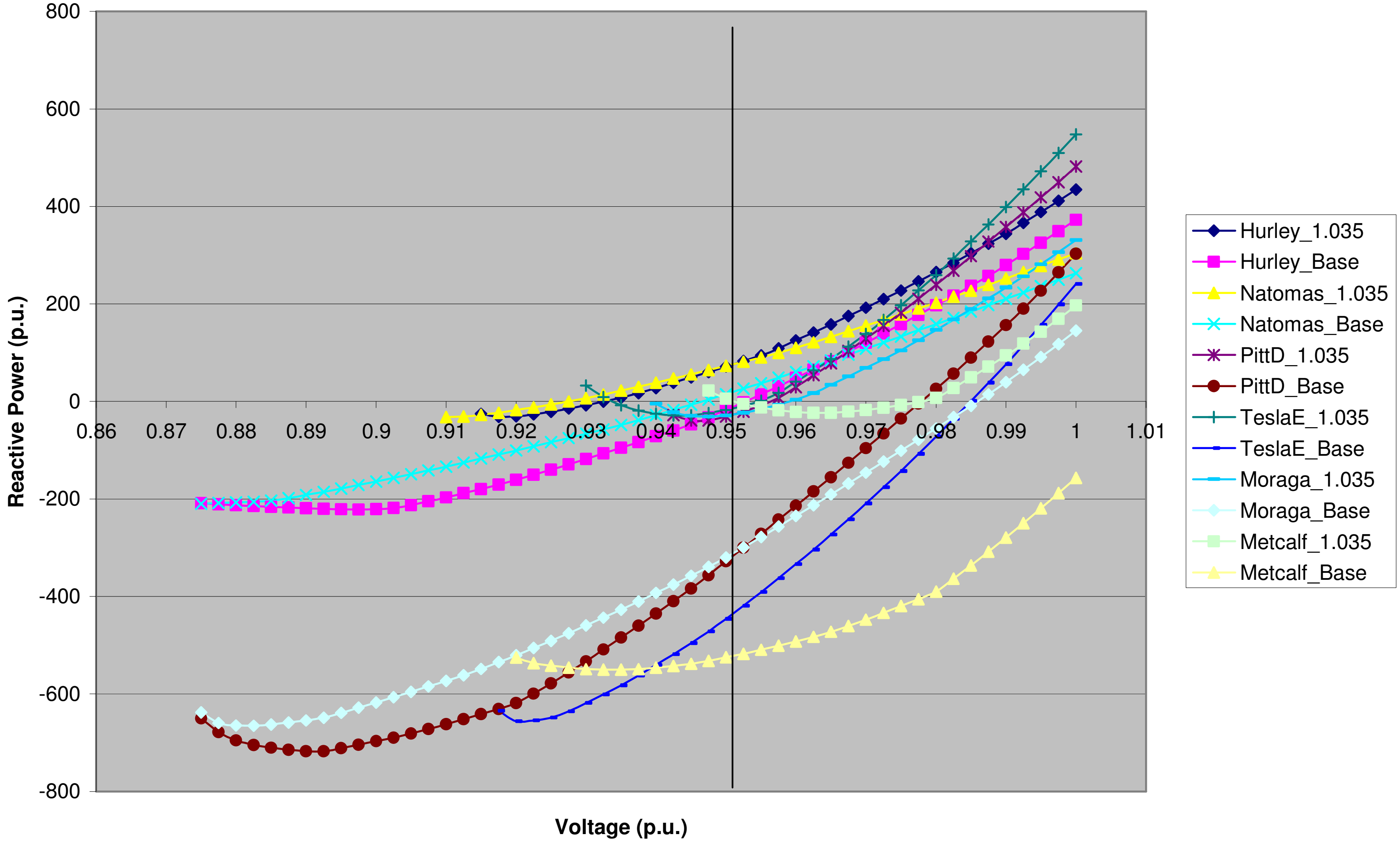

Figure 7-13 Case 1 – 2015: V-Q Curves of 230kV Buses Local to GBA with DEC Outage

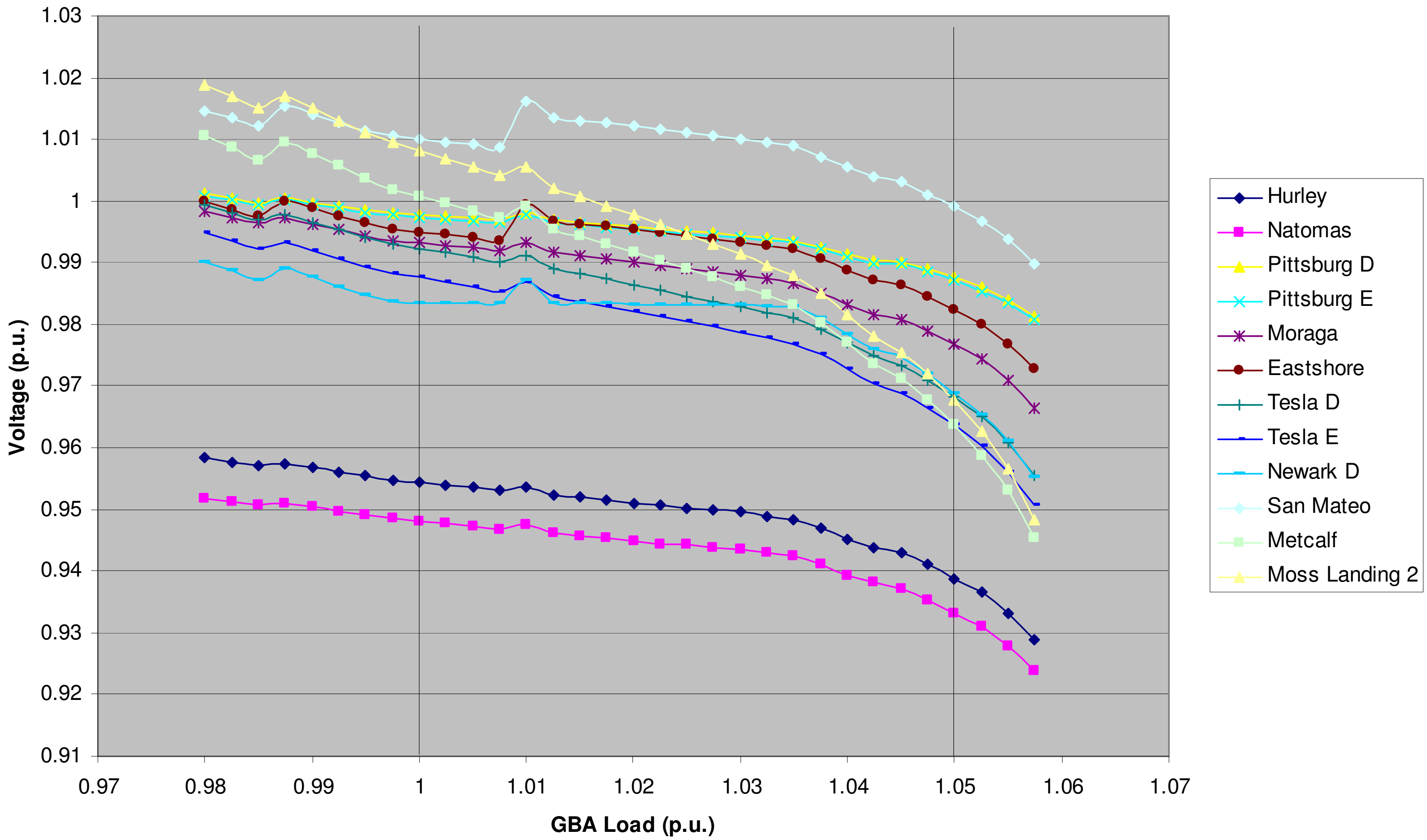

Figure 7-14 Case 1 – 2015: P-V Curves of 230kV Buses Local to GBA with MEC Outage

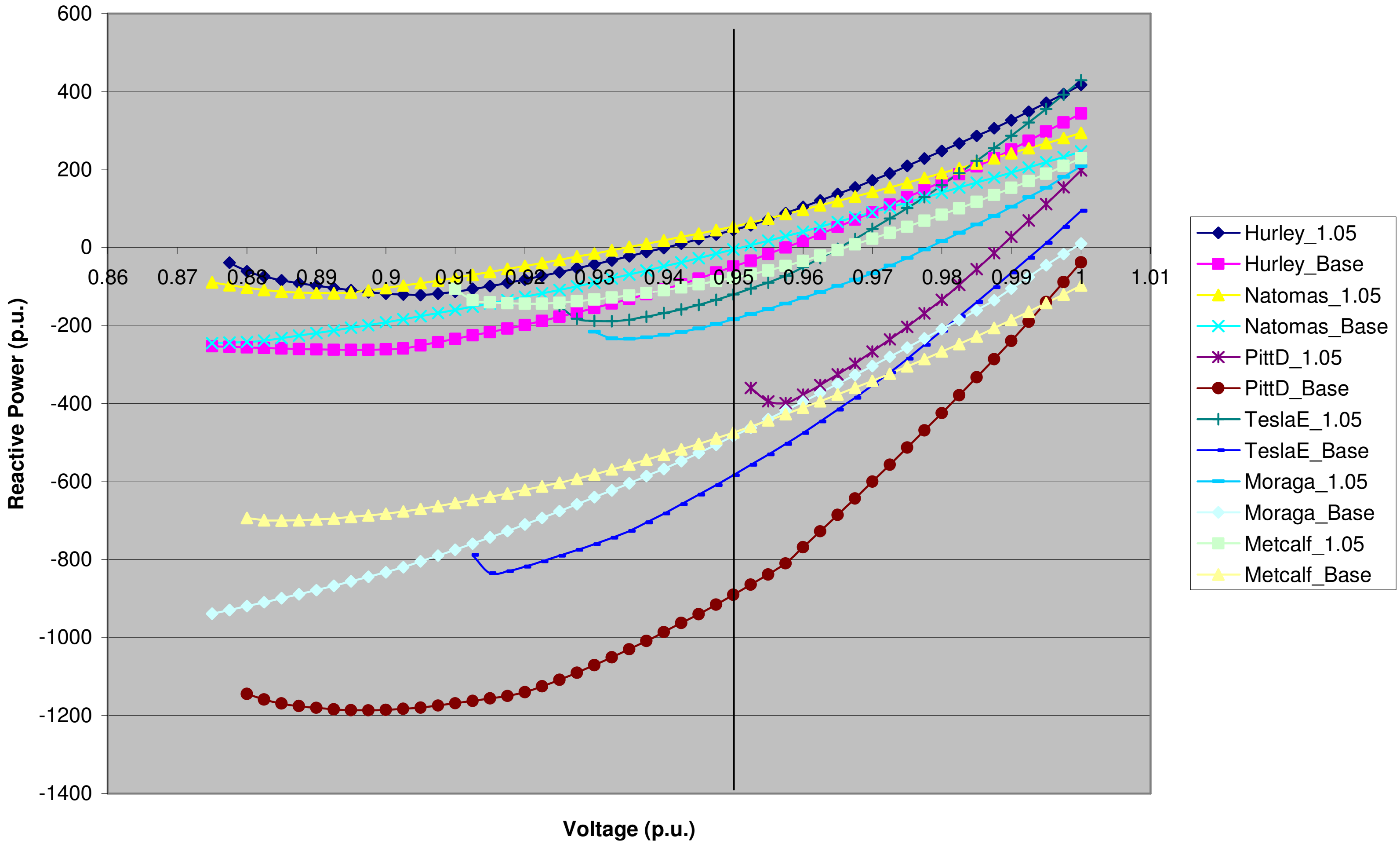

Figure 7-15 Case 1 – 2015: V-Q Curves of 230kV Buses Local to GBA with MEC Outage

7.16 Case 3 – 2015 Sensitivity with Russell City Energy Center (RCEC) Online

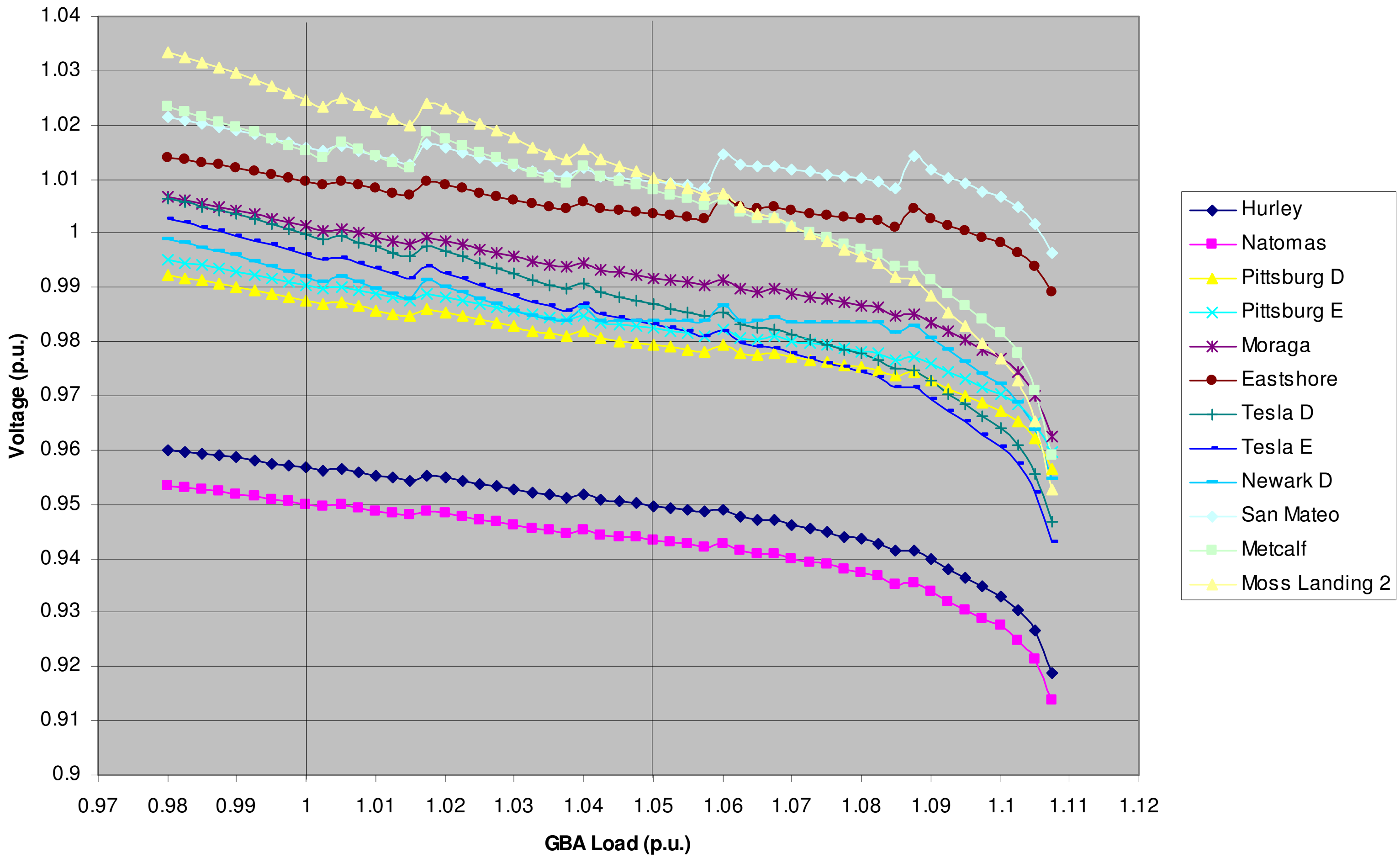

Figure 7-16 Case 3 – 2015: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & RCEC Plant (614 MW) In-Service

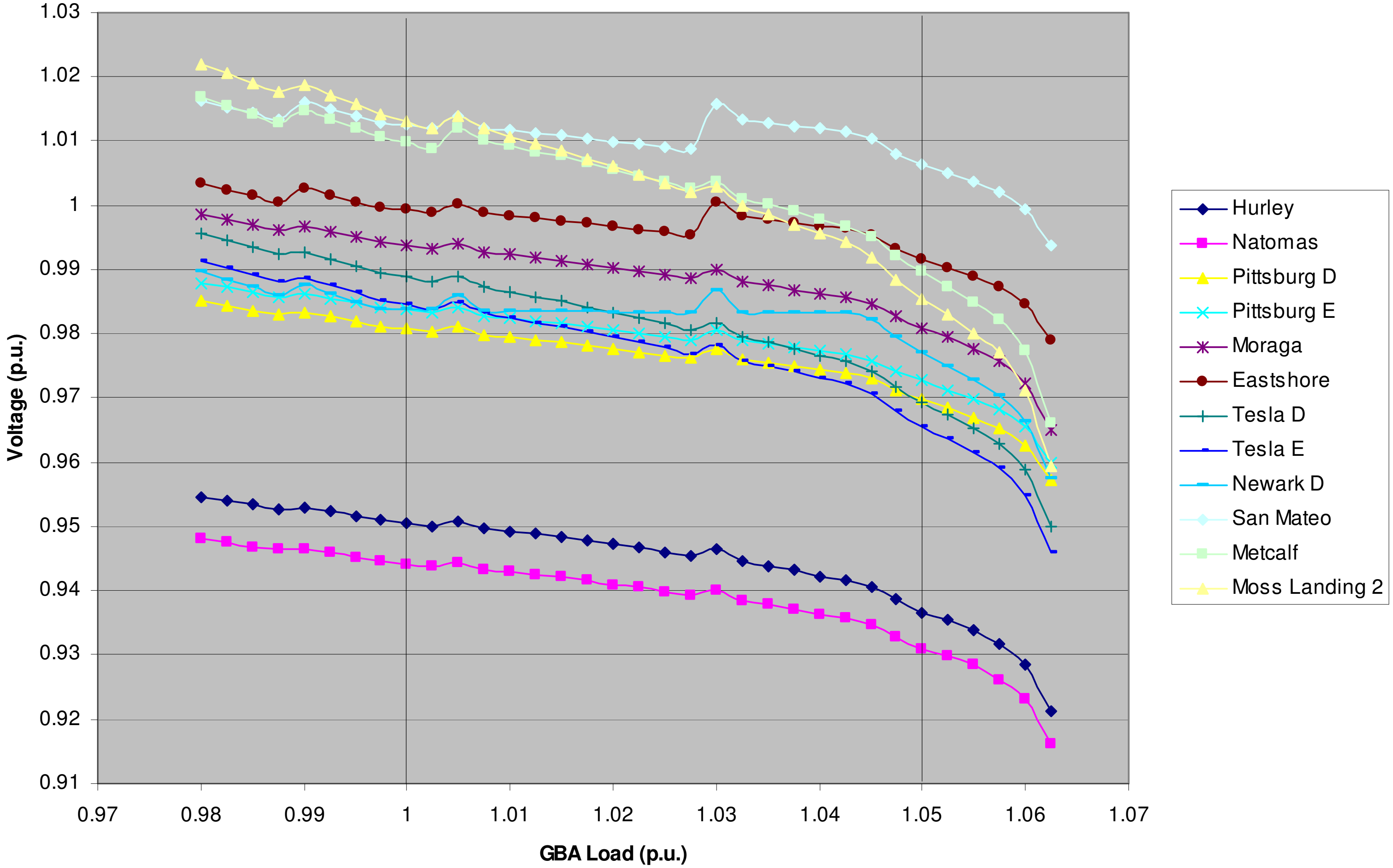

Figure 7-17 Case 3 – 2015: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & 1 CT at RCEC (180 MW) In-Service

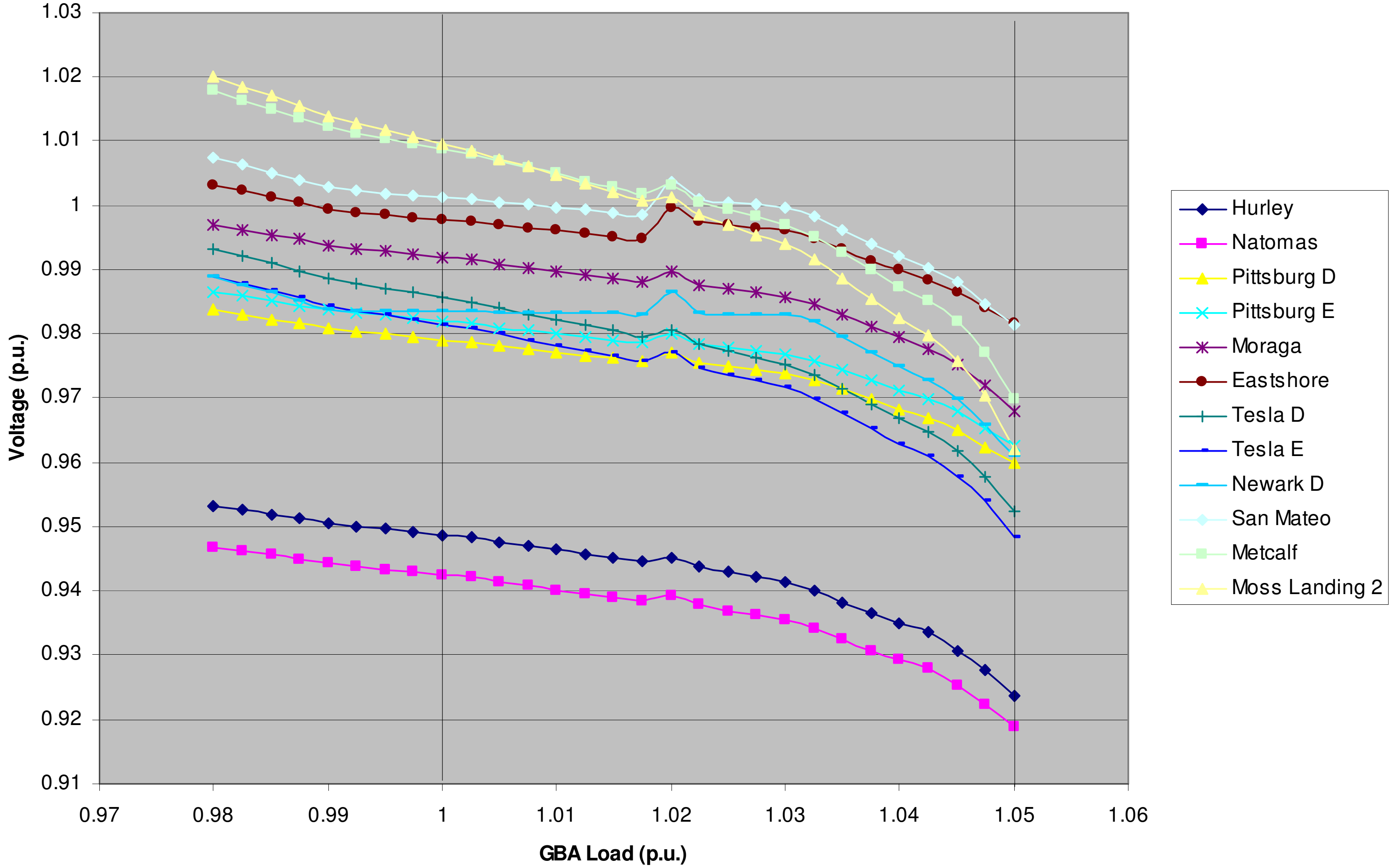

Figure 7-18 Case 3 – 2015: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & 1 CT at RCEC (50 MW) In-Service

7.17 Case 1 – 2015 Sensitivity with Russell City Energy Center (RCEC) Online

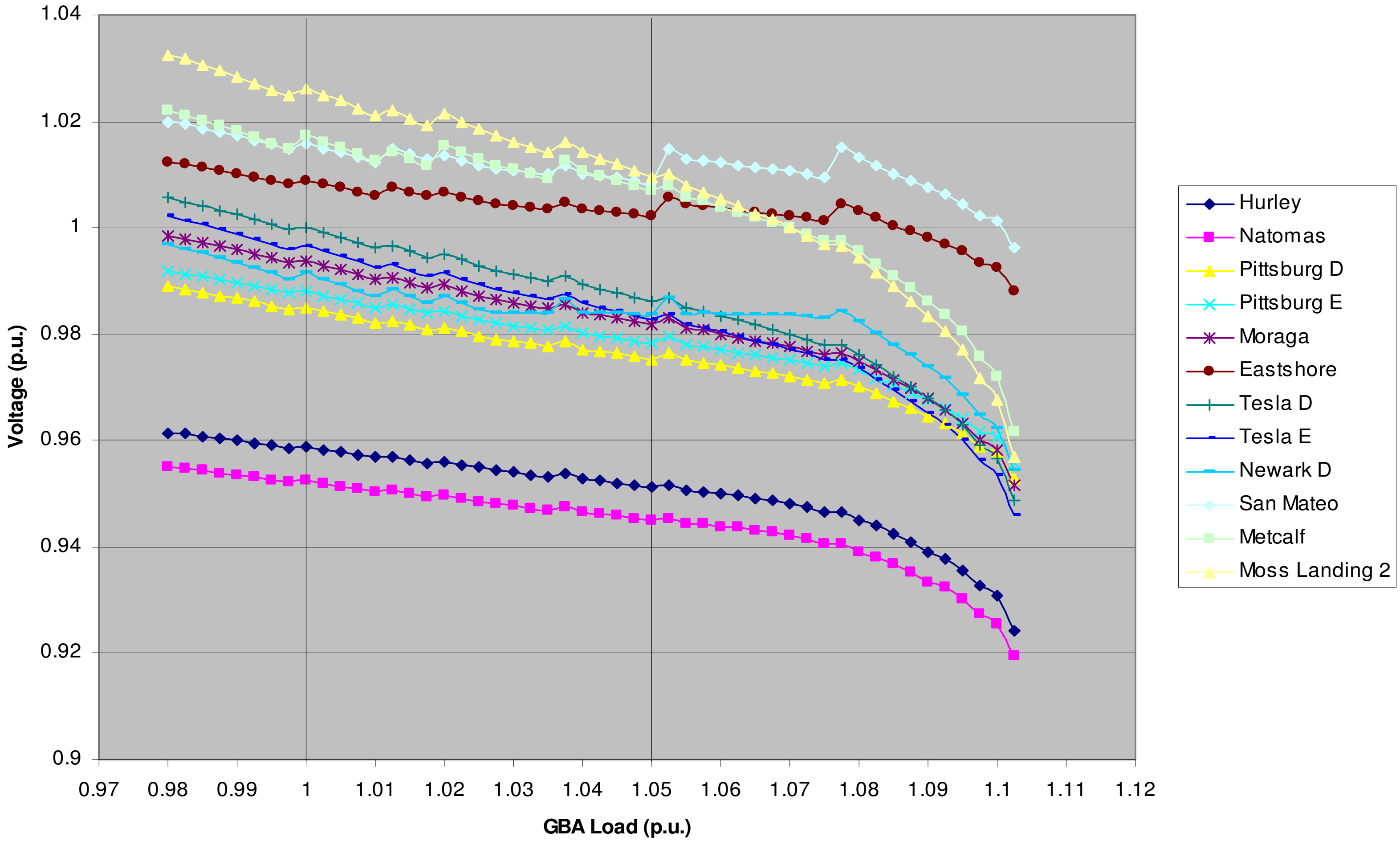

Figure 7-19 Case 1 – 2015: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & RCEC Plant (614 MW) In-Service

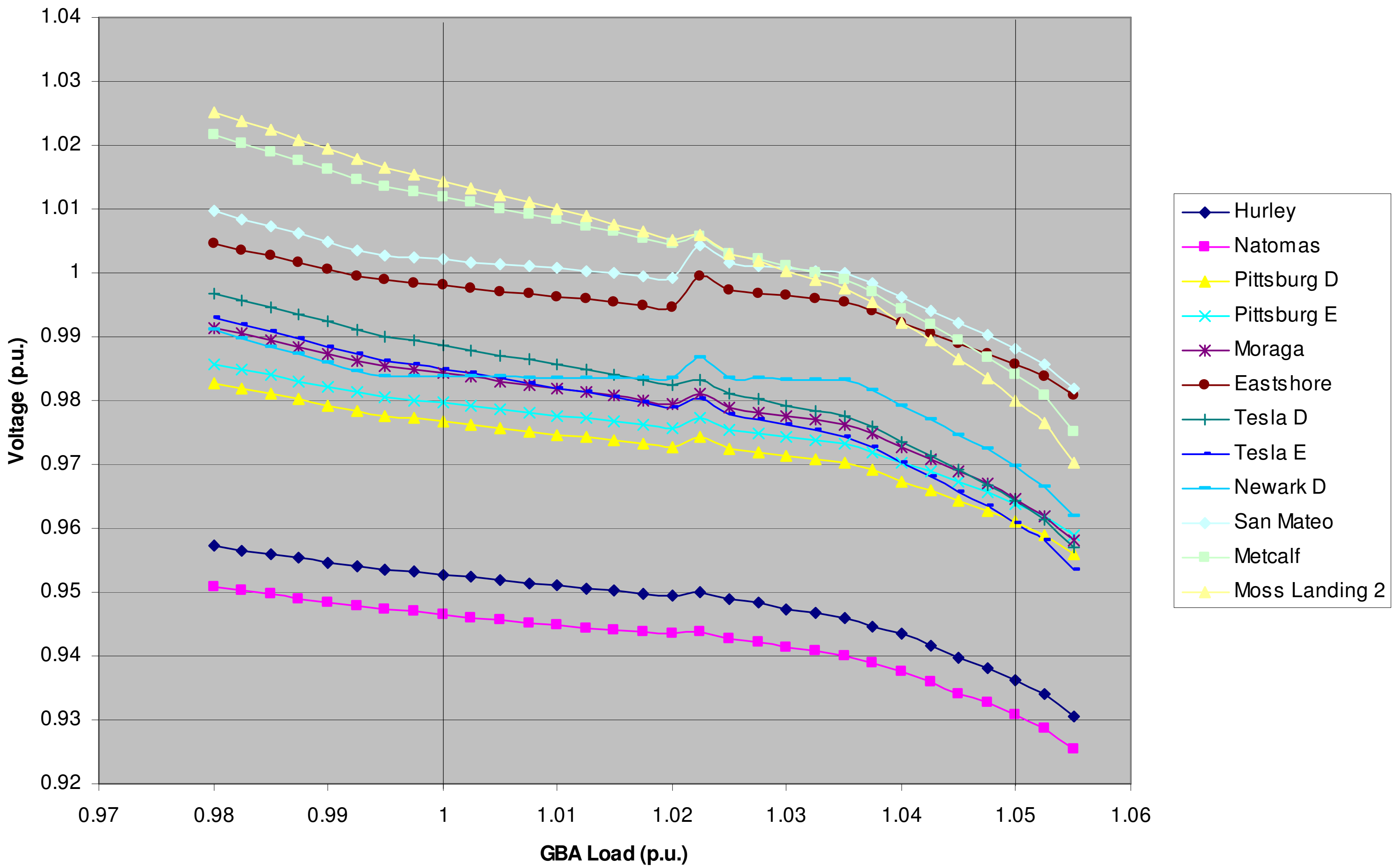

Figure 7-20 Case 1 – 2015: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & 1 CT at RCEC (180 MW) In-Service

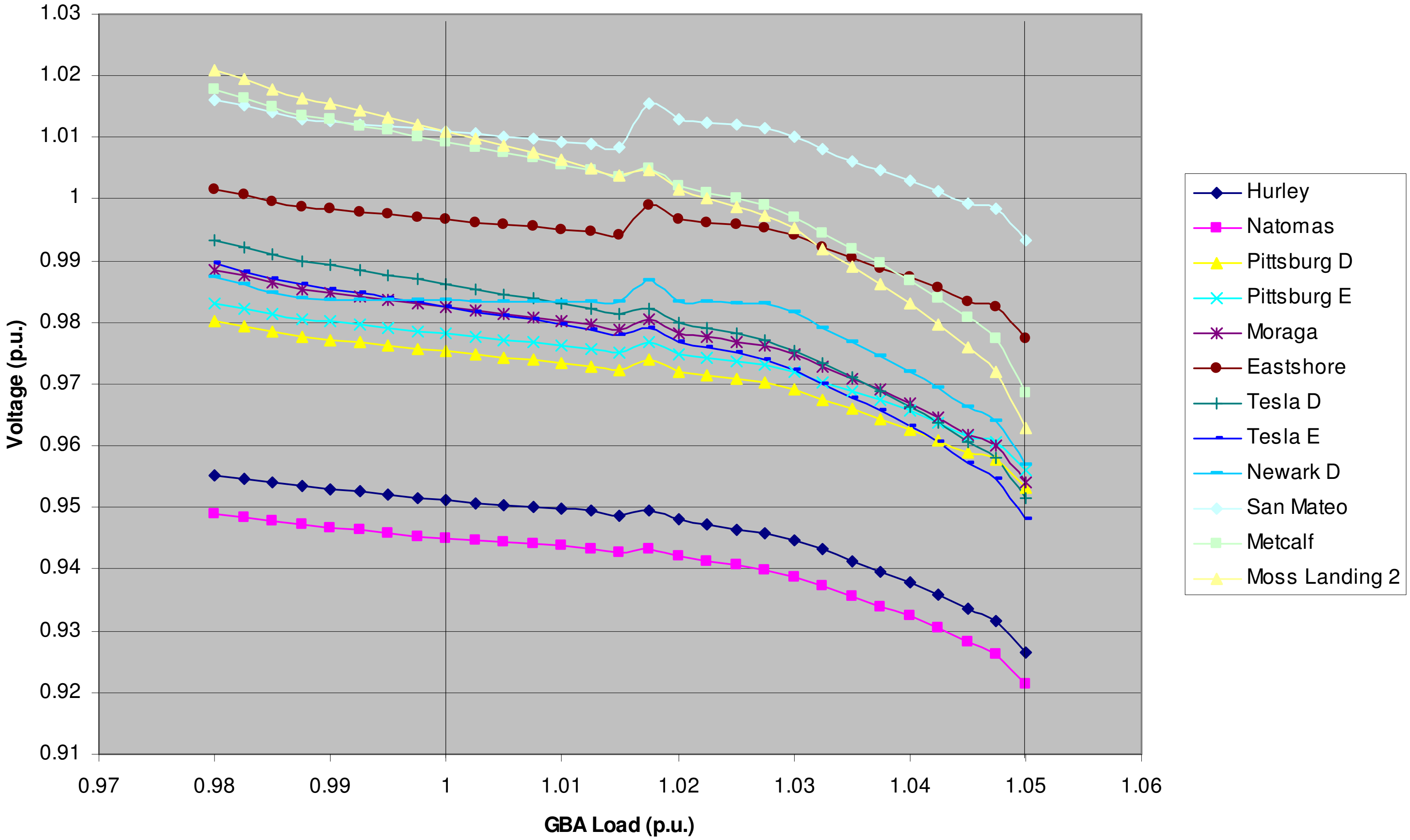

Figure 7-21 Case 1 – 2015: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & 1 CT at RCEC (100 MW) In-Service

7.18 Case 4 – 2020 Curves

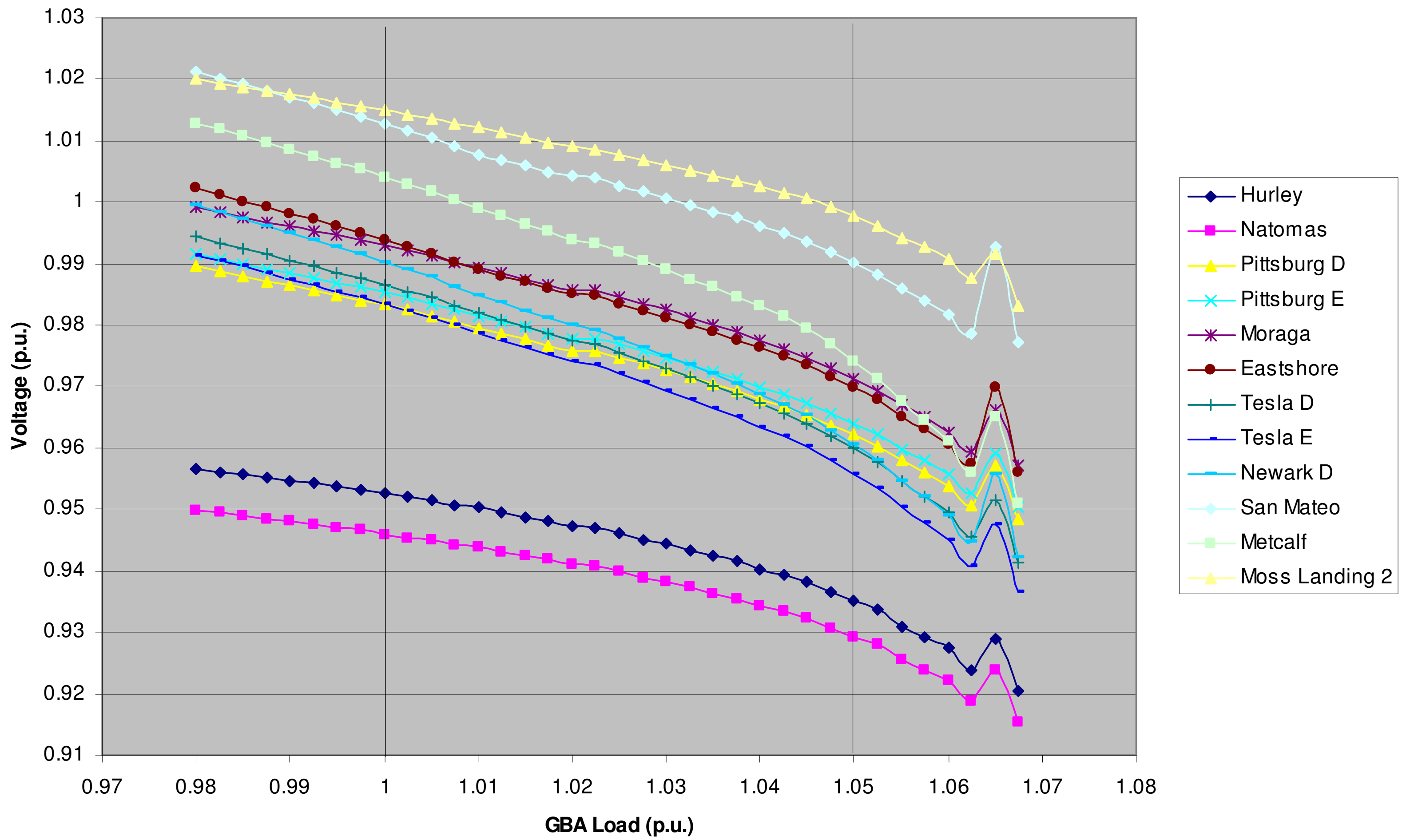

Figure 7-22 Case 4 – 2020: P-V Curves of 230kV Buses Local to GBA with DEC Outage

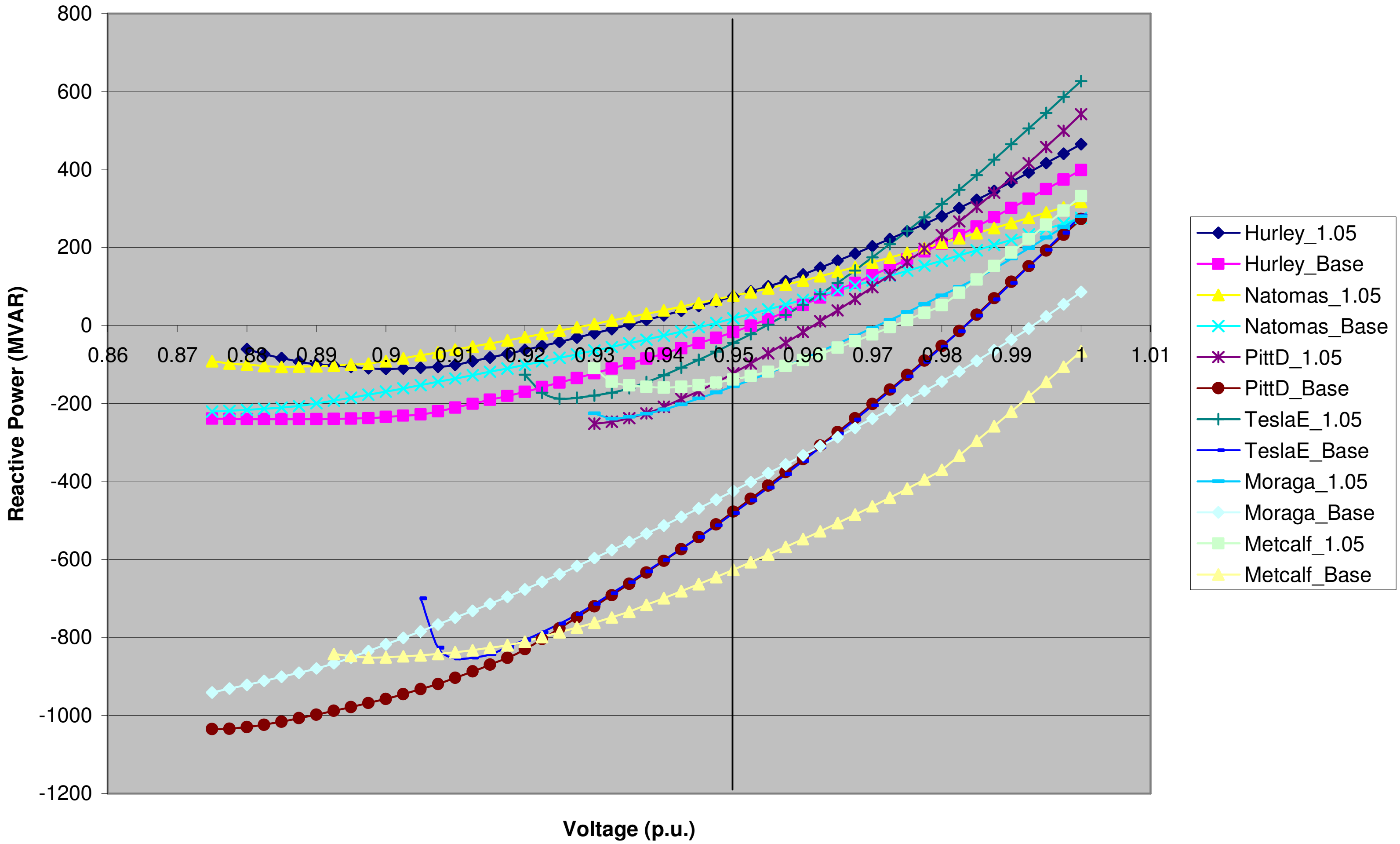

Figure 7-23 Case 4 – 2020: V-Q Curves of 230kV Buses Local to GBA with DEC Outage

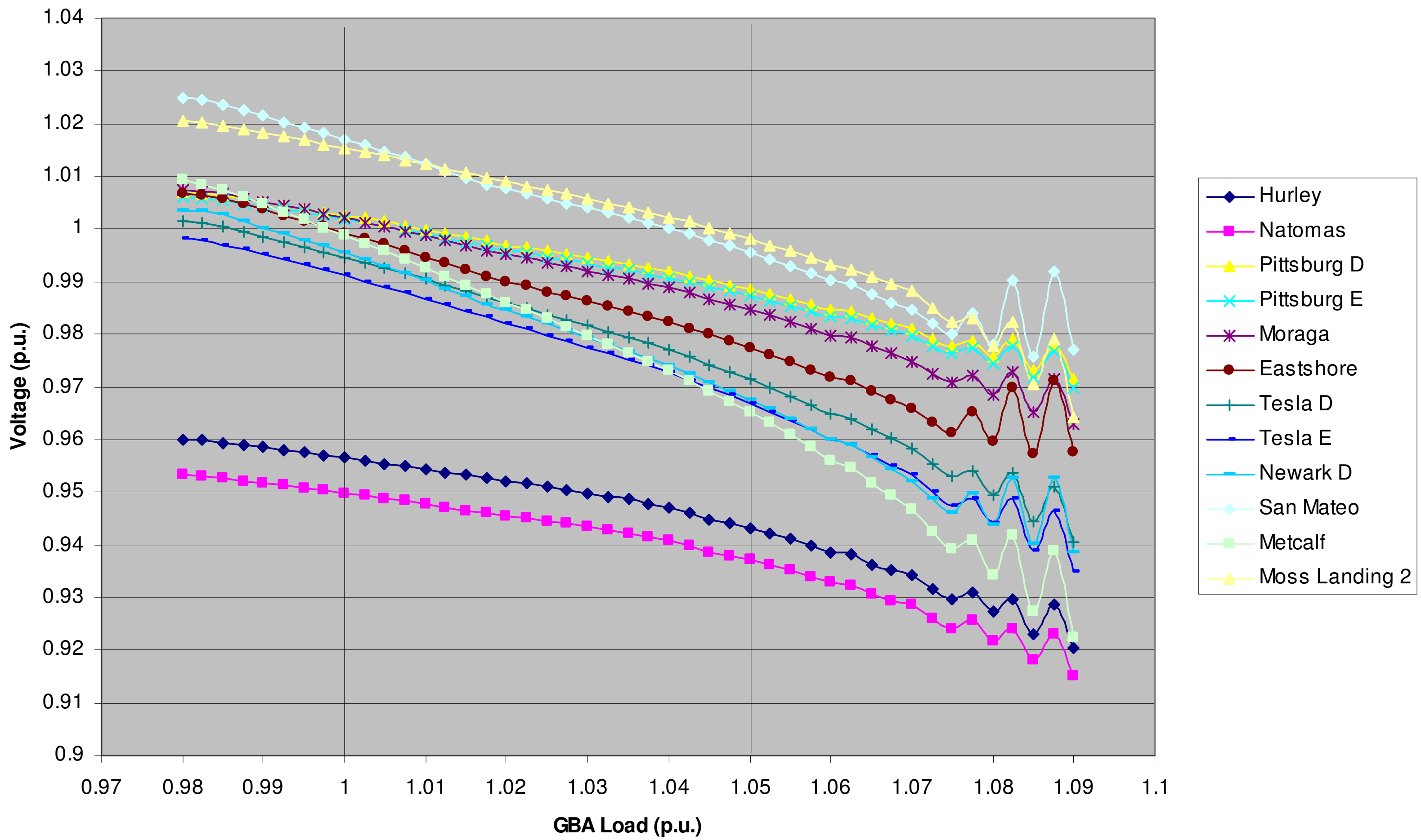

Figure 7-24 Case 4 – 2020: P-V Curves of 230kV Buses Local to GBA with MEC Outage

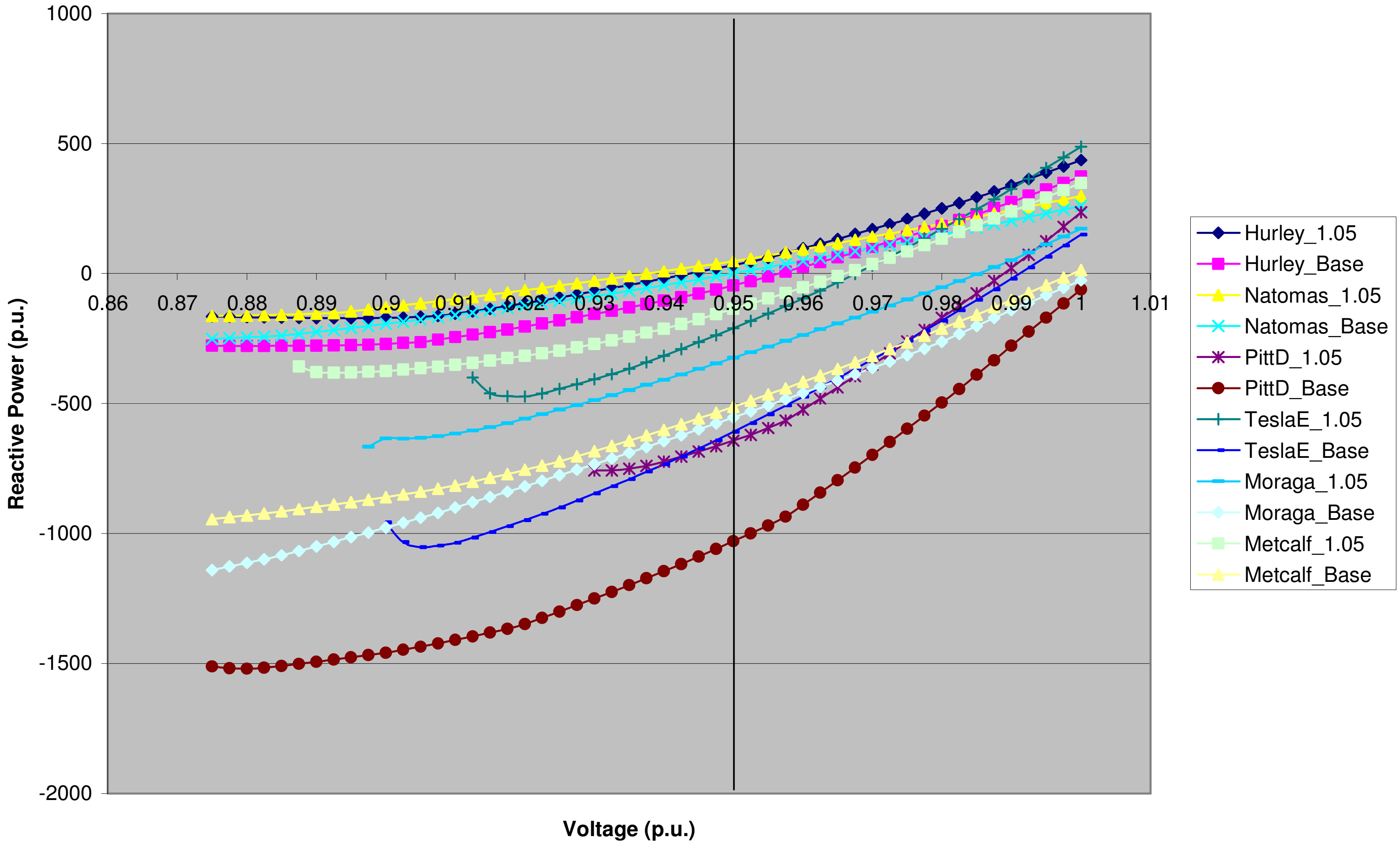

Figure 7-25 Case 4 – 2020: V-Q Curves of 230kV Buses Local to GBA with MEC Outage

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7.19 Sensitivity Analysis – 2020 Curves

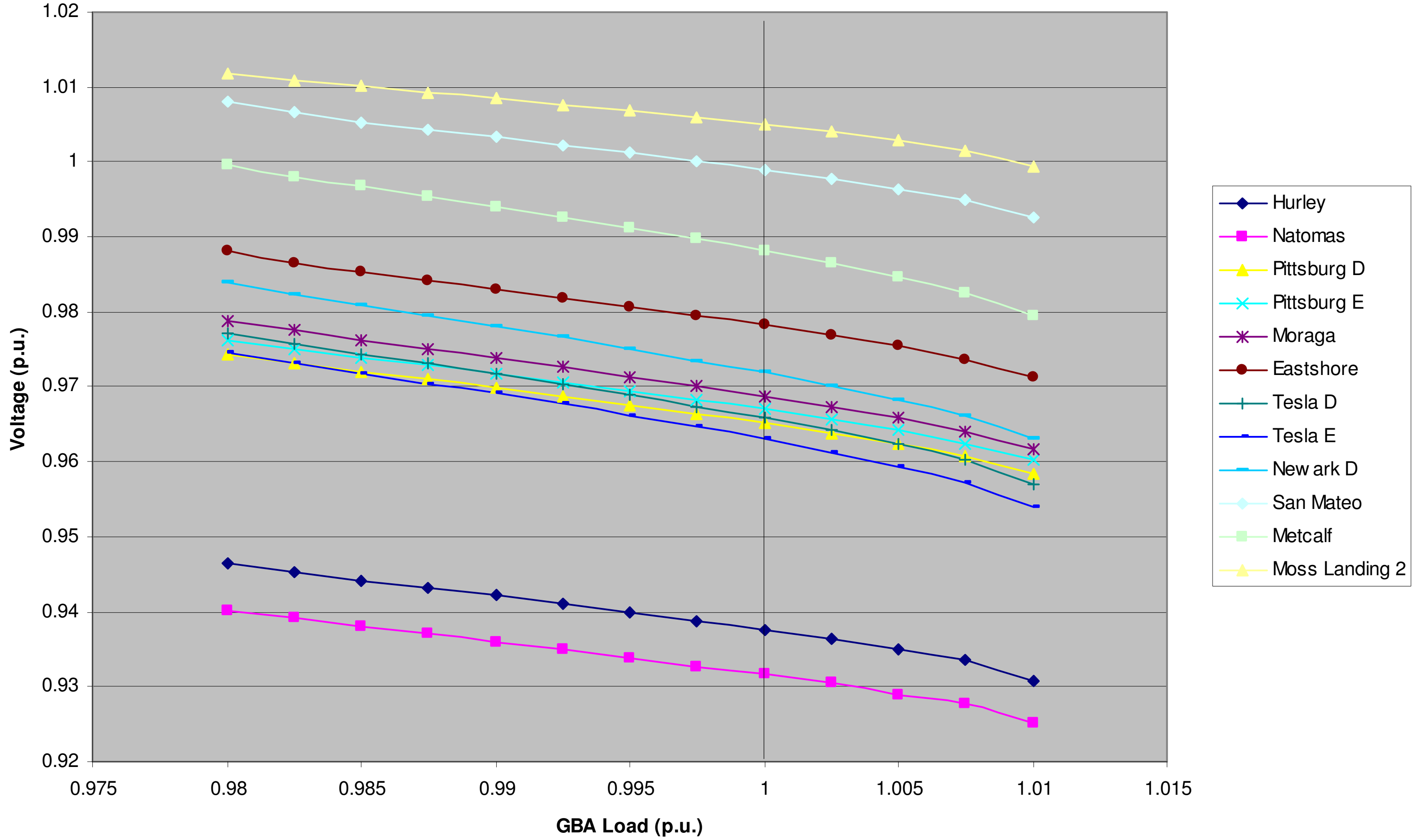

Figure 7-26 Case 3.5 – 2020: P-V Curves of 230 kV Buses Local to GBA with DEC Outage

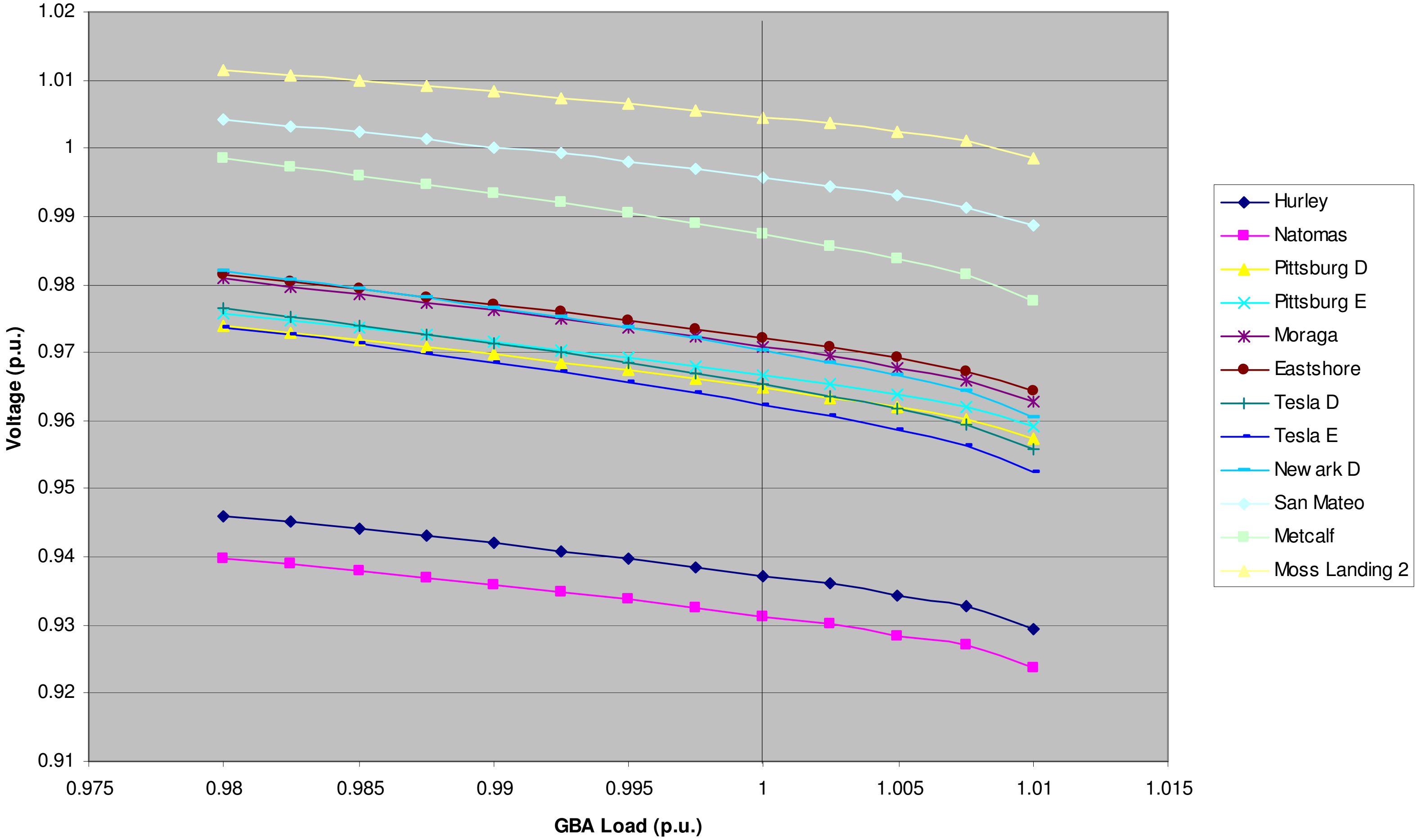

Figure 7-27 Case 3.5 – 2020: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & Oakland Long Term Plan Alternative

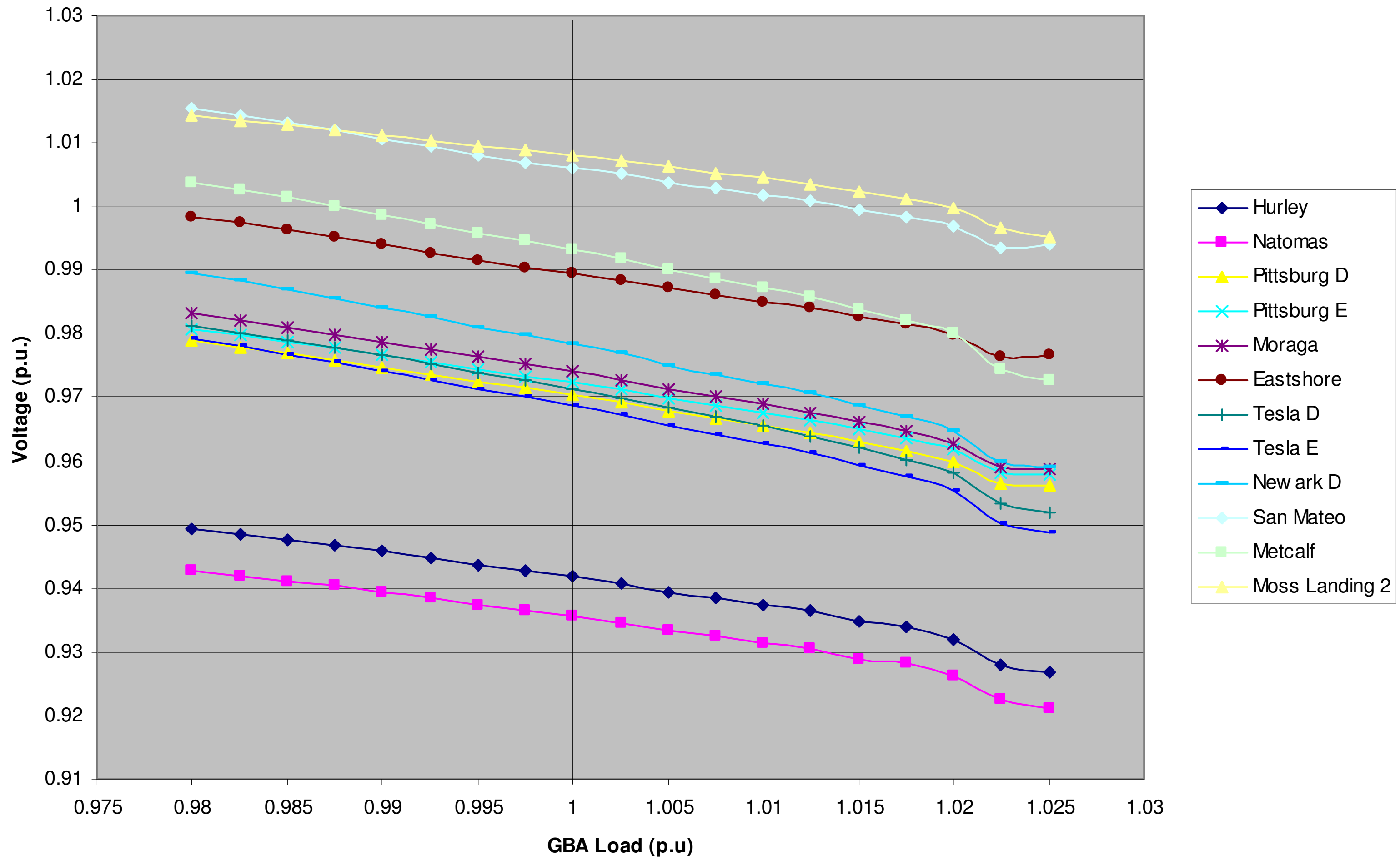

Figure 7-28 Case 3.5 – 2020: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & 1 CT at RCEC (<u>50 MW</u>) In-Service

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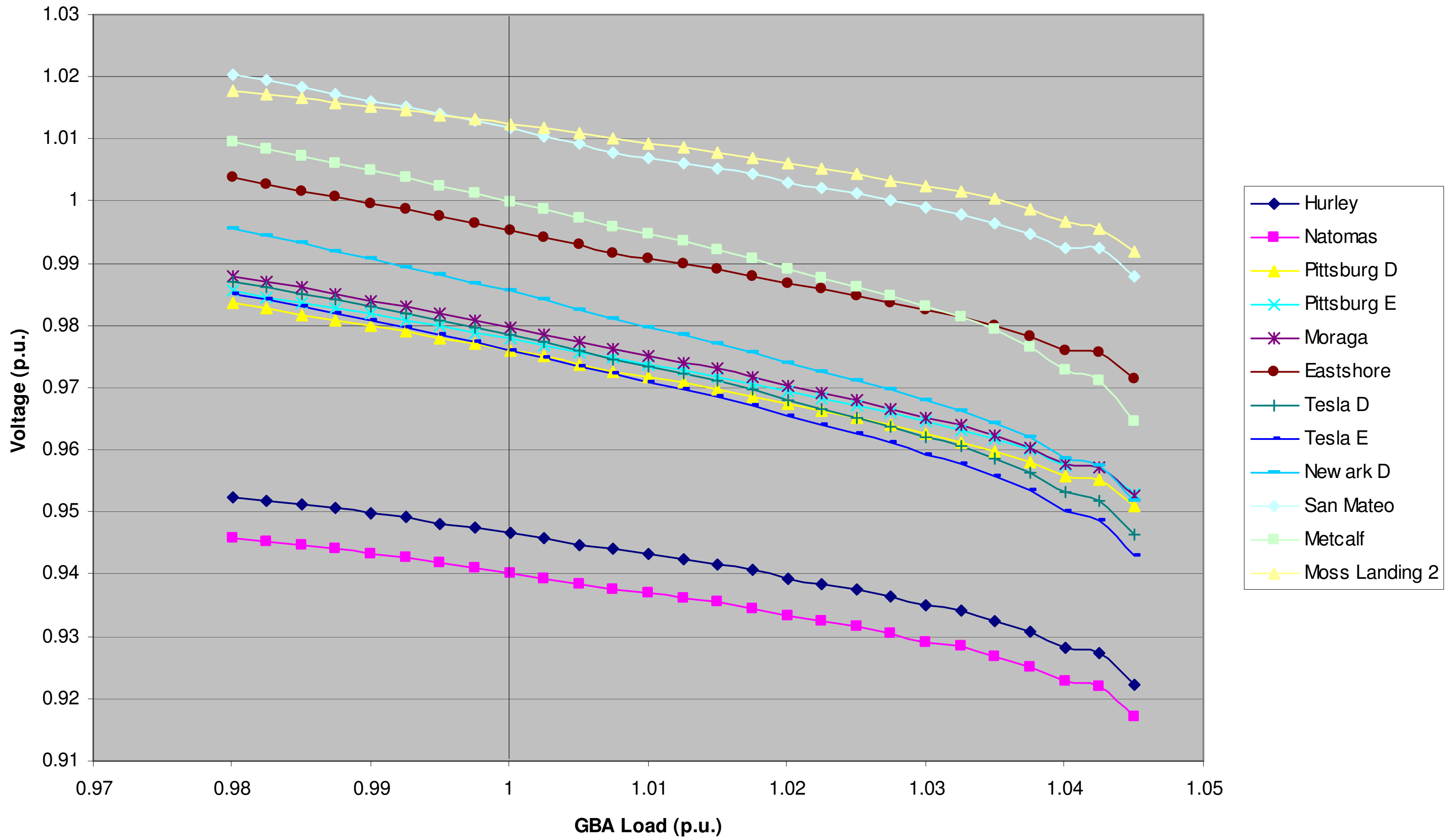

Figure 7-29 Case 3.5 – 2020: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & 1 CT at RCEC (180 MW) In-Service

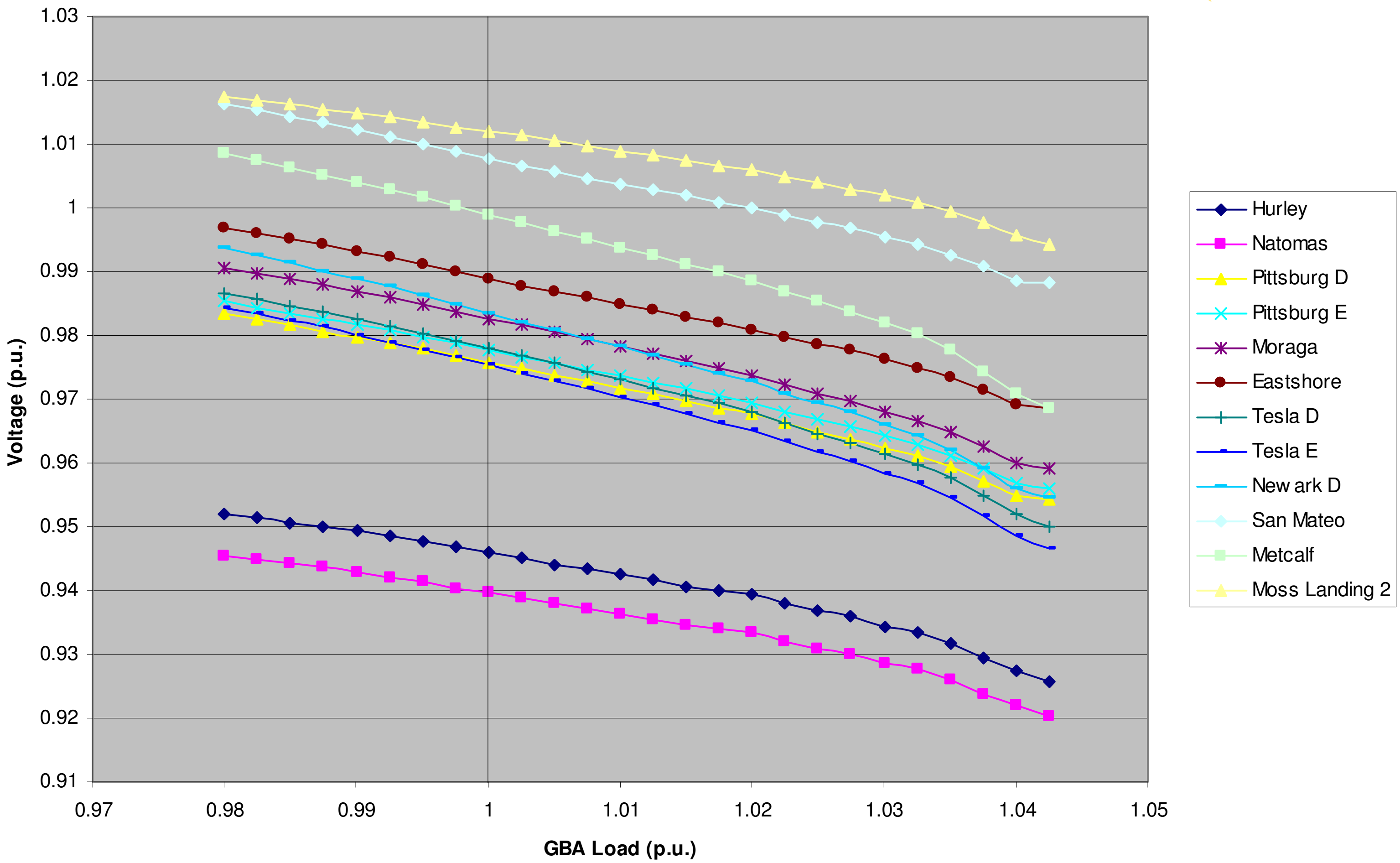

Figure 7-30 Case 3.5 – 2020: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & Oakland Long Term Plan Alternative & 1 CT at RCEC (180 MW) In-Service

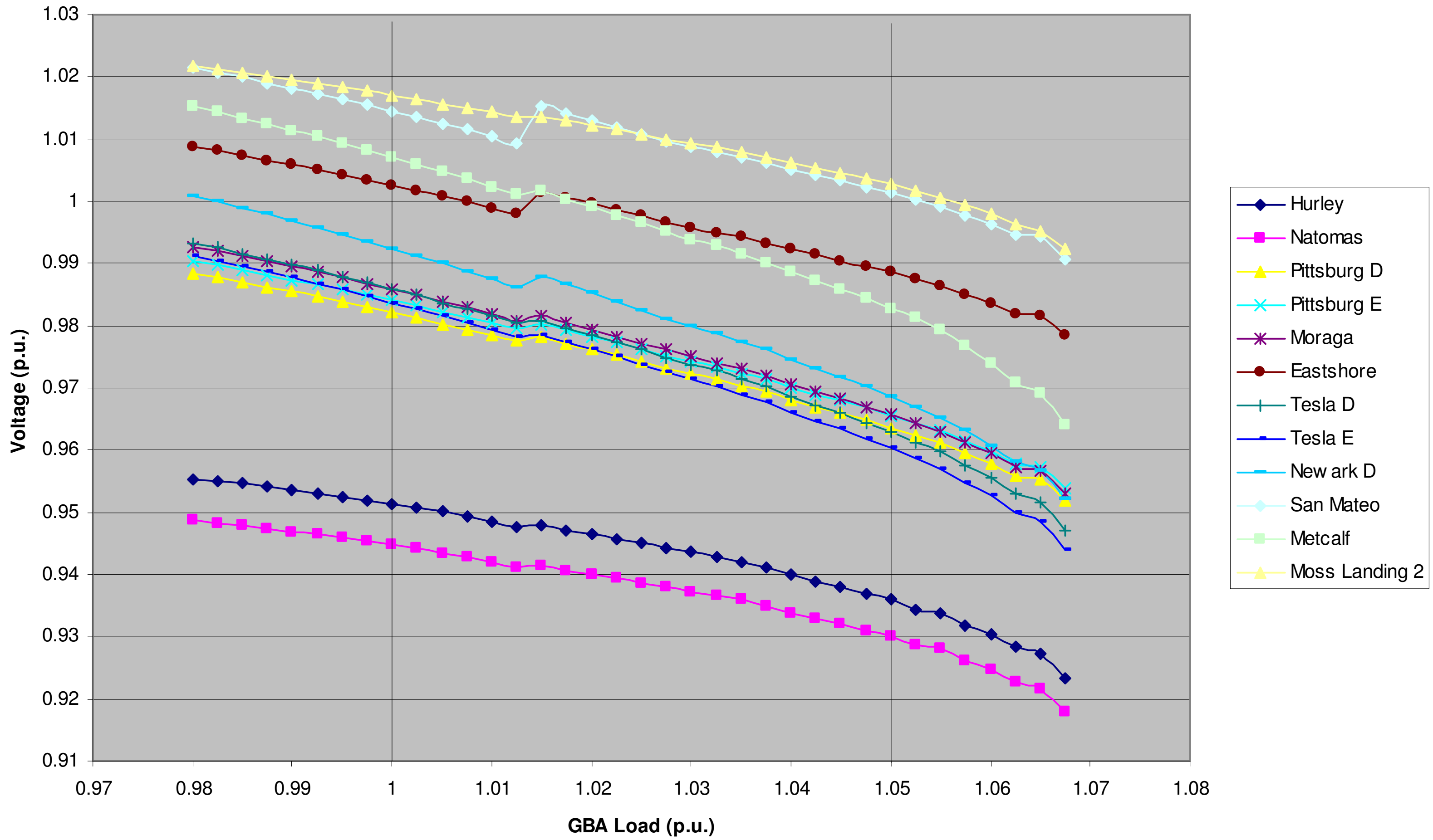

Figure 7-31 Case 3.5 – 2020: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & 2 CTs at RCEC (360 MW) In-Service

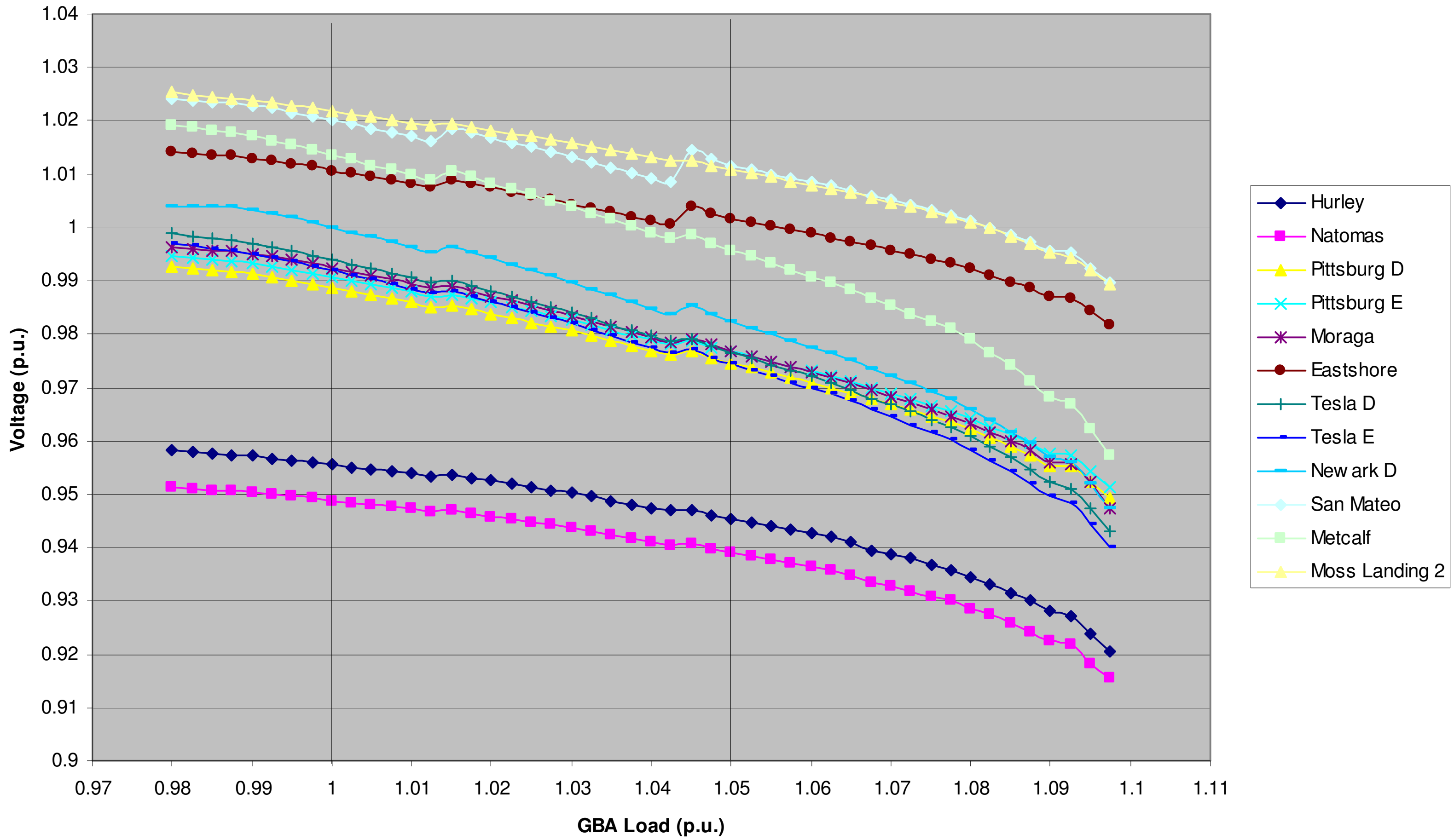

Figure 7-32 Case 3.5 – 2020: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & RCEC Plant (614 MW) In-Service

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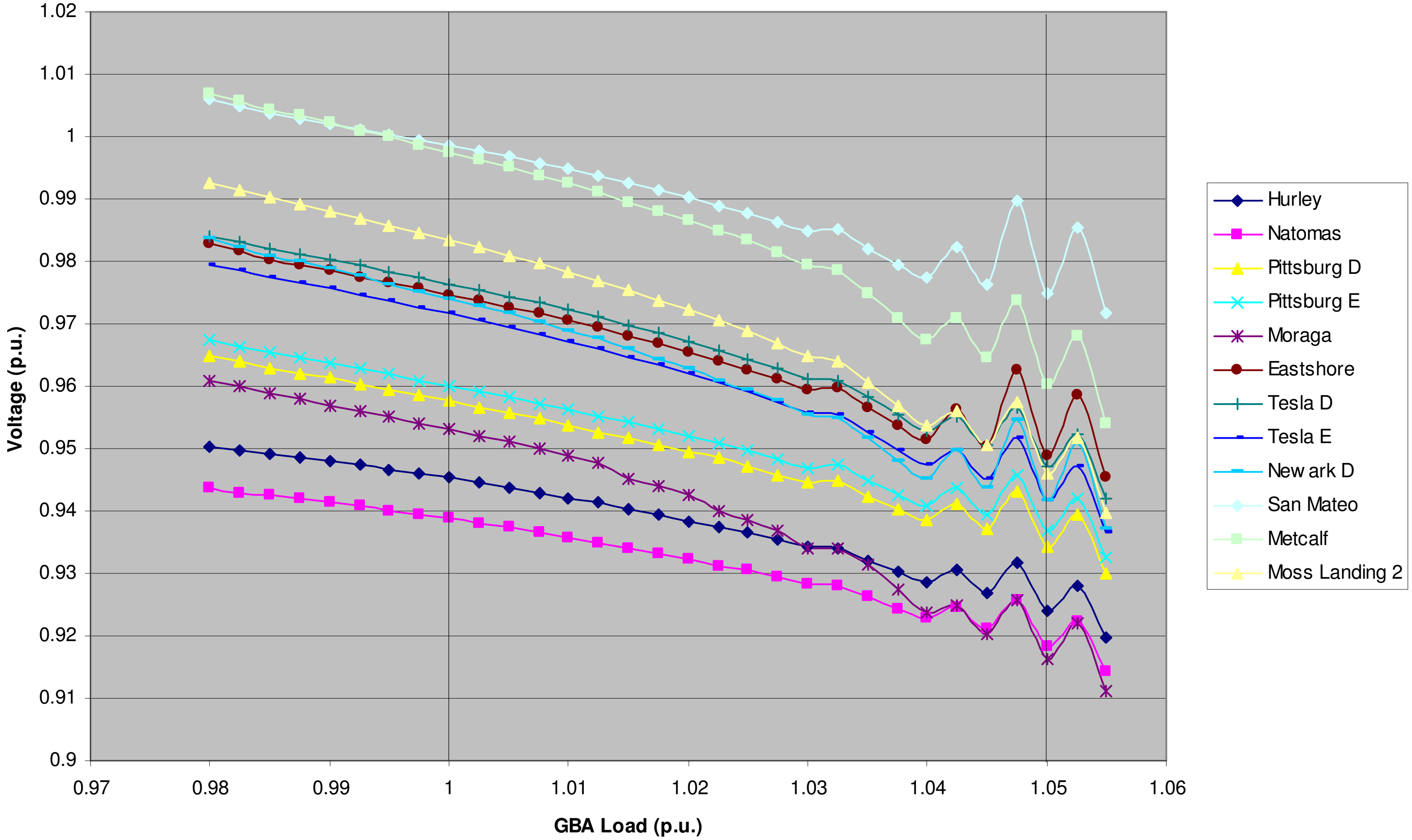


Figure 7-33 Case 1–2020: P-V Curves of 230 kV Buses Local to GBA with DEC Outage & HVDC at Collinsville

Appendix A-1
DCPP Cooling Tower Feasibility Study
Major Equipment Procurement Cost Summary

Mechanical Equipment:

Description	Quantity/Unit	Cost per Item	Total Price Per Unit	Total Price 2 Units
Cooling tower, mechanical draft (40 cells, each with 300HP fan, non plume-abated design; Back-to-back FRP; 60'x60' cell size - includes installation, excludes basin (Marley Corp.)	1	40,000,000	40,000,000	80,000,000
Condenser Waterbox/Tube Bundle Replacement Modules - Includes installation, excludes required modifications for access. (A Badcock Power Inc)	1	31,390,000	31,390,000	62,780,000
Circulating Water Pumps 215,000 GPM x 110' TDH, Model 106 APH 327 RPM 13.2kV 7600 HP Motor AL6XN Construction (Flowserve Corp.)	5	4,640,000	23,200,000	46,400,000
Makeup Water Pump 22,500 GPM x 216' TDH Model 56APK 720 RPM 1600 HP motor 2205 Duplex Construction (Flowserve Corp)	3	636,667	1,910,001	3,820,002
Service Cooling Water Seawater Supply Pumps 3150 GPM x 86' TDH, Model 16ENL 1800 RPM 460V 100 HP Motor 2205 Duplex Construction (Flowserve Corp)	3	180,000	540,000	1,080,000
36" butterfly valves motor-controlled for isolation Henry Pratt Model XR-70 150B Flanged Cast iron body with rubber lining Stainless steel disc edge & shaft Teflon-lined Fiberglass-backed	41	19,900	815,900	1,631,800
36" butterfly valves manual gear/hand wheel actuator for flow balance, placed at each cell Henry Pratt Model XR-70 150B Flanged Cast iron body with rubber lining Stainless steel disc edge & shaft Teflon-lined Fiberglass-backed	40	12,500	500,000	1,000,000
78" Henry Pratt Model XR-70 150B flanged butterfly valve Electrical motor operator Ductile Iron body with rubber lining Stainless steel disc edge & shaft Telfon-lined fiberglass-backed bearings	5	82,500	412,500	825,000
96" Henry Pratt Model XR-70 150B Flanged butterfly valves Electrical motor operator Ductile iron body with rubber lining Stainless steel disc edge & seat Teflon-lined fiberglass-backed bearings	2	135,500	271,000	542,000
20" Henry Pratt Model XR Flanged Butterfly Valves Electrical motor operator	1	12,500	12,500	25,000
Upgraded package sewage treatment system for both units				300,500
Major Mechanical Equipment Total Cost				**198,404,302**

Appendix A-1
DCPP Cooling Tower Feasibility Study
Major Equipment Procurement Cost Summary

Electrical Equipment:

Description	Quantity/Unit	Cost per Item	Total Price Per Unit	Total Price 2 Units
500kV/13.8kV 64MVA AUX transformers with DETC on HV side, +/-2x2.5% HV wye connection graded insulation 2V delta connection HV-B1L 1425kV, HV-neutral BIL 150kV	2	2,000,000	4,000,000	8,000,000
13.8kV/4kV 5.4 MVA oilfilled transformers with DETC	3	420,000	1,260,000	2,520,000
12kV/4 kV 9.0MVA oilfilled transformers with DETC for intake structure	1	420,000	420,000	840,000
Cooling tower electrical building with lineup of 5 kV Outdoor metal clad switchgear consisting of (3) 5 kV, 1200A incoming cubicles, (36) 5kV, 1200A Feeder Cubicles, & (1) 5kV, 1200A Future Feeder Cubicle, HVAC's, Battery Systems, & Work Space. Bldg is approx 161' long x 16' wide x 12' 11 gage coated steel. Foundation not included	1	2,869,555	2,869,555	2,869,555
4160v/440v 550 kVA oil-filled transformers	4	30,000	120,000	240,000
1 complete breaker-and-a-half bay (consisting of (3) 500kV circuit breakers, at least 6 breaker disconnect switches, 2 main bus extensions, all required CCVT's, 2 sets of 500 kV metering units each with a pair of isolation switches)			12,000,000	12,000,000
Major Electrical Equipment Procurement Cost				**26,469,555**

Dechlorination System:

Dechlorination System	1	250,000	250,000	**500,000**

Paralined Steel Piping:

Description	Quantity/Unit	Cost per Item	Total Price Per Unit	Total Price 2 Units
Circulating Water Tower Feed Lines 1440' long 8' dia pipe			2,770,164	5,540,328
Circulating Water Tower Feed Lines 800' long 6' dia pipe			1,079,240	2,158,480
Circulating Water Tower Feed Lines 480' long 4' dia pipe			376,332	752,664
Service Cooling Water Seawater Supply 16" dia pipe, 30 ft long coming off from each pump			18,095	36,190
Service Cooling Water Seawater Supply 4200' long 20" dia pipe			838,255	1,956,770
Makeup Water Line 600' long 48" dia pipe			470,430	940,860
Makeup Water Line 70' long 36" dia pipe			42,014	84,028
Blowdown Discharge 1600' long 36" dia pipe			762,680	1,525,360
Pump discharge 78" paralined steel, ~32ft long			120,378	240,756
Tee's, elbows, & flanges				5,334,058
Paralined Steel Piping Procurement Cost:				**18,569,494**

Appendix A-1
DCPP Cooling Tower Feasibility Study
Major Equipment Procurement Cost Summary

Fiberglass Piping:

36" fiberglass pipe: 600' of pipe w/ diffuser nozzles & 800' w/o difuser nozzles	**1,072,050**

Instrumentation and Controls:

Description	Quantity/Unit	Cost per Item	Total Price Per Unit	Total Price 2 Units
GE Fanuc Operator touchscreens	4	7,520	35,081	70,161
Triconex control system and vendor engineering	1		952,553	1,905,105
Bently Nevada vibration monitoring system, vendor engineering, and software licenses	1		583,764	1,167,529
Uninterruptible power supplies	2	44,950	89,899	179,799
36" magnetic flowmeters	2	69,721	139,443	278,885
Chemistry monitors	1 lot		100,000	200,000
Field instruments	1 lot		126,400	252,800
Cal ISO interface equiment	2		100,000	200,000
Major I&C Equipment Procurement Cost:				**4,254,279**

Total Major Equipment Procurement Cost	**$249,269,680**

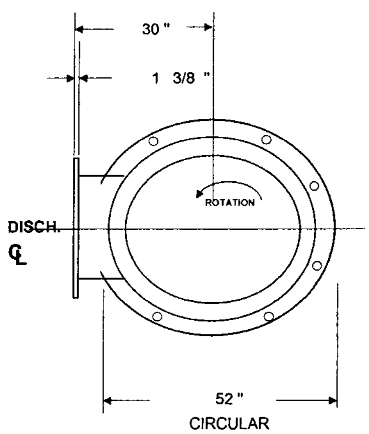
Appendix A-5
DCPP Cooling Tower Feasibility Study
Vendor Pump Quotes

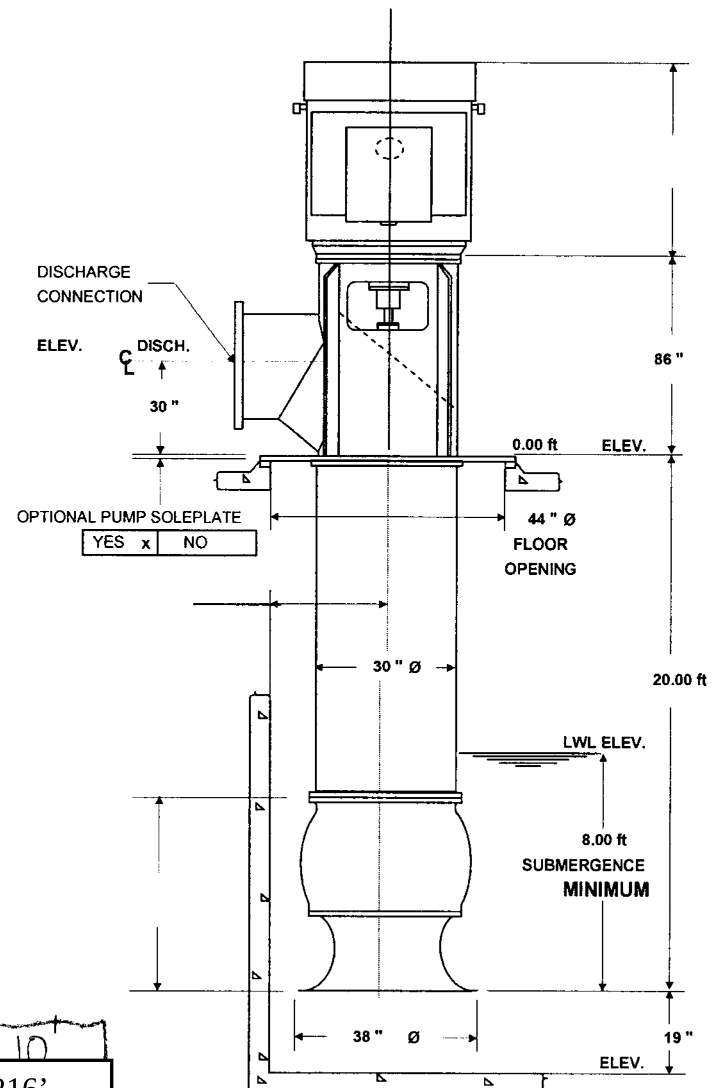
Makeup Water Pumps

VERTICAL CIRCULATING PUMP - STYLE AFS

PRELIMINARY OUTLINE DRAWING

DISCHARGE FLANGE DETAILS	
NOMINAL SIZE	30 "
FLANGE O.D.	38 3/4 "
Ø BOLT CIRCLE	36 "
NO. HOLES	28
Ø HOLES	1 3/8 "





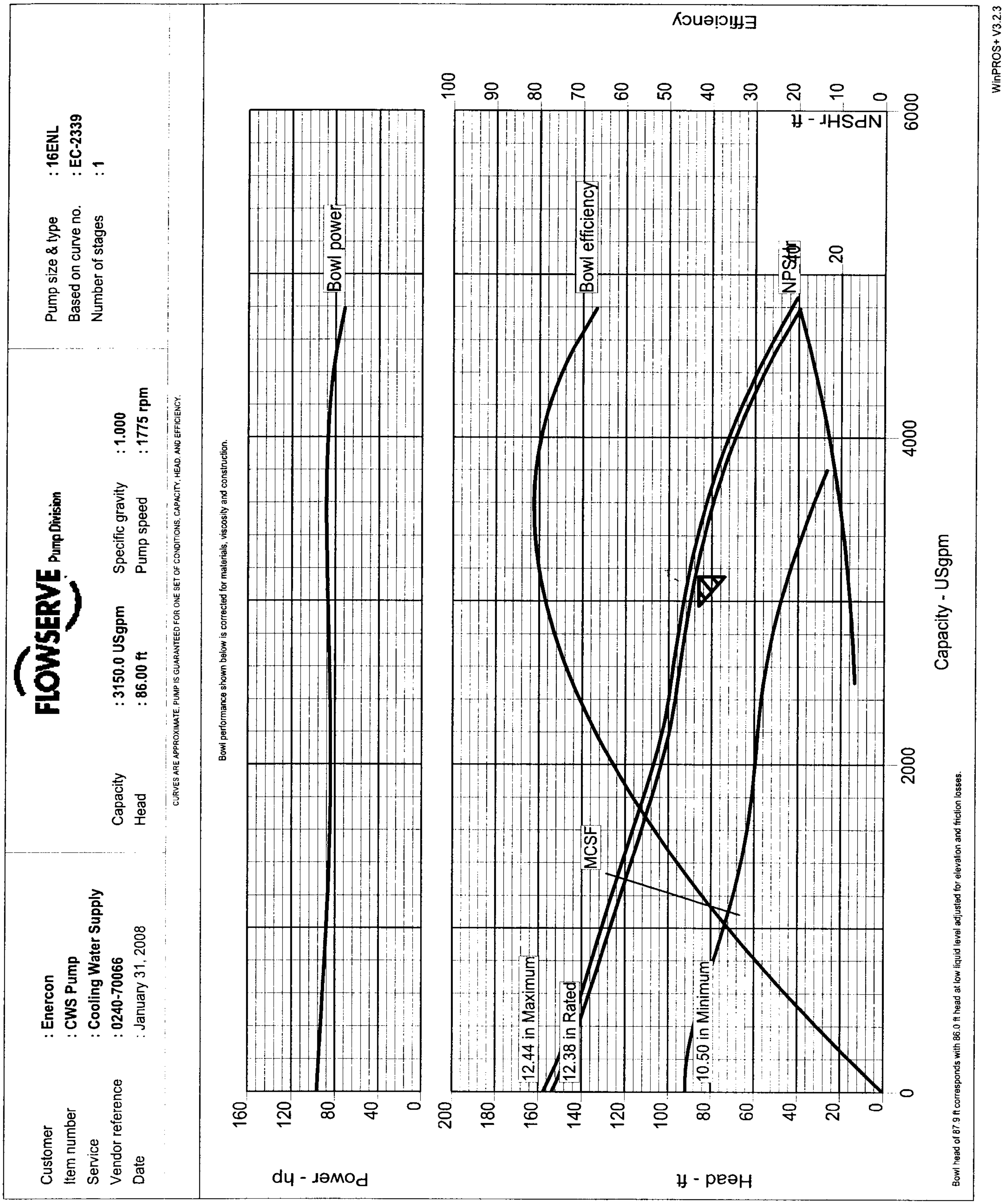
RATED OPERATING CONDITIONS		
CAPACITY - GPM	22,500 GPM	
TDH IN FEET	150.00 ft	210
MOTOR HORSEPOWER	1150 HP	216'
SPEED IN RPM	720 RPM	1470 HP

Makeup water pumps

NOTE: DIMENSIONS ARE PRELIMINARY AND ARE NOT TO BE USED FOR CONSTRUCTION PURPOSES.

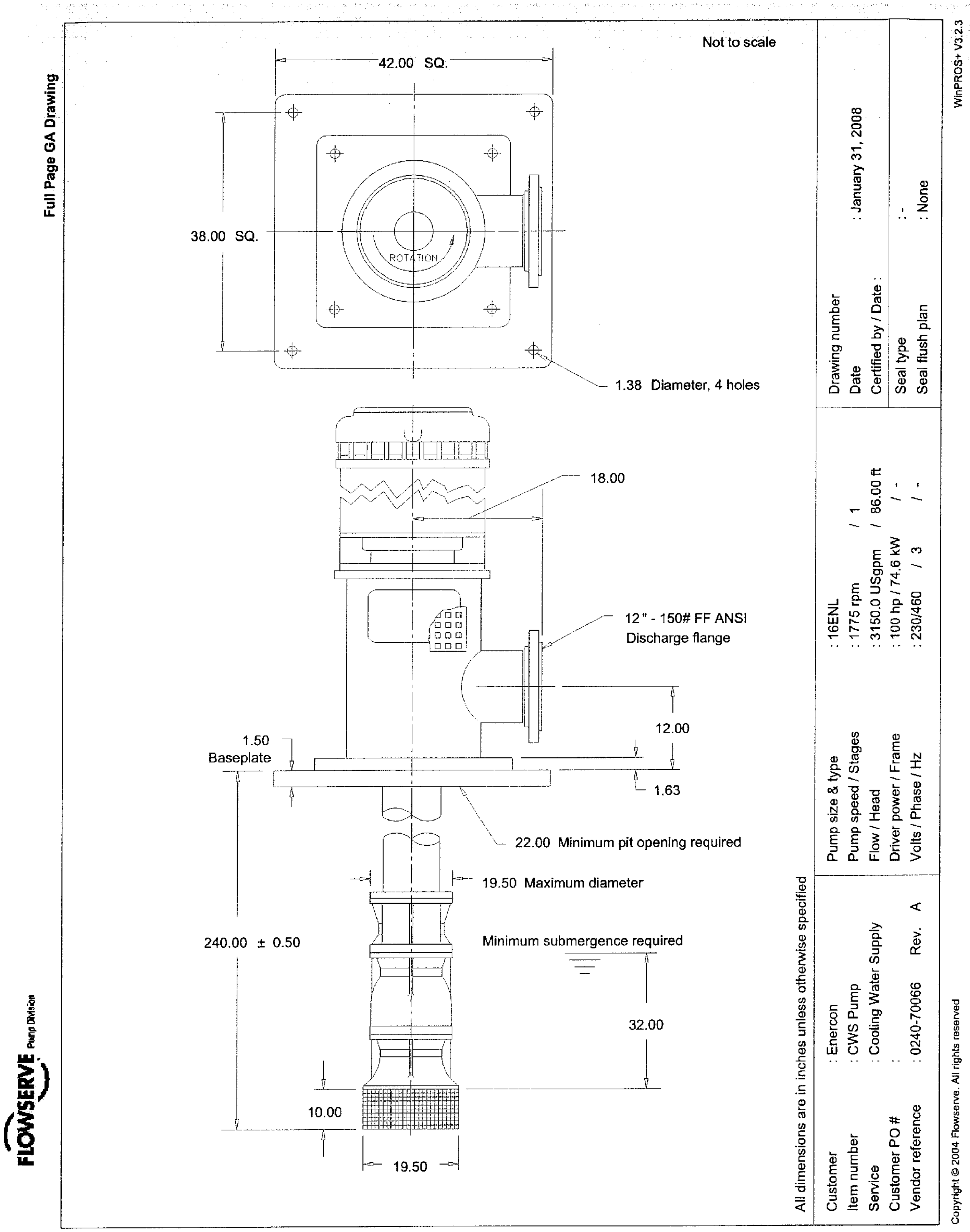
USER: Diablo Canyon Nuclear	DRAWN BY: TMH	DATE: 30JA08	PROP. NO. 0240-70066
LOCATION:			
ENGINEER: Enercon	FLOWSERVE		DRAWING NO.
PUMP SIZE AND TYPE: 42KXH			SK-1

Appendix A-5
DCPP Cooling Tower Feasibility Study
Vendor Pump Quotes
Service Cooling Water Seawater Supply Pumps

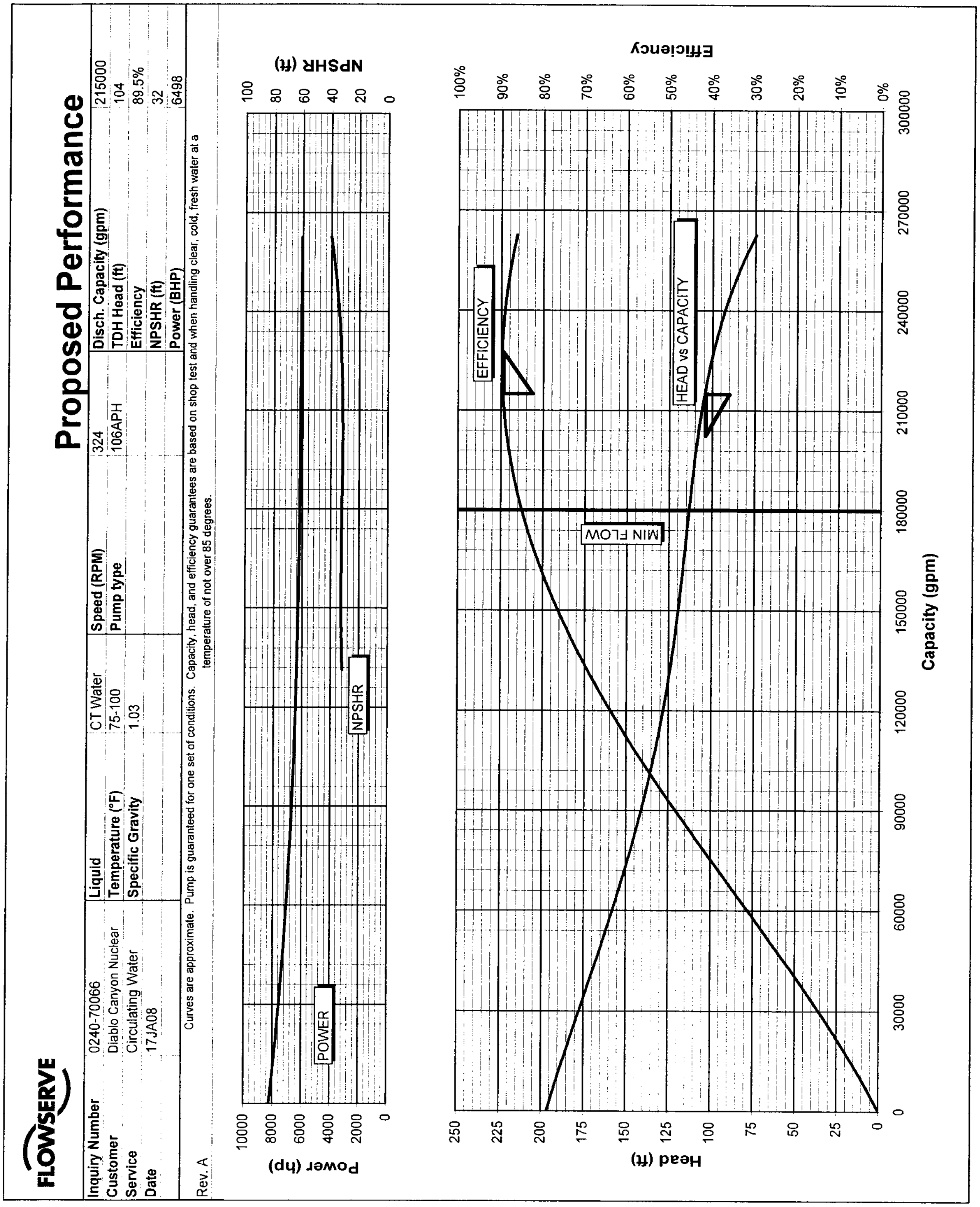


Appendix A-5
DCPP Cooling Tower Feasibility Study
Vendor Pump Quotes

Service Cooling Water Seawater Supply Pumps



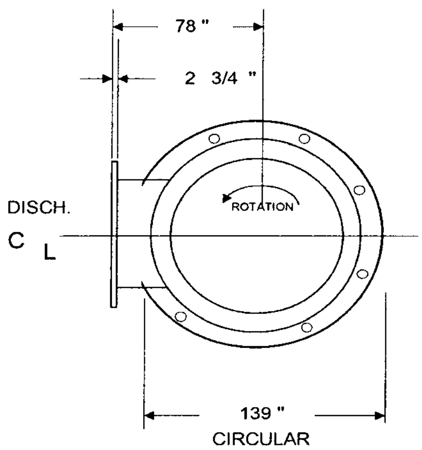
Circulating Water Pumps

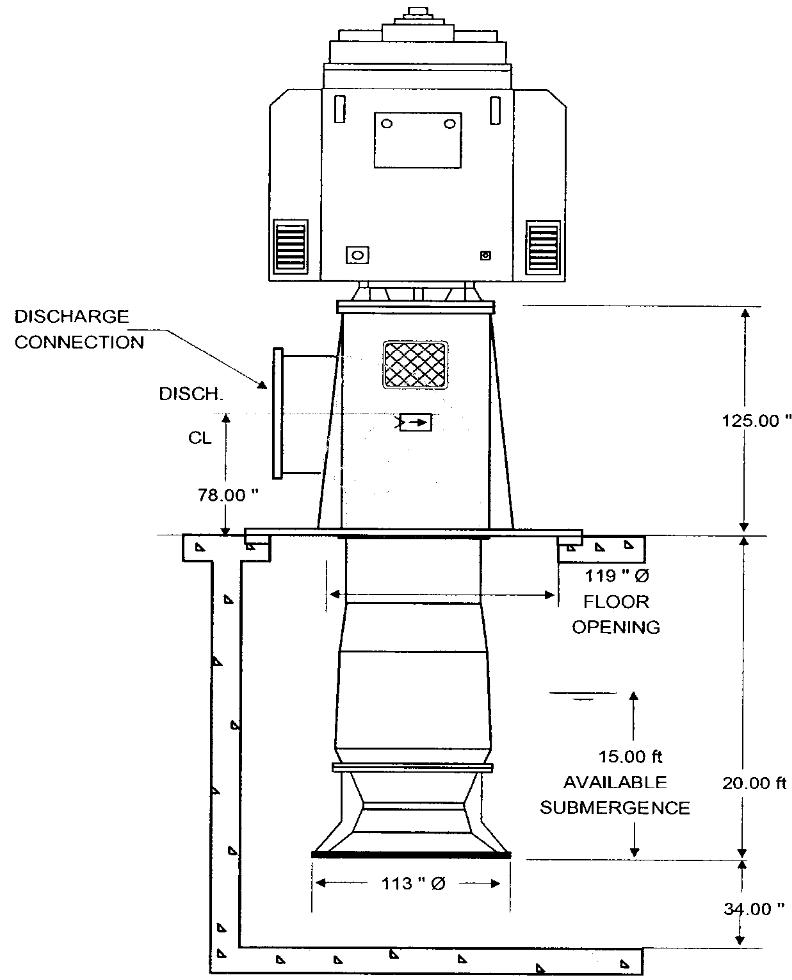


VERTICAL CIRCULATING PUMP - STYLE AFS

PRELIMINARY OUTLINE DRAWING

DISCHARGE FLANGE DETAILS	
NOMINAL SIZE	**78 "**
FLANGE O.D.	**93 "**
Ø BOLT CIRCLE	**89 "**
NO. HOLES	**64**
Ø HOLES	**2 1/8 "**





RATED OPERATING CONDITIONS	
CAPACITY - GPM	**215,000 GPM**
TDH IN FEET	**104.00 ft**
MOTOR HORSEPOWER	**7200 HP**
SPEED IN RPM	**327 RPM**

NOTE: DIMENSIONS ARE PRELIMINARY AND ARE NOT TO BE USED FOR CONSTRUCTION PURPOSES.

USER: **Diablo Canyon Nuclear**	DRAWN BY: **T. Hunt**	DATE: **18JA08**	PROP. NO. **0240-70066**
LOCATION:			
ENGINEER: **Enercon**	FLOWSERVE		DRAWING NO. **SK-1**
PUMP SIZE AND TYPE: **106APH 1-Stg VCT**			

Appendix A-4
DCPP Cooling Tower Feasibility Study
Design Change Package Estimate

Project Description	Engineering Hours									
	Mechanical	Piping	Civil	I&C	Electrical	Seismic	Environmental	Operating, Loop Test, & STP Procedures	PMT Procedure Preparation	Others
Excavation for cooling towers at a base elevation of ~85' incl, soil/geotech calcs, excavation planning, dwg preparation, access assessment, scheduling	400		2000				400			
Cooling towers basin construction, incl soil/geotech calcs, excavation planning, dwg preparation, foundation design.	200		2000							
ISFSI haul road reconstruction, incl heavy load study, soil/geotech coord, road foundation dsgn, ISFSI FSAR Update, LAR Coord, security review	200	200	3000		200	500				1000
Temporary Access route construction, incl soils/geotech coord, foundation dsgn, security review, interference coord	200		3000		600					200
Lighting for cooling towers, incl temporary & permanent, load dsgn, circuit analysis, conduit dsgn, O&M review	1000		1000		1000			200	200	200
New conduit tunnels from condenser discharge to cooling towers, incl soils/geotech dsgn, surveying reqts, flow resistance calcs, civil dsgn, concrete/rebar calcs, O&M review, dwg preparation, security review, interference coord.	600	1000	3,000	200	1000	2000	400	200	400	200
Circulating Water Pump Pit construction, incl soils/geotech coord, concrete/rebar dsgn, hydraulic review, O&M review, pump vendor coord.	2000		3000	200						200
Cooling Towers Electrical Building & Transformer Yard, incl soils/geotech coord, foundation dsgn, electrical safety review, security review, O&M review	2000		2000	500	3,000					100
Modification of the 500kV switchyard to install 500kV/13.8kV 62MVA AUX transformers, incl soils/geotech input, electrical safety review, relocation of interferences, Cal ISO coord, O&M review.	2000		2000	1000	3000	1000		800	800	
Power supply and controls to cooling tower fans, incl vendor coord, excavation planning, soils/geotech coord, O&M review, conduit support	3000		2000	200	5000			400	400	

Appendix A-4
DCPP Cooling Tower Feasibility Study
Design Change Package Estimate

Project Description	Engineering Hours									
	Mechanical	Piping	Civil	I&C	Electrical	Seismic	Environmental	Operating, Loop Test, & STP Procedures	PMT Procedure Preparation	Others
Installation of CW pumps, 8' dia paralined steel pipe at pump pit, other individual l.o. pumps, HXs & valves, incl vendor coord, O&M review, civil/electr/I&C/piping support, installation planning/scheduling	4000	3000	2000	200	2000			400	400	
Installation of CW Piping, incl planning/scheduling, access planning, concrete logistics, O&M, security review, soils/geotech coord, utility interference review	5000	1,500	4,000	100				200	200	
Installation of Piping at Cooling Tower Cell interface (w/ valves, motor operators), incl piping support, soils coord, O&M review.	5000	5000	2000	200	1200			400	400	
New Makeup Water Supply Piping & M.O.Valves, incl piping, intake structure mods, restraint dsgn, soils/geotech coord, O&M review, security, coord w/ circ wtr conduits, utility interferences.	1000	1500	1,500	200	1000			200	200	
Installation of makeup water pumps, incl intake structure mods, l.o clrs, O&M review, security, utility interference.	2,000	400	1000	200	600			400	400	
Modification of sodium hypochlorite injection system, incl pipe routing, support, environmental/safety review, O&M review, .	2000	1000	1000	500	200		400	200	200	
Power Supply for New Svc Clg Water Seawater Supply & Makeup Pumps, incl 12kV/4kV & 4kv/440v xfmrs, conduit routing, I&C coord, O&M review, Security & Electr Safety review	2000	600	2000	200	5000			400	400	
Tubine Building Structural Modification to Accommodate new Svc Clg Water Seawater Supply & Return Lines, incl piping & structural support analysis, O&M review, access study, planning & scheduling, temporary equipment relocation, security review.	800	2,000	2,000	200	1,000	2,000				
Installation of Svc Clg Water Seawater Supply (SCWSS) Piping & Valves, incl piping, intake structure mods, restraint dsgn, soils/geotech coord, O&M review, security, coord w/ circ wtr conduits, utility interferences.	1,000	3,000	3000	200				200	200	

Appendix A-4
DCPP Cooling Tower Feasibility Study
Design Change Package Estimate

Project Description	Engineering Hours									
	Mechanical	Piping	Civil	I&C	Electrical	Seismic	Environmental	Operating, Loop Test, & STP Procedures	PMT Procedure Preparation	Others
Installation of SCWSS Pumps, incl intake structure mods, O&M review, security & utiltiy interference reviews, I&C interface to control room, local control stations.	2,000		2000	200	1,000			400	400	
Blowdown system piping installation, incl weir discharge structure, pipe routing, O&M review, permit coord w/ Cal Coastal Comm, Regional Water Quality board, difussion study coord.	1,400	2,000	3,000	200	400		1200	200	200	
Procurement of Circ Water Pumps, incl spec development, interdiscipline coord, O&M review, bidding, evaluation, award, vendor print review, procurement support	4000	200	400	200	2000					1200
Procurement of Makeup Water Pumps, incl spec development, interdiscipline coord, O&M review, bidding, evaluation, award, vendor print review, procurement support	1600	40	200	200	1000					1000
Procurement of Svc Clg Wtr Seawater Supply Pumps, incl spec development, interdiscipline coord, O&M review, bidding, evaluation, award, vendor print review, procurement support	1200	40	200	200	800					800
Procurement of Paralined Steel Piping, incl spec development, mech & piping coord, San Ramon coatings group coord, procurement support	200	1600	200							800
Procurement of (2) 500kV/13.8kV 62 MVA Aux transformers w/ DETC on HV Side, incl spec development, interdiscipline coord, O&M review, bidding, evaluation, award, vendor print review, fire protection & procurement support.	300		800	200	2000					400
Procurement of (6) 13.8kV/4kV 5.4 MVA Aux transformers, oil filled w/ DETC, incl spec development, interdiscipline coord, O&M review, bidding, evaluation, award, vendor print review, fire protection & procurement support.	200		800	200	1600					400

Appendix A-4
DCPP Cooling Tower Feasibility Study
Design Change Package Estimate

Project Description	Engineering Hours									
	Mechanical	Piping	Civil	I&C	Electrical	Seismic	Environmental	Operating, Loop Test, & STP Procedures	PMT Procedure Preparation	Others
Procurement of (2) 12kV/4kV 8.0 MVA Aux transformers, oil filled w/ DETC, for intake structure, incl spec development, interdiscipline coord, O&M review, bidding, evaluation, award, vendor print review, fire protection & procurement support.	200		800	200	1600					200
Procurement of (3) SF6500kV breakers, 550kV, 3000 Amps CC, 55 kAIC, 500 Amps, incl spec development, interdiscipline coord, O&M review, bidding, evaluation, award, vendor print review, procurement support.	200		800	200	2000					
Procurement of (2) Clg Twr Electrical Buildings, 177' L x 16'W, incl spec development, interdiscipline coord, O&M review, bidding, evaluation, award, vendor print review, fire protection & procurement support.	400		1600	200	2600					200
Procurement of (1) 500kV Electric Current metering system, incl spec development, interdiscipline coord, O&M review, bidding, evaluation, award, vendor print review, procurement support.	200		400	200	1600					
Procurement of (2) 4kV/460V 550 kVA Aux transformers, oil filled, for intake structure, incl spec development, interdiscipline coord, O&M review, bidding, evaluation, award, vendor print review, fire protection & procurement support.	200		800	200	1200					100
Procurement of Triconex control system, coordination with supplier, drawing review, and factory testing.				2000	200					
Procurement of Bently Nevada vibration monitoring system, coordination with supplier, drawing review, and factory testing.				1000	200					
Procurement of control system UPS's, coordination with supplier, drawing review, and factory testing.				200	1000					

Appendix A-4
DCPP Cooling Tower Feasibility Study
Design Change Package Estimate

Project Description	Engineering Hours									
	Mechanical	Piping	Civil	I&C	Electrical	Seismic	Environmental	Operating, Loop Test, & STP Procedures	PMT Procedure Preparation	Others
Procurement and drawing review for flowmeters and miscellaneous instrumentation.				500	50					
Preparation of DCPs for control system.			1000	12000	16000	1000		8000	8000	
Licensing Amendment Request and Evaluation	3000	400	2000	1000	2000	400	2000			
Main Condenser Waterbox/Tubesheet/Tube Bundle Modification	3000	400	1000	200	300			400	400	
Turbine Builing Flooding Reanalyses	400		400	400	400					
Special Analyses (such as water hammer, circ pump pit modelling)	2000		1200		1600					1000
Contigency hours (20% of the hours)	10980	4776	11820	4760	12870	1380	880	2600	2640	1600
Total Hours	65,880	28,656	70,920	28,560	77,220	8,280	5,280	15,600	15,840	9,600
Total Hours										**325,836**

Notes:

1. Technical coordinator, ESC designer, and drafter hours are included in engineering estimates.

Appendix A-3
Cooling Tower Feasibility Study
Estimate of Engineering

Pre-Procurement Design Engineering

Discipline	No. of Workers	Duration	Hrs/Month	Total Hrs
Management	2	30	160	9,600
Administration	2	30	160	9,600
Mechanical	6	30	160	28,800
Civil/Arch	6	30	160	28,800
Electrical	5	24	160	19,200
I&C	2	18	160	5,760
Planning/Scheduling	3	24	160	11,520
Piping	3	18	160	8,640
Layout	4	18	160	11,520
Permitting/Environmental	4	30	160	19,200
Licensing	4	30	160	19,200
Total Hours				**171,840**

Appendix A-2
DCPP Cooling Tower Feasibility Study
Equipment List

List of Major Equipment (Total for BOTH UNITS)

Mechanical Equipment

1) (2) Mechanical Draft Non Plume-Abated Saltwater Cooling Towers, Each w/ 40 cells, each cell 60’ x 60’ plan w/ 300 hp fan.
2) (2) Condenser Modules 90,000 0.75” OD x 22BWG titanium tubes, surface area of 716,800 ft^2, pressure drop of 10.65 ft H_2O at 862,690 GPM
3) (10) Circulating Water Pumps, 215,000gpm x 110’ tdh vertical, Flowserve Model 106APH w/ 327 rpm 13.2kV 7600 hp WPII Induction Motor.
4) (6) Makeup Water Pumps, 22,500 gpm x 216’ tdh vertical, Flowserve Model 56APK w/ 720 rpm 4kV 1600 hp WPII motor.
5) (6) Service Cooling Water Seawater Supply Pumps, 3150 gpm x 86’ tdh vertical, Flowserve Model 16ENL w/ 1800 rpm 460V 100 hp WPII motor.
6) (82) 36” Henry Pratt Model XR-70 150B flanged butterfly valves w/ replaceable packing bonnet & elec. mtr op, cast iron w/ rubber lining body, ductile iron w/ rubber lining disc, stainless steel disc edge & shaft, Teflon-lined Fiberglass-back bearings. (1) valve at each cooling tower cell for isolation. (1) valve at discharge of each makeup water pump.
7) (80) 36” Henry Pratt Model XR-70 150B flanged butterfly valves w/ manual gear/hand wheel actuator, cast iron w/ rubber lining body, ductile iron w/ rubber lining disc, stainless steel disc edge & shaft, Teflon-lined Fiberglass-back bearings. (1) valve at each cooling tower cell for flow balance.
8) (10) 78" Henry Pratt Model XR-70 150B flanged butterfly valve w/ replaceable packing bonnet & electrical motor operator, ductile iron w/ rubber lining body & disc, stainless steel disc edge & shaft, Telfon-lined fiberglass-backed bearings. (1) valve at discharge of each circulating water pump.
9) (4) 96" Henry Pratt Model XR-70 150B Flanged butterfly valves w/ replaceable packing bonnet & electrical motor operator, ductile iron w/ rubber lining & disc, stainless steel disc edge & seat, Teflon-lined fiberglass-backed bearings. (2) valves at the common discharge line where 5 discharge pumps connect.
10) (2) 20” Henry Pratt Model 2FII 150B Flanged Butterfly valves with replaceable packing bonnet & electrical motor operator, cast iron with rubber lining. Valves at the service cooling seawater supply line before the blowdown inlet.
11) Upgraded packaged sewage treatment system consisting of flow equalization tank, aeration tank, clarifier, clearwell, pressurized multimedia filtration system, anoxic tank for nitrate reduction and UV light system for disinfection.

Electrical Equipment

1) (4) HV Transformers, each 64MVA, 500/13.8kV AUX w/o CTs, arresters, w/ DETC on HV side, HV wye connection graded insulation, LV delta connection, HV-BIL 1425kV, HV-neutral BIL 150kV.
2) (6) Medium Voltage Cooling Tower Transformers, each 5.4MVA, 13.8kV/4kV oil filled w/ DETC.

3) (2) Medium Voltage Intake Structure Auxiliary Transformers, each 9 MVA, 12kV/4kV oil-filled w/ DETC.
4) (1) Electrical Equipment Houses, each 177'L x 16'W x 12' H, of 11 gauge coated steel, (5) 15kV/1200A metalclad switchgear breakers & (1) Lineup of 5kV Outdoor Metalclad Switchgear consisting of (3) 5kV/1200A Incoming Cubicles, (36) 5kV/1200A Feeder Cubicles, & (1) 5kV/1200A future Feeder Cubicle, HVAC's, Battery Systems, & Work Space. Building is approximately 161'long x16'wide x 12', 11 gage coated steel. Foundation is not included.
5) (2) 4160v/440v 550kVA oil-filled transformers for Service Cooling Water Seawater Supply pump motor.
6) (1) complete breaker-and-a-half bay consisting of (3) 500kV circuit breakers, no fewer than 6 breaker disconnect switches, (2) main bus extensions, all required CCVT's (2) sets of 500KV metering units each with a pair of isolation switches.

Paralined Steel Piping (total for both units):
Circulating Water Tower Feed Lines: 2880' long 8' dia. Pipe.
Circulating Water Tower Feed Lines: 1600' long 6' dia. Pipe.
Circulating Water Tower Feed Lines: 960' long 4' dia. Pipe.
Service Cooling Water Seawater Supply: 16" dia. pipe, 30 ft long coming off from each pump.
Service Cooling Water Seawater Supply: 8400' long 20" dia. Pipe.
Makeup Water Line: 1200' long 48" dia. pipe.
Makeup Water Line: 140' long 36" dia. pipe.
Blowdown Discharge: 3200' long 36" dia. pipe.
Pump discharge: 78" paralined steel, ~32ft long.
Tee fittings: (32) 96" dia., (32) 72" dia., & (8) 48" dia..
90^o elbows: (4) 96" dia., (10) 48" dia. (38) 20" dia. & (18) 32" dia..
45^o elbows: (2) 36" dia. & (24) 20" dia..
30^o elbows: (2) 48" dia., (2) 36" dia., (4) 32" dia., & (8) 20" dia..

36" diameter Fiberglass Pipe (for both units):
36" dia. 1400' total, 1.199" thick wall, 3/8" thick stiffeners, 400' with (80) FRP couplings mounted in (2) rows the length of the pipe, 12" on centers.
(2) 50 PSI rated flanges both ends.

Instrumentation and Controls Equipment
1) (8) GE Fanuc 15" touch screen PC operator interfaces with Wonderware software.
2) (2) Triconex model 8110 main chassis.
3) (8) Triconex model 8111 expansion chassis.
4) (6) Triconex model 9000 expansion chassis I/O bus cable.
5) (20) Triconex model 8310 chassis power module.
6) (6) Triconex model 3008 main processors.
7) (8) Triconex model 4352A TCM communications module.
8) (40) Triconex model 3501E/T digital input module.

9) (80) Triconex model 9563-810 digital input field termination module.
10) (26) Triconex model 3636R/T relay output module.
11) (52) Triconex model 9668-110 relay output field termination module.
12) (18) Triconex model 3700 0-5VDC analog input module.
13) (36) Triconex model 9771-210 analog input field termination module.
14) (10) Triconex model 3706A thermocouple analog input module.
15) (20) Triconex model 9764-310 thermocouple input field termination module.
16) (4) Triconex model 3511 pulse input module.
17) (4) Triconex model 9753-110 pulse input field termination module.
18) (1) Triconex model 7254-4 Trisation license.
19) (1) Triconex model 7260 diagnostics monitor license.
20) (8) Kepco model HSP 28-36MR 24 VDC power supply.
21) (8) Kepco model HSP 48-36MR 48 VDC power supply.
22) (8) Garrettcom model 6K16 fiber switches.
23) (2) Kontron Compact PCI maintenance PC.
24) (2) Nematron model LM8006-2WO maintenance HMI.
25) (12) Triconex system cabinets.
26) (14) Bently Nevada model 3500/05 racks.
27) (28) Bently Nevada model 3500/15 power supplies.
28) (14) Bently Nevada model 3500/22 TDI transient data interface modules.
29) (14) Bently Nevada model 3500/92 gateway communication modules.
30) (14) Bently Nevada model 3500/25 keyphasor modules.
31) (54) Bently Nevada model 3500/42 proximitor/velometor modules.
32) (62) Bently Nevada model 3500/42 proximitor/velometor modules with modification for triaxial accelerometers.
33) (8) Bently Nevada model 3500/33 relay output modules.
34) (4) Bently Nevada model 3500/92 VGA modules.
35) (4) Bently Nevada model 3500/94 touch screen HMIs.
36) (10) Bently Nevada system cabinets.
37) (2) Bently Nevada System 1 server.
38) (1) Bently Nevada 3500 software and licenses and System 1 licenses.
39) (4) 5KVA UPS with 120 VAC input and output and integral sealed batteries.
40) (4) 36" flanged magnetic flowmeters.
41) (96) Temperature transmitters.
42) (lot) Chemistry monitors.
43) (lot) Miscellaneous instrumentation.
44) (2) Interface equipment for Cal ISO.

Commodities

1) 13.8kV insulated cable
2) 4kV insulated cable
3) Carbon Steel Pipe with internal "Paraline" coating.

I&C Detailed Material and Vendor Engineering Cost Estimate

Assumptions:
1. Valves are covered in other estimates.
2. Vibration, temperature, and other sensors on equipment are included in equipment costs.
3. All costs are in 2008 dollars.

Operator Touchscreens:

Manufacturer	Model Number	Description	Quantity per Unit	Cost per Item	Total Cost per Unit	Total Cost for Both Units	Notes
GE Fanuc	IC5005	15" touchscreen PC operator interface	4	$7,520	$30,081	$60,161	2
Wonderware		Wonderware license			$5,000	$10,000	5
Touch Screen Total Cost					**$35,081**	**$70,161**	

Triconex Supplied Equipment and Engineering:

Manufacturer	Model Number	Description	Quantity per Unit	Cost per Item	Total Cost per Unit	Total Cost for Both Units	Notes
Triconex	8110	Main chassis	1	$7,778	$7,778	$15,556	3
Triconex	8111	Expansion chassis	4	$6,546	$26,184	$52,369	3
Triconex	9000	Expansion chassis IO bus cable	3	$513	$1,539	$3,078	3
Triconex	8310	Chassis power module	10	$2,303	$23,026	$46,053	3
Triconex	3008	Main Processors	3	$12,982	$38,946	$77,893	3
Triconex	4352A	TCM communication module with multimode fiber	4	$12,040	$48,158	$96,316	3
Triconex	3501E/T	Digital input module (32 points)	20	$5,076	$101,519	$203,038	3
Triconex	9563-810	Field termination module for digital inputs (16 points)	40	$1,013	$40,511	$81,022	3
Triconex	3636R/T	Relay output module (32 points)	13	$5,558	$72,248	$144,496	3
Triconex	9668-110	Field termination module for relay outputs (16 points)	26	$1,013	$26,332	$52,664	3
Triconex	3700	0-5 VDC analog input module (32 points)	9	$9,378	$84,398	$168,795	3
Triconex	9771-210	Field termination module for analog inputs (16 points)	18	$1,013	$18,230	$36,460	3
Triconex	3706A	Thermocouple analog input module (32 points)	5	$9,378	$46,888	$93,775	3
Triconex	9764-310	Field termination module for thermocouple inputs (16 points)	10	$2,491	$24,914	$49,828	3
Triconex	3511	Pulse input module (8 points)	2	$6,100	$12,199	$24,398	2

I&C Detailed Material and Vendor Engineering Cost Estimate

Triconex	9753-110	Field termination module for pulse inputs (8 points)	2	$1,013	$2,026	$4,051	4
Triconex	7254-4	Tristation 1131 license	1	$4,840	$4,840	$9,680	3
Triconex	7260	Diagnostics monitor license	1	$1,210	$1,210	$2,420	3
Kepco	HSP 28-36MR	24 VDC power supply	4	$2,355	$9,419	$18,837	2
Kepco	HSP 48-36MR	48 VDC field power supply	4	$2,355	$9,419	$18,837	2
Garrettcom	6K16	Fiber switches	4	$975	$3,901	$7,802	2
Kontron	Compact PCI	Maintenance PC	1	$6,299	$6,299	$12,599	2
Nematron	LM8006-2WO	Maintenance HMI	1	$2,570	$2,570	$5,140	2
		Cabinet	6	$5,000	$30,000	$60,000	5
		Miscellaneous components	Lot	$10,000	$10,000	$20,000	5
Triconex Total Material Cost					$652,553	$1,305,105	
System Integration Engineering (incl factory test)					$100,000	$200,000	5
Programming					$150,000	$300,000	5
Graphics Development					$50,000	$100,000	5
Triconex Total Cost					**$952,553**	**$1,905,105**	

Bently Nevada Equipment:

Manufacturer	Model Number	Description	Quantity per Unit	Cost per Item	Total Cost per Unit	Total Cost for Both Units	Notes
Bently Nevada	3500/05	3500 rack	7	$5,000	$35,000	$70,000	5
Bently Nevada	3500/15	Power supply	14	$311	$4,354	$8,707	2
Bently Nevada	3500/22	TDI transient data interface module	7	$4,979	$34,854	$69,708	2
Bently Nevada	3500/92	Gateway communications module	7	$842	$5,895	$11,790	2
Bently Nevada	3500/25	Keyphasor module	7	$1,465	$10,257	$20,514	2
Bently Nevada	3500/42	Proximitor/velometor module	27	$3,290	$88,830	$177,659	2
Bently Nevada	3500/42	Proximitor/velomitor module with mod for triaxial accelerometers	31	$4,091	$126,821	$253,643	2
Bently Nevada	3500/33	Relay output module	4	$3,284	$13,136	$26,272	2
Bently Nevada	3500/92	VGA module	2	$1,768	$3,536	$7,071	2
Bently Nevada	3500/94	Touchscreen HMI	2	$8,310	$16,621	$33,241	2
		Cabinet	5	$5,000	$25,000	$50,000	5
Bently Nevada		System 1 server	1	$14,178	$14,178	$28,355	2
Bently Nevada		3500 software and licenses and System 1 license	1		$105,284	$210,568	6
Bently Nevada Total Material Cost					$483,764	$967,529	
System Integration Engineering					$100,000	$200,000	5
Bently Nevada Total Cost					**$583,764**	**$1,167,529**	

I&C Detailed Material and Vendor Engineering Cost Estimate

UPS:

Manufacturer	Model Number	Description	Quantity per Unit	Cost per Item	Total Cost per Unit	Total Cost for Both Units	Notes
		5 KVA UPS with 120 VAC input and output and integral sealed batteries	2	$44,950	$89,899	$179,799	7
Total UPS Cost					**$89,899**	**$179,799**	

Flowmeters:

Manufacturer	Model Number	Description	Quantity per Unit	Cost per Item	Total Cost per Unit	Total Cost for Both Units	Notes
		36" magnetic flowmeter with 300 lb flanges, remote electronics, teflon liner, and epoxy coated carbon steel body.	2	$69,721	$139,443	$278,885	8
Total Flowmeter Cost					**$139,443**	**$278,885**	

Chemistry Instruments:

Manufacturer	Model Number	Description	Quantity per Unit	Cost per Item	Total Cost per Unit	Total Cost for Both Units	Notes
		Miscellaneous chemistry monitors			$100,000	$200,000	5
Total Chemistry Monitor Cost					**$100,000**	**$200,000**	

Field Instruments:

Manufacturer	Model Number	Description	Quantity per Unit	Cost per Item	Total Cost per Unit	Total Cost for Both Units	Notes
		Temperature transmitters	48	$500	$26,400	$52,800	5
		Miscellaneous instruments			$100,000	$200,000	5
Total Field Instrument Cost					$126,400	$252,800	

I&C Detailed Material and Vendor Engineering Cost Estimate

Cal ISO Interface Equipment:

Manufacturer	Model Number	Description	Quantity per Unit	Cost per Item	Total Cost per Unit	Total Cost for Both Units	Notes
		Servers, communication equipment, etc.			$100,000	$200,000	5
Total Cal ISO Interface Cost					**$100,000**	**$200,000**	

Total I&C Equipment and Vendor Engineering Cost	**$2,127,140**	**$4,254,279**

Notes:
1. All costs include 10% additional for tax and freight.
2. Cost is based on PIMS inventory parts catalog with 10% escalation and 10% for tax and freight.
3. Triconex material costs are based on 4/3/2007 quotation for another project with escalation of 10% to 2008 dollars and 10% additional for tax and freight.
4. Used 4/3/2007 quotation price for 9771-210 with 10% escalation and 10% tax and freight.
5. Assumed price based on experience.
6. Based on 12/2006 budgetary quote for a similar system. Escalated 10% and added 10% tax and freght.
7. Based on inventory parts catalog for 5KVA UPS. 2003 price was $21,345. Assumed integral batteries increase price by 50% and escalated price to 2008 at 5% per year. Added 10% tax and freight.
8. Based on verbal quote from Rosemount.

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

TABLE of CONTENTS

1.	PURPOSE	2
2.	BACKGROUND	2
3.	ASSUMPTIONS	3
4.	DESIGN INPUTS	4
5.	METHODOLOGY	9
6.	ACCEPTANCE CRITERIA	14
7.	CALCULATION	15
8.	RESULTS	22
9.	MARGIN ASSESSMENT	46
10.	CONCLUSIONS	46
11.	IMPACT EVALUATION	47
12.	REFERENCES.	48
ATTACHMENT 1 - MISCELLANEOUS DATA SOURCES		49
ATTACHMENT 2 - FILES		57

Record of Revision

Revision 0: Initial Issue

1. PURPOSE

This calculation estimates plume characteristics for cooling towers at the Diablo Canyon Nuclear Power Plant (DCPP) owed by the Pacific Gas and Electric Company (PG&E). The characteristics of interest are visible plume lengths, fogging, and salt deposition on surrounding lands.

2. BACKGROUND

DCPP is located near Avila Beach, California, on the Pacific Coast. Figure 1 shows the site.

Currently, the plant is cooled by a once-through pass of ocean water. Diablo Canyon Power Plant (DCPP) could be subject to a requirement to retrofit the existing once-through cooling system to closed-cycle cooling.

Ongoing development of Federal Clean Water Act Section 316(b) regulations regarding aquatic organism Impingement and Entrainment (I & E) and a California Specific Policy for 316(b) rule implementation may require all coastal power plants to reduce marine I&E to levels commensurate with a closed-cycle cooling system. PG&E is investigating the use of cooling towers; however, cooling towers produce visible plumes and deposition of water and salt on the surrounding lands.

As part of the investigation, plume characteristics are quantified by use of the Seasonal/Annual Cooling Tower Impacts (SACTI) cooling tower plume model. This model was identified in Section 5.3.3.1 of the NRC's standard review plan (Reference 12.6) as an acceptable code for cooling tower plume impacts in the nuclear industry.

3. ASSUMPTIONS

3.1. The meteorological data described in Section 5 are representative of future conditions.

3.2. The SACTI computer software is used with all its associated assumptions per Reference 12.2. It is noted that the accuracy of the SACTI code has been recognized by the NRC (Section 5.3.3.1 of Reference 12.6).

3.3. The meteorological data is a hybrid of various data sources, but the impact of merging these sources is assumed to be insignificant compared to the inherent uncertainties of predicting future meteorological conditions. The wind speeds and direction are taken from the site meteorology tower (Reference 12.3, referred to here as "site met data"), the temperature, humidity, and cloud cover data are from the Nation Weather Service station KSBP at San Luis Obispo (SLO) airport located 20 miles to the southeast (Reference 12.4), and the mixing height data is purchased from the National Climatic Data Center using their best information, which is upper air conditions at San Diego and surface conditions at SLO (Reference 12.5).

3.4. The terrain around DCPP in the direction of most plumes is grassland. Table D-1 of Reference 12.2 recommends use of 3.2 to 3.94 cm for grasslands, so a value of 3.5 cm is used.

3.5. A number of required but non-critical data inputs are based on scaling to the LMDCT example in the SACTI manual (Reference 12.2). The Reference 12.2 cell discharge diameter/center-to-center ratio is 9.14/11. The airflow rate to MW heat dissipation is 13818/1400 kg/sMW.

3.6. Since the cooling tower design is still in the conceptual phase, various characteristics of the cooling tower must be assumed. Attachment 1 (Reference 12.8) gives some of these values. A critical issue for this calculation is drift. Towers without drift eliminators have drift on the order of 0.01% of circulating water flow rate (Reference 12.7), while those with high efficiency drift eliminators have drift as low as 0.0005% of circulating water flow rate (page B-1-60 of Reference 12.9, reproduced in Attachment 1). This analysis assumes the high efficiency drift eliminators, which will tend to reduce deposition. It is noted that the authors have made this 0.0005% assumption for cooling tower analyses for new nuclear plant license applications.

4. DESIGN INPUTS

4.1 SITE DATA

4.1.1 Latitude: 35° 12’ 30”N (Reference 12.1)

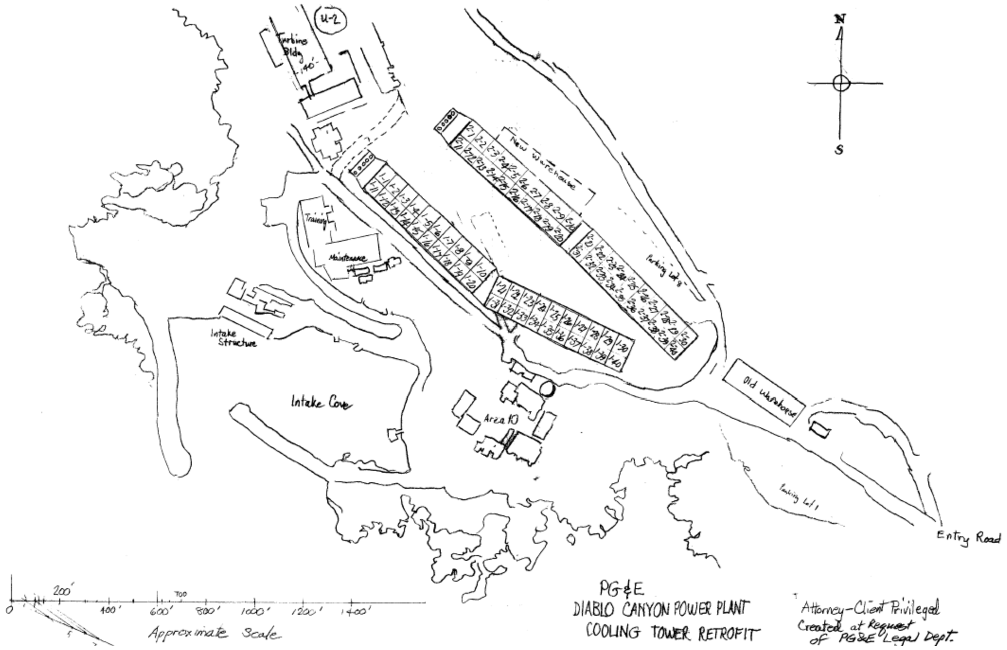
4.1.2 Longitude: 120° 51’ 08”W (Reference 12.1)

4.1.3 Ground level elevation: 100’ above mean sea level (Reference 12.1)

4.1.4 Ground characterization: although there is a steep drop-off to the west to 0' elevation and hills to the east at 800' elevation, the predominant winds blow along the coast line (NW or SE). In 2003, for example, 54% of the winds were from the northwest (+/- 22.5°) blowing towards the southeast and 20% were from the southeast (+/- 22.5°) blowing towards the northwest. These data are from Table 3 below that, despite being based on program output, is really an echo of the meteorological input data. In these NW and SE directions, the ground is relatively flat with grassland and low hills (Reference 12.1). The appropriate roughness is 3.5 cm per assumption 3.4.

Note: the site location is used for meteorological and insolation purposes. Insolation is the sunlight energy deposited at the site and is an input required by the SACTI code. The exact positioning of the towers within the site does not affect the study results, but the orientation with respect to North does.

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**



PG&E
DIABLO CANYON POWER PLANT
COOLING TOWER RETROFIT

Attorney-Client Privileged
Created at Request of PG&E Legal Dept.

Figure 1: DCPP Site and Cooling Tower Placement

4.2 METEOROLOGICAL DATA

4.2.1. Five years of hourly site met data collected from 1/1/2003 to 12/31/2007 (Reference 12.3)

4.2.2. Five years of hourly SLO airport met data, data collected from 1/1/2003 to 12/31/2007 (Reference 12.4)

4.2.3. Mixing height data purchased from NCDC from nearest possible sources (SLO ground data and San Diego upper air data). This mixing height data is located in the file dcppmix.txt for use by the code.

4.2.4. The tower height at which the met data was collected is about 10 m (Reference 12.8)

4.3 MECHANICAL FORCED-DRAFT COOLING TOWERS

4.1.1 The density of the circulation water is 64.5 lbm/ft^3 per Reference 12.11, making it more dense than fresh water. The flow rate is 860,000 gpm per Ref. 12.8.

4.1.2 Heat rejected: The total heat rejection is 4469 MWs based on two units per Reference 12.15. This is very close to the existing condenser duty in Reference 12.14 (2*7,559 MBtu/hr /3.412 MW/(MBtu/hr))= 4454 MWs. The loss of efficiency due to higher condenser back pressure due to the cooling towers is offset with a gain in efficiency due to new turbine rotors for a net small impact.

4.1.3 Drift is 0.0005% of circulating water flow per assumption 3.6. This makes the drift .000005*860,000 gpm/unit*2 units = 86 gpm total.

4.1.4 There are 20 cells per tower for a total of 80 cells for the site (Figure 1). They are arraigned along an axis that is approximately 130 degrees east of north. The center to center distance between adjacent cells is 60 feet per Reference 12.10.

4.1.5 Height: 55’ (17m) above ground level. This is an average height based on other mechanical draft towers, such as 55.4' for the example tower in Reference 12.2 and 52'7" for Marley mechanical draft towers at the Grand Gulf nuclear power plant.

4.1.6 Cell exit diameter: 50' (15m). This is a calculated diameter per assumption 3.5 based on a Reference 12.2 ratio of discharge diameter to center-to-center distance, specifically 9.14/11 * 60' = 50'.

4.1.7 Air flow rate for all cells combined (both units) is 44,100 kg/s. This is a calculated flow rate per assumption 3.5 based on a Reference 12.2 flow to MW ratio, specifically 13818/1400*4469 = 44,100 kg/s.

4.1.8 Sodium salts in cooling water: 40,500 ppm per Reference 12.8 assuming 1.5 concentration factor. By comparison to publish ocean salinity data, this is verified to be ppm by mass, so that the salt concentration can also be expressed as 0.0405 gm/gm.

4.1.9 Density of sodium salt: 2.17 gm/cm^3. The value of 2.17 gm/cm is a generic value from the plume software manual for salts (pg. 4-54,Reference 12.2).

4.1.10 The total dissolved solids are 51,750 ppm or .0518 gm/gm per Reference 12.8.

4.1.11 Density of total dissolved solids: 2.17 gm/cm^3. This number is developed using the constituencies listed in Reference 12.8 along with a variety of density sources. The development is included at the end of Attachment 1.

4.1.12 Drop Mass Spectrum: Values used in previous LMDCT modeling effort based on standard Marley forced draft cooling tower (Reference 12.7). The data provided by Marley did not contain bounding limits for smallest or largest size. Since the program requires this, arbitrary limits were added at half the smallest size and about twice the largest size listed by Marley.

Table 1: Drop Mass Spectrum

Mass in Range	Droplet Size in Microns Provided by Marley	Used in Program
0.12	<10 microns	5-10
0.08	10-15	10-15
0.20	15-35	15-35
0.20	35-65	35-65
0.20	65-115	65-115
0.10	115-170	115-170
0.05	170-230	170-230
0.04	230-375	230-375
0.008	375-525	375-525
0.002	>525	525-1000

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

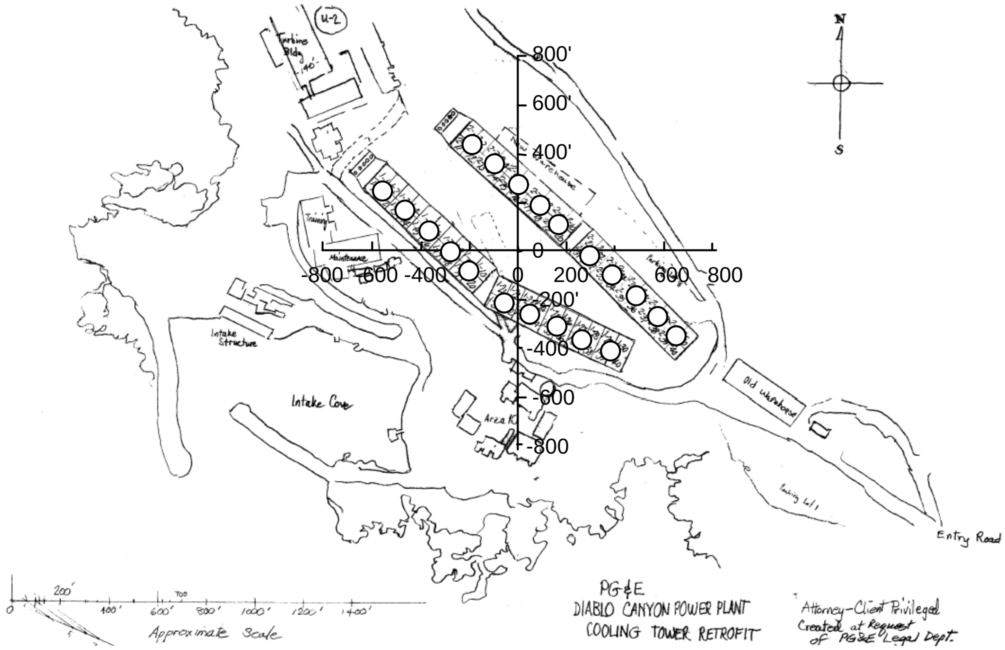


Figure 2: Determination of cooling tower locations

Note: Due to code limitations, it is not possible to model 80 cells. Instead, a representative cell is located at the center of each group of four. The long axis angle based on the data of Table 2 is 90° + atan(350/390) = 130° east of north for three of the four housings, and close to this for the fourth.

Table 2: Approximate Cooling Tower X-Y Locations (ft and meters)

X-value (ft)	Y-Value (ft)		X-value (ft)	Y-Value (ft)		X-value (m)	Y-Value (m)		X-value (m)	Y-Value (m)
-200	450		300	-20		-61.0	137.2		91.4	-6.1
-102.5	362.5		397.5	-107.5		-31.2	110.5		121.2	-32.8
-5	275		495	-195		-1.5	83.8		150.9	-59.4
92.5	187.5		592.5	-282.5		28.2	57.2		180.6	-86.1
190	100		690	-370		57.9	30.5		210.3	-112.8
X-value (ft)	Y-Value (ft)		X-value (ft)	Y-Value (ft)		X-value (m)	Y-Value (m)		X-value (m)	Y-Value (m)
-590	250		-50	-110		-179.8	76.2		-15.2	-33.5
-492.5	162.5		47.5	-197.5		-150.1	49.5		14.5	-60.2
-395	75		145	-285		-120.4	22.9		44.2	-86.9
-297.5	-12.5		242.5	-372.5		-90.7	-3.8		73.9	-113.5
-200	-100		-400	400		-61.0	-30.5		-121.9	121.9

5. METHODOLOGY

5.1 Meteorological Data File

The meteorology data is put into the file dcppMet.txt. Its development involved format changes to match the CD144 format required by the SACTI code. The met data consists of downloaded NCDC data from the San Luis Obispo airport (SLO), and site data in Excel files DCPP03.xls through DCPP07.xls. These data files are included in the companion CD. The site data is used for wind speed and direction, but no data is collected relative to sky coverage or ceiling heights. It was also discovered that the dew point measurement at the site had a high allowable uncertainty associated with it (+/- 10°F) that impacted humidity estimates and therefore plume length estimates. Therefore the nearby SLO data is used for temperatures, humidity, and sky coverage.

San Luis Airport Data (Files 2003.xls, 2004.xls, 2005.xls, 2006.xls and 2007.xls)
The following data was collected from San Luis Obispo airport via the National Climatic Data Center (NCDC) on an hourly basis from 1/1/2003 through 12/31/2007.

sky cover	ceiling	dewpt	drybulb	wetbulb	humidity

The raw data was down loaded into sixty files named 200301.txt, 200302.txt, 200303.txt ... 200712.txt. These were copied and renamed with the designator for comma separated files (200301.csv, 200302.csv, 200303.csv ... 200712.csv) so that Excel could open them properly. Once opened, all the year 2003 files were collected in order of January to December in the Excel spreadsheet 2003.xls, filling up rows 1 through 10,721. Similar files were created for 2004 through 2007.

Collecting the data for hourly times in columns ab through ah

The data is collected at times, using a 24 hour clock format, of 00:56, 01:56, 02:56 ... 23:56. Other times may appear in the data set when a particular event is noted. That is, many lines of the airport data must be ignored. This is accomplished by converting month/day/time to a single indicating number via the below formula, where B4 is the month (1 to 12), C4 is the day (1 to 31), and D4 is the 24 hour clock format time without the colon, i.e., 56, 156, 256 ... 2356.

=B4*10000+C4*100+IF(ROUND(D4/100,0)=24,IF(B4=B5,100,-C4*100+100+10000),(D4-INT(D4/100)*100)/56+INT(D4/100))

Thus all indications taken at 56 minutes after the hour give non-decimal numbers, specifically, 10100, 10101, 10102, ... 123123. Moving from right to left through these values, the first two decimals at right are the hours from 00 to 23, the next two are the day from 01 to 31, and the next one or two are the month from 1 to 12. The undesirable data collected at times other than 56 minutes after the hour have digits after the decimal due to the /56 in the formula.

The desired times for the data are listed in cells aa2 through aa8761. Lookup functions then collect the desired data in cells ab2 through ah8761. For example, the raw data dew point is listed in column N. Cell aa4 is date 10104. To collect the desired dew point for January 1 at 4:00 am, the formula is:

= LOOKUP($AA4,$A$3:$A$11200,$N$3:$N$11200)

which looks for the date in cell aa4 in the column of data a3:a11200, and then returns the value in column N corresponding to that date.

Note that the data each year begins at 00:56 in the morning, so for our purpose, the last datum of the year (12/30 23:56) is interpreted as the first datum of the next year (1/1 00:00). The first datum of 2003 is copied from 1/1 00:56 to avoid look up errors for 1/1/2003 00:00.

Note also that for the leap year 2004, additional rows of data are added for 22900 through 22923, thus instead of 8760 rows of data, there are 8784 rows.

<u>Sky Cover and Ceiling Height</u>

For sky cover, the data key from the NCDC reads:

```
CLR: CLEAR BELOW 12,000 FT
FEW: > 0/8 - 2/8 SKY COVER
SCT SCATTERED: 3/8 - 4/8 SKY COVER
BKN BROKEN: 5/8 - 7/8 SKY COVER
OVC OVERCAST: 8/8 SKY COVER
VVXXX INDICATES INDEFINITE CEILING WITH THE VERTICAL VISIBILITY (XXX)
LISTED IN HUNDREDS OF FEET.
```

The spreadsheet coverts "clr" to a skycover of 0; "few" to a skycover of 20% or an indicator of 2; "sct" to a skycover of 5; "bkn" to a skycover of 7; and either "ovc" or "vv" to a skycover indicator of "-", which indicates 100% coverage. This is done with a lookup table. The approach is to enter these values in three steps. First, the raw data is selected for the specific hourly rating in column AB:

=IF(LOOKUP($AA4,$A$3:$A$11200,$G$3:$G$11200)="
",AB3,LOOKUP($AA4,$A$3:$A$11200,$G$3:$G$11200))

Example results here might be CLR, BKN110, SCT100, OVC010, or VV004. The purpose for the check for 45 blanks is that occasionally sky cover data is missing. In 2004, this occurred 10 times. In 2003, it occurred 35 times. It did not occur at all in 2005 or 2006. When missing, the previously recorded sky cover is used.

The second step is to identify the sky cover percentage in column AH using the first letter of the column AB value and a lookup table. The formula is:

=LOOKUP(LEFT(AB4,1),$AK$2:$AK$7,$AL$2:$AL$7)

where the lookup in cells ak2:al7 is:

B	7
C	0
F	2
O	-
S	5
V	-

The third step is to record the ceiling height if the AH cell is "-":

=IF(AH3="-",IF(LEFT(AB3)="V",MID(AB3,3,3),MID(AB3,4,3)),"---")

This formula collects the characters 3 through 5 if the initial letter is "V" and characters 4 through 6 otherwise, correctly getting the ceiling height from cell values such as OVC010 or VV00.

Dew Point, Dry Bulb, Wet Bulb, and Humidity

The dew point, dry bulb, wet bulb, and humidity are all selected without manipulation, in columns AD through AG as follows:

=LOOKUP($AA4,$A$3:$A$11200,$N$3:$N$11200)
=LOOKUP($AA4,$A$3:$A$11200,$J$3:$J$11200)
=LOOKUP($AA4,$A$3:$A$11200,$L$3:$L$11200)
=LOOKUP($AA4,$A$3:$A$11200,$P$3:$P$11200)

Specific Data Manipulation

Occasionally, these formulas will fail to produce the desired result. This is often the fault of bad data or unique situations. They are discovered by searching for the character # in the values in Cells AB2 through AH8761. The following are identified:

2003 Manipulations
None required.

2004 Manipulations
In the month of February, 2004, for some reason the temperature data only appears in Celsius and not Fahrenheit. The Celsius data looks reasonable, so that for this month, the raw data values of "-" were replaced by formula (for example):

=IF(K907="-",K907,ROUND(K907*180/100+32,0))

This was also the case for wet bulb only in January 2004. The purpose of the check for "-" was to avoid errors for cases where the temperatures in degrees Celsius are also missing.

2005 Manipulations

The data format and columns changed in 2005 (also applies to 2006). The year month and day are all in column C in a format such as 20050101, while the time is in column D. So the new date value generation equation is:

=RIGHT(C4,4)*100+IF(INT(D4/100)+RIGHT(D4,2)/56=24,100,INT(D4/100)
+RIGHT(D4,2)/56)

The sky cover moves from column G to column F
The dew point moves from column N to column T
The dry bulb temperature moves from column J to column L
The wet bulb temperature moves from column L to column P
The humidity moves from column P to column X

The greater number of columns causes the desired data to be relocated from columns AA through AH to columns BA through BH. Other than these location changes, there were no other changes and no unusual data required manipulation.

Note: missing data was represented by "M" instead of "-" in 2005-2006. This results in some data in the final columns to consist of the letter M.

2006 Manipulations

No data manipulation required other than what is described above for 2005.

2007 Manipulations

No data manipulation required other than what is described above for 2005.

Site Data (Files DCPP03.xls, DCPP04.xls, DCPP05.xls, DCPP06.xls, and DCPP07_JANTDEC.xls)

The site data provides hourly wind speed and wind direction. The data at 10m is used. The 2007 data was supplied at a later time causing a different file name format, but no other impact. Only the two columns F and H, wind speed and wind direction at 10m, are utilized. Fortunately, the data is provided one row per hour, so no manipulation is required.

Site Data combined with SLO data (Files DCPP2003.xls, DCPP2004.xls, DCPP2005.xls, DCPP2006.xls, and DCPP2007.xls)

The two site columns F and H, wind speed and wind direction, are copied into files DCPP2003.xls through DCPP2007.xls, into columns E&F (note: row1 data for 1/1 0:00 come from the last row of the previous year). The first few columns, A through D, are date columns indentifying each hour in the same manner as in the files 2003.xls through 2007.xls, that is, year (2003 to 2007), month (1 to 12), day (1 to 31) , and hour (0 to 23).

Then the SLO data columns BC through BH from files 2003.xls through 2007.xls, entitled ceiling, dewpt, drybulb, wetbulb, humid, and skycover, are pasted as values into columns G through L. This completes the data entry.

Spreadsheets DCPP2003.xls through DCPP2007.xls then produce the necessary met file format data in columns N through AC. These satisfy the CD144 format. The CD144 format requires each line to contain IYEAR, IMONTH, IDAY, IH, ICH(3), IDP(2), IWD, IWS(2), IDB(2), IWB(2), IRH(2), IOSC where numbers in parentheses indicate array dimensions.

where:
IYEAR is the year
IMONTH is the month (1 to 12)
IDAY is the day of the month
IH is the hour
ICH is the ceiling height in hundreds of feet (each digit is a separate entry in the array)
IDP is the dew point temperature in degrees F
IWD is the wind direction in tens of degrees east of north
IWS is the wind speed in knots
IDB is the dry bulb temperature in degrees F
IWB is the wet bulb temperature in degrees F
IRH is the relative humidity in percent
IOSC is the fraction of sky cover in tenths of sky covered (0 = clear blue sky)

The input format in standard FORTRAN nomenclature is:
(5X,4I2,ich3A1,19X,idpA1,I2,iwdA2,iwsA1,I1,4X,idbA1,I2,iwbA1,I2,irhA1,I2,23X,A1)

where lower case letters have been added to help identify which data are associated with which variable. For example, IDP, which is a two-member array, reads its first element as 1 character, and the next two digits as integers. This approach is necessary to recognize data blanks or dashes without generating an “Invalid integer” fatal error.

Each of the appropriate data cells (typically N2.AC8761, but N2.AC8785 for the leap year 2004) are copied and pasted into the text file **<u>dcppMet.txt</u>**. Only two final manipulations are done. The first is to replace all tabs with nothing, to make the data lines compacted. The second is to change all years to avoid leading zeros. This was discovered to be a Y2K bug in SACTI. Thus 03 is changed to 83, 04 to 84, and so on. The 1980s were used simply to keep 04 (now 84) a leap year consistent with the calendar.

The first few lines of dcppMet.txt are as follows:

```
0000083010100---000000000000000000004235090000050046074000000000000000000000000
0000083010101---000000000000000000004205070000050046074000000000000000000000000
0000083010102---000000000000000000004106030000048045077000000000000000000000000
0000083010103---000000000000000000004035050000048044074000000000000000000000000
0000083010104---000000000000000000003901060000049044069000000000000000000000000
```

5.2 SACTI Input File

The data of Section 4 is used to develop the SACTI input file in Section 7. The SACTI file interacts with the Met data file to predict plume characteristics. The line by line development of the input file is described in Section 7.

6. ACCEPTANCE CRITERIA

There are no explicit acceptance criteria for plume characteristics.

7. CALCULATION

7.1 BACKGROUND

The plumes are modeled with the SACTI computer programs originally developed by the Electric Power Research Institute (EPRI). A copy of this code has been purchased directly from the author for use in analyses such as this one. The meteorological data is described in Section 5.1.

7.2 LMDCT MODEL DESCRIPTION

The Linear Mechanical Draft Fan Tower (LMDCT) has 80 cells in 4 housings. Unfortunately, SACTI is limited to just 20 as a practical maximum. The advised approach is to model the LMDCT with larger cells that represent the adjacent ones in the same number of housings. In this case, each housing, which is in reality two rows of 10 cells each, is modeled with one row of 5 cells. This simplification is a necessity of the code. Since the total mass and energy release is correct, and since the plumes will merge in a relatively short distance, the impact of the simplification is acceptable.

PREP (reads and analyzes met data, defines plume categories)

card 1: Diablo Canyon: Linear Mechanical Cooling Tower Plume Model (80 cells)

card 2: ISTOP: Number of days in record period (43824 for the records available from the five years 2003 to 2007)
ISKIP: 1 to process every record
IOUT: 0 to generate full listing (1 to suppress)
IMIX: 2 to use daily mixing height data
IUR: 1 to use rural terrain
IWIND: 2 to use delta-T stability class method (sigma-T data is not available)
NFOG: 1 to calculate fogging and icing
NDRIFT: 1 to calculate drift
ITOWER: 3 to model linear mechanical draft cooling towers
ITAPE: 1 since data is in cd144 format
IZONE: 8 since Pacific Time Zone

card 3: ALAT: 35.21 (equals 35+12/60+30/3600 from Input 4.1.1)
ALONG: 120.58 (equals 120+51/60+8/3600 from Input 4.1.2)
ROUGHT: 3.5 cm per input 4.1.4
HREF: 10 m met tower per input 4.2.4
HTERR: 0 m terrain modification due to flat terrain

card 4: TWRHT: m tower height is 17m per input 4.3.5.
TWRDM: m effective diameter (=sqrt(total area*4/π) so $\pi D_e^2/4$ = total area). The single top diameter is 15m by input 4.3.6, giving a single cell area of $\pi 15^2/4$ so the effective diameter is sqrt($80*15^2$) = 134m.

TWRHE: Total heat dissipated is 4469 MWt as developed per input 4.3.1.

TWRAF: Total airflow is 50,000 kg/s per input 4.3.7.

card 5: Twelve monthly clearness index based on Santa Maria, CA data contained in the SACTI Manual (Reference 12.2) Appendix B. Values are, January to December:

.60 .63 .69 .66 .67 .71 .71 .69 .69 .70 .67 .62

card 6: Twelve monthly values for average daily insolation based on Santa Maria, CA data contained in the SACTI Manual (Reference 12.2) Appendix B. Values are, from January to December:

11.08 14.64 20.32 23.42 26.64 29.11 28.48 25.59 21.91 17.48 13.01 10.58

cards 7 to 12: Names of files containing data or being written. Note that the met data is in dcppMet.txt and the mixing height data is in dcppmix.txt.

The input file prep.usr is as follows:

```
Diablo Canyon: Linear Mechanical Cooling Tower Plume Model (80 cells)
 35064     1 0 2 1 2 1 1 3 1 8
  35.21    120.58      3.5      10.0       0.0
  17.0     134.0    4469.0     44100.0
.60.63.69.66.67.71.71.69.69.70.67.62
11.0814.6420.3223.4226.6429.1128.4825.5921.9117.4813.0110.58
dcppMet.txt
fort.2
fort.3
fort.4
prep.out
dcppmix.txt
```

The input echo is repeated here to demonstrate correct input:

```
*************************************************************************************
**********************************
  EPRI PLUME AND DRIFT ANALYSIS SYSTEM PREPROCESSOR CODE, PRE-RELEASE VERSION 09-01-90
  CASE STUDY: Diablo Canyon: Linear Mechanical Cooling Tower Plume Model (80 cells)

*************************************************************************************
**********************************

  INPUT INFORMATION
  -----------------

  SURFACE TAPE TYPE:            CD144
  TOWER TYPE:             LINEAR MECHANICAL DRAFT
  TOWER HEIGHT (M):             17.00
  TOWER DIAMETER (M):          134.00
  TOWER HEAT (KW):         4469000.00
  TOWER AIR FLOW (KG/S):     44100.00
  SITE LATITUDE:                35.21
  SITE LONGITUDE:              120.58
  SITE TIME ZONE:             PACIFIC
  ROUGHNESS HEIGHT (CM):         3.50
  REFERENCE HEIGHT (M):         10.00

  RECORD STOPPING SWITCH:       43824
  RECORD SKIPPING FACTOR:           1
  HOURLY RECORD PRINT LOG:      NOT SELECTED
  BI-DAILY MIXING HEIGHT TAPE:  SELECTED
```

```
MIXING HEIGHT TYPE:          RURAL
FOGGING/ICING OPTION:        SELECTED
DRIFT OPTION:                SELECTED


MONTHLY CLEARNESS INDEX
-----------------------

 JAN   FEB   MAR   APR   MAY   JUN   JUL   AUG   SEP   OCT   NOV   DEC
 ---   ---   ---   ---   ---   ---   ---   ---   ---   ---   ---   ---
.600  .630  .690  .660  .670  .710  .710  .690  .690  .700  .670  .620


TOTAL DAILY SOLAR ENERGY DEPOSITION
   (LONG-TERM AVERAGE FOR MONTH)
-----------------------------------

 JAN     FEB     MAR     APR     MAY     JUN     JUL     AUG     SEP     OCT     NOV     DEC
 ---     ---     ---     ---     ---     ---     ---     ---     ---     ---     ---     ---
11.08   14.64   20.32   23.42   26.64   29.11   28.48   25.59   21.91   17.48   13.01   10.58
```

Note: the output of the PREP code also gives wind speed and direction summary as follows. This verifies that 54% of the wind is from WNW, NW, or NNW, and another 20% is from ESE, SE, or SSE, re-enforcing the conclusion that most plumes will parallel the coast line between the ocean and the hills.

Table 3: Wind Speeds and Direction, DCPP Site, 2003 - 2007

	Wind Headed From																
	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	
	Wind Headed Towards:																
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	SUM
SUM	2.9%	2.4%	3.0%	2.8%	3.1%	4.5%	8.4%	6.7%	3.9%	1.7%	1.3%	1.3%	3.0%	13.6%	30.7%	9.4%	100%
<1m/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.002
<2	0.004	0.004	0.007	0.008	0.014	0.015	0.017	0.014	0.017	0.009	0.007	0.006	0.009	0.008	0.008	0.005	0.152
<3	0.01	0.011	0.01	0.007	0.009	0.013	0.026	0.022	0.016	0.006	0.005	0.006	0.012	0.02	0.021	0.015	0.209
<4	0.007	0.005	0.006	0.005	0.004	0.005	0.016	0.015	0.004	0.001	0.001	0.001	0.006	0.022	0.026	0.016	0.14
<5	0.005	0.003	0.004	0.003	0.002	0.004	0.011	0.008	0.001	0.001	0	0	0.002	0.019	0.03	0.017	0.111
<6	0.002	0.001	0.002	0.003	0.001	0.003	0.007	0.003	0.001	0	0	0	0.001	0.016	0.032	0.014	0.086
<7	0.001	0	0.001	0.001	0.001	0.002	0.003	0.002	0	0	0	0	0	0.013	0.034	0.009	0.068
<8	0	0	0	0.001	0	0.002	0.002	0.001	0	0	0	0	0	0.011	0.031	0.006	0.056
<9	0	0	0	0	0	0.001	0.001	0.001	0	0	0	0	0	0.009	0.03	0.004	0.048
<10	0	0	0	0	0	0	0.001	0.001	0	0	0	0	0	0.007	0.027	0.003	0.04
<11	0	0	0	0	0	0	0	0	0	0	0	0	0	0.005	0.022	0.002	0.031
<12	0	0	0	0	0	0	0	0	0	0	0	0	0	0.003	0.018	0.002	0.025
<13	0	0	0	0	0	0	0	0	0	0	0	0	0	0.001	0.013	0.001	0.016
<14	0	0	0	0	0	0	0	0	0	0	0	0	0	0.001	0.008	0	0.01
<15	0	0	0	0	0	0	0	0	0	0	0	0	0	0.001	0.004	0	0.005
<20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.003	0	0.003
>20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The MULT program runs the plume code for the multiple sources. Its input is described as follows.

MULT (analyzes each plume)

cards 1 to 3: Names of files containing data or being written
card 4: Title: DCPP: Linear Mechanical Cooling Towers (80 cells)
card 5: IOUT: 2 for maximum printout
NFOG: 1 to run fogging cases
NDRIFT: 1 to run drift analysis
NFRAD: Fogging, Ice radials. 0 leads to a default of 16, with each radial distance 100m out to 1600m.
SMAXP: 10000 m maximum distance to calculate plume
SMAXF: 1600 m maximum distance for fogging analysis
NPORTS: 20 cells (maximum allowed by code)
NPLATE: 0 defaults to equal NPORTS
NTWRS: 4 tower housing for LMDCTs
ISOURC: 0 for multiple ports (would be 1 for a single tower)
NEXPL: 0 external plates for direct user input (no building wakes modeled)
cards 6 to 25: X, Y coordinates of tower cells in meters from center point (see Table 2 for values)
card 26: NWD: Number of critical wind directions (3), followed by values in degrees east of North: (0 degrees, 130 degrees to represent plumes headed up the coast towards the power plant, and 315 degrees to represent plumes headed down the coast towards Avila Beach)
card 27: Wind Equivalent Array for 16 wind direction starting with north and moving clockwise in 22.5^{o} increments 2333211123332112. Here 1 is parallel to the axis, 2 is roughly 30^{o} to axis, and 3 is cross axis (See below Figure 3).

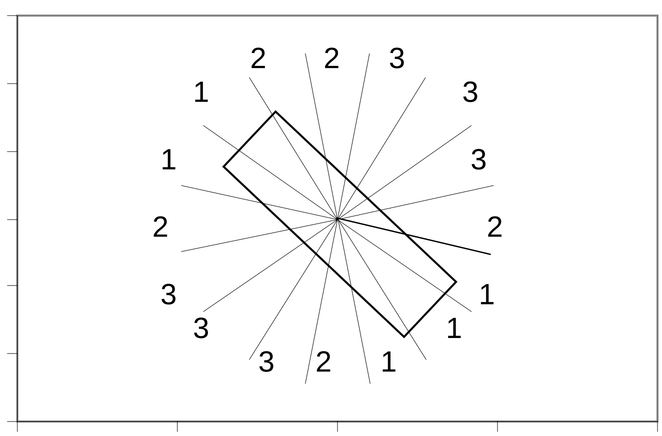


Figure 3: Showing Wind Direction Axes Relative to LMDCT Axis

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

card 28: TWRADM: Left blank, this is the diameter of a circular mechanical draft cooling tower.

DA: Length of each Linear mechanical draft tower housing (600' or 183m).

DB: Width of linear mechanical draft towers (120' or 36.6m).
THTWR: Degrees east of north of the LMDCT long axis (130).

cards 29 - 32: XTWR: m X-coordinate of the center of the LMDCT houses from Table 2.
YTWR: m Y-coordinate of the center of the LMDCT houses from Table 2.

card 33: Label to identify drift data. DRIFT DEPOSITION SPECTRUM

card 34: NDROPS: # of drop sizes (11)
DRIFTR: gm/s total drift rate from all sources. This value is 86 gpm per input 4.3.3. At 64.5 lbm/ft^3 density per input 4.3.1, this is:

$$86 \text{ gpm}/7.481 \text{ gal/ft}^3 * 64.5 \text{ lbm/ft}^3 * 1\text{min}/60\text{s} * 453.59 \text{ gm/lbm} = 5600 \text{ gm/s}$$

CWSC: gm salt/gm solution. This is .0405 gm/gm by input 4.3.8
SDENS: gm/cm TDS density equal to 2.17 g/cm^3 by input 4.3.9.

cards 35 to end: DROPS(I) Ith drop diameter (μm). The data is from Table 1.

The mult.usr input file is as follows:

```
fort.3
mult.out
fort.8
DCPP: Linear Mechanical Cooling Towers (80 cells)
  2  1  1  0   10000.0    1600.0 20  0  4  0  0
    -61.0     137.2
    -31.2     110.5
     -1.5      83.8
     28.2      57.2
     57.9      30.5
     91.4      -6.1
    121.2     -32.8
    150.9     -59.4
    180.6     -86.1
    210.3    -112.8
   -179.8      76.2
   -150.1      49.5
   -120.4      22.9
    -90.7      -3.8
    -61.0     -30.5
    -15.2     -33.5
     14.5     -60.2
     44.2     -86.9
     73.9    -113.5
   -121.9     121.9
  3       0.0     130.0     315.0
  2  3  3  3  2  1  1  1  2  3  3  3  2  1  1  2
             183.0       36.6     130.0
     -1.5        83.8
    150.9       -59.4
```

```
 -120.4        22.9
   44.2       -86.9
SALTS: DRIFT DEPOSITION SPECTRUM
11         5600.0   .0405       2.17
       5.0    0.00      0.0
      10.0    0.12      0.0
      15.0    0.08      0.0
      35.0    0.20      0.0
      65.0    0.20      0.0
     115.0    0.20      0.0
     170.0    0.10      0.0
     230.0    0.05      0.0
     375.0    0.04      0.0
     525.0    0.008     0.0
    1000.0    0.002     0.0
```

The TABLES program summarizes the MULT output for the seasons and places it into more convenient tabular format. Its input is described as follows.

TABLES (averages plume results and presents results)

cards 1 to 5: Names of files containing data or being written

card 6: NSEASNQ: 5 seasons to be examined (the 5th is "Annual")
MM: Number of sector partitions to use in shadowing (0 results in the default of 13)

cards 7 to 16: The first card names the season, the second gives the first and last Julian day of the season.

card 17: RSTAR: Effective radius of the combined plume source, 0 leaves it to be calculated

card 18: NXL: Number of grids for length frequency (0 results in default of 100)
NXH: Number of grids for height frequency (0 results in default of 100)
NXR: Number of grids for radius frequency (0 results in default of 100)
NXS: Number of grids for shadowing table (0 results in default of 40)
NXD: Number of grids for deposition table (0 results in default of 40)

Print out of Tables.usr:

```
fort.2
fort.4
tables.out
fort.8
fort.9
  5  0
WINTER
                      335   59
SPRING
                       60  151
SUMMER
                      152  243
```

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

```
FALL
                          244  334
ANNUAL
                            0    0
0.0
  0  0  0  0  0
```

Total Dissolved Solids and PM10 Cases

An additional case is run to supply the data for Table 9b below. In the main run, the mult.usr line relating to solids deposition is:

```
SALTS: DRIFT DEPOSITION SPECTRUM
11          5600.0   .0405       2.17
```

The only change for TDS is in the concentration (per input 4.3.10) since the density is the same (input 4.3.11):

```
TDS: DRIFT DEPOSITION SPECTRUM
11          5600.0   .0518       2.17
```

This change to the mult.usr file results in a new mult.out (renamed multTDS.out) and, after running through the Tables program, a new tables.out file (renamed tablesTDS.out). The output is store on a worksheet in DCPPplumeResults.xls.

An additional case is run to supply the data for Table 9c below for PM10 results.

The PM10 case is for particulates of 10 microns or less, which are significant because they cause irritation to the lungs. Since the Table 1 indication is that these make up 12% of the total TDS, the input change is to multiply the concentration .0518 by 0.12 to obtain .12*.0518 = .0062. The input to that case is as follows:

```
PM10: DRIFT DEPOSITION SPECTRUM
11          5600.0   .0062       2.17
```

This change to the mult.usr file results in a new mult.out (renamed multPM10.out) and, after running through the Tables program, a new tables.out file (renamed tablesPM10.out). The output is store on a worksheet in DCPPplumeResults.xls.

8. RESULTS

8.1 RESULTS

The input files described above were run on a PC. The results are contained in the output files listed in Attachment 2. They are summarized here.

8.2 VISIBLE PLUMES

Tables 4a and 4b present the plume lengths by season. The average length in meters in Table 4a is calculated in file results.xls by summing up the length*frequency change, and then dividing by the total frequency in the given direction. For example, if the lengths in meters were 1000, 2000, 3000, 4000, and the frequencies of being at least that long were 1.5, 0.8, 0.4, 0, respectively, then the average length would be calculated as [1000*(1.5-.8) + 2000*(.8-.4) + 3000* (.4-0)]/1.5 = 1800 m. Note: the actual lengths produced by SACTI are given in divisions of 100 meters each, so the round off error is much smaller than in this example. Table 4b is identical to Table 4a, except that the length unit is miles (generated by multiplying the length in meters by (1ft/.3048m*1mile/5280ft). Table 4c indicates length versus frequency on an annual basis. Tables 4d and 4e give plume heights and radii.

Tables 5 through 8 present the percent frequency of plume lengths versus direction on a seasonal basis.

The total sodium salt deposition rates are described in Table 9a. The SACTI code produces salt deposition in units of kg/km^2-month. These can be converted to English units of lbm/(100-acre-months) by multiplying by (2.205 lbm/kg)*(1/2.471 km^2/100 acres) = 0.893 (lbm- km^2/100-acre-kg).

Table 9b is the total dissolved solids deposition, in the same units as sodium salt deposition. Table 9c is the deposition of particles of 10 microns or less, which is significant because these small particles can cause irritation to the lungs.

Water deposition is shown in Table 10. These data can be converted into inches per year by 0.893 (lbm- km^2/100-acre-kg)*1ft^3/62.4 lbm (freshwater) * 1/100 acre * 1 acre/43560 ft^2 * 12 inch/ft * 12 months/yr = 4.7e-7. Results show all areas beyond a quarter mile of the towers see less than 1/1000 in/yr added precipitation.

Plume shadowing is presented in Table 11. Fogging is shown in Table 12. It is seen that fogging will occur on occasion out to a full mile from the cooling towers usually to the NW or SE.

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 4a: Average Plume Lengths in Meters

	Winter	Spring	Summer	Fall	Annual
Plume from LMDCT moving in the indicated direction					
S	2780	3460	3170	2520	2900
SSW	2750	3510	3170	2730	2930
SW	2820	3560	2870	2530	2870
WSW	2890	3600	2810	2430	2860
W	3090	3670	2720	2380	2970
WNW	3790	4300	3040	3170	3680
NW	3710	3990	2930	2660	3360
NNW	2270	2530	1980	1870	2170
N	1920	1860	1470	1280	1620
NNE	2420	1910	1540	1650	1840
NE	1720	1990	1860	1860	1860
ENE	1370	1880	1890	1450	1660
E	1670	1790	1660	1100	1560
ESE	1370	1380	1270	1070	1280
SE	2230	2530	2080	1930	2190
SSE	3520	3980	3030	2640	3310
All	2710	2720	2050	2070	2380

Table 4b: Average Plume Lengths in Miles

	Winter	Spring	Summer	Fall	Annual
Plume from LMDCT moving in the indicated direction					
S	1.73	2.15	1.97	1.57	1.8
SSW	1.71	2.18	1.97	1.7	1.82
SW	1.75	2.21	1.78	1.57	1.78
WSW	1.8	2.24	1.75	1.51	1.78
W	1.92	2.28	1.69	1.48	1.85
WNW	2.35	2.67	1.89	1.97	2.29
NW	2.31	2.48	1.82	1.65	2.09
NNW	1.41	1.57	1.23	1.16	1.35
N	1.19	1.16	0.91	0.8	1.01
NNE	1.5	1.19	0.96	1.03	1.14
NE	1.07	1.24	1.16	1.16	1.16
ENE	0.85	1.17	1.17	0.9	1.03
E	1.04	1.11	1.03	0.68	0.97
ESE	0.85	0.86	0.79	0.66	0.8
SE	1.39	1.57	1.29	1.2	1.36
SSE	2.19	2.47	1.88	1.64	2.06
All	1.68	1.69	1.27	1.29	1.48

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 4c: Annual Plume Percent Frequency by Length and Direction

Heading	<500m (<1/3 mile)	500 - <3200m (1/3 - 2 miles)	3200-<8000m (2- 5 miles)	8000m or longer (>5 miles)	Total
S	0.47	1.36	1.08	0.09	3
SSW	0.33	1.34	0.77	0.09	2.53
SW	0.43	1.63	0.93	0.11	3.1
WSW	0.44	1.43	0.82	0.09	2.78
W	0.45	1.5	1.13	0.13	3.21
WNW	0.41	1.82	2.09	0.24	4.56
NW	1.14	3.49	3.36	0.4	8.39
NNW	2.37	2.84	1.5	0.23	6.94
N	1.77	1.5	0.64	0.06	3.97
NNE	0.65	0.76	0.24	0.05	1.7
NE	0.54	0.63	0.23	0.04	1.44
ENE	0.61	0.53	0.21	0.03	1.38
E	1.52	1.13	0.56	0.03	3.24
ESE	9.1	2.74	1.64	0.2	13.68
SE	15.13	6.7	8.2	0.67	30.7
SSE	1.54	3.34	4.05	0.45	9.38
All	36.9	32.74	27.45	2.91	100

Table 4d: Plume Centerline Heights

Heading	<100m (<330 ft)	100 - <500m (330 - 1640 ft)	500-<750m (1640 - 2460 ft)	750 - 810m (2460 - 2700 ft)	Total
S	0.43	0.36	0.71	1.5	3
SSW	0.26	0.39	0.66	1.22	2.53
SW	0.35	0.49	0.86	1.4	3.1
WSW	0.39	0.42	0.67	1.3	2.78
W	0.38	0.4	0.83	1.6	3.21
WNW	0.23	0.78	1	2.55	4.56
NW	0.56	1.89	1.94	4	8.39
NNW	1.24	2.51	1.26	1.93	6.94
N	1.36	1.02	0.62	0.97	3.97
NNE	0.43	0.52	0.3	0.45	1.7
NE	0.36	0.44	0.27	0.37	1.44
ENE	0.43	0.42	0.22	0.31	1.38
E	1.24	0.75	0.49	0.76	3.24
ESE	7.44	2.87	1.29	2.08	13.68
SE	13.81	3.34	3.8	9.75	30.7
SSE	1.44	0.71	1.87	5.36	9.38
All	30.35	17.31	16.79	35.55	100

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 4e: Plume Radii By Direction that the Plume is Headed

Heading	<50m (<160 ft)	50 - <200m (160 - 660 ft)	200-<300m (660 - 980 ft)	300 - <355m (980 - 1160 ft)	Total
S	0.47	0.66	1.69	0.18	3
SSW	0.33	0.71	1.25	0.24	2.53
SW	0.43	0.93	1.46	0.28	3.1
WSW	0.44	0.81	1.24	0.29	2.78
W	0.45	0.82	1.7	0.24	3.21
WNW	0.34	0.85	2.19	1.18	4.56
NW	0.89	1.92	3.41	2.17	8.39
NNW	2	2.01	1.85	1.08	6.94
N	1.76	1.02	1.07	0.12	3.97
NNE	0.65	0.52	0.41	0.12	1.7
NE	0.54	0.45	0.37	0.08	1.44
ENE	0.61	0.38	0.31	0.08	1.38
E	1.52	0.73	0.91	0.08	3.24
ESE	8.59	1.99	2.11	0.99	13.68
SE	14.55	3.18	8.69	4.28	30.7
SSE	1.54	1.51	5.46	0.87	9.38
All	35.11	18.49	34.12	12.28	100

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 5: Winter Plume Percent Frequency by Length and Direction
(Note bolded plumes, which total 1.4%, are visible from Avila Beach)

	0 - <500 m (0 to 1/3 mile)	500 - <3200 m (1/3 - 2 mile)	3200 - <8000 m (2 - 5 miles)	8000 m and longer (>5 miles)	Total Freq
Plume from LMDCT moving in the indicated direction					
S	0.66	1.87	1.24	0.13	3.9
SSW	0.49	2.62	1.02	0.12	4.25
SW	0.72	3.54	1.84	0.21	6.31
WSW	0.86	3.13	1.73	0.22	5.94
W	0.83	3.18	2.38	0.3	6.69
WNW	0.71	3.33	4.21	0.49	8.74
NW	1.75	4.41	5.83	0.88	12.87
NNW	2.36	3.53	1.8	0.27	7.96
N	1.68	1.58	0.89	0.11	4.26
NNE	0.55	0.69	0.31	0.11	1.66
NE	0.54	0.61	0.22	0.03	1.4
ENE	0.65	0.45	0.15	0.03	1.28
E	1.5	1.01	0.68	0.04	3.23
ESE	5.62	2.14	1.06	**0.22**	9.04
SE	6.75	3.75	3.61	**0.49**	14.6
SSE	1.22	2.7	3.3	**0.65**	7.87
All	26.9	38.5	30.3	4.3	100

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 6: Spring Plume Percent Frequency by Length and Direction
(Note bolded plumes, which total 2.1%, are visible from Avila Beach)

	0 - <500 m (0 to 1/3 mile)	500 - <3200 m (1/3 - 2 mile)	3200 - <8000 m (2 - 5 miles)	8000 m and longer (>5 miles)	Total Freq
Plume from LMDCT moving in the indicated direction					
S	0.28	1.16	1.19	0.18	2.81
SSW	0.2	0.88	0.82	0.12	2.02
SW	0.16	1.02	0.84	0.11	2.13
WSW	0.17	0.68	0.69	0.08	1.62
W	0.15	0.81	1.16	0.13	2.25
WNW	0.14	1.27	2.33	0.21	3.95
NW	0.65	2.52	3.48	0.47	7.12
NNW	2.09	2.44	1.64	0.37	6.54
N	1.22	1.45	0.63	0.06	3.36
NNE	0.47	0.6	0.19	0.03	1.29
NE	0.39	0.53	0.22	0.03	1.17
ENE	0.38	0.54	0.14	0.06	1.12
E	1.27	1.38	0.59	0.05	3.29
ESE	11.07	3.19	2.2	**0.36**	16.82
SE	15.1	6.66	10.63	**0.96**	33.35
SSE	1.27	3.03	6.04	**0.81**	11.15
All	35.0	28.2	32.8	4.0	100

Table 7: Summer Plume Percent Frequency by Length and Direction
(Note bolded plumes, which total 0.9%, are visible from Avila Beach)

	0 - <500 m (0 to 1/3 mile)	500 - <3200 m (1/3 - 2 mile)	3200 - <8000 m (2 - 5 miles)	8000 m and longer (>5 miles)	Total Freq
Plume from LMDCT moving in the indicated direction					
S	0.04	0.78	0.48	0	1.3
SSW	0.04	0.56	0.31	0.04	0.95
SW	0.04	0.61	0.24	0	0.89
WSW	0.02	0.53	0.16	0	0.71
W	0.05	0.42	0.18	0	0.65
WNW	0.07	0.66	0.28	0.06	1.07
NW	0.49	2.31	1.47	0.06	4.33
NNW	2.49	2.86	1.42	0.13	6.9
N	2.06	1.86	0.58	0.06	4.56
NNE	0.72	0.94	0.23	0.01	1.9
NE	0.58	0.83	0.26	0.04	1.71
ENE	0.64	0.64	0.32	0.02	1.62
E	1.47	1.28	0.62	0.02	3.39
ESE	10.44	3.04	2.08	**0.13**	15.69
SE	23.85	9.73	12.46	**0.62**	46.66
SSE	1.14	3.24	3.19	**0.1**	7.67
All	44.2	30.3	24.3	1.3	100

Pacific Gas and Electric Company
Engineering - Calculation Sheet
Project: Diablo Canyon Unit ( )1 ( )2 (X)1&2

CALC. NO. N/A (Study Only)
REV. NO. 0

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 8: Fall Plume Percent Frequency by Length and Direction
(Note bolded plumes, which total 0.9%, are visible from Avila Beach)

	0 - <500 m (0 to 1/3 mile)	500 - <3200 m (1/3 - 2 mile)	3200 - <8000 m (2 - 5 miles)	8000 m and longer (>5 miles)	Total Freq
Plume from LMDCT moving in the indicated direction					
S	0.95	1.71	1.43	0.06	4.15
SSW	0.59	1.48	0.94	0.11	3.12
SW	0.86	1.58	0.93	0.14	3.51
WSW	0.77	1.64	0.81	0.07	3.29
W	0.81	1.86	0.96	0.1	3.73
WNW	0.76	2.24	1.78	0.25	5.03
NW	1.79	4.86	2.99	0.24	9.88
NNW	2.58	2.6	1.15	0.15	6.48
N	2.08	1.12	0.47	0.03	3.7
NNE	0.86	0.78	0.24	0.06	1.94
NE	0.64	0.54	0.23	0.06	1.47
ENE	0.76	0.5	0.19	0.03	1.48
E	1.85	0.83	0.34	0.02	3.04
ESE	8.81	2.48	1.13	**0.09**	12.51
SE	13.77	6.25	5.39	**0.6**	26.01
SSE	2.51	4.34	3.55	**0.24**	10.64
All	40.4	34.8	22.5	2.2	100

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 9a: Annual Sodium Salt Deposition in kg/(km^2-month).
Directions are directions that the plume is headed. Values can be converted to lbm/100-acre-month by multiplying by 0.893.

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
0.06	100	785.0	345.0	511.0	450.0	921.0	763.0	1903	2426	6285	1915	1536	1690	5029	22693	55965	2062
0.12	200	443.0	190.0	323.0	364.0	504.0	181.0	532	943	1135	41	34	58	993	5345	8746	1553
0.19	300	140.9	62.0	100.0	100.1	136.0	90.3	237.4	297.3	116.3	28.0	25.9	32.0	138.9	402.6	629.0	548.1
0.25	400	59.5	39.1	60.2	52.3	64.9	64.4	146.2	166.1	94.4	25.7	24.6	27.1	52.0	220.8	421.4	148.9
0.31	500	59.5	39.1	56.2	52.3	64.9	52.7	99.9	97.2	86.2	25.7	24.6	27.1	51.9	136.4	325.5	148.8
0.37	600	57.4	37.2	49.4	52.3	60.6	56.9	94.4	84.2	70.5	25.3	23.3	27.1	49.8	139.5	332.3	144.6
0.43	700	57.4	33.7	44.9	38.8	60.6	56.9	94.4	84.2	70.5	25.2	23.1	22.6	49.8	139.5	332.3	144.6
0.5	800	57.4	33.1	43.9	36.7	60.6	56.2	93.6	83.5	70.5	24.6	22.0	20.9	49.8	139.5	330.8	144.6
0.56	900	56.5	32.6	43.1	36.2	59.9	51.5	91.9	82.4	70.2	23.3	19.4	18.3	49.7	136.5	323.1	143.8
0.62	1000	53.1	32.6	43.1	36.2	57.1	47.6	90.8	81.8	69.1	23.3	19.4	18.3	49.1	133.7	317.1	141.0
0.68	1100	53.1	32.6	43.1	36.2	57.1	47.6	90.8	81.8	69.1	23.3	19.4	18.3	49.1	133.7	317.1	141.0
0.75	1200	51.4	32.6	43.1	36.2	55.6	47.6	90.8	81.8	66.1	23.3	19.4	18.3	46.8	133.7	317.1	137.8
0.81	1300	44.9	32.6	41.1	36.2	49.4	47.6	88.8	77.9	53.8	23.3	19.4	18.3	39.8	133.7	317.1	125.2
0.87	1400	43.2	32.6	41.1	36.2	46.8	47.6	88.8	77.9	51.8	23.3	19.4	18.3	38.2	133.7	317.1	120.5
0.93	1500	40.3	32.6	41.1	36.2	42.9	47.6	88.8	77.9	48.2	23.3	19.4	18.3	36.0	133.7	317.1	113.5
0.99	1600	37.8	31.5	39.7	35.0	40.5	47.6	88.8	77.9	43.9	22.1	18.5	17.5	32.6	133.7	317.1	107.6
1.06	1700	36.0	29.6	37.1	32.9	38.6	47.6	88.8	77.9	42.5	20.3	17.0	16.3	31.4	133.7	317.1	103.4
1.12	1800	35.5	29.2	36.6	32.4	38.2	47.6	88.8	77.8	42.1	20.0	16.7	16.0	31.1	133.7	317.0	102.2
1.18	1900	35.5	28.6	35.9	31.8	38.2	47.6	88.7	76.9	42.2	19.1	16.0	15.2	31.1	132.5	316.8	102.2
1.24	2000	35.5	28.1	35.4	31.5	38.2	47.1	87.4	73.3	42.2	18.1	15.1	14.2	31.1	128.6	314.5	102.2
1.3	2100	35.5	27.8	34.9	31.3	38.3	47.1	87.5	70.2	42.2	17.7	14.7	13.7	31.1	125.6	315.6	102.4
1.37	2200	35.7	28.0	35.1	31.5	38.4	47.9	89.1	71.3	42.3	17.7	14.8	13.8	31.2	126.7	318.4	102.8
1.43	2300	35.7	28.1	35.3	31.6	38.5	49.4	92.5	74.0	42.3	17.8	14.8	13.8	31.2	128.9	323.6	103.0
1.49	2400	36.0	28.4	35.6	31.8	38.7	55.7	103.2	79.8	42.4	17.9	14.8	13.8	31.3	133.0	345.6	103.8
1.55	2500	36.1	28.4	35.6	31.8	38.8	61.1	111.4	83.8	42.5	17.9	14.8	13.8	31.4	136.2	365.1	104.4
1.62	2600	36.6	28.7	36.1	32.1	39.1	62.8	114.3	85.3	42.2	17.9	15.0	13.9	31.3	137.7	372.0	106.1
1.68	2700	38.4	30.1	37.8	33.3	40.6	65.8	120.6	87.2	42.3	17.7	15.3	13.9	31.7	136.9	380.9	111.4
1.74	2800	39.3	32.9	41.1	36.3	41.8	65.8	120.6	87.2	42.9	18.5	16.0	14.6	32.1	136.9	380.9	115.4
1.8	2900	39.4	32.9	41.1	36.3	41.8	65.8	120.6	87.2	43.0	18.5	16.0	14.6	32.2	136.9	380.9	115.6
1.86	3000	39.4	32.9	41.1	36.3	41.8	65.8	120.6	87.2	43.0	18.5	16.0	14.6	32.2	136.9	380.9	115.6
1.93	3100	39.4	33.5	41.1	36.8	41.8	67.1	122.5	86.9	41.6	18.7	16.2	14.8	32.2	137.9	386.6	115.6
1.99	3200	39.6	33.9	41.5	37.3	42.1	67.7	123.6	87.2	41.6	18.8	16.4	14.9	32.3	138.4	389.4	116.8
2.05	3300	39.7	34.3	41.8	37.6	42.3	67.7	123.6	87.2	41.5	18.8	16.5	15.0	32.3	138.4	389.4	117.3
2.11	3400	39.7	34.3	41.8	37.6	42.2	67.7	123.6	87.2	40.1	18.8	16.5	15.0	31.7	138.4	389.4	117.3

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 9a (continued): Annual Sodium Salt Deposition in kg/(km^2-month).
Directions are directions that the plume is headed. Values can be converted to lbm/100-acre-month by multiplying by 0.893

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
2.17	3500	39.7	34.3	41.8	37.6	42.2	67.7	123.6	87.2	40.1	18.8	16.5	15.0	31.7	138.4	389.4	117.3
2.24	3600	39.7	34.8	42.4	38.1	42.3	70.7	128.2	89.6	40.1	18.4	16.2	14.8	31.7	140.7	398.1	117.7
2.3	3700	40.5	36.4	44.1	39.7	43.3	73.7	132.2	91.5	40.7	19.1	16.7	15.4	31.9	142.7	407.2	122.0
2.36	3800	40.5	36.6	44.4	40.1	43.3	73.7	132.2	91.5	40.7	19.2	16.7	15.4	31.9	142.7	407.2	122.0
2.42	3900	40.6	36.6	44.5	39.6	43.4	73.2	131.1	90.7	40.7	19.4	16.8	15.2	32.0	142.0	404.9	122.3
2.49	4000	40.5	36.1	43.9	38.7	43.3	72.5	129.9	89.7	40.6	19.1	16.7	14.9	31.9	141.0	402.1	121.9
2.55	4100	39.6	34.8	42.3	37.3	42.3	69.6	124.9	86.3	39.9	18.5	16.2	14.5	31.4	137.1	391.5	119.7
2.61	4200	37.8	32.0	38.5	34.5	40.3	61.0	108.4	73.3	38.3	17.0	14.8	13.5	30.3	124.7	361.8	115.2
2.67	4300	34.2	30.8	37.2	33.2	35.8	57.7	101.4	67.2	34.5	16.5	14.4	13.2	27.2	115.1	338.1	106.5
2.73	4400	33.1	30.5	36.8	32.9	34.6	56.3	98.4	64.5	33.4	16.4	14.3	13.1	26.1	75.6	223.9	104.2
2.8	4500	32.0	29.5	35.7	31.7	33.7	54.8	95.0	61.4	31.4	15.7	13.5	12.4	24.7	72.7	217.7	102.3
2.86	4600	30.9	28.7	35.0	30.9	32.5	52.1	90.3	58.1	30.4	15.4	13.3	12.2	23.9	69.5	207.4	99.1
2.92	4700	30.4	26.7	32.4	28.7	32.1	51.5	89.4	57.6	30.1	14.3	12.3	11.3	23.7	69.0	205.0	97.7
2.98	4800	30.1	26.4	31.9	28.3	31.7	51.0	88.7	57.3	29.9	14.2	12.1	11.2	23.6	68.6	203.3	96.7
3.04	4900	29.9	26.1	31.5	27.9	31.4	50.9	88.7	57.3	29.8	14.1	12.1	11.1	23.5	68.6	203.2	96.0
3.11	5000	29.9	26.1	31.5	27.9	31.4	50.9	88.6	57.3	29.8	14.1	12.1	11.1	23.5	68.6	203.1	95.7
3.17	5100	29.7	25.7	31.0	27.5	31.2	50.5	88.0	57.0	29.7	14.0	11.9	11.0	23.4	68.3	201.2	95.0
3.23	5200	29.5	25.6	30.9	27.4	31.0	50.3	87.7	56.9	29.5	14.0	11.9	11.0	23.3	68.1	200.1	94.1
3.29	5300	29.5	25.6	30.9	27.4	31.0	50.2	87.5	56.8	29.6	14.0	11.9	11.0	23.3	68.0	199.5	94.3
3.36	5400	29.8	25.4	30.7	27.2	31.3	49.0	84.8	53.8	29.7	13.9	11.9	10.9	23.4	63.9	193.1	95.3
3.42	5500	29.8	25.3	30.6	27.1	31.3	49.0	84.8	53.8	29.7	13.9	11.8	10.9	23.4	63.9	193.1	95.4
3.48	5600	29.8	25.3	30.6	27.1	31.3	49.0	84.8	53.8	29.7	13.9	11.8	10.9	23.4	63.9	193.1	95.4
3.54	5700	29.8	25.3	30.6	27.1	31.3	49.0	84.8	53.8	29.7	13.9	11.8	10.9	23.4	63.9	193.1	95.4
3.6	5800	29.8	25.3	30.6	27.0	31.4	49.1	85.0	53.9	29.8	13.8	11.7	10.8	23.5	64.0	193.6	95.7
3.67	5900	29.9	25.2	30.5	27.0	31.5	49.0	85.4	54.1	29.8	13.0	11.1	10.0	23.5	63.9	194.0	96.0
3.73	6000	29.9	25.2	30.5	27.0	31.5	48.9	85.3	54.0	29.8	13.0	11.1	10.0	23.5	63.8	193.8	96.0
3.79	6100	29.9	25.2	30.5	27.0	31.4	48.9	85.3	54.0	29.7	13.0	11.1	10.0	23.4	63.8	193.8	95.9
3.85	6200	29.6	25.1	30.4	26.9	30.9	48.9	85.3	54.0	28.6	12.9	11.1	10.0	22.6	63.8	193.8	95.2
3.91	6300	28.9	24.7	29.9	26.5	30.4	48.9	85.3	54.0	27.4	12.6	10.7	9.6	21.7	63.8	193.8	94.2
3.98	6400	28.7	24.7	29.9	26.5	30.2	48.9	85.3	54.0	26.9	12.6	10.7	9.6	21.3	63.8	193.8	93.8
4.04	6500	28.7	24.7	29.9	26.5	30.2	48.4	84.3	52.5	26.9	12.6	10.7	9.6	21.3	62.4	192.3	93.8
4.1	6600	28.7	24.6	29.8	26.4	30.2	48.4	84.2	52.3	26.9	12.3	10.5	9.4	21.3	62.3	192.1	93.8
4.16	6700	28.7	24.1	29.2	26.0	30.2	48.4	84.2	52.3	26.9	11.5	9.9	8.8	21.3	62.3	192.1	93.8

Pacific Gas and Electric Company
Engineering - Calculation Sheet
Project: Diablo Canyon Unit ( )1 ( )2 (X)1&2

CALC. NO. N/A (Study Only)
REV. NO. 0

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 9a (continued): Annual Sodium Salt Deposition in kg/(km^2-month). Directions are directions that the plume is headed. Values can be converted to lbm/100-acre-month by multiplying by 0.893

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
4.23	6800	28.7	24.1	29.2	26.0	30.2	48.4	84.2	52.3	26.1	11.5	9.9	8.8	20.6	62.3	192.1	93.8
4.29	6900	28.5	24.1	29.2	26.0	29.9	48.3	84.2	52.2	24.5	11.5	9.9	8.8	19.4	62.1	192.1	93.5
4.35	7000	28.5	24.1	29.2	26.0	29.9	48.3	84.1	51.9	24.4	11.5	9.9	8.8	19.3	61.7	192.0	93.5
4.41	7100	28.5	24.1	29.2	26.0	29.9	48.2	83.9	51.2	24.4	11.5	9.9	8.8	19.3	61.0	191.6	93.5
4.47	7200	28.5	24.1	29.2	26.0	29.9	48.0	83.4	49.3	24.4	11.5	9.9	8.7	19.3	57.7	190.1	93.5
4.54	7300	27.9	23.9	28.9	25.8	29.4	47.7	82.6	49.0	24.2	11.4	9.7	8.6	18.9	57.4	189.1	90.7
4.6	7400	26.8	23.2	27.9	24.9	28.6	46.6	79.6	47.5	23.7	11.3	9.5	8.4	18.3	56.3	185.3	87.1
4.66	7500	26.8	23.0	27.5	24.5	28.6	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.3	56.3	185.3	87.1
4.72	7600	26.8	23.0	27.5	24.5	28.6	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.3	56.3	185.3	87.1
4.78	7700	26.8	23.0	27.5	24.5	28.6	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.3	56.3	185.3	87.1
4.85	7800	26.8	23.0	27.5	24.5	28.6	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.3	56.3	185.3	87.1
4.91	7900	26.8	23.0	27.5	24.5	28.6	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.3	56.3	185.3	87.1
4.97	8000	26.8	23.0	27.5	24.5	28.6	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.3	56.3	185.3	87.1
5.03	8100	26.8	23.0	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.3	56.3	185.3	87.0
5.1	8200	26.7	23.0	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.16	8300	26.7	23.0	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.22	8400	26.7	23.0	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.28	8500	26.7	23.0	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.34	8600	26.7	23.0	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.41	8700	26.7	22.9	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.47	8800	26.7	22.9	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.53	8900	26.7	22.9	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.59	9000	26.7	22.9	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.65	9100	26.7	22.9	27.5	24.5	28.5	46.6	79.6	47.5	23.7	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.72	9200	26.7	22.9	27.5	24.5	28.5	46.6	79.6	47.5	23.6	11.2	9.5	8.4	18.2	56.3	185.3	87.0
5.78	9300	26.6	22.9	27.4	24.3	28.4	46.6	79.6	47.5	23.2	11.1	9.4	8.3	17.9	56.3	185.3	86.7
5.84	9400	26.6	22.8	27.3	24.0	28.4	46.5	79.3	47.0	23.2	11.0	9.3	8.1	17.9	55.0	184.5	86.7
5.9	9500	26.6	22.8	27.3	24.0	28.4	46.5	79.3	47.0	23.2	11.0	9.3	8.1	17.9	55.0	184.5	86.7
5.97	9600	26.6	22.8	27.3	24.0	28.4	46.5	79.3	47.0	23.2	11.0	9.3	8.1	17.9	55.0	184.5	86.7
6.03	9700	26.6	22.8	27.3	24.0	28.4	46.5	79.3	47.0	23.2	11.0	9.3	8.1	17.9	55.0	184.5	86.7
6.09	9800	26.6	22.8	27.3	24.0	28.4	45.9	78.4	46.5	23.2	11.0	9.3	8.1	17.9	54.6	183.0	86.7
6.15	9900	26.6	22.3	26.7	23.5	28.4	45.1	77.1	45.7	23.2	10.7	9.1	7.9	17.9	53.9	180.7	86.7
6.21	1e4	26.4	22.2	26.5	23.5	28.0	44.8	76.2	44.9	22.7	10.7	9.1	7.9	17.8	53.4	179.2	85.5

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 9b: Annual Total Dissolved Solids Deposition in kg/(km^2-month).
Directions are directions that the plume is headed. Values can be converted to lbm/100-acre-month by multiplying by 0.893.

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
0.06	100	1023	444	658	579	1201	995	2487	3194	8117	2448	1964	2160	6488	29774	73107	2700
0.12	200	573	246	423	469	650	228	678	1201	1448	55	45	76	1260	6615	10757	2018
0.19	300	327.0	82.0	139.0	131.0	321.0	119.0	319.0	404.0	186.0	38.0	36.0	43.0	289.0	562.0	929.0	1541
0.25	400	308.0	52.0	85.0	69.0	316.0	85.0	198.0	229.0	162.0	35.0	34.0	36.0	242.0	326.0	659.0	1535
0.31	500	308.0	52.0	67.0	69.0	315.0	71.0	128.0	118.0	126.0	35.0	33.0	36.0	242.0	221.0	541.0	1535
0.37	600	101.2	49.7	67.5	69.4	105.8	77.2	129.6	118.5	104.2	34.6	31.5	36.5	86.7	225.7	550.1	328.7
0.43	700	78.2	45.3	61.7	52.0	82.8	77.2	129.6	118.5	102.0	34.6	31.5	30.6	69.5	225.7	550.1	193.6
0.5	800	78.2	44.7	60.7	50.1	82.8	75.4	127.8	116.6	102.0	33.8	30.0	28.6	69.5	225.7	546.4	193.6
0.56	900	76.0	44.1	59.7	49.5	81.0	67.1	125.4	115.4	101.2	32.3	26.8	25.4	69.2	219.8	533.5	191.8
0.62	1000	72.7	44.1	59.7	49.5	78.2	64.4	124.6	115.0	100.1	32.3	26.8	25.4	68.6	217.8	529.2	189.0
0.68	1100	72.7	44.1	56.4	49.5	78.2	64.4	121.4	108.5	93.6	32.3	26.8	25.4	68.6	217.8	529.2	189.0
0.75	1200	65.2	44.1	56.1	49.5	71.8	64.4	121.0	107.9	81.0	32.3	26.8	25.4	59.4	217.8	529.2	175.4
0.81	1300	59.8	44.1	56.1	49.5	65.4	64.4	121.0	107.9	75.3	32.3	26.8	25.4	54.2	217.8	529.2	163.0
0.87	1400	56.0	44.1	56.1	49.5	60.0	64.4	121.0	107.9	70.7	32.3	26.8	25.4	51.4	217.8	529.2	153.5
0.93	1500	52.8	43.9	55.8	49.3	56.3	64.4	121.0	107.9	66.1	32.0	26.6	25.3	48.1	217.8	529.2	145.8
0.99	1600	49.6	40.2	50.8	45.2	53.3	64.4	121.0	107.9	62.1	28.2	23.7	22.8	44.7	217.8	529.2	138.6
1.06	1700	47.4	39.8	50.2	44.7	51.2	64.4	121.0	107.8	60.4	28.0	23.4	22.6	43.3	217.8	529.1	133.5
1.12	1800	47.4	39.0	49.1	43.7	51.2	64.4	120.9	107.3	60.4	27.5	22.9	22.1	43.3	217.2	529.0	133.3
1.18	1900	47.3	38.2	48.3	43.1	51.0	64.3	120.5	105.5	60.3	26.0	21.7	20.7	43.3	214.7	528.5	132.9
1.24	2000	47.2	38.0	48.1	43.0	50.9	63.9	119.5	101.3	60.2	25.3	21.2	20.0	43.2	210.5	526.7	132.7
1.3	2100	47.1	37.9	47.9	42.9	50.8	64.5	120.8	99.7	60.2	25.0	20.9	19.7	43.2	209.1	529.9	132.4
1.37	2200	47.1	37.9	47.9	42.9	50.8	65.8	123.8	101.6	60.2	25.0	20.9	19.7	43.2	209.1	533.9	132.4
1.43	2300	47.3	38.2	48.4	43.2	51.0	71.0	133.5	107.0	60.3	25.2	20.9	19.8	43.3	211.5	551.1	133.1
1.49	2400	47.4	38.3	48.5	43.3	51.1	77.5	144.0	113.5	60.4	25.2	21.0	19.8	43.3	218.5	574.8	133.5
1.55	2500	47.7	38.3	48.5	43.3	51.3	83.0	152.4	118.1	60.5	25.2	21.0	19.8	43.5	223.2	595.6	134.6
1.62	2600	48.1	39.6	49.2	44.5	51.5	85.7	156.2	118.4	58.0	25.2	21.3	19.9	42.8	224.0	605.7	135.7
1.68	2700	50.6	41.7	51.3	46.5	53.7	89.0	162.9	119.7	57.7	25.4	21.9	20.2	43.9	224.6	615.7	143.4
1.74	2800	51.8	44.4	54.5	49.3	55.2	89.0	162.9	119.7	58.5	26.2	22.6	21.0	44.5	224.6	615.7	148.4
1.8	2900	51.8	44.4	54.5	49.3	55.2	89.0	162.9	119.7	58.5	26.2	22.6	21.0	44.5	224.6	615.7	148.4
1.86	3000	51.8	45.3	55.6	50.2	55.2	90.4	165.7	120.9	57.6	26.4	22.9	21.3	44.2	225.7	622.3	148.6
1.93	3100	52.1	45.8	56.0	50.7	55.6	91.3	167.5	121.7	56.4	26.5	23.1	21.3	43.8	226.4	625.8	150.3
1.99	3200	51.9	46.0	56.1	50.8	55.2	91.3	167.5	121.7	56.2	25.9	22.6	21.1	43.6	226.4	625.8	149.9
2.05	3300	51.8	46.0	56.1	50.8	55.1	91.3	167.5	121.7	56.2	25.5	22.3	20.9	43.6	226.4	625.8	149.8
2.11	3400	51.8	45.5	55.8	49.9	55.1	88.7	161.8	116.6	56.2	25.5	22.3	20.6	43.6	150.1	405.5	149.8

Pacific Gas and Electric Company
Engineering - Calculation Sheet
Project: Diablo Canyon Unit ( )1 ( )2 (X)1&2

CALC. NO. N/A (Study Only)
REV. NO. 0

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 9b (continued): Annual Total Dissolved Solids Deposition in kg/(km^2-month). Directions are directions that the plume is headed. Values can be converted to lbm/100-acre-month by multiplying by 0.893

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
2.17	3500	51.8	45.3	55.5	48.7	55.1	88.0	160.4	115.3	56.2	25.5	22.3	20.1	43.6	131.4	351.2	149.8
2.24	3600	52.2	47.1	57.6	50.8	55.7	91.9	166.5	118.8	56.4	26.4	22.9	20.7	43.7	134.5	362.1	151.8
2.3	3700	53.1	48.5	59.1	52.2	57.0	96.0	171.8	120.8	57.1	27.0	23.4	21.1	44.0	136.8	375.1	156.4
2.36	3800	53.1	48.5	59.1	52.2	57.0	96.0	171.8	120.8	57.1	27.0	23.4	21.1	44.0	136.8	375.1	156.4
2.42	3900	53.4	48.7	59.3	52.3	57.2	95.4	170.5	119.8	57.2	27.1	23.5	21.2	44.2	135.8	372.0	157.1
2.49	4000	53.0	47.4	57.8	50.9	56.7	94.0	168.3	118.2	56.9	26.4	23.0	20.8	43.9	133.9	367.3	156.0
2.55	4100	52.0	45.0	54.4	48.5	55.5	84.3	149.8	103.5	55.9	25.0	21.7	19.9	43.3	119.6	334.0	153.4
2.61	4200	46.8	43.3	52.4	46.9	49.2	78.9	138.5	94.1	50.6	24.3	21.0	19.4	38.8	111.4	314.9	141.3
2.67	4300	45.0	42.3	51.3	45.6	47.5	78.0	136.5	92.2	47.7	23.7	20.4	18.8	36.6	109.7	311.7	137.7
2.73	4400	44.3	41.6	50.3	44.6	47.0	76.1	132.0	87.7	46.4	23.2	19.8	18.3	35.7	105.8	304.4	136.5
2.8	4500	44.1	40.2	48.4	42.9	46.8	75.2	130.6	87.0	46.3	22.2	18.8	17.5	35.6	105.0	300.7	136.0
2.86	4600	43.5	38.9	47.1	41.6	46.2	74.1	129.0	86.1	46.0	21.7	18.4	17.1	35.4	104.0	296.4	134.3
2.92	4700	43.5	38.7	46.8	41.4	46.1	74.1	129.0	86.0	45.9	21.6	18.4	17.1	35.3	104.0	296.5	134.1
2.98	4800	43.4	38.4	46.4	41.1	46.0	74.1	129.0	86.0	45.9	21.6	18.3	17.0	35.3	104.0	296.5	133.7
3.04	4900	43.4	38.3	46.4	41.0	46.0	74.1	129.0	86.0	45.9	21.6	18.3	17.0	35.3	104.0	296.5	133.7
3.11	5000	43.4	38.3	46.3	40.9	45.9	73.6	127.2	83.4	45.9	21.5	18.3	17.0	35.3	100.3	292.3	133.6
3.17	5100	43.3	38.1	46.1	40.8	45.9	73.1	126.3	82.2	45.8	21.5	18.2	16.9	35.2	98.6	290.1	133.3
3.23	5200	43.3	38.1	46.1	40.8	45.8	73.1	127.0	82.6	45.8	21.3	18.1	16.8	35.2	98.6	290.9	133.2
3.29	5300	43.8	38.2	46.3	40.9	46.4	72.8	126.7	82.5	46.2	20.3	17.2	15.7	35.5	98.5	289.9	135.8
3.36	5400	44.1	38.1	46.1	40.8	46.7	72.6	126.4	82.4	46.3	20.2	17.2	15.6	35.6	98.3	289.2	137.2
3.42	5500	43.1	38.1	46.1	40.8	45.4	72.6	126.4	82.4	44.2	20.2	17.2	15.6	34.2	98.3	289.2	135.5
3.48	5600	43.1	37.4	45.3	40.1	45.4	72.6	126.4	82.4	44.2	19.6	16.6	15.1	34.2	98.3	289.2	135.5
3.54	5700	42.7	37.3	45.2	40.1	45.1	72.4	126.0	81.8	42.8	19.6	16.6	15.0	33.0	97.8	288.7	134.8
3.6	5800	42.6	37.4	45.3	40.2	45.1	72.4	126.1	80.2	42.0	19.6	16.6	15.0	32.4	96.2	289.3	135.3
3.67	5900	42.6	37.2	45.2	40.1	45.1	72.4	126.1	80.2	42.0	19.3	16.4	14.7	32.4	96.2	289.3	135.3
3.73	6000	42.6	36.8	44.7	39.7	45.1	72.4	126.1	80.2	42.0	18.4	15.7	14.0	32.4	96.2	289.3	135.3
3.79	6100	42.5	36.4	44.2	39.3	45.0	72.4	126.1	80.2	40.3	17.9	15.4	13.7	30.9	96.2	289.3	135.1
3.85	6200	42.3	36.4	44.2	39.3	44.7	72.4	126.0	79.8	38.2	17.9	15.4	13.7	29.4	95.7	289.2	134.7
3.91	6300	42.3	36.4	44.2	39.3	44.7	72.2	125.6	78.6	38.2	17.9	15.4	13.7	29.4	94.4	288.6	134.7
3.98	6400	42.3	36.4	44.2	39.3	44.7	71.9	124.9	76.0	38.2	17.9	15.3	13.6	29.4	90.3	286.6	134.7
4.04	6500	42.3	36.4	44.1	39.3	44.7	71.9	124.8	75.5	38.2	17.9	15.2	13.6	29.4	89.1	286.1	134.7
4.1	6600	42.3	36.4	44.1	39.3	44.7	71.9	124.8	75.5	38.2	17.9	15.2	13.6	29.4	89.1	286.1	134.7
4.16	6700	42.3	36.4	44.1	39.3	44.7	71.9	124.8	75.5	38.2	17.9	15.2	13.6	29.4	89.1	286.1	134.7

Appendix A-7

Pacific Gas and Electric Company
Engineering - Calculation Sheet
Project: Diablo Canyon Unit ( )1 ( )2 (X)1&2

CALC. NO. N/A (Study Only)
REV. NO. 0

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 9b (continued): Annual Total Dissolved Solids Deposition in kg/(km^2-month). Directions are directions that the plume is headed. Values can be converted to lbm/100-acre-month by multiplying by 0.893

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
4.23	6800	42.3	36.4	44.1	39.3	44.7	71.9	124.8	75.5	38.2	17.9	15.2	13.6	29.4	89.1	286.1	134.7
4.29	6900	42.3	36.4	44.1	39.3	44.7	71.9	124.8	75.5	38.2	17.9	15.2	13.6	29.4	89.1	286.1	134.7
4.35	7000	42.2	36.4	44.1	39.3	44.5	71.9	124.8	75.5	38.1	17.9	15.2	13.6	29.3	89.1	286.1	134.5
4.41	7100	42.2	36.4	44.1	39.3	44.5	71.9	124.8	75.5	38.1	17.9	15.2	13.6	29.3	89.1	286.1	134.5
4.47	7200	41.4	35.8	43.3	38.7	44.0	70.9	122.2	74.2	37.7	17.7	14.9	13.4	28.9	88.1	282.9	132.7
4.54	7300	40.9	35.1	42.1	37.4	43.7	70.2	120.5	73.4	37.5	17.6	14.8	13.2	28.7	87.5	280.8	131.5
4.6	7400	40.9	35.0	42.1	37.4	43.7	70.2	120.5	73.4	37.5	17.6	14.8	13.2	28.7	87.5	280.8	131.5
4.66	7500	40.9	35.0	42.1	37.4	43.7	70.2	120.5	73.4	37.5	17.6	14.8	13.2	28.7	87.5	280.8	131.5
4.72	7600	40.9	35.0	42.1	37.4	43.7	70.2	120.5	73.4	37.5	17.6	14.8	13.2	28.7	87.5	280.8	131.5
4.78	7700	40.9	35.0	42.1	37.4	43.7	70.2	120.5	73.4	37.5	17.6	14.8	13.2	28.7	87.5	280.8	131.5
4.85	7800	40.9	35.0	42.1	37.4	43.7	70.2	120.5	73.4	37.5	17.6	14.8	13.2	28.7	87.5	280.8	131.5
4.91	7900	40.9	35.0	42.1	37.4	43.7	70.2	120.5	73.4	37.5	17.6	14.8	13.2	28.7	87.5	280.8	131.5
4.97	8000	40.9	34.9	42.0	37.1	43.7	70.2	120.5	73.4	37.5	17.6	14.8	13.1	28.7	87.5	280.8	131.5
5.03	8100	40.9	34.9	41.9	36.8	43.7	70.2	120.5	73.4	37.5	17.6	14.8	13.0	28.7	87.5	280.8	131.5
5.1	8200	40.9	34.9	41.9	36.8	43.7	70.2	120.5	73.4	37.4	17.6	14.8	13.0	28.6	87.5	280.8	131.5
5.16	8300	40.8	34.8	41.8	36.8	43.5	70.2	120.5	73.4	36.6	17.5	14.7	12.9	28.2	87.5	280.8	131.1
5.22	8400	40.8	34.7	41.6	36.7	43.5	70.1	119.9	72.5	36.4	17.2	14.6	12.7	28.2	85.7	279.6	131.1
5.28	8500	40.8	34.7	41.5	36.7	43.5	70.1	119.7	72.1	36.1	17.2	14.6	12.7	28.2	85.6	279.5	131.1
5.34	8600	40.8	34.7	41.5	36.7	43.5	70.1	119.7	72.1	36.1	17.2	14.6	12.7	28.2	85.6	279.5	131.1
5.41	8700	40.8	34.7	41.5	36.7	43.5	70.1	119.7	72.1	36.1	17.2	14.6	12.7	28.2	85.6	279.5	131.1
5.47	8800	40.8	34.7	41.5	36.7	43.5	70.1	119.7	72.1	36.1	17.2	14.6	12.7	28.2	85.6	279.5	131.1
5.53	8900	40.8	34.7	41.5	36.7	43.5	70.1	119.7	72.1	36.1	17.2	14.6	12.7	28.2	85.6	279.5	131.1
5.59	9000	40.8	34.7	41.5	36.7	43.5	70.1	119.7	72.1	36.1	17.2	14.6	12.7	28.2	85.6	279.5	131.1
5.65	9100	40.8	34.7	41.5	36.7	43.5	70.0	119.7	72.0	36.1	17.2	14.6	12.7	28.2	85.6	279.4	131.1
5.72	9200	40.8	34.7	41.5	36.7	43.5	70.0	119.7	72.0	36.1	17.2	14.6	12.7	28.2	85.6	279.4	131.1
5.78	9300	40.8	34.7	41.5	36.7	43.5	68.4	116.0	69.5	36.1	17.2	14.6	12.7	28.2	83.3	272.0	131.1
5.84	9400	40.8	34.7	41.5	36.7	43.5	68.4	116.0	69.5	36.1	17.2	14.6	12.7	28.2	83.3	272.0	131.1
5.9	9500	40.8	34.7	41.5	36.7	43.5	68.4	116.0	69.5	36.1	17.2	14.6	12.7	28.2	83.3	272.0	131.1
5.97	9600	39.2	33.1	39.5	35.1	42.1	67.1	113.9	68.3	34.9	16.5	14.1	12.4	27.3	82.3	268.4	127.3
6.03	9700	38.0	32.2	38.5	34.2	40.6	65.3	111.0	66.4	34.1	16.1	13.8	12.1	26.8	80.3	261.6	122.6
6.09	9800	37.4	31.4	37.8	33.4	40.0	65.1	110.8	66.2	33.8	15.8	13.5	11.9	26.5	80.1	261.0	120.6
6.15	9900	37.4	31.3	37.7	33.3	40.0	63.9	108.7	64.9	33.8	15.7	13.5	11.9	26.5	79.0	256.7	120.6
6.21	1e4	37.4	30.5	36.8	32.2	40.0	59.5	101.8	61.2	33.8	15.2	13.1	11.5	26.5	74.6	241.2	120.6

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 9c: Annual Total <10 micron Solids Deposition in kg/(km^2-month).
Directions are directions that the plume is headed. Values can be converted to lbm/100-acre-month by multiplying by 0.893.

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
0.06	100	106	50	76	67	120	105	255	314	908	289	231	256	731	3211	8096	277
0.12	200	65	28	46	54	75	23	62	118	175	6	5	8	154	842	1415	225
0.19	300	22.2	8.98	12.84	14.8	22.24	7.13	12.43	10.48	16.02	3.34	3.05	4.06	23.56	14.74	36.25	90.6
0.25	400	6.96	5.22	6.3	7.15	7.65	7.11	12.4	10.45	7.3	2.96	2.82	3.35	5.51	14.74	36.21	17.85
0.31	500	6.96	5.22	6.3	7.15	7.65	7.04	12.33	10.38	7.3	2.96	2.82	3.35	5.51	14.74	36.06	17.85
0.37	600	6.72	5.04	6.3	7.15	7.18	6.91	12.3	10.36	7.06	2.96	2.82	3.35	5.27	14.65	35.87	17.38
0.43	700	6.64	4.44	5.67	5.28	7	6.91	12.29	10.36	6.97	2.95	2.79	2.73	5.19	14.64	35.86	17.21
0.5	800	6.64	4.25	5.44	4.57	7	6.91	12.29	10.36	6.97	2.92	2.68	2.5	5.19	14.64	35.86	17.21
0.56	900	6.64	4.23	5.41	4.56	7	6.91	12.29	10.36	6.97	2.88	2.6	2.42	5.19	14.64	35.86	17.21
0.62	1000	6.64	4.17	5.3	4.49	7	6.91	12.29	10.36	6.97	2.69	2.23	2.05	5.19	14.64	35.86	17.21
0.68	1100	6.64	4.17	5.3	4.49	7	6.91	12.29	10.36	6.97	2.69	2.23	2.05	5.19	14.64	35.86	17.21
0.75	1200	6.43	4.17	5.3	4.49	6.83	6.91	12.29	10.36	6.9	2.69	2.23	2.05	5.15	14.64	35.86	17.03
0.81	1300	6.22	4.17	5.3	4.49	6.66	6.61	12.21	10.32	6.84	2.69	2.23	2.05	5.12	14.43	35.4	16.86
0.87	1400	5.86	4.17	5.3	4.49	6.36	6.38	12.11	10.24	6.19	2.69	2.23	2.05	4.64	14.3	35	16.21
0.93	1500	4.98	4.17	5.3	4.49	5.45	6.37	12.1	10.24	5.11	2.69	2.23	2.05	3.7	14.3	34.99	14.4
0.99	1600	4.82	4.17	5.3	4.49	5.22	6.37	12.1	10.23	4.93	2.69	2.23	2.05	3.56	14.29	34.99	13.98
1.06	1700	4.48	4.17	5.21	4.49	4.77	6.36	11.99	10.04	4.32	2.69	2.23	2.05	3.3	14.28	34.98	13.17
1.12	1800	4.15	3.9	4.82	4.23	4.46	6.36	11.96	9.96	3.63	2.44	2.04	1.89	2.83	14.28	34.98	12.42
1.18	1900	4.01	3.62	4.42	3.88	4.32	6.2	11.39	9.15	3.53	2.17	1.8	1.7	2.73	13.15	33.68	12.1
1.24	2000	3.98	3.42	4.18	3.65	4.29	6.18	11.33	9.06	3.51	1.93	1.59	1.46	2.71	13.03	33.54	12.04
1.3	2100	4	3.28	4.02	3.53	4.32	6.11	11.15	8.89	3.52	1.67	1.38	1.22	2.72	12.88	33.27	12.11
1.37	2200	4.01	3.15	3.87	3.42	4.33	5.88	10.62	7.88	3.53	1.56	1.26	1.1	2.73	11.95	32.52	12.14
1.43	2300	4.04	3.25	3.97	3.52	4.36	5.76	10.37	7.11	3.54	1.6	1.3	1.13	2.74	11.2	32.19	12.22
1.49	2400	4.13	3.25	3.97	3.52	4.45	5.93	10.7	7.35	3.6	1.6	1.3	1.13	2.78	11.46	32.95	12.48
1.55	2500	4.16	3.28	4.01	3.54	4.48	6.63	11.86	8.1	3.62	1.61	1.3	1.13	2.81	12.23	35.39	12.58
1.62	2600	4.22	3.32	4.06	3.58	4.53	7.18	12.68	8.58	3.65	1.63	1.31	1.14	2.83	12.75	37.49	12.75
1.68	2700	4.48	3.45	4.25	3.69	4.74	7.71	13.71	9.06	3.79	1.67	1.38	1.19	2.96	13.23	39.42	13.48
1.74	2800	4.68	3.73	4.54	3.95	4.96	7.9	14.19	9.29	3.92	1.76	1.47	1.27	3.06	13.41	40.03	14.19
1.8	2900	4.66	3.88	4.68	4.12	4.94	7.94	14.26	9.32	3.83	1.81	1.51	1.3	3	13.45	40.21	14.15
1.86	3000	4.7	3.86	4.65	4.09	4.98	8.06	14.32	9.12	3.69	1.68	1.43	1.22	2.92	12.9	40.47	14.45
1.93	3100	4.71	3.86	4.65	4.09	4.98	8.05	14.29	9.01	3.69	1.68	1.43	1.22	2.93	12.73	40.41	14.5
1.99	3200	4.76	3.96	4.89	4.23	5.03	8.05	14.29	9.01	3.72	1.69	1.47	1.23	2.95	12.73	40.41	14.71
2.05	3300	4.81	3.96	4.89	4.23	5.07	8.05	14.29	9.01	3.74	1.69	1.47	1.23	2.98	12.73	40.41	14.92
2.11	3400	4.81	3.96	4.89	4.23	5.07	8.05	14.29	9.01	3.74	1.69	1.47	1.23	2.98	12.73	40.41	14.92

Appendix A-7

Pacific Gas and Electric Company
Engineering - Calculation Sheet
Project: Diablo Canyon Unit ( )1 ( )2 (X)1&2

CALC. NO. N/A (Study Only)
REV. NO. 0

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 9c (continued): Annual Total <10 micron Solids Deposition in kg/(km^2-month). Directions are directions that the plume is headed. Values can be converted to lbm/100-acre-month by multiplying by 0.893

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
2.17	3500	4.81	4.06	5.01	4.33	5.07	8.05	14.29	9.01	3.74	1.72	1.5	1.27	2.98	12.73	40.41	14.92
2.24	3600	4.81	4.11	5.06	4.38	5.07	8.13	14.44	9.08	3.74	1.73	1.52	1.29	2.98	12.79	40.67	14.92
2.3	3700	4.87	4.41	5.37	4.66	5.15	9.02	15.88	9.77	3.78	1.84	1.63	1.36	3	13.45	43.64	15.2
2.36	3800	4.95	4.53	5.49	4.78	5.27	9.37	16.45	10.01	3.84	1.89	1.66	1.4	3.03	13.7	45.04	15.61
2.42	3900	4.95	4.53	5.49	4.78	5.27	9.37	16.45	10.01	3.84	1.89	1.66	1.4	3.03	13.7	45.04	15.61
2.49	4000	4.98	4.55	5.53	4.83	5.32	9.35	16.4	9.98	3.86	1.91	1.66	1.4	3.04	13.67	44.97	15.8
2.55	4100	5.04	4.58	5.57	4.89	5.39	8.98	15.59	9.43	3.89	1.92	1.67	1.41	3.07	13.2	43.39	16.09
2.61	4200	5.01	4.51	5.49	4.83	5.36	8.9	15.4	9.3	3.86	1.9	1.65	1.39	3.05	13.08	43.01	16
2.67	4300	4.7	4.09	4.98	4.37	5.08	8.57	14.82	8.87	3.59	1.69	1.5	1.28	2.88	12.63	41.84	15.25
2.73	4400	4.47	3.89	4.77	4.13	4.82	7.15	12.43	7.23	3.42	1.59	1.43	1.22	2.76	10.92	36.44	14.58
2.8	4500	3.89	3.54	4.4	3.77	4.2	7.1	12.34	7.11	2.95	1.46	1.32	1.13	2.43	10.68	36.2	13.08
2.86	4600	3.67	3.49	4.35	3.72	3.94	7.09	12.32	7.03	2.8	1.44	1.3	1.11	2.22	10.5	36.12	12.53
2.92	4700	3.62	3.23	3.97	3.42	3.89	6.55	11.39	6.47	2.77	1.3	1.18	1.03	2.19	9.89	34.04	12.4
2.98	4800	3.25	2.93	3.6	3.1	3.46	5.67	9.96	5.62	2.57	1.16	1.07	0.93	1.99	8.98	30.79	11.3
3.04	4900	2.96	2.4	3.05	2.59	3.19	4.96	8.99	5.18	2.39	0.98	0.94	0.8	1.88	8.49	28.29	10.43
3.11	5000	2.58	2.07	2.54	2.25	2.65	4.57	8.29	4.73	2.03	0.86	0.82	0.7	1.67	8.11	26.93	9.3
3.17	5100	2.41	1.87	2.27	2.02	2.45	4.42	7.92	4.42	1.9	0.8	0.76	0.66	1.58	7.88	26.38	8.77
3.23	5200	2.32	1.87	2.27	2.02	2.36	4.39	7.87	4.39	1.83	0.8	0.76	0.66	1.53	7.85	26.23	8.33
3.29	5300	2.22	1.58	1.91	1.74	2.27	3.92	7.14	4.07	1.77	0.71	0.66	0.56	1.48	7.4	24.04	7.88
3.36	5400	2.02	1.56	1.89	1.73	2.06	3.53	6.42	3.76	1.63	0.71	0.66	0.55	1.35	7.07	22.24	7.12
3.42	5500	1.85	1.45	1.77	1.62	1.84	3.18	5.9	3.54	1.47	0.67	0.61	0.53	1.22	6.83	21	6.52
3.48	5600	1.66	1.28	1.61	1.45	1.65	2.97	5.64	3.43	1.36	0.61	0.56	0.49	1.12	6.7	20.34	5.63
3.54	5700	1.66	1.25	1.58	1.42	1.65	2.97	5.64	3.43	1.36	0.6	0.55	0.48	1.12	6.7	20.34	5.63
3.6	5800	1.66	1.25	1.58	1.42	1.65	2.97	5.64	3.43	1.36	0.6	0.55	0.48	1.12	6.7	20.34	5.63
3.67	5900	1.66	1.25	1.58	1.42	1.65	2.97	5.64	3.43	1.36	0.6	0.55	0.48	1.12	6.7	20.34	5.63
3.73	6000	1.59	1.19	1.49	1.31	1.58	2.88	5.45	3.35	1.32	0.57	0.54	0.47	1.09	6.63	19.96	5.34
3.79	6100	1.55	1.19	1.49	1.31	1.52	2.79	5.25	3.27	1.29	0.57	0.54	0.47	1.07	6.56	19.59	5.14
3.85	6200	1.55	1.19	1.49	1.31	1.52	2.69	5.05	3.09	1.29	0.57	0.54	0.47	1.07	3.82	11.67	5.14
3.91	6300	1.55	1.19	1.49	1.31	1.52	2.56	4.79	2.84	1.29	0.57	0.54	0.47	1.07	2.94	9.38	5.14
3.98	6400	1.55	1.19	1.49	1.31	1.52	2.49	4.65	2.71	1.29	0.57	0.54	0.47	1.07	2.81	9.16	5.14
4.04	6500	1.55	1.19	1.49	1.31	1.52	2.49	4.65	2.71	1.29	0.57	0.54	0.47	1.07	2.81	9.16	5.14
4.1	6600	1.55	1.19	1.49	1.31	1.52	2.49	4.65	2.71	1.29	0.57	0.54	0.47	1.07	2.81	9.16	5.14
4.16	6700	1.55	1.19	1.49	1.31	1.52	2.49	4.65	2.71	1.29	0.57	0.54	0.47	1.07	2.81	9.16	5.14

Pacific Gas and Electric Company
Engineering - Calculation Sheet
Project: Diablo Canyon Unit ( )1 ( )2 (X)1&2

CALC. NO. N/A (Study Only)
REV. NO. 0

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 9c (continued): Annual Total <10 micron Solids Deposition in kg/(km^2-month). Directions are directions that the plume is headed. Values can be converted to lbm/100-acre-month by multiplying by 0.893

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
4.23	6800	1.55	1.19	1.49	1.31	1.52	2.49	4.65	2.71	1.29	0.57	0.54	0.47	1.07	2.81	9.16	5.14
4.29	6900	1.55	1.19	1.49	1.31	1.52	2.49	4.65	2.71	1.29	0.57	0.54	0.47	1.07	2.81	9.16	5.14
4.35	7000	1.55	1.19	1.49	1.31	1.52	2.49	4.65	2.71	1.29	0.57	0.54	0.47	1.07	2.81	9.16	5.14
4.41	7100	1.55	1.19	1.49	1.31	1.52	2.49	4.65	2.71	1.29	0.57	0.54	0.47	1.07	2.81	9.16	5.14
4.47	7200	1.55	1.19	1.49	1.31	1.52	2.49	4.65	2.71	1.29	0.57	0.54	0.47	1.07	2.81	9.16	5.14
4.54	7300	1.53	1.19	1.49	1.31	1.51	2.49	4.65	2.71	1.28	0.57	0.54	0.47	1.05	2.81	9.16	5.11
4.6	7400	1.45	1.19	1.49	1.31	1.44	2.49	4.65	2.71	1.2	0.57	0.54	0.47	0.98	2.81	9.16	4.97
4.66	7500	1.45	1.19	1.49	1.31	1.44	2.49	4.65	2.71	1.2	0.57	0.54	0.47	0.98	2.81	9.16	4.97
4.72	7600	1.45	1.19	1.49	1.31	1.44	2.49	4.65	2.71	1.2	0.57	0.54	0.47	0.98	2.81	9.16	4.97
4.78	7700	1.45	1.19	1.49	1.31	1.44	2.49	4.65	2.71	1.2	0.57	0.54	0.47	0.98	2.81	9.16	4.97
4.85	7800	1.45	1.19	1.49	1.31	1.44	2.49	4.65	2.71	1.2	0.57	0.54	0.47	0.98	2.81	9.16	4.97
4.91	7900	1.35	1.14	1.43	1.27	1.34	2.41	4.45	2.62	1.18	0.55	0.51	0.45	0.9	2.74	8.91	4.43
4.97	8000	1.08	1.04	1.28	1.18	1.16	2.11	3.68	2.24	1.05	0.52	0.45	0.42	0.77	2.44	7.93	3.76
5.03	8100	1.08	0.98	1.19	1.07	1.16	2.11	3.68	2.24	1.05	0.52	0.45	0.41	0.77	2.44	7.93	3.76
5.1	8200	1.08	0.97	1.17	1.04	1.16	2.11	3.68	2.24	1.05	0.52	0.45	0.4	0.77	2.44	7.93	3.76
5.16	8300	1.08	0.97	1.17	1.04	1.16	2.11	3.68	2.24	1.05	0.52	0.45	0.4	0.77	2.44	7.93	3.76
5.22	8400	1.08	0.97	1.17	1.04	1.16	2.11	3.68	2.24	1.01	0.52	0.45	0.4	0.76	2.44	7.93	3.76
5.28	8500	1.08	0.93	1.13	1	1.16	2.11	3.68	2.24	1	0.49	0.42	0.38	0.75	2.44	7.93	3.76
5.34	8600	1.08	0.93	1.12	1	1.16	2.11	3.68	2.24	1	0.49	0.42	0.37	0.75	2.44	7.93	3.76
5.41	8700	1.08	0.93	1.12	1	1.16	2.11	3.68	2.24	1	0.49	0.42	0.37	0.75	2.44	7.93	3.76
5.47	8800	1.08	0.93	1.12	1	1.16	2.11	3.68	2.24	1	0.49	0.42	0.37	0.75	2.44	7.93	3.76
5.53	8900	1.08	0.93	1.12	1	1.16	2.1	3.64	2.21	1	0.49	0.42	0.37	0.75	2.42	7.88	3.76
5.59	9000	1.08	0.93	1.12	1	1.16	2.05	3.51	2.08	1	0.48	0.41	0.37	0.75	2.3	7.67	3.76
5.65	9100	1.04	0.93	1.12	1	1.13	2.05	3.51	2.08	0.92	0.47	0.4	0.36	0.7	2.3	7.67	3.68
5.72	9200	1.03	0.93	1.12	1	1.12	2.05	3.51	2.08	0.91	0.47	0.4	0.36	0.69	2.3	7.67	3.67
5.78	9300	1.03	0.93	1.12	1	1.12	2.05	3.51	2.08	0.91	0.47	0.4	0.36	0.69	2.3	7.67	3.67
5.84	9400	1.03	0.93	1.12	1	1.12	2.05	3.51	2.08	0.91	0.47	0.4	0.36	0.69	2.3	7.67	3.67
5.9	9500	1.03	0.93	1.12	1	1.12	2.05	3.51	2.08	0.91	0.47	0.4	0.36	0.69	2.3	7.67	3.67
5.97	9600	1.03	0.93	1.12	1	1.12	2.05	3.51	2.08	0.91	0.47	0.4	0.36	0.69	2.3	7.67	3.67
6.03	9700	1.03	0.93	1.12	1	1.12	2.05	3.51	2.08	0.91	0.47	0.4	0.36	0.69	2.3	7.67	3.67
6.09	9800	1.03	0.93	1.12	1	1.12	2.05	3.51	2.08	0.91	0.47	0.4	0.36	0.69	2.3	7.67	3.67
6.15	9900	1.03	0.93	1.12	1	1.12	2.05	3.51	2.08	0.91	0.47	0.4	0.36	0.69	2.3	7.67	3.67
6.21	1e4	1.03	0.93	1.12	1	1.12	2.05	3.51	2.08	0.91	0.47	0.4	0.36	0.69	2.3	7.67	3.67

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 10:Annual Water Deposition in kg/(km^2-month).
Directions are directions that the plume is headed.
Note: these can be converted to inches/yr of increased precipitation by multiplying by 4.7×10^{-7}

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
0.06	100	.18E+05	.79E+04	.11E+05	.11E+05	.21E+05	.18E+05	.45E+05	.56E+05	.14E+06	.42E+05	.33E+05	.37E+05	.11E+06	.54E+06	.13E+07	.48E+05
0.12	200	.10E+05	.44E+04	.74E+04	.87E+04	.12E+05	.43E+04	.12E+05	.22E+05	.25E+05	.85E+03	.69E+03	.13E+04	.23E+05	.13E+06	.21E+06	.37E+05
0.19	300	.32E+04	.14E+04	.20E+04	.23E+04	.30E+04	.21E+04	.53E+04	.63E+04	.20E+04	.54E+03	.50E+03	.63E+03	.31E+04	.92E+04	.15E+05	.13E+05
0.25	400	.12E+04	.80E+03	.11E+04	.10E+04	.13E+04	.14E+04	.31E+04	.32E+04	.15E+04	.48E+03	.47E+03	.49E+03	.10E+04	.48E+04	.97E+04	.32E+04
0.31	500	.12E+04	.80E+03	.10E+04	.10E+04	.13E+04	.11E+04	.20E+04	.16E+04	.14E+04	.48E+03	.47E+03	.49E+03	.10E+04	.28E+04	.73E+04	.32E+04
0.37	600	.12E+04	.77E+03	.98E+03	.10E+04	.13E+04	.11E+04	.20E+04	.15E+04	.13E+04	.48E+03	.44E+03	.49E+03	.10E+04	.28E+04	.73E+04	.32E+04
0.43	700	.12E+04	.71E+03	.90E+03	.80E+03	.13E+04	.11E+04	.20E+04	.15E+04	.13E+04	.47E+03	.44E+03	.41E+03	.10E+04	.28E+04	.73E+04	.32E+04
0.5	800	.12E+04	.70E+03	.88E+03	.76E+03	.13E+04	.11E+04	.19E+04	.15E+04	.13E+04	.46E+03	.42E+03	.38E+03	.10E+04	.28E+04	.73E+04	.32E+04
0.56	900	.12E+04	.69E+03	.86E+03	.75E+03	.13E+04	.11E+04	.19E+04	.15E+04	.13E+04	.44E+03	.37E+03	.33E+03	.10E+04	.27E+04	.72E+04	.32E+04
0.62	1000	.12E+04	.69E+03	.86E+03	.75E+03	.12E+04	.10E+04	.19E+04	.15E+04	.13E+04	.44E+03	.37E+03	.33E+03	.99E+03	.27E+04	.71E+04	.31E+04
0.68	1100	.12E+04	.69E+03	.86E+03	.75E+03	.12E+04	.10E+04	.19E+04	.15E+04	.13E+04	.44E+03	.37E+03	.33E+03	.99E+03	.27E+04	.71E+04	.31E+04
0.75	1200	.11E+04	.69E+03	.86E+03	.75E+03	.12E+04	.10E+04	.19E+04	.15E+04	.12E+04	.44E+03	.37E+03	.33E+03	.93E+03	.27E+04	.71E+04	.30E+04
0.81	1300	.93E+03	.69E+03	.86E+03	.75E+03	.10E+04	.10E+04	.19E+04	.15E+04	.95E+03	.44E+03	.37E+03	.33E+03	.73E+03	.27E+04	.71E+04	.27E+04
0.87	1400	.88E+03	.69E+03	.86E+03	.75E+03	.95E+03	.10E+04	.19E+04	.15E+04	.89E+03	.44E+03	.37E+03	.33E+03	.68E+03	.27E+04	.71E+04	.25E+04
0.93	1500	.78E+03	.69E+03	.86E+03	.75E+03	.82E+03	.10E+04	.19E+04	.15E+04	.77E+03	.44E+03	.37E+03	.33E+03	.61E+03	.27E+04	.71E+04	.23E+04
0.99	1600	.71E+03	.66E+03	.81E+03	.72E+03	.75E+03	.10E+04	.19E+04	.15E+04	.66E+03	.40E+03	.34E+03	.31E+03	.52E+03	.27E+04	.71E+04	.21E+04
1.06	1700	.63E+03	.59E+03	.72E+03	.64E+03	.66E+03	.10E+04	.19E+04	.15E+04	.59E+03	.35E+03	.29E+03	.27E+03	.46E+03	.27E+04	.71E+04	.19E+04
1.12	1800	.60E+03	.56E+03	.68E+03	.61E+03	.64E+03	.10E+04	.19E+04	.15E+04	.57E+03	.33E+03	.27E+03	.25E+03	.45E+03	.27E+04	.71E+04	.19E+04
1.18	1900	.59E+03	.48E+03	.59E+03	.52E+03	.63E+03	.10E+04	.19E+04	.15E+04	.57E+03	.28E+03	.23E+03	.21E+03	.44E+03	.27E+04	.71E+04	.18E+04
1.24	2000	.59E+03	.46E+03	.56E+03	.50E+03	.62E+03	.10E+04	.18E+04	.14E+04	.56E+03	.25E+03	.21E+03	.19E+03	.44E+03	.26E+04	.70E+04	.18E+04
1.3	2100	.57E+03	.43E+03	.53E+03	.47E+03	.60E+03	.97E+03	.17E+04	.12E+04	.56E+03	.23E+03	.19E+03	.17E+03	.43E+03	.25E+04	.69E+04	.18E+04
1.37	2200	.55E+03	.43E+03	.53E+03	.47E+03	.59E+03	.94E+03	.17E+04	.12E+04	.54E+03	.23E+03	.19E+03	.17E+03	.42E+03	.24E+04	.68E+04	.17E+04
1.43	2300	.55E+03	.43E+03	.53E+03	.47E+03	.59E+03	.92E+03	.17E+04	.11E+04	.54E+03	.23E+03	.19E+03	.17E+03	.42E+03	.24E+04	.67E+04	.17E+04
1.49	2400	.55E+03	.43E+03	.52E+03	.47E+03	.58E+03	.94E+03	.17E+04	.11E+04	.54E+03	.23E+03	.19E+03	.17E+03	.42E+03	.23E+04	.68E+04	.17E+04
1.55	2500	.55E+03	.43E+03	.52E+03	.47E+03	.58E+03	.98E+03	.17E+04	.11E+04	.54E+03	.23E+03	.19E+03	.17E+03	.42E+03	.23E+04	.69E+04	.17E+04
1.62	2600	.55E+03	.43E+03	.53E+03	.47E+03	.59E+03	.99E+03	.18E+04	.12E+04	.53E+03	.23E+03	.19E+03	.17E+03	.42E+03	.23E+04	.69E+04	.17E+04
1.68	2700	.59E+03	.45E+03	.56E+03	.49E+03	.61E+03	.11E+04	.19E+04	.12E+04	.54E+03	.22E+03	.20E+03	.17E+03	.43E+03	.23E+04	.71E+04	.18E+04
1.74	2800	.60E+03	.49E+03	.60E+03	.52E+03	.63E+03	.11E+04	.19E+04	.12E+04	.55E+03	.23E+03	.20E+03	.18E+03	.43E+03	.23E+04	.71E+04	.19E+04
1.8	2900	.60E+03	.49E+03	.60E+03	.52E+03	.63E+03	.11E+04	.19E+04	.12E+04	.55E+03	.23E+03	.20E+03	.18E+03	.43E+03	.23E+04	.71E+04	.19E+04
1.86	3000	.60E+03	.49E+03	.60E+03	.52E+03	.63E+03	.11E+04	.19E+04	.12E+04	.55E+03	.23E+03	.20E+03	.18E+03	.43E+03	.23E+04	.71E+04	.19E+04
1.93	3100	.60E+03	.49E+03	.61E+03	.53E+03	.63E+03	.11E+04	.19E+04	.12E+04	.54E+03	.23E+03	.21E+03	.18E+03	.43E+03	.23E+04	.72E+04	.19E+04
1.99	3200	.61E+03	.50E+03	.61E+03	.54E+03	.64E+03	.11E+04	.20E+04	.12E+04	.54E+03	.23E+03	.21E+03	.18E+03	.43E+03	.23E+04	.73E+04	.19E+04
2.05	3300	.61E+03	.51E+03	.62E+03	.55E+03	.64E+03	.11E+04	.20E+04	.12E+04	.54E+03	.24E+03	.21E+03	.18E+03	.44E+03	.23E+04	.73E+04	.19E+04
2.11	3400	.61E+03	.51E+03	.62E+03	.55E+03	.64E+03	.11E+04	.20E+04	.12E+04	.52E+03	.24E+03	.21E+03	.18E+03	.43E+03	.23E+04	.73E+04	.19E+04
2.17	3500	.61E+03	.51E+03	.62E+03	.55E+03	.64E+03	.11E+04	.20E+04	.12E+04	.52E+03	.24E+03	.21E+03	.18E+03	.43E+03	.23E+04	.73E+04	.19E+04
2.24	3600	.61E+03	.52E+03	.63E+03	.56E+03	.64E+03	.12E+04	.21E+04	.13E+04	.52E+03	.23E+03	.21E+03	.18E+03	.43E+03	.24E+04	.75E+04	.19E+04
2.3	3700	.63E+03	.56E+03	.67E+03	.59E+03	.67E+03	.12E+04	.22E+04	.13E+04	.54E+03	.25E+03	.22E+03	.19E+03	.43E+03	.24E+04	.76E+04	.20E+04
2.36	3800	.63E+03	.56E+03	.67E+03	.60E+03	.67E+03	.12E+04	.22E+04	.13E+04	.54E+03	.25E+03	.22E+03	.19E+03	.43E+03	.24E+04	.76E+04	.20E+04
2.42	3900	.63E+03	.56E+03	.68E+03	.60E+03	.67E+03	.12E+04	.21E+04	.13E+04	.54E+03	.25E+03	.22E+03	.19E+03	.43E+03	.24E+04	.76E+04	.20E+04
2.49	4000	.62E+03	.55E+03	.66E+03	.58E+03	.66E+03	.12E+04	.21E+04	.13E+04	.53E+03	.24E+03	.22E+03	.19E+03	.43E+03	.24E+04	.75E+04	.20E+04
3.11	5000	.36E+03	.31E+03	.37E+03	.33E+03	.37E+03	.69E+03	.12E+04	.65E+03	.31E+03	.14E+03	.13E+03	.11E+03	.25E+03	.74E+03	.27E+04	.13E+04

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

6.21	10000	.26E+03	.21E+03	.25E+03	.22E+03	.27E+03	.47E+03	.81E+03	.42E+03	.18E+03	.83E+02	.75E+02	.63E+02	.14E+03	.50E+03	.19E+04	.90E+03

Table 11: Annual Hours/yr of Plume Shadow. Directions are directions from the tower.

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
0.12	200	6005	5200	5080	4788	5043	5671	5656	5561	5128	5166	6140	8000	8760	8760	8760	8760
0.25	400	1652	1671	1870	1921	2231	2959	3209	2267	1708	1318	1273	1978	2939	5390	2633	1720
0.37	600	1108	1204	1282	1341	1529	2043	1920	1318	864	688	628	1096	1473	1345	907	1051
0.5	800	829	924.5	996.3	1009	1167	1571	1306	906	554.6	410.5	385.1	647.5	770	708.7	543.7	714.9
0.62	1000	678.8	743.5	799.4	837	985.7	1286	964.8	640.7	382.8	284.8	281.2	442.3	536.3	445.4	361.8	538.6
0.75	1200	581.9	623.2	667.7	723.3	863.6	1090	793.9	498.3	293.7	218.8	211.6	363.7	377.5	360.8	239.7	436.7
0.87	1400	507.8	542.3	580.9	621.7	769.5	921.6	697.5	387.7	241.9	172.7	165	295.5	299.2	287.4	186.5	361.8
0.99	1600	456.3	481.1	515.5	544	684.6	811.6	626.8	356.8	214.6	137.4	135.1	249.1	250.8	234.8	142.5	303.1
1.12	1800	402.7	425.7	458.4	475.5	617.6	726	578.5	314.7	183.5	121	106.2	202.6	215.2	207.8	112.4	253.5
1.24	2000	356.1	382.4	421.5	435.3	560.2	647.1	540.5	281.8	166.6	103.7	93.3	168.6	188.5	173.9	85.2	214.4
1.37	2200	311.9	341.5	376.4	385.6	515.8	579.1	510.9	262.1	141.7	88.4	78	138.4	161.6	145	74.7	196.3
1.49	2400	275.2	304.7	345.4	356	471.1	542.8	466.2	235.7	124.2	75.7	68.7	125.4	147.1	130	64.8	174.9
1.62	2600	245.7	262.9	318.8	325	430.7	507.5	436.1	211.7	112.2	68.6	56.9	108.5	129.5	119.9	54.9	155.7
1.74	2800	219.6	231.4	294.9	302.8	392.2	477.5	398.5	178.9	98.8	62	48.3	93.9	115.3	106.2	43.9	148.2
1.86	3000	199.8	206.5	273	276.8	370.1	453.8	368.1	150.9	87.8	52.2	43.7	85.3	108.4	98.2	36.8	135.6
1.99	3200	186.6	183.1	247	251.2	335.8	434.1	324	135.8	75.9	42.7	40	74.8	101.7	89.9	35.8	122.6
2.11	3400	167.5	162.3	234.6	237.5	305.9	405	292.4	118.8	63.6	38.3	36.1	70.1	92	80.9	34.8	111.6
2.24	3600	157.1	151	204.4	221.6	291.6	380.1	265.8	110.9	55.6	29.2	31.5	59.6	83.2	71.7	29.8	103.6
2.36	3800	144.9	132.9	191.3	212.5	279.3	355.3	246.3	102.6	45.6	24.6	31.5	53.8	74.6	66.9	27.8	90.1
2.49	4000	131.1	122.3	181.1	202.8	261.2	338	223.1	94.6	41.5	22.6	28.4	51	67.1	59.5	24.7	81.1
2.61	4200	121.7	116.8	168.7	191.4	242.6	312.2	204.7	83.6	40.5	22.6	25.8	47.1	62.5	56.7	17.7	76.1
2.73	4400	110.9	103.7	155.8	181.8	227	290.2	194.7	73.4	38.5	20.5	23.8	42.8	57.9	50	14.5	66.2
2.86	4600	100.4	90.7	143.9	176	209.9	273.3	185.5	68.1	35.2	15.1	22.8	40.1	55.3	50	12	60.4
2.98	4800	91.8	79.9	123.2	166.8	199.5	255.4	166.8	59.7	28.9	13.1	22.8	38.2	47	46.1	10	55.4
3.11	5000	84	69.9	114.7	157.5	185.5	238	149.5	54.3	26.7	12.1	20.4	37.7	44.6	44.5	10	48.6
3.23	5200	70.5	54.5	103	146.6	173.2	224.3	141.5	46.7	25.4	12.1	16.6	36.4	40.9	39.1	10	41.8
3.36	5400	66.2	52.4	94.7	141.6	166.5	215.6	127.5	40.8	20.8	12.1	16.6	35.8	38.9	38.6	10	37.8
3.48	5600	55.4	47.7	87.1	137.7	162.7	205	119.3	38.3	18.8	12.1	14.4	32.3	37.9	38.1	10	36.8
3.6	5800	47.9	44.8	82.3	134.2	153.2	195.5	108.7	38.3	15.8	9.5	13.6	30.5	32.3	35.6	9	32.3
3.73	6000	44	43.8	75.7	127.9	147.2	188	102.7	35.8	14	9.5	10.7	28.7	28.2	33.2	9	28.3
3.85	6200	39.6	34.3	72.2	120.6	131.3	178.2	94.7	31.8	14	9.5	9.8	27.6	27.7	30.4	9	24.2
3.98	6400	34.5	33.3	70.3	114	123.6	170.9	90.4	26.5	10.7	9.5	8.8	27.1	26.4	28.9	9	21.8
4.1	6600	32.5	30.1	68.1	108.8	112.2	160.6	87.4	23.2	10.7	8.5	8.8	25.5	20.6	27.9	7	18.3
4.23	6800	29	27.1	64.2	104.2	105.5	150.2	78.8	22.2	9.7	7.5	7.3	24.8	20.6	24.9	7	13.3
4.35	7000	24.7	27.1	59.3	101.9	99.3	140	73.1	21.2	8.7	7.5	7.3	24.1	20	24.3	6	12.3
4.47	7200	22.5	25.8	53.9	99	94.9	125.3	66.6	21.2	8.7	6.5	6	23.3	16.9	24.3	6	12.3
4.6	7400	16.1	25.8	51.8	97.8	89.3	117.2	63.9	18.7	8.7	6.5	4.9	22.4	16.9	21.9	6	11.3
4.72	7600	11.9	24.7	48.4	90.1	82.2	106.1	61.9	16.8	7.3	6.5	4.9	21.2	16.3	18.4	6	7.6
4.85	7800	8.7	22.9	44.3	88.9	78.5	101	59.9	14.4	7.3	6.5	4.9	21.2	15.3	16.6	5	6.4

Table 12: Annual Hours/yr of Fogging. Directions are directions from the tower.

(mi)	(m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
0.06	100	0	0.2	0	0.2	0	2	9.8	12.3	0	0	0	0	0	12.3	51.8	0
0.12	200	1.1	3.6	0.8	1.4	2.1	18.3	56.8	55.9	16.6	25.3	0	0	20.1	235.2	672.4	243.2
0.19	300	3.9	3.7	1.2	1.8	1.9	17	52	54.1	14.8	24.7	0.7	0	19.4	173.4	555.1	224.9
0.25	400	2.8	3.9	1.4	2.4	0.9	9.8	37	36.6	8.9	21.9	0	0	12	142.3	484.7	181
0.31	500	0.9	3	1.4	2	0.3	5.7	26.5	30.7	6.3	15	2.5	0	6.8	95	402	139.1
0.37	600	0	2.2	0.7	1.2	0	3	23	28	1	14	0	0	2.2	31	397	55.8
0.43	700	0	1.6	0.4	0.6	0	3	23	28	1	12.5	0	0	0.7	31	397	28
0.5	800	0	1	0	0	0	3	18	24	1	11	0	0	0	23.5	242.7	14.6
0.56	900	0	1	0	0	0	1.5	11.7	14.5	0.5	11	0	0	0	16.3	202.9	6
0.62	1000	0	0.9	0	0	0	1.5	6.5	10	0.5	9.6	0	0	0	8.5	45.5	6
0.68	1100	0	0.5	0	0	0	1.5	6.5	10	0.5	5.5	0	0	0	8.5	45.5	6
0.75	1200	0	0.5	0	0	0	1.5	6.5	10	0.5	5.5	0	0	0	8.5	45.5	5.2
0.81	1300	0	0.5	0	0	0	1.5	5.7	8.5	0.5	5.5	0	0	0	5.6	30.8	4.5
0.87	1400	0	0.5	0	0	0	1.5	5.5	8	0.5	5.5	0	0	0	4	23	4.5
0.93	1500	0	0.5	0	0	0	1.1	4.1	5.9	0.5	5.5	0	0	0	3	16.7	4.5
0.99	1600	0	0.4	0	0	0	0	0	0	0.5	4.1	0	0	0	0	0	4.5

8.1. Visibility of Plume from San Luis and Avila Beach

Figure 4 shows a map of the local region. The most common direction for the plume to travel is SE towards Port San Luis, particularly in the summertime when the plumes travel either ESE or SE over 60% of the time. But in all four seasons, the plumes extend in this direction (within a 1/16th quadrant) over 5 miles approximately 1.3% of the time (as seen in Tables 5 through 8, where plumes of longer than 5 miles exist in the SSE to ESE direction 1.4% in winter, 2.1% in spring, 0.9% in summer and 0.9% in fall). As seen in Figure 4, plumes would be visible from Avila Beach if they extended about 5 miles in this direction and are high over the hills.

Table 13 presents the plume characteristics when wind is coming from the NW and the plume is headed SE. The frequencies in Table 13 are the summation of annual frequencies in the ESE, SE, and SSE directions. As is seen in Table 13, the annual frequency of plumes extending to Port San Luis totals the frequency of plumes in this direction of about 6 miles, which is 0.9% of the time. It is noted that the data of Table 13 is for one specific wind direction (315° east of north) and that category 43 plumes are longer when wind blows from closer to the north. That is, Table 13 does not contradict the previous paragraph's conclusion of 1.3% of plumes longer than 5 miles in the SE direction. Also, it is noted that the category 43 plumes, which extend 4.7 miles, are 2600 ft in centerline altitude and 1000 feet in diameter. These would also be visible from Avila Beach, hence the total frequency of visible plumes is estimated at 1.92% of the time, with 0.9% of these encroaching over the Port San Luis area.

It is also cautioned that the plume lengths are best estimate with a good deal of variation in practice. Thus the 5.7 miles for category 44 plumes is a mean length for plumes when these general weather conditions exist - actual plumes will be both shorter and longer. Thus the final conclusion is that plumes will occasionally extend far enough to be visible from Avila Beach with a frequency on the order of 1.9% of the year.

The SACTI code does not provide information about the time of day or days per year of plume visibility. Results can be inferred from the meteorological data, but these are not code predictions. To estimate plume visibility from Avila Beach, the wind data was queried as to the hours per day that winds blew in the ESE to SSE direction with stronger than 1.2*average wind speed and greater than 90% humidity. This combination of criteria was selected since it promotes plumes in the direction of Avila Beach and totals 1.7% of the time, which is close to the 1.9% just described above. These conditions occurred 80 times per year for a cumulative 150 hours per year, with a maximum duration of 12 hours. The mean time was 1.9 hours with a standard deviation of 1.5 hours. The conclusion is that weather conditions are favorable to produce plumes that might be within view of Avila Beach approximately 80 times per year, but typically only for 0.4 to 3.4 hours at a time. Again, this is not an output of the SACTI code, but is rather an estimate based on evaluation of the meteorological data.

Figure 4 shows that San Luis will be able to see the plumes when visibility is about 12 miles or greater, and the plumes are higher than the intervening mountains. The height of the mountains can be estimated at 1600' (500 m) at roughly 8/12 or 2/3rds of the distance. Thus only plumes that are higher than 500*3/2 = 750 m would be visible from San Luis. Table 13 lists both the height of the plume centerline and the radius. It is seen that the plumes will be visible to San Luis fairly frequently over the tops of the hills. The table predicts that SE directional plumes will exceed 750m in height (that is, the height+radius>750m) about 19% of the year.

To estimate the number of times per year plumes occur that could be seen from San Luis Obispo, the meteorology data was queried for all winds (any direction) above average velocity during humidities above 75%. This condition exists for 17.3% of the time, which is close to the 19% calculated above, and is conducive to greater plume formation. Higher winds were selected because it is noted in Table 13 that higher plumes are associated with longer plumes, which are associated with above average wind. The defined meteorological criteria was met an average of 270 days per year in the 5 year meteorological data base, with an average duration of 3.6 hours and a standard deviation of 3.3 hours.

The conclusion is that weather conditions are favorable to produce plumes that might be within view of San Luis Obispo approximately 270 days per year, for typically about 3.6 hours at a time. Again, this is not an output of the SACTI code, but is rather an estimate based on evaluation of the meteorological data.

The time of day in which the longest plumes appear will be during periods of high humidity. Higher humidities occur in the early morning, late evenings, and nighttime. Plots of the meteorlogical conditions described above are presented in Figures 5 and 6. These figures show on a time versus day of year scale for the meteorological data of the year 2003 when conditions are conducive for the plumes.

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

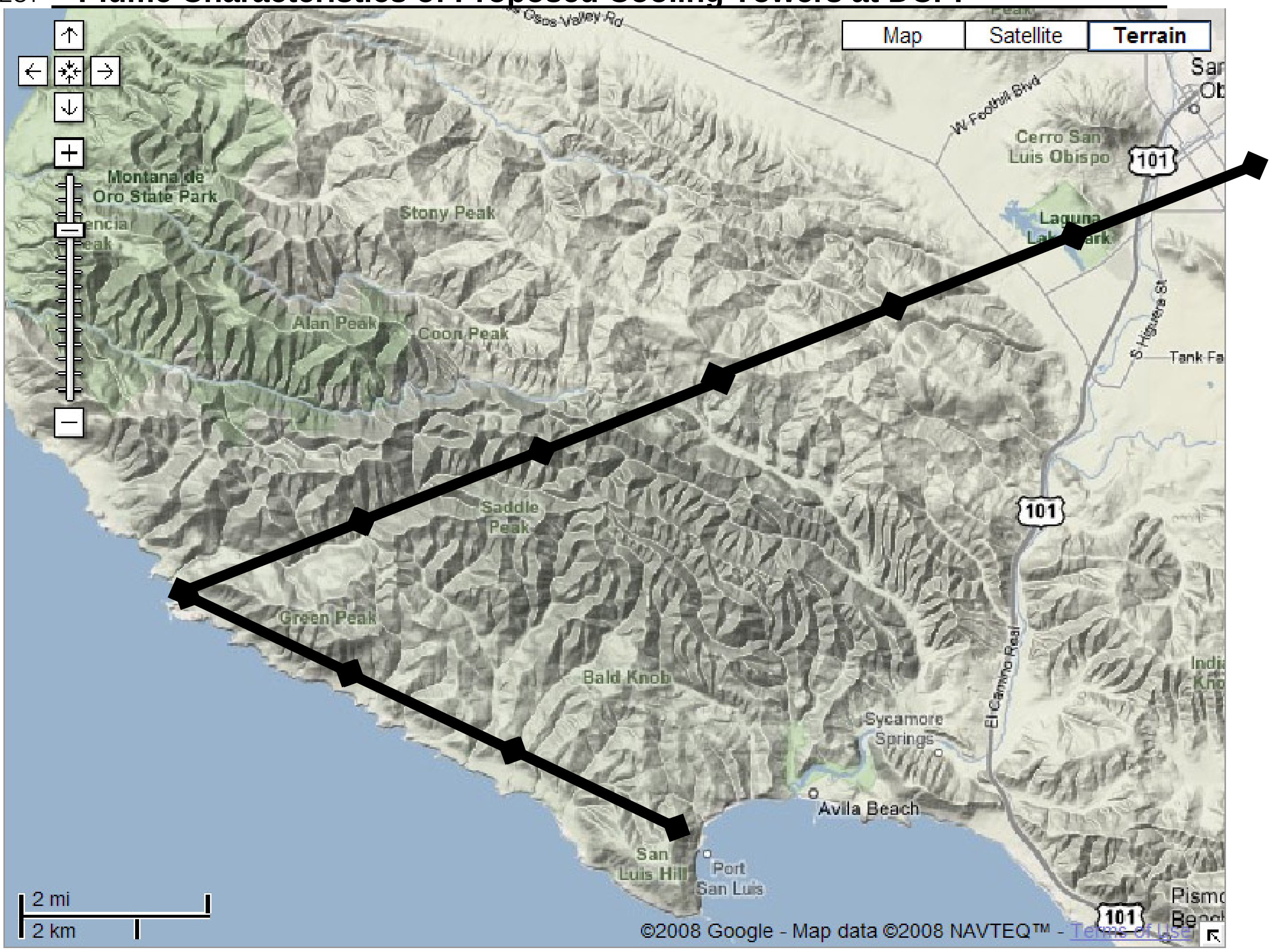


Figure 4: Each node is 2 miles. The elevation of Saddle Peak is 1600'

It is observed in Figures 5 and 6 that the period of visible plumes is expected to be near sunrise and sunset, without a strong dependency on time of year. The data used to draw Figure 5 indicate the possibility of visible plumes within site of Avila Beach within 1 hour of sunrise or sunset to have occurred 45 times in the year 2003. The data used to draw Figure 6 indicate the possibility of visible plumes within site of San Luis Obispo within 1 hour of sunrise or sunset to have occurred 327 times in the year 2003. Of these occurrances, 203 were associated with sunset time.

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Table 13: Annual Characteristics of Plumes in the SE Direction

Category	LENGTH (m)	LENGTH (miles)	HEIGHT (m)	RADIUS (m)	Frequency	Top>750m Freq
11	46.5	0.03	31.3	15.7	1.98	0
12	48.3	0.03	11.1	9.9	5.92	0
13	123.8	0.08	16.3	13.5	13.8	0
14	71.3	0.04	31.4	14.5	0.04	0
15	88.2	0.05	106	27.7	0.1	0
16	64.3	0.04	97.1	19.9	0	0
17	45.1	0.03	154.9	56.7	0	0
18	89.9	0.06	56.9	25	0.37	0
19	89.4	0.06	56.8	24.4	0	0
20	121.8	0.08	78.3	22.5	0	0
21	170	0.11	80.2	30.9	1.3	0
22	211.6	0.13	145.2	39.4	1.01	0
23	507.7	0.32	207.3	47.3	1.25	0
24	561.2	0.35	362	77	0.91	0
25	819.9	0.51	363.9	79	1	0
26	1010.5	0.63	424.7	87.8	0.96	0
27	2271.9	1.41	714.6	116.3	0.94	0.94
28	2261.8	1.41	731.7	174.7	0.93	0.93
29	2271.7	1.41	710.9	192.1	0.93	0.93
30	2071.7	1.29	709.1	193.5	1.07	1.07
31	2256.4	1.40	748.5	253.5	0.86	0.86
32	2453.2	1.52	748.5	265.7	0.98	0.98
33	2590.1	1.61	724.8	262.4	1.08	1.08
34	2959.7	1.84	744.3	262.1	0.91	0.91
35	3059.3	1.90	776	261.9	1.02	1.02
36	3359.4	2.09	770	265.4	1.03	1.03
37	3892.2	2.42	748	273.7	1.32	1.32
38	4075.1	2.53	761.9	267.6	1.01	1.01
39	4382.2	2.72	746.6	270.1	1.04	1.04
40	4892.4	3.04	738.9	273.8	1.27	1.27
41	5690.6	3.54	763	293.2	0.99	0.99
42	6382	3.97	787.9	307.2	1.11	1.11
43	7594.6	4.72	793.9	322	1.02	1.02
44	9183.2	5.71	772.9	345.2	0.9	0.9
45	4455.2	2.77	694.5	276.4	0.58	0.58
TOTALS					47.6	18.99

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

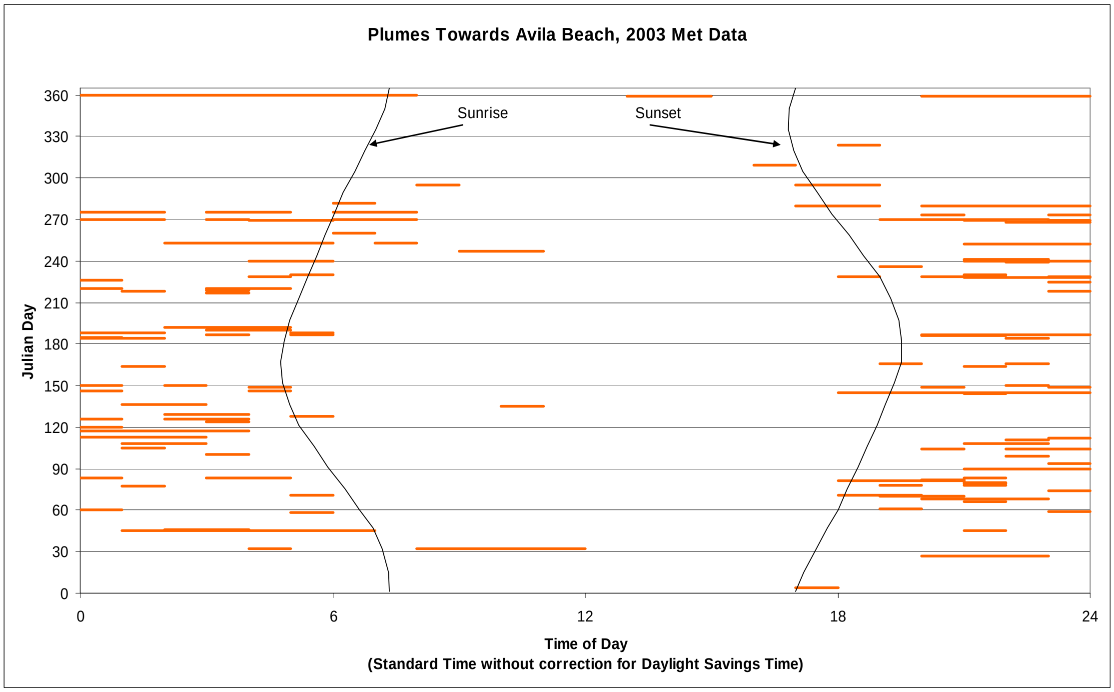


Figure 5: Periods of Humidity and Wind and Wind Direction conducive to long plumes extending towards Avila Beach

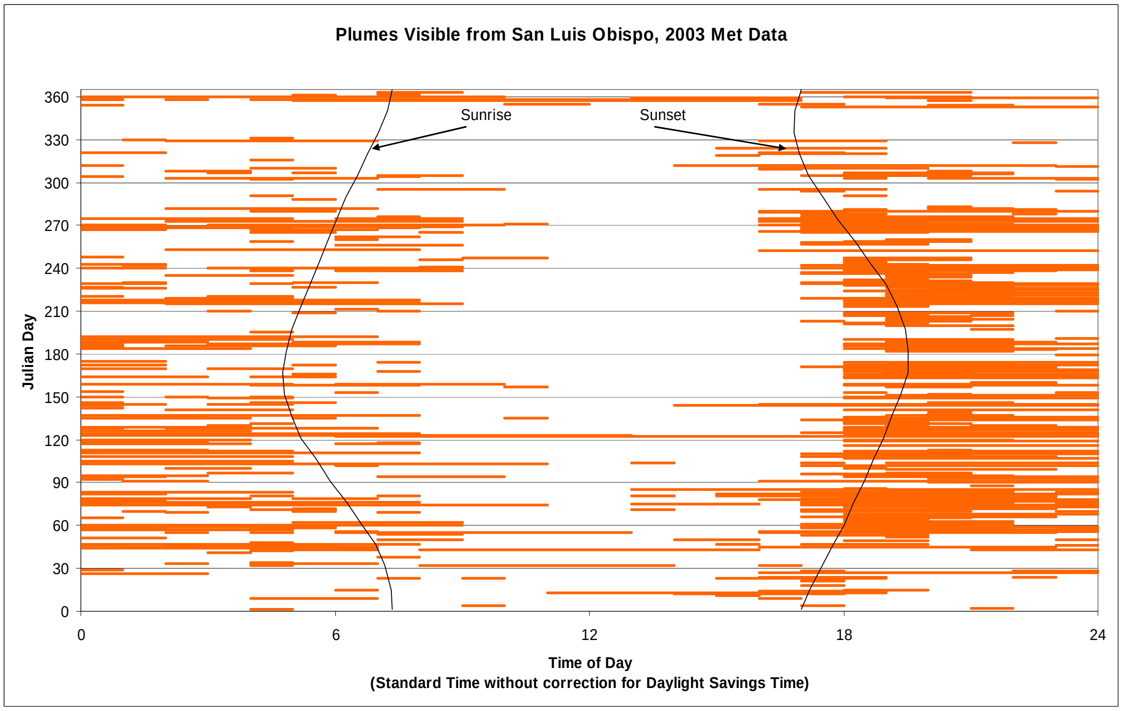


Figure 6: Periods of Humidity and Wind conducive to plume visibility from San Luis Obispo

9. MARGIN ASSESSMENT

This calculation does not impact any design or licensing basis margin.

10. CONCLUSIONS

A summary of Plume lengths is presented in Table 14. In most cases, the plumes tend to lie either towards the Northwest (over the plant itself, especially in the winter) or to the Southeast (along the access road from Avila Beach).

Table 14:Visible Plume Length Summary

	Winter	Spring	Summer	Fall
Most Frequent Plume Heading Directions	NW,SE	SE,ESE,SSE	SE,ESE	SE,ESE,SSE
Percent of Plumes < 1/3 miles	26.9	35.0	44.2	40.4
Percent of Plumes >1/3 to 2 mile	38.5	28.2	30.3	34.8
Percent of Plumes >2 to 5 miles	30.3	32.8	24.3	22.5
Percent of Plumes >5 Miles	4.3	4.0	1.3	2.2

Estimates of salt, TDS, PM10, and water deposits are given in Tables 9a, 9b, 9c, and 10, respectively. Due to the use of salt water, the salt deposition rates are notable for some distance. The length of the access road, once it reaches the coastline, will be exposed to some amount of salt. The makeup of the TDS is over 3/4ths sodium salt.

Shading and fog from the plumes are given in Tables 11 and 12. There will be some loss of sunlight near the towers. The fogging is predicted to interact with plant components to the NW and plant worker vehicles approaching from the SE.

Plumes are predicted to occasionally (about 1.9% of the time) be long enough to be visible from the recreational area around Avila Beach. Plumes will be large enough to be visible over the tops of the coastal hills from San Luis approximately 19% of the year. The time of day that plumes appear is not estimated by the SACTI code, but evaluation of meteorological data imply most plumes will occur at night or near the sunrise or sunset. Meteorological conditions conducive to plumes visible from Avila Beach near sunrise or sunset are estimated to occur on the order of 45 times per year, while conditions for plumes to be visible from San Luis on are the order of 300 times per year, and roughly 200 sunsets per year.

11. IMPACT EVALUATION

This calculation does not impact any design or licensing basis document associated with DCPP. Its purpose is solely to support the assessment of the impacts associated with cooling tower operation at the site.

12. REFERENCES.

1. Google Earth (for site location and images showing general site topography)
2. SACTI User's Manual: Cooling-Tower-Plume Prediction Code, EPRI CS-3403-CCM, April 1984
3. Site meteorology data, hourly observations, years 2003 through 2006, transmitted by Email, McCarthy to Berger, 2/12/2008 12:40 pm (data in project files listed in Attachment 2). The data for 2007 was by Email, McCarthy to Berger, 5/8/2008 7:31 pm, and is also in the project files.
4. SLO meteorological data, purchased and downloaded from NCDC 2/8/2008 (data in project files listed in Attachment 2)
5. SLO/San Diego mixing height data, purchased and downloaded from NCDC 2/25/2008 (data in project files listed in Attachment 2)
6. NRC Environmental Standard Review Plan, NUREG-1555
7. Cooling Tower Drift Mass Distribution, Excel Drift Eliminators, Marley Cooling Technologies Sales Brochure, faxed to Enercon 12/4/2001. (Note: the same drop spectrum data is available online at pg 4 of http://awmasandiego.org/SDC-2002/4-1-lindahl.pdf.)
8. Email Denicke to Berger, 2/4/2008 transmitting tower height information and meteorology data (contained in Attachment 1)
9. Pacific Mountain Energy Center, ESFEC Application 2006-1, obtained 2/22/2008 from http://www.efsec.wa.gov/PMEC/App/PMEC%20Appx%20B.pdf
10. Email Denicke to Berger, 2/22/2008 transmitting tower dimensional information (contained in Attachment 1)
11. Email Denicke to Berger 2/25/2008 transmitting estimated concentrated seawater density
12. Donald Connors, On the Enthalpy of Seawater, US Naval Underwater Weapons Research and Engineering Station, Newport, Rhode Island
13. Heat Balance Diagrams for DCPP, Unit 1 DC 6021770-5 and Unit 2 DC 6021770-22
14. Existing Condenser duty from DC 663041-35-2
15. Email, Clark to Berger, 5/30/2008 3:34 PM

ATTACHMENT 1 - Miscellaneous Data Sources

Reference 12.8

From: Martin Denicke [mdenicke@enercon.com]
Sent: Monday, February 04, 2008 4:27 PM
To: 'Ralph Berger'
Cc: rclark@enercon.com
Subject: Cooling Tower Location for Plume Study

Attachments: SKMBT_C35208020111010.pdf

Ralph, attached is a sketch showing the location of the cooling towers.

1. Each unit has 40 cells, with a combined evaporation of 12,600 gpm (assumed evenly distributed among the 40 cells).

2. The hot water temperature entering the cooling tower is 96F, and it is cooled to 78F, with an ambient wet bulb of 61F.

3. The cooling tower flow is approximately 860,000 gpm per unit, having a saltwater concentration of 1.5 x normal seawater (typical breakdown by chemical constituent given below), with a density of 64.9 lb/cu ft at 78F and 64.5 lb/cu ft at 96F. I obtained the density values from a curve excerpted from an article entitled "The Use of Cooling Towers for Salt Water Heat Rejection" by D.M. Suptic, P.E., Marley Cooling Tower Company, 1991.

4. Cooling Tower Chemistry is as follows:

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Constituent                      Seawater
Cooling tower Water

Ca(HCO3)2                   185 ppm          x1.5=      278
ppm
CaSO4                      1200 ppm          x1.5=     1800
ppm
MgSO4                      2150 ppm          x1.5=     3225
ppm
MgCl2                      3250 ppm          x1.5=     4875
ppm
NaCl                      27000 ppm          x1.5=    40500
ppm
KCl                         500 ppm          x1.5=      750
ppm
KBr                         100 ppm          x1.5=      150
```

SUBJECT Plume Characteristics of Proposed Cooling Towers at DCPP

ppm
CaCO3 115 ppm x1.5= 173
ppm

Total TDS 34,500 ppm 51,751
ppm

pH about 8
about 8

These values are given in an article "Cooling Towers & Salt Water" by J.A. Nelson, The Marley Cooling Tower Company, 11/5/1986.

Calculation of TDS Density based on component constituents in 12.8 and Miscellaneous Data Sources

$CaCO_3$ density is 2.71 gm/cm^3 at 300K (173/51751 = .0033 fraction total)
Source: http://www.almazoptics.com/CaCO3.htm

KBr density is 2.75 gm/cm^3 (150/51751 = .0029 fraction total)
Source: http://www.hilger-crystals.co.uk/prior/mat_kbr.htm

NaCl density is 2.17 gm/cm^3 (40500/51751 = .7826 fraction total)
Source: Input 4.3.9, verified to within .01 at http://www.hilger-crystals.co.uk/prior/mat_nacl.htm

KCl denisty is 1.99 gm/cm^3 (750/51751 = .0145 fraction total)
Source: http://www.hilger-crystals.co.uk/prior/mat_kcl.htm

$MgSO_4$ density is 2.66 gm/cm^3 (3225/51751 = .0623 fraction total)
Source: http://www.thekrib.com/Plants/CO2/rift.html

$MgCl_2$ density is 1.57 gm/cm^3 (4875/51751 = .0942 fraction total)
Source: http://bulkpharm.mallinckrodt.com/_attachments/msds/m0156.htm

$CaSO_4$ density is 2.96 gm/cm^3 (1800/51751 = .0348 fraction total)
Source: http://www.jtbaker.com/msds/englishhtml/C0497.htm

$Ca(HCO_3)_2$ density was not located, so total constituents identified add to 0.9946 of total.

The averaged density is therefore:
(.0033*2.71+.0029*2.75+.7826*2.17+.0145*1.99+.0623*2.66+.0942*1.57+.0348*2.96)/.9946

= 2.17 gm/cm^3

Table B-1-14 summarizes recent BACT determinations for utility-scale mechanical draft cooling towers. The commercially available techniques listed to limit drift PM_{10} releases from utility-scale cooling towers include:

- Use of Dry Cooling (no water circulation) Heat Exchanger Units
- High-Efficiency Drift Eliminators, as low as 0.0005% of circulating flow
- Limitations on TDS concentrations in the circulating water
- Combinations of Drift Eliminator efficiency rating and TDS limit
- Installation of Drift Eliminators (no efficiency specified)

The use of high-efficiency drift eliminating media to de-entrain aerosol droplets from the air flow exiting the wetted-media tower is commercially proven technique to reduce PM_{10} emissions. Compared to "conventional" drift eliminators, advanced drift eliminators reduce the PM_{10} emission rate by more than 90 percent.

In addition to the use of high efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, to addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered. The proposed PMEC tower will be based on 12 cycles of concentration, that is, the circulating water will be on average 12 times the dissolved solids concentration of the make-up water that is introduced. The proposed cooling tower is to be operated at a design level of total dissolved solids (TDS) concentration of 2,400 ppmw in the cooling water, based on 200 ppmw in the make up water.

Lastly, the substitution of a dry cooling tower is a commercially available option that has been adopted (usually because of concerns other than air emissions) by utility-scale combined cycle plants in arid climates. This option involves use of a very large, finned-tube water-to-air heat exchanger through which one or more large fans force a stream of ambient dry air to remove heat from the circulating water in the tube-side of the exchanger.

B-1.15.3 INFEASIBLE CONTROL MEASURES

One measure that has been adopted in arid, low precipitation climates is the use of a dry, i.e., non-evaporative cooling tower for heat rejection from combined-cycle power plants. Where it has been adopted, this measure is usually a means to reduce the water consumption of the plant, rather than as BACT for PM_{10} emissions. There is a very substantial capital cost penalty in adopting this technology, in addition to the process changes (e.g., operating pressures) necessary to condense water at the ambient dry bulb temperature, rather than at ambient wet bulb temperature. The plants for which this measure has been used are, with few exceptions, smaller capacity combined-cycle plants (smaller than the PMEC facility).

From: Martin Denicke [mdenicke@enercon.com]
Sent: Friday, February 22, 2008 11:31 AM
To: 'Ralph Berger'
Subject: FW: Diablo Canyon

Attachments: Diablo Canyon Back-Back Layout-40 Cells.jpg

From: Jim Hubbard [mailto:jhubbard@enercon.com]
Sent: Tuesday, January 29, 2008 9:16 AM
To: 'Martin Denicke'
Subject: FW: Diablo Canyon

This is the information from SPX.

Jim,
Wet Selection:
HWT= 96.0 deg. F
CWT = 78.0 deg. F
IWBT = 61 deg F + 2 deg. F recirculation & interference = 63 deg. F
Range = 18.0 deg. F
Approach to IWBT = 15 deg. F
Cycles of Concentration = 1.5

Arrangement: Back-Back FRP
Cell Size = 60 ft x 60 ft
Basin Width = 140 ft
Basin Depth = 4 ft
No. Cells = 20 per Unit
Motor Output Power = 300 HP = 6000 HP/ Unit
Pump Head = 36.5 ft referenced to top of curb
Materials; Suitable for 1.5 cyc salt water

Budgetary Price = [ ] for two units
See attached arrangement.

Reference 12.11

From: Martin Denicke [mdenicke@enercon.com]
Sent: Monday, February 25, 2008 3:28 PM
To: 'Ralph Berger'
Subject: Comments on Plume Characteristics Calc

Hi Ralph. I have the following questions re your plume study:

1) item 4.3.1, p.6: you give a density for the water of 62.05 lb/cu ft. Shouldn't this be about 64.5 for our concentrated seawater?
2) item 4.3.2, p.6: is the 4000 mg/l TDS level right? If I have ~53,000ppm TDS, that's a concentration of .053, or 5.3%, so one liter would have 53 grams of salt, or 53,000 mg of salt (as you mention on the next page in item 4.3.10).

That's as far as I got today...

- Martin

Pacific Gas and Electric Company
Engineering - Calculation Sheet
Project: Diablo Canyon Unit ( )1 ( )2 (X)1&2

CALC. NO. N/A (Study Only)
REV. NO. 0

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**
Reference 12.14

STEAM INLET EXPANSION JOINT

The steam inlet expansion joint is a rubber belt type with welded connection to the surface condenser and turbine exhaust. There is a water tray on the external periphery of the expansion joint. The expansion joint is manufactured by Process Engineering Company, Inc. (Drawing EB-69351)

MOVEMENTS

Axial Deflection	-	5/32" normal	53/64 emergency
Lateral Deflection	-	3/32" normal	17/32 emergency
Axial Forces	-	5/32" 8,000 Lbs.	53/64 45,900 Lbs.
Lateral Forces	-	3/32" 4,400 Lbs.	17/32 25,300 Lbs.

Normal operating conditions: 100° - 115°F. Emergency conditions for periods of time up to two (2) hours with temperature of 230°F.

Expansion joint is to be suitable for 30" Hg. internal vacuum with atmospheric pressure outside, also suitable for internal pressure of 15 PSIG with atmospheric pressure outside.

PERFORMANCE DATA - CONDENSER

Percent Cleanliness	85 & 90 △
Heat Load BTU/Hr.	7,599,000,000
Abs. Pressure In. Hg.	1.71 & 1.64 △
Circulating Water Temperature, Deg. F.	56.5
Circulating Water Quantity, G.P.M.	862,690
Water Velocity, Ft. per Sec.	6.791 △
Friction in Water Circuit, Ft.	10.6 Ft. @ 56.5° F

PACIFIC GAS & ELECTRIC CO.
ACCEPTED FOR CONSTRUCTION
ENGINEERING DEPARTMENT
DATE 11-9-83
BY

APPROVED FOR
NOV 15 1983
MICROFILMING

RECORD No. Sh. Ch.

DC 663041-35-2

Pacific Gas and Electric Company
Engineering - Calculation Sheet
Project: Diablo Canyon Unit ( )1 ( )2 (X)1&2

CALC. NO. N/A (Study Only)
REV. NO. 0

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**
Reference 12.15

From: Rich Clark <richclark331@sbcglobal.net>
To: rberger@sbcglobal.net
Cc: rclark@enercon.com
Sent: Friday, May 30, 2008 3:34:55 PM
Subject: Condenser Duty

Ralph,

The attached excel file calculates an average 2 unit condenser duty of 4469 MW with cooling towers installed. The calculation uses the measured steam generator thermal megawatts and the main generator output from the Unit 1 & 2 main turbine post-retrofit performance tests conducted in 2006 after installation of the new Alstom LP turbines.

Thanks,

Rich

Spread sheet attached to Ref. 12.15 email

Condenser Duty

Unit 1 Run #1 Corrected 1/8/2006			
	kw	btu/kw-hr	btu/hr
Reactor Onput	3,425,000	3,412.14	11,686,579,500
Elect Gen Output	1,203,050	3,412.14	4,104,975,027
Mech losses	3,600	3,412.14	12,283,704
Gen losses	15,399	3,412.14	52,543,680
Condenser Q			7,516,777,089
Unit 1 Run #2 Corrected 1/8/2006			
	kw	btu/kw-hr	btu/hr
Reactor Onput	3,425,000	3,412.14	11,686,579,500
Elect Gen Output	1,198,670	3,412.14	4,090,029,854
Mech losses	3,600	3,412.14	12,283,704
Gen losses	15,343	3,412.14	52,352,382
Condenser Q			7,531,913,560

Pacific Gas and Electric Company
Engineering - Calculation Sheet
Project: Diablo Canyon Unit ( )1 ( )2 (X)1&2

CALC. NO. N/A (Study Only)
REV. NO. 0
SHEET NO. 56 OF 57

SUBJECT **Plume Characteristics of Proposed Cooling Towers at DCPP**

Unit 2 Run #1 Corrected 6/25/06			
	kw	btu/kw-hr	btu/hr
Reactor Onput	3,425,000	3,412.14	11,686,579,500
Elect Gen Output	1,198,670	3,412.14	4,090,029,854
Mech losses	3,600	3,412.14	12,283,704
Gen losses	14,684	3,412.14	50,102,866
Condenser Q			7,534,163,076
Unit 2 Run #2 Corrected 6/25/06			
	kw	btu/kw-hr	btu/hr
Reactor Onput	3,425,000	3,412.14	11,686,579,500
Elect Gen Output	1,198,430	3,412.14	4,089,210,940
Mech losses	3,600	3,412.14	12,283,704
Gen losses	14,681	3,412.14	50,092,834
Condenser Q			7,534,992,022
Average Condenser Duty BTU/hr per Unit			7,529,461,437
Average Condenser Duty - MW per Unit			2206.668377
Average Condenser Duty - MW per 2 Units			4413.336755
Approx average MW loss per unit with cooling towers			27.6
Approx average MW loss per 2 units with cooloing towers			55.2
Avg Condenser Duty with cooling towers -MW per unit			**2234**
Avg Condenser Duty with cooling towers - MW per 2 units			**4469**

ATTACHMENT 2 - Files

Met Data

- dcppMet.txt - Met data in CD144 format for use by SACTI
- dcpp2003.xls,dcpp2004.xls, dcpp2005.xls, dcpp2006.xls, dcpp2007.xls - Final Met Data Excel Files
- DCPP03.xls, DCPP04.xls, DCPP05.xls, DCPP06.xls DCPP07_JANTDEC.xls-Site Met Data
- 2003.xls, 2004.xls, 2005.xls, 2006.xls, 2007.xls - SLO Met Data combined
- 200301.txt, 200302.txt, ... 200712.txt - SLO raw data purchased from NCDC
- dcppmix.txt - mixing height data in format for use by SACTI
- mixheight.xls - Excel program used to create dcppmix.txt
- mixheights1.txt, mixheights2.txt - SLO/SanDiego mix height data purchased from NCDC

SACTI files

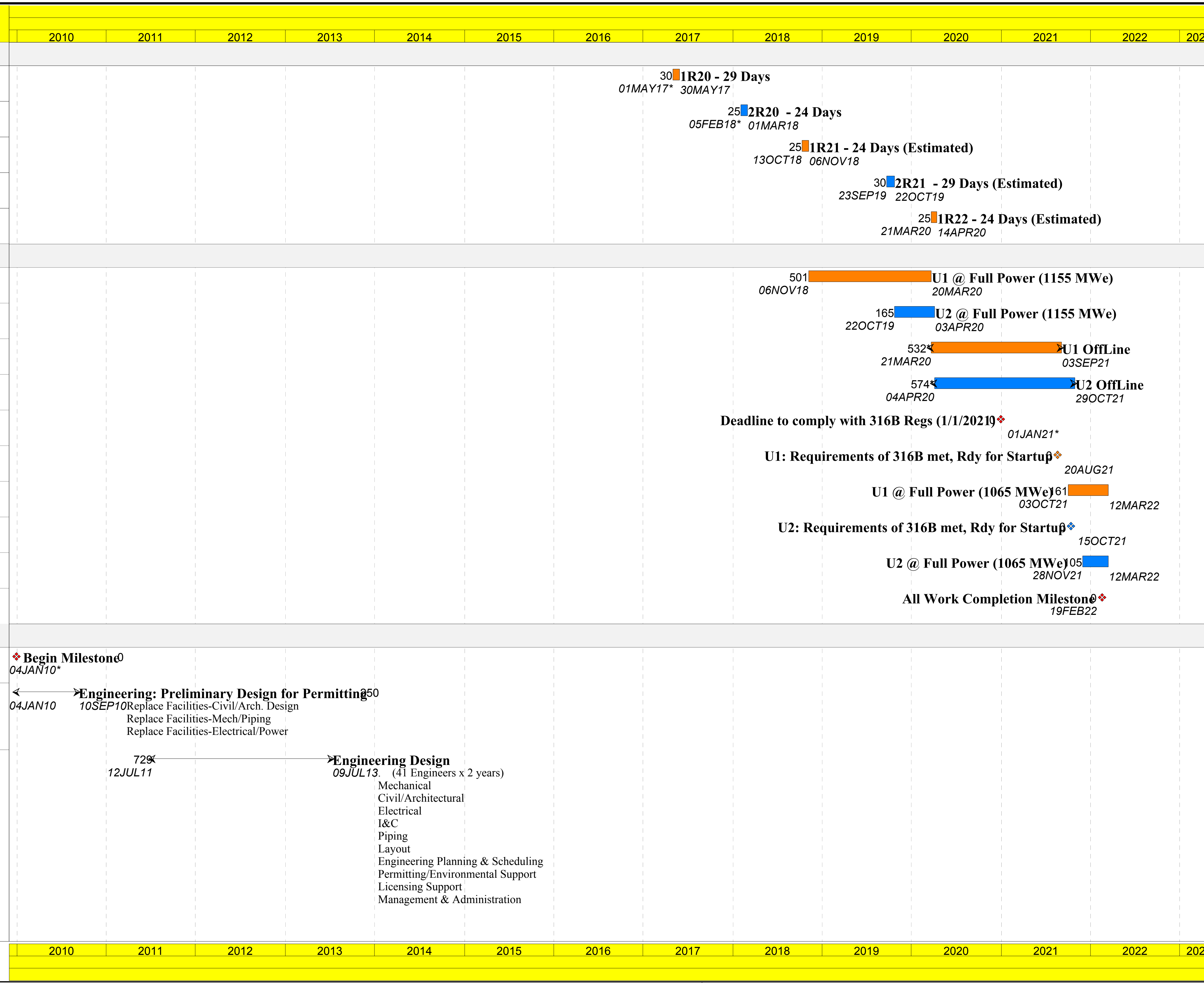
- prep.usr - preparation file that analyses met data
- mult.usr - input files with cooling tower specifics
- tables.usr - defines tables to be produced
- prep.out, mult.out, Tables.out - output files created by SACTI
- multTDS.usr and multPM10.usr - input files for TDS and PM10 depostion rates
- multTDS.out and TablesTDS.out - output associated with Table 9b
- multPM10.out and TablesPM10.out - output associated with Table 9c
- DCPPplumeResults.xls - Excel file that creates Tables 4 through 14 from the output files

Appendix A-8
DCPP Cooling Tower Study

Summary of Civil Quantities

Descriptions	Soil Excavation	Rock Excavation	Soil Backfill	4000 psi Concrete	Hand Rail	Trash Rack	Grating	Two Lane Pavement	6" dia.	8" dia.	36" dia.	Pipe exp.Joints
Unit	C.Y.	C.Y.	C.Y.	C.Y.	Lin. Ft	S. Ft	S. Ft	Lin. Ft	Lin. Ft	Lin. Ft	Lin. Ft	
Above EL. 85	766363	328441										
Basin		64142	1318	18472								
Pump pits		45906	22133	9356	600	6480	7344					
Concrete pipes		347962	187232	90336								Lump Sum
Retaining wall		6750	4492	2258								
IFISI Road								1400				
Drainage M.H.		142		213								
Drainage pipes		4184	4208						1230	480		
Elec. EQ. Rm	227			393								
Blow down		26500	25466								3950	
Total	**766590**	**824027**	**244849**	**121028**	**600**	**6480**	**7344**	**1400**	**1230**	**480**	**3950**	**Lump Sum**

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
Scheduled Refueling Outages				
1R20	1R20 - 29 Days	30	01MAY17*	30MAY17
2R20	2R20 - 24 Days	25	05FEB18*	01MAR18
1R21	1R21 - 24 Days (Estimated)	25	13OCT18	06NOV18
2R21	2R21 - 29 Days (Estimated)	30	23SEP19	22OCT19
1R22	1R22 - 24 Days (Estimated)	25	21MAR20	14APR20
Significant Milestones				
U1@1155MW	U1 @ Full Power (1155 MWe)	501	06NOV18	20MAR20
U2@1155MW	U2 @ Full Power (1155 MWe)	165	22OCT19	03APR20
CCSTSU1OFF	U1 OffLine	532*	21MAR20	03SEP21
CCSTSU2OFF	U2 OffLine	574*	04APR20	29OCT21
CCSTS_999M	Deadline to comply with 316B Regs (1/1/2021)	0		01JAN21*
CCSTS_991F	U1: Requirements of 316B met, Rdy for Startup	0		20AUG21
U1@1065MW	U1 @ Full Power (1065 MWe)	161	03OCT21	12MAR22
CCSTS_992F	U2: Requirements of 316B met, Rdy for Startup	0		15OCT21
U2@1065MW	U2 @ Full Power (1065 MWe)	105	28NOV21	12MAR22
CCSTS_999	All Work Completion Milestone	0	19FEB22	
Engineering for Site Facilities				
CCSTS_000	Begin Milestone	0	04JAN10*	
CCSTS_010A	Engineering: Preliminary Design for Permitting	250	04JAN10	10SEP10
CCSTS_010B	Engineering Design	729	12JUL11	09JUL13



Note: Durations listed are 7days/week (not work days)

Sheet 1 of 5

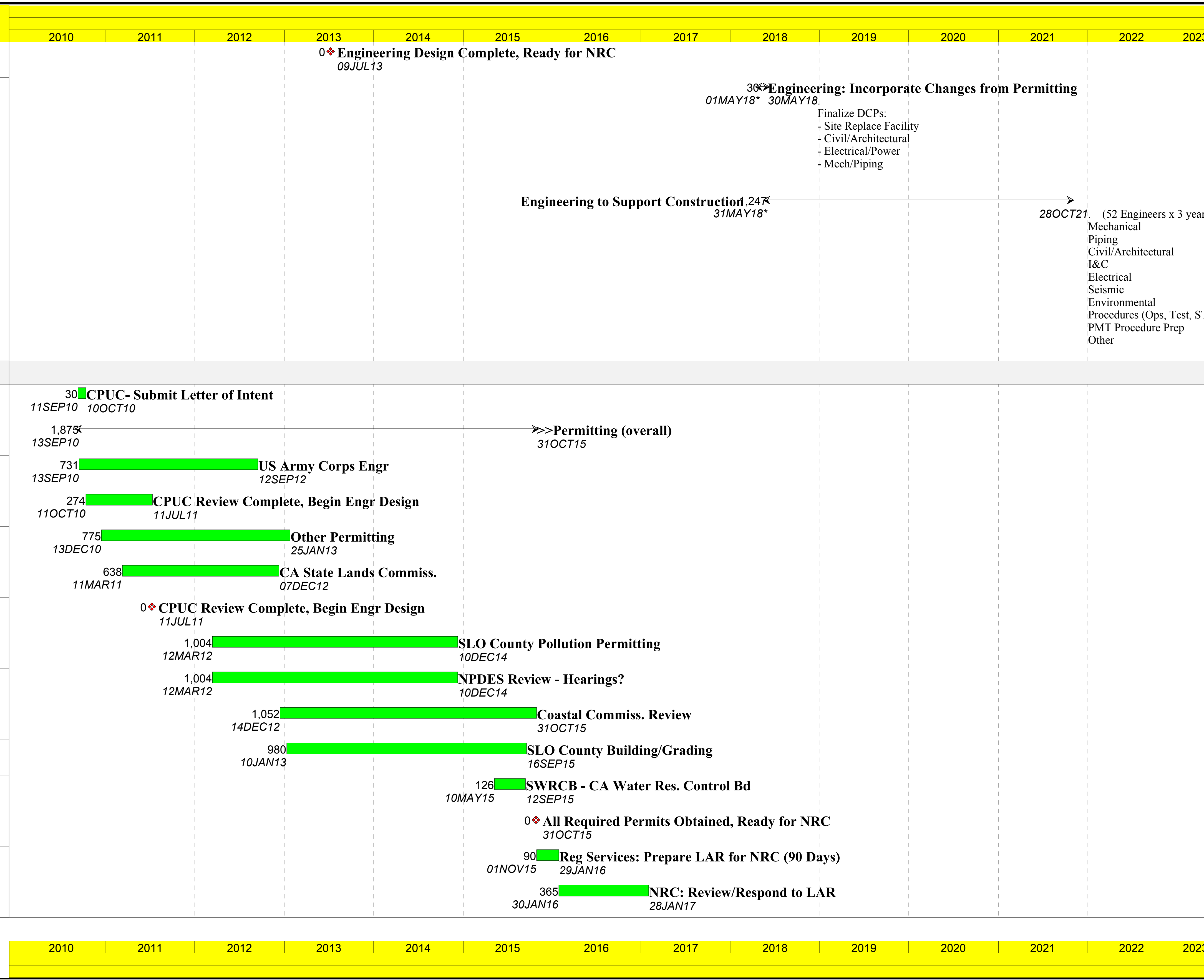
Cooling Tower Feasibility Study
Appendix A-12 Conceptual Schedule

LT-C2 CCSS 11x17 Layout

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
CCSTS_011B	Engineering Design Complete, Ready for NRC	0		09JUL13
CCSTS_010C	Engineering: Incorporate Changes from Permitting	30	01MAY18*	30MAY18
CCSTS_010D	Engineering to Support Construction	1,247	31MAY18*	28OCT21

Permitting/Regulatory

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
CCSTS_101	CPUC- Submit Letter of Intent	30	11SEP10	10OCT10
CCSTS_001	>>Permitting (overall)	1,875	13SEP10	31OCT15
CCSTS_006	US Army Corps Engr	731	13SEP10	12SEP12
CCSTS_102	CPUC Review Complete, Begin Engr Design	274	11OCT10	11JUL11
CCSTS_008	Other Permitting	775	13DEC10	25JAN13
CCSTS_009	CA State Lands Commiss.	638	11MAR11	07DEC12
CCSTS_103M	CPUC Review Complete, Begin Engr Design	0		11JUL11
CCSTS_003	SLO County Pollution Permitting	1,004	12MAR12	10DEC14
CCSTS_005	NPDES Review - Hearings?	1,004	12MAR12	10DEC14
CCSTS_007	Coastal Commiss. Review	1,052	14DEC12	31OCT15
CCSTS_002	SLO County Building/Grading	980	10JAN13	16SEP15
CCSTS_004	SWRCB - CA Water Res. Control Bd	126	10MAY15	12SEP15
CCSTS_011C	All Required Permits Obtained, Ready for NRC	0		31OCT15
CCSTS_121	Reg Services: Prepare LAR for NRC (90 Days)	90	01NOV15	29JAN16
CCSTS_122	NRC: Review/Respond to LAR	365	30JAN16	28JAN17



Note: Durations listed are 7days/week (not work days)

Sheet 2 of 5

Cooling Tower Feasibility Study
Appendix A-12 Conceptual Schedule

LT-C2 CCSS 11x17 Layout

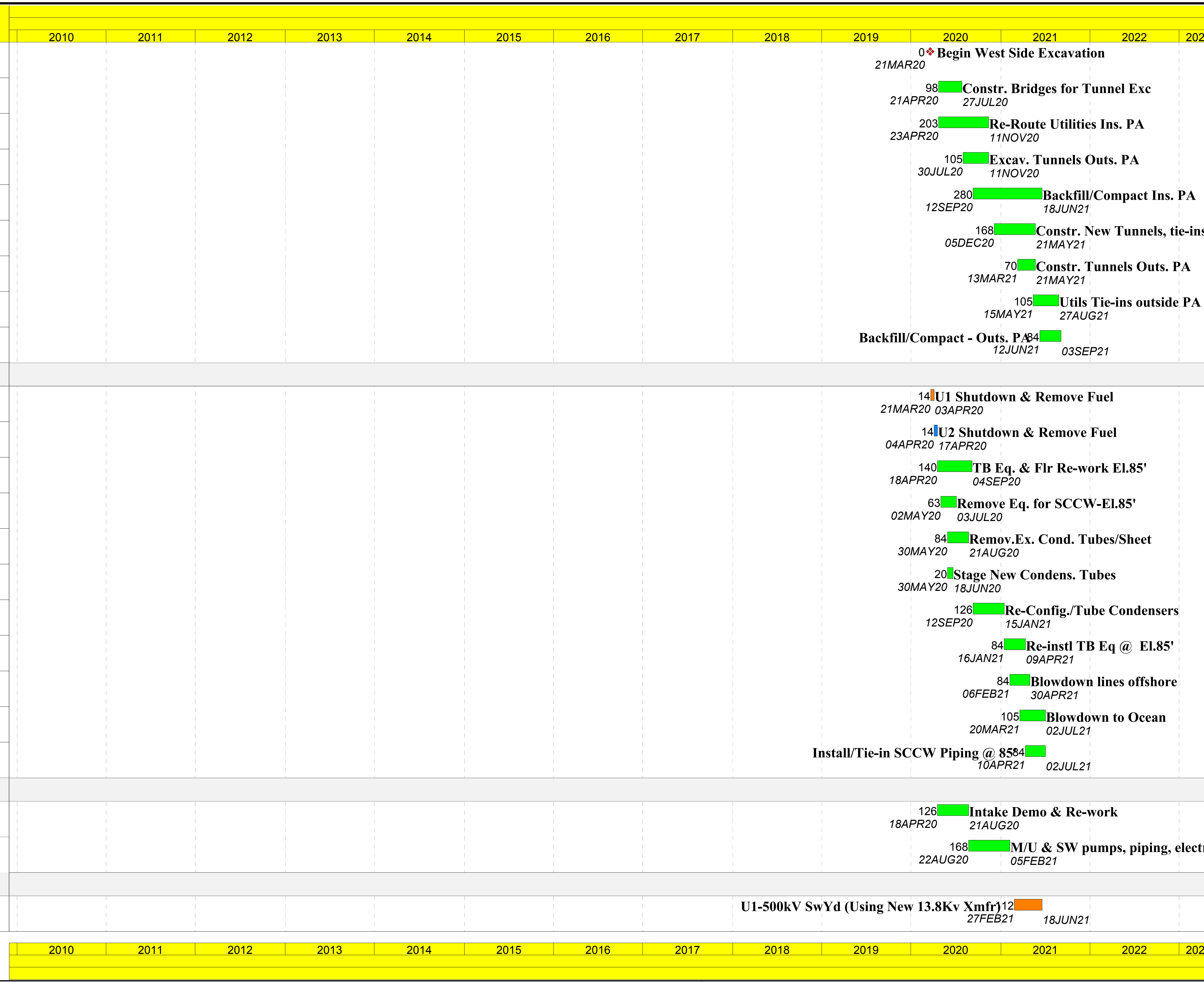
Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
CCSTS_123	NRC Hearings (2 years)	731	30APR16	30APR18
Site Facility Construction				
CCSTS_019	>>Build Site Repl. Facilities	294	31MAY18	20MAR19
CCSTS_020	Build Sewage Treatmt. Plant	252	31MAY18	06FEB19
CCSTS_021	- Replacmt Warehouse	294	31MAY18	20MAR19
CCSTS_022	- Replacmt Cold Mach Shop	273	21JUN18	20MAR19
CCSTS_024	- Replacmt Engr/Other Offices	245	19JUL18	20MAR19
CCSTS_023	- Replacmt Parking Facility	189	06SEP18	13MAR19
CCSTS_025	Staff & InventoryRe-locations	63	21MAR19	22MAY19
CCSTS_026	Demo. Whse, Engr., CMS	63	02MAY19	03JUL19
Reroute Traffic/Access Roads				
CCSTS_027	Re-align Access/Reserv Rds	182	21MAR19	18SEP19
CCSTS_028	Re-align other main Roads	210	21MAR19	16OCT19
Tower Excavation				
CCSTS_030	>>Excav. Tower Area, Utils.	210	04JUL19	29JAN20
CCSTS_031	Exc. East 1/2 - Tower #2	168	04JUL19	18DEC19
CCSTS_032	Exc. West 1/2 - Tower #1	112	10OCT19	29JAN20
Tower Construction				
CCSTS_033	>>Constr. Towers, CWP's	280	05DEC19	09SEP20
CCSTS_034	Constr. East Tower #2	224	19DEC19	29JUL20
CCSTS_035	Constr. West Towers #1	224	30JAN20	09SEP20
CCSTS_036	Constr. Pump Pit/Basin #2	126	26MAR20	29JUL20
CCSTS_037	Constr. Pump Pit/Basin #1	126	07MAY20	09SEP20
Protected Area Modifications				
CCSTS_042	Re-config. Security PA	189	15AUG19	19FEB20
CCSTS_044	Re-config/route PA Roads	187	17OCT19	20APR20
CCSTS_045	Excavate Tunnels Inside PA	224	20FEB20	30SEP20

Note: Durations listed are 7days/week (not work days)

Cooling Tower Feasibility Study
Appendix A-12 Conceptual Schedule

LT-C2 CCSS 11x17 Layout

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
CCSTS_140M	Begin West Side Excavation	0	21MAR20	
CCSTS_043	Constr. Bridges for Tunnel Exc	98	21APR20	27JUL20
CCSTS_046	Re-Route Utilities Ins. PA	203	23APR20	11NOV20
CCSTS_049	Excav. Tunnels Outs. PA	105	30JUL20	11NOV20
CCSTS_048	Backfill/Compact Ins. PA	280	12SEP20	18JUN21
CCSTS_047	Constr. New Tunnels, tie-ins	168	05DEC20	21MAY21
CCSTS_050	Constr. Tunnels Outs. PA	70	13MAR21	21MAY21
CCSTS_051	Utils Tie-ins outside PA	105	15MAY21	27AUG21
CCSTS_052	Backfill/Compact - Outs. PA	84	12JUN21	03SEP21
Power Plant System Tie-Ins				
CCSTS_039	U1 Shutdown & Remove Fuel	14	21MAR20	03APR20
CCSTS_040	U2 Shutdown & Remove Fuel	14	04APR20	17APR20
CCSTS_054	TB Eq. & Flr Re-work El.85'	140	18APR20	04SEP20
CCSTS_055	Remove Eq. for SCCW-El.85'	63	02MAY20	03JUL20
CCSTS_056	Remov.Ex. Cond. Tubes/Sheet	84	30MAY20	21AUG20
CCSTS_057	Stage New Condens. Tubes	20	30MAY20	18JUN20
CCSTS_058	Re-Config./Tube Condensers	126	12SEP20	15JAN21
CCSTS_059	Re-instl TB Eq @ El.85'	84	16JAN21	09APR21
CCSTS_062	Blowdown lines offshore	84	06FEB21	30APR21
CCSTS_061	Blowdown to Ocean	105	20MAR21	02JUL21
CCSTS_060	Install/Tie-in SCCW Piping @ 85'	84	10APR21	02JUL21
Intake Structure				
CCSTS_063	Intake Demo & Re-work	126	18APR20	21AUG20
CCSTS_064	M/U & SW pumps, piping, electr	168	22AUG20	05FEB21
500Kv Switchyard				
CCSTS_066	U1-500kV SwYd (Using New 13.8Kv Xmfr)	112	27FEB21	18JUN21

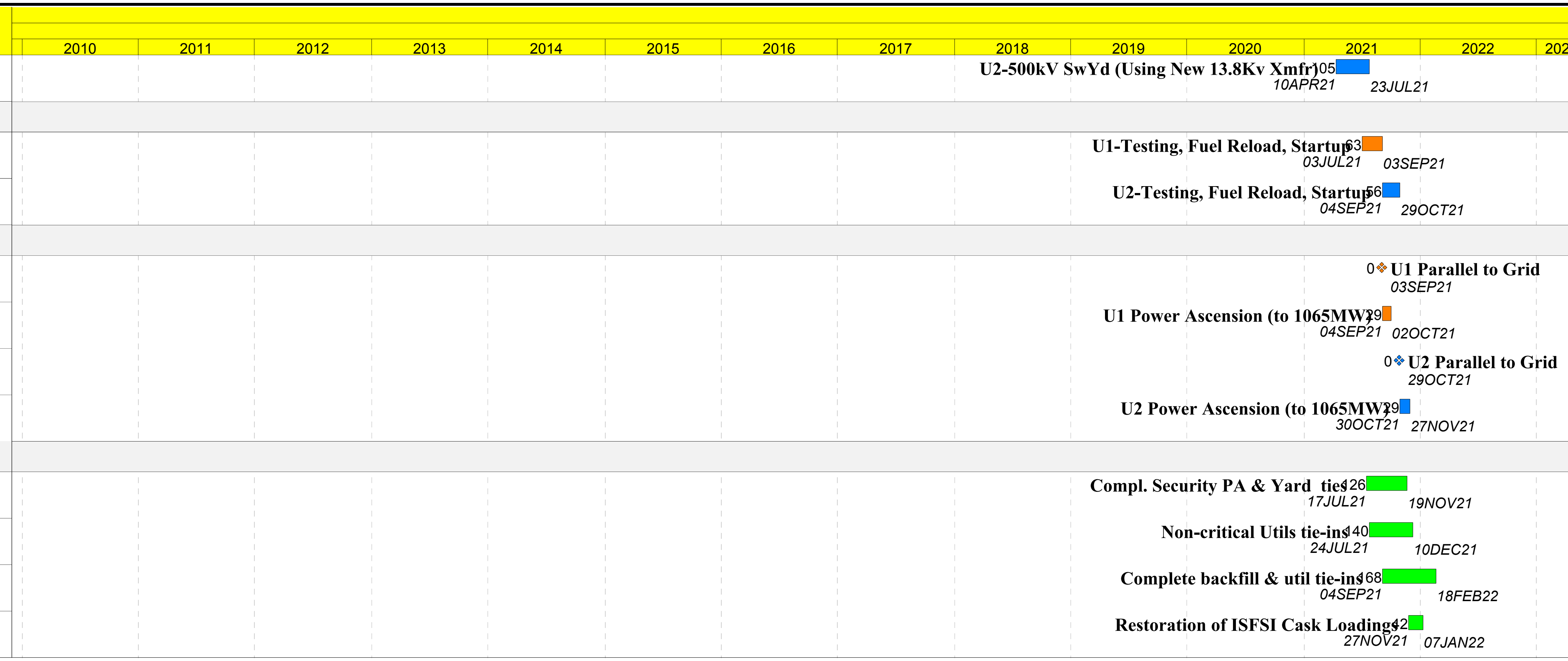


Note: Durations listed are 7days/week (not work days)

Cooling Tower Feasibility Study
Appendix A-12 Conceptual Schedule

LT-C2 CCSS 11x17 Layout

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
CCSTS_067	U2-500kV SwYd (Using New 13.8Kv Xmfr)	105	10APR21	23JUL21
Startup Testing				
CCSTS_069	U1-Testing, Fuel Reload, Startup	63	03JUL21	03SEP21
CCSTS_070	U2-Testing, Fuel Reload, Startup	56	04SEP21	29OCT21
Power Ascension				
U1PARALLEL	U1 Parallel to Grid	0		03SEP21
CCSTS_071	U1 Power Ascension (to 1065MW)	29	04SEP21	02OCT21
U2PARALLEL	U2 Parallel to Grid	0		29OCT21
CCSTS_072	U2 Power Ascension (to 1065MW)	29	30OCT21	27NOV21
Misc Tie-ins				
CCSTS_074	Compl. Security PA & Yard ties	126	17JUL21	19NOV21
CCSTS_075	Non-critical Utils tie-ins	140	24JUL21	10DEC21
CCSTS_076	Complete backfill & util tie-ins	168	04SEP21	18FEB22
CCSTS_078	Restoration of ISFSI Cask Loadings	42	27NOV21	07JAN22

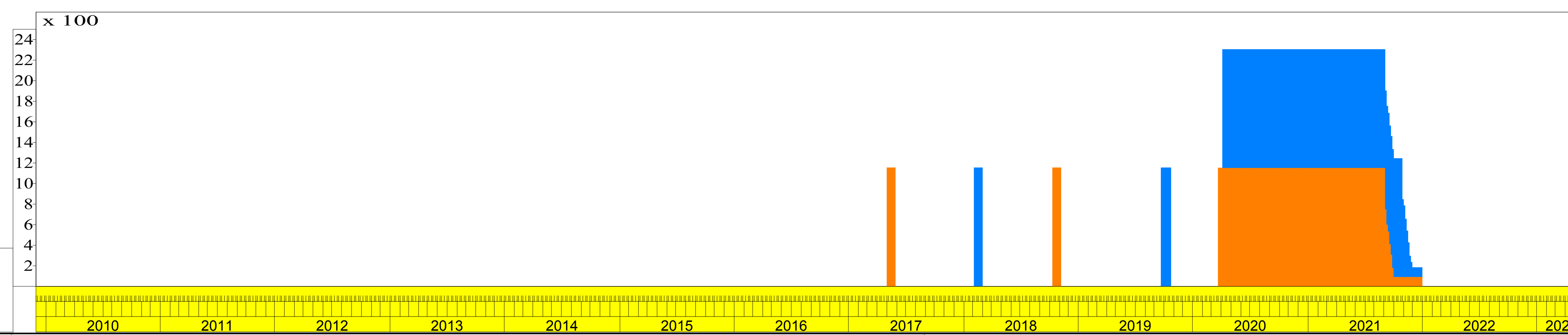


Resource/Cost Profile Legend

- LostMW
- U1MW
- U2MW

Total early cost per Day (Current Estimate)

Detail scale (left): X 100



Note: Durations listed are 7days/week (not work days)

Sheet 5 of 5

Cooling Tower Feasibility Study
Appendix A-12 Conceptual Schedule

LT-C2 CCSS 11x17 Layout

PG&E Diablo Canyon Power Plant

Project :	**Enercon Cooling Tower Feasibility Study** **DCPP Common Facilities** **Cost Estimate**

Capital Project Costs	**$2,689,000,000**
Decommissioning @ 2.5% of Installation	**$67,200,000**
Replacement Power for Lost MW During Construction @ $70/MWHr	
1155 MWs x 24 Hrs/Day x 517 Days x 2-Units x 0.9 Capacity Factor	**$1,805,700,000**
Annual Increase to Station Operation and Maintenance Costs	**$7,400,000. /Year**
Annual Cost of Replacement Power for Lost MW due to Derated Capacity	
451,180 MWHrs/Yr [Ref. Table 3] @ $70/MWHr = $31,582,600 (2-Unit Total)	**$31,600,000. /Year**

Appendix A-11 Project Cost Estimate

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description		Quantity	Unit	Unit Cost	Extension
<u>Annual Increase to Station Operation and Maintenance Costs</u>					
Mechanical Draft Cooling Towers					
Maintenance					
Daily Maintenance (4Hr /Day)		1,460	Hr	120	175,200
Weekly Maintenance (8Hr /Wk)		416	Hr	120	49,920
Monthly Maintenance (2Hr /Mo. Per Cell)	80	24	Hr	120	230,400
Quarterly Maintenance (4Hr /Qtr. Per Cell)	80	16	Hr	120	153,600
Inspections					
Semiannual Inspection (8Hr x 2 Insp /Yr Per Cell)	80	16	Hr	120	153,600
Annual Inspection (4Hr /Yr Per Cell)	80	4	Hr	120	38,400
Annual Transformer Inspection (16Hr /Yr.)		16	Hr	120	1,920
Quarterly Lighting Insp/Replacement (8Hr /Qtr.)		32	Hr	120	3,840
Corrective Maintenance					
Average Annual Replacement Costs /Yr Per Cell		25,000	$	80	2,000,000
Dechlorination System Chemicals		1	Yr	151,000	151,000
Increased Electrical Maintenance Due to Salt Drift		52	Wk	20,000	1,040,000
Facilities Maintenance for Protection Against Accelerated Corrosion		1	Allow	1,500,000	1,500,000
Cost of Travel Between Off-Site Facilities and DCPP		1	Allow	200,000	200,000
Subtotal					5,697,880
Project Indirects (8% of Direct Cost) (Capitalized A&G 2% + Material Burden 6%)					455,830
Contingency (20% of Direct and Indirect Costs)					1,230,742
Total: Annual Increase to Station Operation and Maintenance Costs					7,384,452
				<u>Say</u>	**<u>7,400,000</u>**

PG&E Diablo Canyon Power Plant

Project : Enercon Cooling Tower Feasibility Study
DCPP Common Facilities
Cost Estimate

Capital Project Costs

1	Mechanical Draft Cooling Towers	$242,100,000
2	Recirculating Water Pumps and Piping	$178,800,000
3	Makeup Water Pumps and Piping	$51,100,000
4	Condenser Replacement Bundles	$83,800,000
5	Concrete Recirc Water Tunnel	$72,000,000
6	Sitework	$325,500,000
7	Electrical	$100,900,000
8	Process Control and Instrumentation	$23,700,000
9	Permit and Licensing Fees	$55,500,000
10	Engineering	$74,700,000
11	Construction Offices / Batch Plant / Temp Parking and Roadways	$37,900,000
12	Project Management and Support Staff	$93,800,000
13	Relocate Warehouse & Cold Machine Shop	$10,300,000
14	Demo Displaced Structures	$19,100,000
15	Construct Displaced Structures ON Site	$105,100,000
16	Construct Displaced Structures OFF Site	$40,400,000
17	Displaced Parking	$93,300,000
18	Security Requirements	$44,200,000
19	Pedestrian and Vehicle Bridges	$5,600,000
20	Transportation - Permanent/Construction Personnel	$189,000,000
21	Sewage Treatment Facility	$12,000,000
22	Utility Relocations	$36,200,000
23	SCW System	$36,900,000
24	ASW & Blowdown Water Treatment	$15,500,000
25	Blowdown, Mixing Station and Diffuser	$39,600,000
26	Plant Shutdown and Start-Up	$50,000,000
27	Site Infrastructure (Water/Storm/Power/Tel-Data/etc.)	$38,000,000
	Total: Direct Costs	**$2,075,000,000**
	Project Indirects (8% of Direct Cost) (Capitalized A&G 2% + Material Burden 6%)	$166,000,000
	Contingency (20% of Direct and Indirect Costs)	$448,200,000
	Total: Capital Costs	**$2,689,200,000**
	Say	**$2,689,000,000**

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
<u>Mechanical Draft Cooling Towers</u>				
Excavation with Sitework				
Concrete				
Cooling Tower Basins	18,500	CY	3,000	55,500,000
Pump Pits	9,500	CY	3,000	28,500,000
Cooling Tower Erection				
Cooling Tower Vendor (Marley)	2	Units	40,000,000	80,000,000
Erect Framing / Baffles per cell	80	Cell	80,000	6,400,000
Erect Mechanical per cell	80	Cell	150,000	12,000,000
Erect Electrical per cell	80	Cell	150,000	12,000,000
Rig, Erect and test Fans	80	Cell	400,000	32,000,000
Miscellaneous Platform, Ladders, Grating	80	Cell	25,000	2,000,000
Pump Pit				
Trash Rack	6,500	SF	500	3,250,000
Miscellaneous Platform, Ladders, Grating	7,500	SF	225	1,687,500
Sales Tax and Freight on Equipment	11%		80,000,000	8,800,000
(7.25% Tax & 3.5% Allowance for Freight = 11%)				
Total: Mechanical Draft Cooling Towers				242,137,500
			<u>Say</u>	**<u>242,100,000</u>**

Excavation included with site-work.
Backfill included with site-work.
Based on 4 Cooling Towers at 40 ea. - 60' x 60' Cells.
Trash Rack price based on 50% of current Intake Bar Rack project.

PG&E Diablo Canyon Power Plant

Project :	**Enercon Cooling Tower Feasibility Study** **DCPP Common Facilities** **Cost Estimate**

Description	Quantity	Unit	Unit Cost	Extension
Recirculating Water Pumps and Piping				
Circ Water Pumps Vendor Quote	10	Ea	4,640,000	46,400,000
Circ Water Pumps Installation	10	Ea	7,733,333	77,333,333
Control Valves	1	Allow	5,000,000	5,000,000
Install New Mechanical in Pump Pits	2	Units	3,250,000	6,500,000
Install New Electrical in Pump Pits	2	Units	3,600,000	7,200,000
Install Pipe Supports in Pump Pits	2	Units	1,500,000	3,000,000
Install Paralined Pipe - 8'	1,440	LF	2,500	3,600,000
Install Paralined Pipe - 6'	800	LF	2,250	1,800,000
Install Paralined Pipe - 4'	480	LF	2,000	960,000
Purchase Paralined Pipe	2,720	LF	2,270	6,174,400
Pipe Supports for Large Bore Piping	300	Ea	10,000	3,000,000
Tie-In Paralined Pipe to Concrete Tunnel	4	Ea	500,000	2,000,000
Pipe Distribution to CT Cells	80	Cells	125,000	10,000,000
Process Controls	With Process Controls Section			
Excavation & Backfill	With Sitework Section			
Sales Tax and Freight on Equipment	11%		52,574,400.00	5,783,184
(7.25% Tax & 3.5% Allowance for Freight = 11%)				
Total: Recirculating Water Pumps and Piping				178,750,917
			Say	**178,800,000**

Excavation included with site-work.
Backfill included with site-work.
Paralined Pipe price prorated from vendor quote.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
<u>Makeup Water Pumps and Piping</u>				
Make-Up Water Pumps Vendor Quote	6	Ea	640,000	3,840,000
Make-Up Water Pumps Installation	6	Ea	1,066,667	6,400,000
Control Valves	1	Allow	1,800,000	1,800,000
Excavate to Open Tunnel				
Saw Cut and Open Concrete Tunnels				
Demo Existing Circ Water Pumps	4	Ea	900,000	3,600,000
Demo Mechanical/Electrical	2	Units	2,500,000	5,000,000
Demo Slabs, Steel, Etc.	2	Units	2,000,000	4,000,000
Install New Slabs, Steel, Etc.	2	Units	2,500,000	5,000,000
Install New Mechanical/Electrical in Pump Pits	2	Units	4,000,000	8,000,000
Install Pipe Supports in Intake Tunnels	70	Ea	15,000	1,050,000
Install Paralined Pipe	670	LF	2,000	1,340,000
Purchase Paralined Pipe	670	LF	2,270	1,520,900
Tie-In Paralined Pipe to Concrete Tunnel	4	Ea	500,000	2,000,000
Process Controls	1	Allow	2,500,000	2,500,000
Backfill Excavations	40,000	CY	100	4,000,000
Civil Repairs/Modifications	1	Allow	500,000	500,000
Sales Tax and Freight on Equipment	11%		5,360,900.00	589,699
(7.25% Tax & 3.5% Allowance for Freight = 11%)				
Total: Makeup Water Pumps and Piping				51,140,599
			<u>Say</u>	**<u>51,100,000</u>**

Excavation included with site-work.
Backfill included with site-work.
Paralined Pipe price prorated from vendor quote.
Electrical price based on existing switchgear at intake with new circuitry to pumps.
Control price based on local instrumentation and control panel with basic signals to control room through existing conduit.
Demo includes requirements for SCW System.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
Condenser Replacement				
Building Mods for Delivery of Tube Bundles	1	Loc	1,500,000.00	1,500,000
Stage Tubes	2	Units	100,000.00	200,000
Set-Up Rigging and Open Boxes x 2	4	Boxes	150,000.00	600,000
Remove 720 Tubes x 2	4	Boxes	250,000.00	1,000,000
Clean Water Boxes x 2	4	Boxes	150,000.00	600,000
Water Box Modifications x 2	4	Boxes		w/ Vendor
Install Tube Bundles x 2	4	Boxes		w/ Vendor
Replace & Torque Water Box Covers x 2	4	Boxes		w/ Vendor
Water Box Insulation x 2	4	Boxes	500,000.00	2,000,000
Support Staff for Drain, Fill, QA, etc.	4	Boxes	500,000.00	2,000,000
Remove/Replace Eq./Mech./El..for Tube Installation	4	Boxes	1,500,000.00	6,000,000
Vendor Price	2	Units	31,500,000.00	63,000,000
Sales Tax and Freight on Equipment (7.25% Tax & 3.5% Allowance for Freight = 11%)	11%		63,000,000.00	6,930,000
Total: Condenser Replacement				83,830,000
			Say	**83,800,000**

Based on Vendor Quote - Enercon Report Appendix A-1.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
<u>Concrete Recirc Water Tunnel</u>				
Circ Water Tunnel 10' x 10' Concrete				
Excavation and Backfill				w/ Sitework
Metal Formwork	120,000	SF	100	12,000,000
Spiders for Interior	150	Ea	5,000	750,000
Exterior Formwork	60,000	SF	100	6,000,000
Tunnel Walls - Reinforced Concrete	12,000	CY	3,000	36,000,000
Flow Control				
Turning Vanes	1	Allow	2,000,000	2,000,000
Gates/Weir/Baffles	4	Ea	2,000,000	8,000,000
Special Linings or Coatings	120,000	SF	60	7,200,000
Total: Concrete Recirc Water Tunnel				71,950,000
			<u>Say</u>	**<u>72,000,000</u>**

Excavation included with Sitework.
Backfill included with Sitework.
Metal Formwork used for interior form. Minimum segments fabricated/purchased to be used as slip forms.
External Formwork includes preparation of trench walls to serve as exterior form as well as wood forms as required.
Quantity based on 4 Runs of +/- 750 LF Tunnel.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
Sitework				
Access Road				
Relocate Access Road	3.0	Mi	1,250,000.00	3,750,000
Relocate ISFSI Roadway	5.0	Mi	1,250,000.00	6,250,000
Excavation for road relocation	350,000	CY		
Soil	175,000	CY	60.00	10,500,000
Rock	175,000	CY	150.00	26,250,000
Retaining Walls at road	1,500	CY	5,000.00	7,500,000
Drainage, rails, sign, etc	1	Allow	1,000,000.00	1,000,000
Main Site Excavation				
Strip & remove asphalt	10	Acre	125,000.00	1,250,000
Main retaining walls	2,500	CY	5,000.00	12,500,000
Excavation	1,100,000			
Soil	770,000	CY	60.00	46,200,000
Rock	330,000	CY	150.00	49,500,000
Drainage	10	Acre	1,000,000.00	10,000,000
Roadway and walkway	1	Lot	3,000,000.00	3,000,000
Site Lighting	220	Loc	25,000.00	5,500,000
Landscaping	1	Lot	2,500,000.00	2,500,000
Retaining Walls	1,000	CY	5,000.00	5,000,000
Cooling Tower Basin				
Excavation	65,000			
Soil		CY	60.00	0
Rock	65,000	CY	150.00	9,750,000
Backfill	1,320	CY	75.00	99,000
Cooling Tower Pump Pits				
Excavation	46,000			
Soil		CY	60.00	0
Rock	46,000	CY	150.00	6,900,000
Backfill	22,500	CY	75.00	1,687,500
Electrical Equipment Rm				
Excavation	300			
Soil		CY	60.00	0
Rock	300	CY	150.00	45,000
Backfill		CY	75.00	0
Retaining Wall				
Excavation	7,000			
Soil		CY	60.00	0
Rock	7,000	CY	150.00	1,050,000

Backfill	5,000	CY	75.00	375,000
Concrete Tunnel (Pipe)				
Excavation	350,000			
Soil		CY	60.00	0
Rock	350,000	CY	150.00	52,500,000
Backfill	200,000	CY	75.00	15,000,000
Concrete Tunnel (Pipe) - Tie-In Locations				
Excavation	50,000			
Soil		CY	60.00	0
Rock / Concrete (10,000 Yd x 5 Locations)	50,000	CY	150.00	7,500,000
Sheet Piling	75,000	SF	100.00	7,500,000
Backfill	45,000	CY	75.00	3,375,000
Circ Water Pipe at Cooling Tower				
Excavation	10,500			
Soil		CY	60.00	0
Rock	10,500	CY	150.00	1,575,000
Backfill	4,250	CY	75.00	318,750
Miscellaneous Pipe				
Excavation	32,000			
Soil		CY	60.00	0
Rock	32,000	CY	150.00	4,800,000
Backfill	31,000	CY	75.00	2,325,000
Temporary Roadways	6	Mi	1,250,000.00	7,500,000
Repair Roadways on completion	10	Mi	1,250,000.00	12,500,000
Total: Sitework				325,500,250
			Say	**325,500,000**

This type of heavy traffic will require major repair to all access roads
Price only includes repairs to roadways inside the DCPP gate, public roads not included.

PG&E Diablo Canyon Power Plant

Project :	Enercon Cooling Tower Feasibility Study DCPP Common Facilities Cost Estimate			
Description	**Quantity**	**Unit**	**Unit Cost**	**Extension**
Electrical				
Switch Yard - Complete Breaker-and-a-Half Bay				12,000,000
500 kV Metering System - Complete				500,000
Cathodic Protection:	1	Allow	7,500,000	7,500,000
Intake, CT Area, Circ Water Tunnels				
Complete Major Impressed Current System				
Vendor Furnished Eq.:				
High Voltage Transformers	4	Ea	2,000,000	8,000,000
Cooling Tower Transformers	6	Ea	420,000	2,520,000
Medium Voltage Transformers	2	Ea	420,000	840,000
500 kV Circuit Breakers	3	Ea	1,500,000	4,500,000
4160V/440V/500 kV Oil Filled Transformers for SCW Pumps	2	Ea	30,000	60,000
Electrical Equipment Houses for CTs (Incl Equip't)	2	Ea	3,366,150	6,732,300
Sales Tax and Freight on Equipment	11%		22,652,300	2,491,753
(7.25% Tax & 3.5% Allowance for Freight = 11%)				
Install Vendor Furnished Equipment				37,753,833
Ductbank - Switch Yard to Elect. Eq. Houses	5,000	LF	1,500	7,500,000
Electrical Manholes, Pull Boxes and Junction Boxes	1	Allow	3,000,000	3,000,000
Distribution Panels and Sub-Panels	1	Allow	2,000,000	2,000,000
Cable - Cooling Tower	185,000	LF	5.50	1,017,500
Cable - Switch Yard to El. Eq. House	100,000		25	2,500,000
Cable, Conduit, Cable Tray, Other	1	Allow	2,000,000	2,000,000
Total: Electrical				100,915,386
			Say	**100,900,000**

Ductbank Unit Price Includes; Excavation, Backfill, Concrete and Conduit.
Cooling Tower Cable Quantity based on Enercon Report Appendix A-9.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
<u>Process Control and Instrumentation</u>				
Vendor Furnished Eq.:				
Operator Touch screens	2	Unit	40,000	80,000
Triconex Supplied Eq.	2	Unit	955,000	1,910,000
Bently Nevada Eq.	2	Unit	585,000	1,170,000
Other Eq.	2	Unit	560,000	1,120,000
Install Vendor Furnished Equipment	1	Lot		7,133,333
Control Points - Triconex	943	LF	2,500	2,357,500
Control Points - Bently Nevada	200	LF	2,500	500,000
Control Points - Other	150	LF	2,500	375,000
Control Cable - Cooling Tower	276,000	LF	5.50	1,518,000
Cable, Conduit, Cable Tray, Other	1	Allow	5,000,000	5,000,000
Simulator Modifications / Training Program Mods.	1	Allow	2,500,000	2,500,000
Total: Process Control and Instrumentation				23,663,833
			<u>Say</u>	**<u>23,700,000</u>**

Vendor Pricing Based on Enercon Report Appendix A-6.
Vendor Prices Include Tax and Freight.
Control Point Quantities from Enercon Report Documents SK-J-4 and SK-J-5.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description		Quantity	Unit	Unit Cost	Extension
Permit and Licensing Fees					
Environmental Services	6	2,080	Hrs	150.00	1,872,000
6 Man Years					
LSA Environmental Services - EIR/Monitoring		7	Yrs	500,000.00	3,500,000
Legal Services	5	2,080	Hrs	350.00	3,640,000
5 Man Years					
Regulatory Services	3	2,080	Hrs	200.00	1,248,000
3 Man Years					
Prepare and Present Special Rate Case to CPUC		1	Allow	5,000,000.00	5,000,000
NRC License Amendment	21	160	Hrs	200.00	672,000
15 Man Months - Preparation					
6 Man Months - (1/2 FTE) Review Period					
Allowances for Permit Specific Administrative/Processing Costs and Initial Direct Fees:					
California Coastal Commission - Coastal Development Permit (CDP)					1,500,000
SLO County Building Permits					500,000
Army Corps of Engineers - NWP Structural Discharge Permit					250,000
CA State Lands Commission - Lease for Wastewater Diffuser Area					75,000
SWRCB - Construction Storm Water Discharge Permit & SWPPP					75,000
RWQCB Region 3 - NPDES Wastewater Discharge Permit					500,000
SLO Air Pollution Control District - Batch Plant Operations/EIR					125,000
SLO Air Pollution Control District - Cooling Tower Emissions PTO					250,000
Allowance for Impacts Mitigation and/or Offsets Associated With Permit Approval Conditions					36,250,000
Anticipated Minimum Permit Specific Programs:					
Implement Coastal Development Permit Conditions (Various at Agency Discretion)					
PM_{10} Emissions Offsets or Credits/Fees for Cooling Tower Operations					
Mitigation for Marine Rocky Benthic Habitat Disruption (Diffuser System Installation)					
Batch Plant Operations and Project Related Fossil Fuel Combustion Offsets					
Total: Permit and Licensing Fees					55,457,000
				Say	**55,500,000**

PG&E Diablo Canyon Power Plant

Project :	**Enercon Cooling Tower Feasibility Study** **DCPP Common Facilities** **Cost Estimate**

Description	Quantity	Unit	Unit Cost	Extension
<u>Engineering</u>				
Preliminary Design Engineering				
Mechanical	28,800	Hrs	150.00	4,320,000
Civil / Architectural	28,800	Hrs	150.00	4,320,000
Electrical	19,200	Hrs	150.00	2,880,000
I & C	5,760	Hrs	150.00	864,000
Piping	8,640	Hrs	150.00	1,296,000
Layout	11,520	Hrs	150.00	1,728,000
Engineering Planning & Scheduling	11,520	Hrs	150.00	1,728,000
Permitting/Environmental Support	19,200	Hrs	150.00	2,880,000
Licensing Support	19,200	Hrs	150.00	2,880,000
Management and Administration	19,200	Hrs	150.00	2,880,000
(41 Engineers x 2 Years)	171,840	Hrs.		
Procurement Support and Design Change Packages				
Mechanical	65,880	Hrs	150.00	9,882,000
Piping	28,656	Hrs	150.00	4,298,400
Civil / Architectural	70,920	Hrs	150.00	10,638,000
I & C	28,560	Hrs	150.00	4,284,000
Electrical	77,220	Hrs	150.00	11,583,000
Seismic	8,280	Hrs	150.00	1,242,000
Environmental	5,280	Hrs	150.00	792,000
Procedures (Ops, Test, STP)	15,600	Hrs	150.00	2,340,000
PMT Procedure Preparation	15,840	Hrs	150.00	2,376,000
Other	9,600	Hrs	150.00	1,440,000
(52 Engineers x 3 Years)	325,836	Hrs		
Total: Engineering	497,676	Hrs		74,651,400
			<u>Say</u>	**<u>74,700,000</u>**

Technical Coordinator, ESC Designer and Drafter hours are included in engineering estimates.
Engineering Man-hours and billing rates provided by Enercon.

Appendix A-11 Project Cost Estimate

PG&E Diablo Canyon Power Plant

Project :	**Enercon Cooling Tower Feasibility Study** **DCPP Common Facilities** **Cost Estimate**			
Description	**Quantity**	**Unit**	**Unit Cost**	**Extension**
Construction Offices / Batch Plant / Temp Parking and Roadways				
Install New / Temp Roadways	5	Mi	1,250,000	6,250,000
Clear Parking / Laydown and Trailer Areas	2	Acre	150,000	300,000
Crushed Stone	15,000	Ton	100	1,500,000
Road and Parking Maintenance	72	Mo	2,000	144,000
Construction Facilities	10,000	SF	250	2,500,000
Temp Sanitary	72	Mo	15,000	1,080,000
Temp Water	72	Mo	4,000	288,000
Office Equipment	1	Lot	1,000,000	1,000,000
Office Supplies	72	Mo	10,000	720,000
Office Maintenance	72	Mo	1,500	108,000
Temp Power	1	Lot	3,000,000	3,000,000
Area Lighting	25	Loc	25,000	625,000
Vehicles	25	Ea	25,000	625,000
Fuel Consumption	72	Mo	35,000	2,520,000
Tel/Data Service	1	Allow	1,000,000	1,000,000
Radio/Communications	1	Lot	500,000	500,000
Service Charges	72	Mo	10,000	720,000
Fencing	2,000	LF	25	50,000
Cleaning & Trash Service	72	Mo	24,000	1,728,000
Dust Control	36	Mo	75,000	2,700,000
Mob/De-mob Temp Facilities	1	Lot	500,000	500,000
Night Work Setup - Lighting, Generators and Fuel	1	Allow	5,000,000	5,000,000
Batch Plant	1	Allow	5,000,000	5,000,000
Total: Construction Offices / Batch Plant / Temp Parking and Roadways				37,858,000
			Say	**37,900,000**

Set up and maintain a construction field office on site for a 6 year period.
Does not include Project Staff.
Batch Plant Price includes mob, de-mob, operation, maintenance, trucks and drivers.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description		Quantity	Unit	Unit Cost	Extension
Project Management and Support Staff					
Project Director	1	10	Yr	300,000.00	3,000,000
Sr. Project Managers	2	5	Yr	225,000.00	2,250,000
Project Managers	7	3	Yr	180,000.00	3,780,000
Work Planners	25	4	Yr	180,000.00	18,000,000
Field Engineers	25	4	Yr	200,000.00	20,000,000
Principal Engineer	4	6	Yr	200,000.00	4,800,000
Sr. Engineers	6	4	Yr	180,000.00	4,320,000
Project Engineers	15	3	Yr	150,000.00	6,750,000
Project Controls Manager	1	7	Yr	200,000.00	1,400,000
Cost Engineers	2	7	Yr	150,000.00	2,100,000
Schedulers	2	7	Yr	150,000.00	2,100,000
Field Office Manager	1	10	Yr	150,000.00	1,500,000
Project Clerks	5	7	Yr	100,000.00	3,500,000
Safety	5	3	Yr	200,000.00	3,000,000
Security	50	3	Yr	115,000.00	17,250,000
Total: Project Management and Support Staff					93,750,000
				Say	**93,800,000**

Project Staff annual salaries based on PCC Cost amounts.
Size of security force based on SGRP experience (40 guards on 3 Shifts).

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
<u>Relocate Warehouse & Cold Machine Shop</u>				
Crate Materials and Equipment Warehouse	25,000	Hrs	100.00	2,500,000
Crate Materials and Equipment Machine Shop	11,250	Hrs	100.00	1,125,000
Salvage - storage Bins, Shelves, Racks	7,500	Hrs	100.00	750,000
Load, Transport and Unload	3,200	Hrs	100.00	320,000
Set-Up New Warehouse	25,000	Hrs	100.00	2,500,000
Set-Up New Machine Shop	11,250	Hrs	100.00	1,125,000
Materials - Wood, Pallets, etc	1	Allow	200,000.00	200,000
Trucking	1	Allow	150,000.00	150,000
Allowance for Extra Handling	20%		8,320,000.00	1,664,000
Total: Relocate Warehouse & Cold Machine Shop				10,334,000
			<u>Say</u>	**<u>10,300,000</u>**

Warehouse based on 500 Man-Weeks for Packing and Unpacking.
Cold Machine Shop based on 225 Man-Weeks for Packing and Unpacking.
Allowance for extra handling for interim storage.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Bldg#	Description	Quantity	Unit	Unit Cost	Extension
	Demo Displaced Structures				
116	Cold Machine Shop	15,000	SF	80.00	1,200,000
506	Radwaste Offices	1,000	SF	80.00	80,000
508	Other Shop	1,000	SF	80.00	80,000
127	Haz Mat Warehouse	4,000	SF	80.00	320,000
115	Main Warehouse	50,000	SF	80.00	4,000,000
201	Design Engineering Offices	12,000	SF	80.00	960,000
202	Design Engineering Offices	4,000	SF	80.00	320,000
220	Design Engineering Offices	1,000	SF	80.00	80,000
248	Outage Human Resources	1,000	SF	80.00	80,000
250	Project Offices	3,000	SF	80.00	240,000
252	Project Offices	3,000	SF	80.00	240,000
217	Restrooms	500	SF	80.00	40,000
253	Offices	500	SF	80.00	40,000
260	Security/Records Storage	2,000	SF	80.00	160,000
261	Records Storage/ Site Services Contractor Office	2,000	SF	80.00	160,000
262	Telecom/Project Office	2,000	SF	80.00	160,000
263	Site Services Contractor Training Facility	2,000	SF	80.00	160,000
264	Building Services	2,000	SF	80.00	160,000
251	Fire House	3,000	SF	80.00	240,000
254	Storage Facility	8,000	SF	80.00	640,000
255	Storage Facility	8,000	SF	80.00	640,000
114	Firing Range	3,000	SF	80.00	240,000
114A	Security Tower	500	SF	80.00	40,000
114B	Security Training Building	500	SF	80.00	40,000
113	Warehouse B	18,000	SF	80.00	1,440,000
120	Hazardous Waste	3,000	SF	80.00	240,000
125	Fire Water Tank and Pumphouse	1,000	SF	80.00	80,000
124	Sewage Treatment Plant	1,000	SF	80.00	80,000
165	Biology Offices / Career Center	2,000	SF	80.00	160,000
160	Biology Laboratory	4,000	SF	80.00	320,000
110	Blast and Paint Facility	3,000	SF	80.00	240,000
122	GC Fab Shop	8,000	SF	80.00	640,000
VIS	Vehicle Inspection Station	1,000	SF	80.00	80,000
	Hazardous Material Disposal Allowance	1	Allow	5,500,000	5,500,000
	Total: Demo Displaced Structures				19,100,000
				Say	**19,100,000**

Main Warehouse and Cold Machine Shop Relocation Priced Separately.
Demo Price includes salvage of re-used equipment.
Demo Price includes Hazardous Waste / Contaminated material Clean-Up.
Hazardous Material Disposal Included (Lead, Asbestos, Ballasts).

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

	Description	Quantity	Unit	Unit Cost	Extension
Construct Displaced Structures ON Site					
116	Cold Machine Shop	15,000	SF	1,500.00	22,500,000
506	Radwaste Offices	1,000	SF	1,200.00	1,200,000
508	Other Shop	1,000	SF	1,200.00	1,200,000
127	Haz Mat Warehouse	4,000	SF	1,200.00	4,800,000
115	Main Warehouse	25,000	SF	1,500.00	37,500,000
201	Design Engineering Offices	6,000	SF	1,200.00	7,200,000
202	Design Engineering Offices	2,000	SF	1,200.00	2,400,000
220	Design Engineering Offices	500	SF	1,200.00	600,000
248	Outage Human Resources	500	SF	1,200.00	600,000
250	Project Offices	1,500	SF	1,200.00	1,800,000
252	Project Offices	1,500	SF	1,200.00	1,800,000
217	Restrooms	500	SF	1,200.00	600,000
253	Offices	250	SF	1,200.00	300,000
260	Security/Records Storage	1,000	SF	1,200.00	1,200,000
261	Records Storage/ Site Services Contractor Office	1,000	SF	1,200.00	1,200,000
262	Telecom/Project Office	1,000	SF	1,200.00	1,200,000
263	Site Services Contractor Training Facility	1,000	SF	1,200.00	1,200,000
264	Building Services	1,000	SF	1,200.00	1,200,000
251	Fire House	3,000	SF	1,200.00	3,600,000
114A	Security Tower	500	SF	1,200.00	600,000
114B	Security Training Building	1	Lot	1,500,000.00	1,500,000
120	Hazardous Waste	3,000	SF	1,200.00	3,600,000
125	Fire Water Tank and Pumphouse	1,000	SF	1,200.00	1,200,000
110	Blast and Paint Facility	3,000	SF	1,200.00	3,600,000
Special Equipment Allowance		1	Allow	2,500,000.00	2,500,000
	Total: Construct Displaced Structures ON Site				105,100,000
				Say	**105,100,000**

$/SF based on historical cost data at DCPP.
Price Does Not include OFF Site Construction of Displaced Facilities.
Security Training Building Price based on recent experience.
Main Warehouse and Cold Machine Shop Relocation Priced Separately.
Vehicle Inspection Station Priced with Security.
Sewage Treatment Plant Priced Separately.
Special equipment allowance for Fire House, Shops and Hazardous Material Storage Building.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

	Description	Quantity	Unit	Unit Cost	Extension
Construct Displaced Structures OFF Site					
115	Main Warehouse	25,000	SF	800.00	20,000,000
201	Design Engineering Offices	6,000	SF	1,000.00	6,000,000
202	Design Engineering Offices	2,000	SF	1,000.00	2,000,000
220	Design Engineering Offices	500	SF	1,000.00	500,000
248	Outage Human Resources	500	SF	1,000.00	500,000
250	Project Offices	1,500	SF	1,000.00	1,500,000
252	Project Offices	1,500	SF	1,000.00	1,500,000
260	Security/Records Storage	1,000	SF	1,000.00	1,000,000
261	Records Storage/ Site Services Contractor Office	1,000	SF	1,000.00	1,000,000
262	Telecom/Project Office	1,000	SF	1,000.00	1,000,000
263	Site Services Contractor Training Facility	1,000	SF	1,000.00	1,000,000
264	Building Services	1,000	SF	1,000.00	1,000,000
114	Firing Range	3,000	SF	800.00	2,400,000
Special Equipment Allowance		1	Allow	1,000,000.00	1,000,000
	Total: Construct Displaced Structures OFF Site				40,400,000
				Say	**40,400,000**

Price Includes procurement of 5+ Acres of commercial land in SLO County.
Main Warehouse Relocation Priced Separately.
Special Equipment Allowance for Firing Range and Main Warehouse.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description		Quantity	Unit	Unit Cost	Extension
Displaced Parking					
Displaced Parking					
Lot #2 300 x 100		30,000	SF		
Lot #6 650 x 250		162,500	SF		
Lot #7 500 x 250		125,000	SF		
Lot #8 500 x 150		75,000	SF		
		392,500	SF		
Parking Garage					
New 3 Story Parking Garage (200' x 300')		180,000	SF	400.00	72,000,000
Parking Lot #2					
Remote Paved Parking Areas		215,000	SF	40.00	8,600,000
Shuttle Service					
Shuttle Bus Stops		10	Ea	25,000.00	250,000
Shuttle Busses		6	Ea	100,000.00	600,000
Shuttle Bus Drivers (6 Full Time Employees)	6	24	Yrs	80,000.00	11,520,000
Maintenance (6 Busses)	6	24	Yrs	2,500.00	360,000
Total: Displaced Parking					93,330,000
				Say	**93,300,000**

Assumes Shuttle Service Day Shift Only.
Parking Garage location within walking distance to Plant.
24-Year Duration based on 4-Years left in current license + 1 full license period.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
Security Requirements				
New Vehicle Inspection Station				
Civil - Gates-Roadway-Structures	1	LS	5,000,000	5,000,000
Electrical - Power-Light-Tel/Data	1	LS	10,000,000	10,000,000
Mechanical - HVAC-Plumbing-Fire Protection	1	LS	2,000,000	2,000,000
New Guard Posts	3	Ea	2,500,000	7,500,000
New Perimeter Fence w/ Barb Wire	5,000	LF	250	1,250,000
Concrete Barrier	25,000	LF	125	3,125,000
CCTV	20	Ea	50,000	1,000,000
Other Security Devices	1	Allow	2,000,000	2,000,000
New PA Vehicle Barrier	2	Ea	3,500,000	7,000,000
Temporary PA Vehicle Barrier - During Construction	1	Sta.	1,724,625	1,724,625
Temp Security Personnel - During Construction (3 Yr)	10	Ea	300,000	3,000,000
Security System Outages				
Electrical - Re-Start and Test (8 Men x 30 Days)	2,880	MH	100.00	288,000
Security Comp Measures	30	Days	10,000.00	300,000
Total: Security Requirements				44,187,625
			Say	**44,200,000**

Assuming all new construction will fall outside Protected Area.
All New Systems outside Protected Area will be Non Safety Related.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
<u>Pedestrian and Vehicle Bridges</u>				
Pedestrian Access to Security Building				
12' Bridge with 30' Span	50	Ton	10,000	500,000
6' Crossover 30' Span 18' High	100	Ton	15,000	1,500,000
Vehicle Access To Protected Area				
25' Bridge with 30' Span	125	Ton	15,000	1,875,000
Miscellaneous Accessway	1	Allow	750,000	750,000
Miscellaneous Egress / Covered Walkway	1	Allow	1,000,000	1,000,000
Total: Pedestrian and Vehicle Bridges				5,625,000
			Say	**5,600,000**

Access, Egress and Walkway allowances based on wood construction and basic lighting.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
<u>Transportation - Permanent/Construction Personnel</u>				
Lease Land for Offsite Parking				
Prep Land for Parking				
Busses & Drivers				
Travel Pay / OT Expenses				
Estimate Basis -				
SGRP 2R14:				
1,100 Craft for 3.5 Months Cost = $15MM Total				
1,100 Man x 3.5 Months = 3,850 Man Months				
CCCT Project:				
Up to 3,000 Craft + 1,000 Staff Require Transport During Project				
Transport in Stages; Prior to Shutdown + Peak Period + Reduced Period				
= (1,500 Man x 12 Months) + (3,000 x 18) + (1,000 x 9)				
= 18,000 + 54,000 + 9,000				
= 81,000 Man Months				
CCCT Project Cost Estimate Factor Relative to 2R14:				
81,000 / 3,850 =	21		15,000,000.00	315,000,000
Optimization - Non-Bargaining Unit Personnel vs. Bargaining Unit Travel Time				
Stronger Contract Negotiating Power for Long Term Leases/Contracts			-40%	-126,000,000
Total: Transportation - Permanent/Construction Personnel				189,000,000
			<u>Say</u>	**<u>189,000,000</u>**

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
Sewage Treatment Facility				
Sitework and Concrete	1	Allow	1,500,000	1,500,000
Purchase all Equipment	1	Allow	500,000	500,000
Installation - Civil	1	Allow	1,000,000	1,000,000
Installation - Mechanical	1	Allow	4,000,000	4,000,000
Installation - Electrical	1	Allow	4,000,000	4,000,000
Installation - Process Controls	1	Allow	1,000,000	1,000,000
Total: Sewage Treatment Facility				12,000,000
			Say	**12,000,000**

Allowance based on low volume treatment plant. Pricing would not cover storm water treatment.

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
Utility Relocations				
Trenching	10,000	LF		
Rock / Concrete (10,000 Yd x 5 Locations)	5,926	CY	125.00	740,741
Sheet Piling	5,000	SF	100.00	500,000
Backfill	5,500	CY	75.00	412,500
Electrical	1	Allow	10,000,000	10,000,000
Fiber Optic	1	Allow	5,000,000	5,000,000
Mechanical				
Fire Protection Loop	1	Allow	1,500,000	1,500,000
Mechanical Pressurized Systems	1	Allow	5,000,000	5,000,000
Mechanical Drainage Systems	1	Allow	3,000,000	3,000,000
Premium for Relocation of Class 1 Systems	1	Allow	10,000,000	10,000,000
Total: Utility Relocations				36,153,241
			Say	**36,200,000**

Allowances based on remove and replace/relocate hundreds of systems in conflict with new Cooling Tower Footprint, Circulation and Makeup Water Systems Routing and Major Tie-Ins.

Appendix A-11 Project Cost Estimate

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
SCW System				
SCW Pumps - Vendor Quote	6	Ea	180,000	1,080,000
SCW Pumps - Installation	6	Ea	300,000	1,800,000
Control Valves	1	Allow	1,500,000	1,500,000
Install Pipe Supports in Intake Tunnels	400	Ea	15,000	6,000,000
Install Paralined Pipe	3,630	LF	2,000	7,260,000
Purchase Paralined Pipe	3,630	LF	2,270	8,240,100
Above Ground Pipe - Inside Turbine Building	1,500	LF	3,000	4,500,000
Electrical	1	Allow	3,000,000	3,000,000
Process Controls	1	Allow	2,500,000	2,500,000
Sales Tax and Freight on Equipment (7.25% Tax & 3.5% Allowance for Freight = 11%)	11%		9,320,100	1,025,211
Total: SCW System				36,905,311
			Say	**36,900,000**

Excavation included with site-work.
Backfill included with site-work.
Condensate Cooler pricing based on reworking piping around existing Coolers.
Paralined Pipe price prorated from vendor quote.
Electrical price based on existing switchgear at intake with new circuitry to pumps.
Control price based on local instrumentation and control panel with basic signals to control room through existing conduit.
Demo at intake included with Makeup Water System.

PG&E Diablo Canyon Power Plant

Project :	**Enercon Cooling Tower Feasibility Study** **DCPP Common Facilities** **Cost Estimate**

Description	Quantity	Unit	Unit Cost	Extension
ASW & Blowdown Water Treatment				
Chlorination System				
Use Existing Chemical Injection Equipment for Chlorination as Required.				
Miscellaneous Minor Modifications	1	Allow	1,000,000	1,000,000
Dechlorination System				
Dechlorination Skid w/ Tanks Pumps, etc.	1	Ea	5,000,000	5,000,000
Mechanical	1	Allow	3,500,000	3,500,000
Electrical	1	Allow	3,000,000	3,000,000
Instrumentation & Controls	1	Allow	2,000,000	2,000,000
Tie-Ins	1	Allow	1,000,000	1,000,000
Total: ASW & Blowdown Water Treatment				15,500,000
			Say	**15,500,000**

Pricing does not include special consideration for Chlorine Use or Storage.
Cost of Chemicals included in O&M Burden.

Appendix A-11 Project Cost Estimate

PG&E Diablo Canyon Power Plant

Project : **Enercon Cooling Tower Feasibility Study**
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
<u>Blowdown, Mixing Station and Diffuser</u>				
Blowdown Discharge Pipe 36" Paralined Steel - Vendor	1,600	LF	2,270	3,632,000
Blowdown Discharge Pipe 36" Paralined Steel - Install	1,600	LF	2,000	3,200,000
Mixing Station				
Makeup Water 36" Paralined Steel - Vendor	1,500	LF	2,270	3,405,000
Makeup Water 36" Paralined Steel - Install	1,500	LF	2,000	3,000,000
SCW/CCW Paralined Steel - Vendor	1,500	LF	2,270	3,405,000
SCW/CCW Paralined Steel - Install	1,500	LF	2,000	3,000,000
Tie-Ins	1	Lot	1,000,000	1,000,000
Mixing Skid w/ Tanks Pumps, etc.	1	Ea	3,500,000	3,500,000
Temperature Control System	1	Ea	1,500,000	1,500,000
Power	1	Allow	1,800,000	1,800,000
Diffuser System				
Flanged FRP Pipe on Land	1,000	LF	1,000	1,000,000
Flanged FRP Pipe in Water	1,400	LF	2,000	2,800,000
Floating Work Platforms	3	Mo	10,000	30,000
Anchors to Ocean Floor				
Divers 12 FTEs	36	Mo	110,000	3,960,000
5 CY Conc. Slurry every 50 LF	24	Ea	150,000	3,600,000
Sales Tax and Freight on Equipment	11%		7,037,000	774,070
(7.25% Tax & 3.5% Allowance for Freight = 11%)				
Total: Blowdown, Mixing Station and Diffuser				39,606,070
			<u>Say</u>	**<u>39,600,000</u>**

Appendix A-11 Project Cost Estimate

PG&E Diablo Canyon Power Plant

Project :	Enercon Cooling Tower Feasibility Study DCPP Common Facilities Cost Estimate			
Description	**Quantity**	**Unit**	**Unit Cost**	**Extension**
Plant Shutdown and Start-Up				
Typical expense cost of a 1 unit shutdown = $50MM	2	Units	25,000,000	50,000,000

Plant Shutdown and Start-Up functions will be performed during Cooling Tower construction period.
Work such as routine maintenance, preservation of safe conditions, and maintenance of mechanical equipment will be performed by existing staff, therefore there will be no savings in personnel during shutdown period.

Total: Plant Shutdown and Start-Up	50,000,000
Say	**50,000,000**

Based on 50% expense actuals from 2R14 refueling outage. Good representation of bare maintenance costs as the majority of plant recourses were dedicated to capital projects.

PG&E Diablo Canyon Power Plant

Project : Enercon Cooling Tower Feasibility Study
DCPP Common Facilities
Cost Estimate

Description	Quantity	Unit	Unit Cost	Extension
Site Infrastructure (Water/Storm/Power/Tel-Data/etc.)				
Trenching and Backfill	1	Allow	5,000,000	5,000,000
Electrical	1	Allow	10,000,000	10,000,000
Fiber Optic	1	Allow	10,000,000	10,000,000
Mechanical				
Fire Protection Loop	1	Allow	5,000,000	5,000,000
Mechanical Pressurized Systems	1	Allow	3,000,000	3,000,000
Mechanical Drainage Systems	1	Allow	5,000,000	5,000,000
Total: Site Infrastructure (Water/Storm/Power/Tel-Data/etc.)				38,000,000
			Say	**38,000,000**

Based on upgrade of existing systems as well as new distribution based on the re-alignment of plant facilities and personnel.

Appendix A-10
DCPP Cooling Tower Feasibility Study
Fuel Consumption Summary

Hauling of Excavations, Backfill, Concrete		
Excavation Removed from Site	2,010,800	Cubic Yards (CY)
Backfill Imported to Site	300,000	CY
Concrete - Material to Site	200,000	CY
Total CY	2,510,800	CY
Truckloads of Material (10 CY/truck)	251,080	Trucks (Round Trips)
Total Miles (70 Miles per Round Trip)	17,575,600	Miles Driven
Diesel Fuel (@ 6 MPG)***	2,929,267	Gallons Fuel
Material / Equipment Deliveries		
Cooling Tower	1,440	Deliveries
Mechanical Equipment	400	Deliveries
Electrical Equipment	150	Deliveries
Total Round Trips	1,990	Round Trips
Total Miles (RTs from LA x 400 Miles)	796,000	Miles
Diesel Fuel (@ 6 MPG)***	132,667	Gallons Fuel
Site Equipment Fuel/Day		
Including Excavating Equipment, Concrete trucks (To and From Batch Plant), Cranes, Pick-Ups, Other equipment		
Gallons of Diesel Fuel per Day - 1 Year	1,000	Gallons/Day for 1 Yr
Gallons of Diesel Fuel per Day - 2 Years	500.00	Gallons/Day for 2 Yrs
Total Gallons of Diesel Fuel	730,000	Gallons Fuel Total
Buses for Craft Workers*		
1 Year /1500 Craft / 50 Craft per Bus / 30 RTs per day	9,360.00	Bus Trips
1.5 Years / 3000 Craft / 50 Craft per Bus / 60 RTs per day	28,080.00	Bus Trips
9 Months /1000 Craft / 50 Craft per Bus / 20 RTs per day	4,680.00	Bus Trips
25% Return Trips - Buses not full	10,530.00	Bus Trips
Total Bus Trips	52,650.00	Total Bus Trips
AVG. 120 Miles Per Trip (In full, out empty, in empty, out full - all buses park offsite)	6,318,000.00	Total Miles
Diesel Fuel (@ 10 MPG)***	631,800	Gallons Fuel
Total		
Total Miles (Trucks plus Buses)	24,689,600	Miles Trucks plus Buses
Gallons Fuel - Trucks plus Buses plus Site Equipment	4,423,733	Gallons Fuel

* Number of bus trips based on the Replacement Steam Generator Project experience

** Number of cooling tower deliveries based on input from Marley (18 truck loads/cell x 80 cells)

***The California Air Resource Board (CARB) estimates a statewide average of 5.6 miles per gallon for class eight vehicles (GVWR 33,000 lb and up). PG&E estimates the fuel consumption at 4.5 miles per gallon for their fleet of heavy line trucks. For conservatism this study assumes a truck MPG at 6 miles per gallon and bus MPG at 10 miles per gallon.

Appendix A-9
DCPP Cooling Tower Study
Tray Conduit Estimates (part 2 of 2)

Function	Cable Type	Voltage	Cables	OD(in)	Area (in^2)	Total Area	Raceway Type	Allowance	Size rqrd(in)	Tray Size	length(ft) each run	actual percent fill	Total Length
Fan Power	1-3/C #6 Shielded	4160	20	1.34	-	-	Tray	eq dia spacing	53.6	2 - 36" tray	1090	-	1090
Fan Power	1-3/C #6 Shielded	4160	20	1.34	-	-	Tray	eq dia spacing	53.6	2 - 36" tray	1820	-	1820
Fan Power	1-3/C #6 Shielded	4160	40	1.34	1.4103	-	Conduit	53% fill	Use Table	40 - 2" RMC	175	41.38%	7000
Fan Control	1-12/C # 12	600	40	0.76	0.4536	-	Conduit	53% fill	Use Table	40 - 1" RMC	175	51.14%	7000
Fan Control	1-12/C # 12	600	40	0.76	0.4536	36.292	Tray	50% fill	~18" width	1 - 24" 4" deep cable tray	1820	37.80%	1820
MOV Control	1-12/C # 12	600	40	0.76	0.4536								
MOV Control	1-12/C # 12	600	40	0.76	0.4536	-	Conduit	53% fill	Use Table	40 - 1" RMC	175	51.14%	7000
MOV Power	1-3/C #6	600	40	0.72	0.4072	-	Conduit	53% fill	Use Table	40 - 1" RMC	175	45.90%	7000
MOV Power	1-3/C #6	600	40	0.72	0.4072	17.949	Tray	Use Table	< =18" width	1 - 24" 4" deep	1820	18.70%	1820
Lighting	1-3/C #12	480	12	0.42	0.1385								
Lighting	1-3/C #12	480	12	0.42	0.1385		Conduit	53% fill	Use Table	11 - 3/4" RMC	175	25.24%	2100
Instrument	1-4/C #16	600	40	0.36	0.1018		Conduit	53% fill	Use Table	40 - 3/4" RMC	175	18.54%	7000
Instrument	1-4/C #16	600	40	0.36	0.1018	5.5029	Tray	50% fill	any width	1 - 24" 4" deep	1820	5.73%	1820
GAI-Tronics	3/C#14,3/C#18	600	4	0.675	0.3578								
GAI-Tronics	3/C#14,3/C#18	600	4	0.675	0.3578	-	Conduit	53% fill	Use Table	4 - 1" RMC	175	40.34%	700

CABLES

Type	Voltage	Length
1-3/C #6 Shielded	5000	91200
1-12/C # 12	600	182400
1-3/C #6	600	91200
1-4/C #16	600	91200
1-3/C #12	600	27360
3/C#14,3/C#18	600	9120

Type	Size	Length	Total	Type	Size	Length	Total
Tray	36"	5820	11640	Conduit	2" RSG	7000	14000
Tray	24"	5460	10920	Conduit	1"RSG	21700	43400
				Conduit	3/4" RSG	9100	18200

Item Description	Size	Power 5Kv Cable, MV-105	Power Cable length	Fan Control Cable	Fan Control Cable Length	Motor Operated Valve 480 V Power Cable	MOV Power Cable Length	MOV Control Cable	MOV Control Cable Length	Instr. Cable	Instr. Cable Length	Lighting Power Cable	Lighting Power Cable Length	GAI-Tronics Comm. Cable	GAI-Tronics Comm. Cable Length
Cooling Twr U1 Fan 1	300 hp	1-3/C #6 Shielded	460.00	1-12/C # 12	460.00	1-3/C #6	460.00	1-12/C # 12	460.00	1-4/C #16	460.00	1-3/C #12	460.00	3/C#14,3/C#18	460.00
Cooling Twr U1 Fan 2	300 hp	1-3/C #6 Shielded	530.00	1-12/C # 12	530.00	1-3/C #6	530.00	1-12/C # 12	530.00	1-4/C #16	530.00				
Cooling Twr U1 Fan 3	300 hp	1-3/C #6 Shielded	600.00	1-12/C # 12	600.00	1-3/C #6	600.00	1-12/C # 12	600.00	1-4/C #16	600.00				
Cooling Twr U1 Fan4	300 hp	1-3/C #6 Shielded	670.00	1-12/C # 12	670.00	1-3/C #6	670.00	1-12/C # 12	670.00	1-4/C #16	670.00				
Cooling Twr U1 Fan 5	300 hp	1-3/C #6 Shielded	740.00	1-12/C # 12	740.00	1-3/C #6	740.00	1-12/C # 12	740.00	1-4/C #16	740.00	1-3/C #12	775.00		
Cooling Twr U1 Fan 6	300 hp	1-3/C #6 Shielded	810.00	1-12/C # 12	810.00	1-3/C #6	810.00	1-12/C # 12	810.00	1-4/C #16	810.00				
Cooling Twr U1 Fan 7	300 hp	1-3/C #6 Shielded	880.00	1-12/C # 12	880.00	1-3/C #6	880.00	1-12/C # 12	880.00	1-4/C #16	880.00				
Cooling Twr U1 Fan 8	300 hp	1-3/C #6 Shielded	950.00	1-12/C # 12	950.00	1-3/C #6	950.00	1-12/C # 12	950.00	1-4/C #16	950.00				
Cooling Twr U1 Fan 9	300 hp	1-3/C #6 Shielded	1,020.00	1-12/C # 12	1,020.00	1-3/C #6	1,020.00	1-12/C # 12	1,020.00	1-4/C #16	1,020.00				
Cooling Twr U1 Fan 10	300 hp	1-3/C #6 Shielded	1,090.00	1-12/C # 12	1,090.00	1-3/C #6	1,090.00	1-12/C # 12	1,090.00	1-4/C #16	1,090.00	1-3/C #12	1,090.00		
Cooling Twr U1 Fan 11	300 hp	1-3/C #6 Shielded	460.00	1-12/C # 12	460.00	1-3/C #6	460.00	1-12/C # 12	460.00	1-4/C #16	460.00	1-3/C #12	460.00		
Cooling Twr U1 Fan 12	300 hp	1-3/C #6 Shielded	530.00	1-12/C # 12	530.00	1-3/C #6	530.00	1-12/C # 12	530.00	1-4/C #16	530.00				
Cooling Twr U1 Fan 13	300 hp	1-3/C #6 Shielded	600.00	1-12/C # 12	600.00	1-3/C #6	600.00	1-12/C # 12	600.00	1-4/C #16	600.00				
Cooling Twr U1 Fan 14	300 hp	1-3/C #6 Shielded	670.00	1-12/C # 12	670.00	1-3/C #6	670.00	1-12/C # 12	670.00	1-4/C #16	670.00				
Cooling Twr U1 Fan 15	300 hp	1-3/C #6 Shielded	740.00	1-12/C # 12	740.00	1-3/C #6	740.00	1-12/C # 12	740.00	1-4/C #16	740.00	1-3/C #12	775.00		
Cooling Twr U1 Fan 16	300 hp	1-3/C #6 Shielded	810.00	1-12/C # 12	810.00	1-3/C #6	810.00	1-12/C # 12	810.00	1-4/C #16	810.00				
Cooling Twr U1 Fan 17	300 hp	1-3/C #6 Shielded	880.00	1-12/C # 12	880.00	1-3/C #6	880.00	1-12/C # 12	880.00	1-4/C #16	880.00				
Cooling Twr U1 Fan 18	300 hp	1-3/C #6 Shielded	950.00	1-12/C # 12	950.00	1-3/C #6	950.00	1-12/C # 12	950.00	1-4/C #16	950.00				
Cooling Twr U1 Fan 19	300 hp	1-3/C #6 Shielded	1,020.00	1-12/C # 12	1,020.00	1-3/C #6	1,020.00	1-12/C # 12	1,020.00	1-4/C #16	1,020.00				
Cooling Twr U1 Fan 20	300 hp	1-3/C #6 Shielded	1,090.00	1-12/C # 12	1,090.00	1-3/C #6	1,090.00	1-12/C # 12	1,090.00	1-4/C #16	1,090.00	1-3/C #12	1,090.00	3/C#14,3/C#18	1,090.00
Cooling Twr U1 Fan 21	300 hp	1-3/C #6 Shielded	1,190.00	1-12/C # 12	1,190.00	1-3/C #6	1,190.00	1-12/C # 12	1,190.00	1-4/C #16	1,190.00	1-3/C #12	1,190.00	3/C#14,3/C#18	1,190.00
Cooling Twr U1 Fan 22	300 hp	1-3/C #6 Shielded	1,260.00	1-12/C # 12	1,260.00	1-3/C #6	1,260.00	1-12/C # 12	1,260.00	1-4/C #16	1,260.00				
Cooling Twr U1 Fan 23	300 hp	1-3/C #6 Shielded	1,330.00	1-12/C # 12	1,330.00	1-3/C #6	1,330.00	1-12/C # 12	1,330.00	1-4/C #16	1,330.00				
Cooling Twr U1 Fan24	300 hp	1-3/C #6 Shielded	1,400.00	1-12/C # 12	1,400.00	1-3/C #6	1,400.00	1-12/C # 12	1,400.00	1-4/C #16	1,400.00				
Cooling Twr U1 Fan 25	300 hp	1-3/C #6 Shielded	1,470.00	1-12/C # 12	1,470.00	1-3/C #6	1,470.00	1-12/C # 12	1,470.00	1-4/C #16	1,470.00	1-3/C #12	1,505.00		
Cooling Twr U1 Fan 26	300 hp	1-3/C #6 Shielded	1,540.00	1-12/C # 12	1,540.00	1-3/C #6	1,540.00	1-12/C # 12	1,540.00	1-4/C #16	1,540.00				
Cooling Twr U1 Fan 27	300 hp	1-3/C #6 Shielded	1,610.00	1-12/C # 12	1,610.00	1-3/C #6	1,610.00	1-12/C # 12	1,610.00	1-4/C #16	1,610.00				
Cooling Twr U1 Fan 28	300 hp	1-3/C #6 Shielded	1,680.00	1-12/C # 12	1,680.00	1-3/C #6	1,680.00	1-12/C # 12	1,680.00	1-4/C #16	1,680.00				
Cooling Twr U1 Fan 29	300 hp	1-3/C #6 Shielded	1,750.00	1-12/C # 12	1,750.00	1-3/C #6	1,750.00	1-12/C # 12	1,750.00	1-4/C #16	1,750.00				
Cooling Twr U1 Fan 30	300 hp	1-3/C #6 Shielded	1,820.00	1-12/C # 12	1,820.00	1-3/C #6	1,820.00	1-12/C # 12	1,820.00	1-4/C #16	1,820.00	1-3/C #12	1,820.00		
Cooling Twr U1 Fan 31	300 hp	1-3/C #6 Shielded	1,190.00	1-12/C # 12	1,190.00	1-3/C #6	1,190.00	1-12/C # 12	1,190.00	1-4/C #16	1,190.00	1-3/C #12	1,190.00		
Cooling Twr U1 Fan 32	300 hp	1-3/C #6 Shielded	1,260.00	1-12/C # 12	1,260.00	1-3/C #6	1,260.00	1-12/C # 12	1,260.00	1-4/C #16	1,260.00				
Cooling Twr U1 Fan 33	300 hp	1-3/C #6 Shielded	1,330.00	1-12/C # 12	1,330.00	1-3/C #6	1,330.00	1-12/C # 12	1,330.00	1-4/C #16	1,330.00				
Cooling Twr U1 Fan 34	300 hp	1-3/C #6 Shielded	1,400.00	1-12/C # 12	1,400.00	1-3/C #6	1,400.00	1-12/C # 12	1,400.00	1-4/C #16	1,400.00				

Appendix A-9
DCPP Cooling Tower Study
Cable Estimate (part 1 of 2)

Cooling Twr U1 Fan 35	300 hp	1-3/C #6 Shielded	1,470.00	1-12/C # 12	1,470.00	1-3/C #6	1,470.00	1-12/C # 12	1,470.00	1-4/C #16	1,470.00	1-3/C #12	1,505.00		
Cooling Twr U1 Fan 36	300 hp	1-3/C #6 Shielded	1,540.00	1-12/C # 12	1,540.00	1-3/C #6	1,540.00	1-12/C # 12	1,540.00	1-4/C #16	1,540.00				
Cooling Twr U1 Fan 37	300 hp	1-3/C #6 Shielded	1,610.00	1-12/C # 12	1,610.00	1-3/C #6	1,610.00	1-12/C # 12	1,610.00	1-4/C #16	1,610.00				
Cooling Twr U1 Fan 38	300 hp	1-3/C #6 Shielded	1,680.00	1-12/C # 12	1,680.00	1-3/C #6	1,680.00	1-12/C # 12	1,680.00	1-4/C #16	1,680.00				
Cooling Twr U1 Fan 39	300 hp	1-3/C #6 Shielded	1,750.00	1-12/C # 12	1,750.00	1-3/C #6	1,750.00	1-12/C # 12	1,750.00	1-4/C #16	1,750.00				
Cooling Twr U1 Fan 40	300 hp	1-3/C #6 Shielded	1,820.00	1-12/C # 12	1,820.00	1-3/C #6	1,820.00	1-12/C # 12	1,820.00	1-4/C #16	1,820.00	1-3/C #12	1,820.00	3/C#14,3/C#18	1,820.00
Cooling Twr U2 Fan 1	300 hp	1-3/C #6 Shielded	460.00	1-12/C # 12	460.00	1-3/C #6	460.00	1-12/C # 12	460.00	1-4/C #16	460.00	1-3/C #12	460.00	3/C#14,3/C#18	460.00
Cooling Twr U2 Fan 2	300 hp	1-3/C #6 Shielded	530.00	1-12/C # 12	530.00	1-3/C #6	530.00	1-12/C # 12	530.00	1-4/C #16	530.00				
Cooling Twr U2 Fan 3	300 hp	1-3/C #6 Shielded	600.00	1-12/C # 12	600.00	1-3/C #6	600.00	1-12/C # 12	600.00	1-4/C #16	600.00				
Cooling Twr U2 Fan4	300 hp	1-3/C #6 Shielded	670.00	1-12/C # 12	670.00	1-3/C #6	670.00	1-12/C # 12	670.00	1-4/C #16	670.00				
Cooling Twr U2 Fan 5	300 hp	1-3/C #6 Shielded	740.00	1-12/C # 12	740.00	1-3/C #6	740.00	1-12/C # 12	740.00	1-4/C #16	740.00	1-3/C #12	775.00		
Cooling Twr U2 Fan 6	300 hp	1-3/C #6 Shielded	810.00	1-12/C # 12	810.00	1-3/C #6	810.00	1-12/C # 12	810.00	1-4/C #16	810.00				
Cooling Twr U2 Fan 7	300 hp	1-3/C #6 Shielded	880.00	1-12/C # 12	880.00	1-3/C #6	880.00	1-12/C # 12	880.00	1-4/C #16	880.00				
Cooling Twr U2 Fan 8	300 hp	1-3/C #6 Shielded	950.00	1-12/C # 12	950.00	1-3/C #6	950.00	1-12/C # 12	950.00	1-4/C #16	950.00				
Cooling Twr U2 Fan 9	300 hp	1-3/C #6 Shielded	1,020.00	1-12/C # 12	1,020.00	1-3/C #6	1,020.00	1-12/C # 12	1,020.00	1-4/C #16	1,020.00				
Cooling Twr U2 Fan 10	300 hp	1-3/C #6 Shielded	1,090.00	1-12/C # 12	1,090.00	1-3/C #6	1,090.00	1-12/C # 12	1,090.00	1-4/C #16	1,090.00	1-3/C #12	1,090.00		
Cooling Twr U2 Fan 11	300 hp	1-3/C #6 Shielded	460.00	1-12/C # 12	460.00	1-3/C #6	460.00	1-12/C # 12	460.00	1-4/C #16	460.00	1-3/C #12	460.00		
Cooling Twr U2 Fan 12	300 hp	1-3/C #6 Shielded	530.00	1-12/C # 12	530.00	1-3/C #6	530.00	1-12/C # 12	530.00	1-4/C #16	530.00				
Cooling Twr U2 Fan 13	300 hp	1-3/C #6 Shielded	600.00	1-12/C # 12	600.00	1-3/C #6	600.00	1-12/C # 12	600.00	1-4/C #16	600.00				
Cooling Twr U2 Fan 14	300 hp	1-3/C #6 Shielded	670.00	1-12/C # 12	670.00	1-3/C #6	670.00	1-12/C # 12	670.00	1-4/C #16	670.00				
Cooling Twr U2 Fan 15	300 hp	1-3/C #6 Shielded	740.00	1-12/C # 12	740.00	1-3/C #6	740.00	1-12/C # 12	740.00	1-4/C #16	740.00	1-3/C #12	775.00		
Cooling Twr U2 Fan 16	300 hp	1-3/C #6 Shielded	810.00	1-12/C # 12	810.00	1-3/C #6	810.00	1-12/C # 12	810.00	1-4/C #16	810.00				
Cooling Twr U2 Fan 17	300 hp	1-3/C #6 Shielded	880.00	1-12/C # 12	880.00	1-3/C #6	880.00	1-12/C # 12	880.00	1-4/C #16	880.00				
Cooling Twr U2 Fan 18	300 hp	1-3/C #6 Shielded	950.00	1-12/C # 12	950.00	1-3/C #6	950.00	1-12/C # 12	950.00	1-4/C #16	950.00				
Cooling Twr U2 Fan 19	300 hp	1-3/C #6 Shielded	1,020.00	1-12/C # 12	1,020.00	1-3/C #6	1,020.00	1-12/C # 12	1,020.00	1-4/C #16	1,020.00				
Cooling Twr U2 Fan 20	300 hp	1-3/C #6 Shielded	1,090.00	1-12/C # 12	1,090.00	1-3/C #6	1,090.00	1-12/C # 12	1,090.00	1-4/C #16	1,090.00	1-3/C #12	1,090.00	3/C#14,3/C#18	1,090.00
Cooling Twr U2 Fan 21	300 hp	1-3/C #6 Shielded	1,190.00	1-12/C # 12	1,190.00	1-3/C #6	1,190.00	1-12/C # 12	1,190.00	1-4/C #16	1,190.00	1-3/C #12	1,190.00	3/C#14,3/C#18	1,190.00
Cooling Twr U2 Fan 22	300 hp	1-3/C #6 Shielded	1,260.00	1-12/C # 12	1,260.00	1-3/C #6	1,260.00	1-12/C # 12	1,260.00	1-4/C #16	1,260.00				
Cooling Twr U2 Fan 23	300 hp	1-3/C #6 Shielded	1,330.00	1-12/C # 12	1,330.00	1-3/C #6	1,330.00	1-12/C # 12	1,330.00	1-4/C #16	1,330.00				
Cooling Twr U2 Fan24	300 hp	1-3/C #6 Shielded	1,400.00	1-12/C # 12	1,400.00	1-3/C #6	1,400.00	1-12/C # 12	1,400.00	1-4/C #16	1,400.00				
Cooling Twr U2 Fan 25	300 hp	1-3/C #6 Shielded	1,470.00	1-12/C # 12	1,470.00	1-3/C #6	1,470.00	1-12/C # 12	1,470.00	1-4/C #16	1,470.00	1-3/C #12	1,505.00		
Cooling Twr U2 Fan 26	300 hp	1-3/C #6 Shielded	1,540.00	1-12/C # 12	1,540.00	1-3/C #6	1,540.00	1-12/C # 12	1,540.00	1-4/C #16	1,540.00				
Cooling Twr U2 Fan 27	300 hp	1-3/C #6 Shielded	1,610.00	1-12/C # 12	1,610.00	1-3/C #6	1,610.00	1-12/C # 12	1,610.00	1-4/C #16	1,610.00				
Cooling Twr U2 Fan 28	300 hp	1-3/C #6 Shielded	1,680.00	1-12/C # 12	1,680.00	1-3/C #6	1,680.00	1-12/C # 12	1,680.00	1-4/C #16	1,680.00				
Cooling Twr U2 Fan 29	300 hp	1-3/C #6 Shielded	1,750.00	1-12/C # 12	1,750.00	1-3/C #6	1,750.00	1-12/C # 12	1,750.00	1-4/C #16	1,750.00				
Cooling Twr U2 Fan 30	300 hp	1-3/C #6 Shielded	1,820.00	1-12/C # 12	1,820.00	1-3/C #6	1,820.00	1-12/C # 12	1,820.00	1-4/C #16	1,820.00	1-3/C #12	1,820.00		
Cooling Twr U2 Fan 31	300 hp	1-3/C #6 Shielded	1,190.00	1-12/C # 12	1,190.00	1-3/C #6	1,190.00	1-12/C # 12	1,190.00	1-4/C #16	1,190.00	1-3/C #12	1,190.00		

Cooling Twr U2 Fan 32	300 hp	1-3/C #6 Shielded	1,260.00	1-12/C # 12	1,260.00	1-3/C #6	1,260.00	1-12/C # 12	1,260.00	1-4/C #16	1,260.00				
Cooling Twr U2 Fan 33	300 hp	1-3/C #6 Shielded	1,330.00	1-12/C # 12	1,330.00	1-3/C #6	1,330.00	1-12/C # 12	1,330.00	1-4/C #16	1,330.00				
Cooling Twr U2 Fan 34	300 hp	1-3/C #6 Shielded	1,400.00	1-12/C # 12	1,400.00	1-3/C #6	1,400.00	1-12/C # 12	1,400.00	1-4/C #16	1,400.00				
Cooling Twr U2 Fan 35	300 hp	1-3/C #6 Shielded	1,470.00	1-12/C # 12	1,470.00	1-3/C #6	1,470.00	1-12/C # 12	1,470.00	1-4/C #16	1,470.00	1-3/C #12	1,505.00		
Cooling Twr U2 Fan 36	300 hp	1-3/C #6 Shielded	1,540.00	1-12/C # 12	1,540.00	1-3/C #6	1,540.00	1-12/C # 12	1,540.00	1-4/C #16	1,540.00				
Cooling Twr U2 Fan 37	300 hp	1-3/C #6 Shielded	1,610.00	1-12/C # 12	1,610.00	1-3/C #6	1,610.00	1-12/C # 12	1,610.00	1-4/C #16	1,610.00				
Cooling Twr U2 Fan 38	300 hp	1-3/C #6 Shielded	1,680.00	1-12/C # 12	1,680.00	1-3/C #6	1,680.00	1-12/C # 12	1,680.00	1-4/C #16	1,680.00				
Cooling Twr U2 Fan 39	300 hp	1-3/C #6 Shielded	1,750.00	1-12/C # 12	1,750.00	1-3/C #6	1,750.00	1-12/C # 12	1,750.00	1-4/C #16	1,750.00				
Cooling Twr U2 Fan 40	300 hp	1-3/C #6 Shielded	1,820.00	1-12/C # 12	1,820.00	1-3/C #6	1,820.00	1-12/C # 12	1,820.00	1-4/C #16	1,820.00	1-3/C #12	1,820.00	3/C#14,3/C#18	1,820.00
Cable SubTotals			91,200.00		91,200.00		91,200.00		91,200.00		91,200.00		27,360.00		9,120.00

Appendix 13

Power Plant Systems Effluent Concerns

The following considers existing plant effluent management concerns that would occur due to the significant reduction in power plant once-through cooling system throughput. The issues require further assessment to determine potential impacts to the scope of a proposed retrofit, or the additional operation and management burdens that would be realized post retrofit.

1) Potential Residual Copper in Effluent Streams

With the proposed elimination of the large circulating water dilution flow, concerns would exist that effluent streams may contain levels exceeding 1 ppm of toxic copper ion. At DCPP, the Service Cooling Water heat exchangers, the Condensate Coolers and the Component Cooling Water (CCW) heat exchangers have 90-10 copper nickel tubing. Only one of each pair of these heat exchangers is normally in operation with the other on standby, filled with stagnant seawater. The concern is violating Cu discharge concentration limits when bringing the standby heat exchangers on-line with the proposed elimination of the large circulating water dilution flow. The residual copper concentration in these heat exchangers while operating (with saltwater flowing) would be extremely low, on the order of ppb levels. However, prediction of the Cu concentration level with stagnant saltwater is very difficult without detailed information and study. In the idle heat exchanger, the dissolved oxygen would be consumed. Then, in an anaerobic condition, certain bacteria could grow, and the Cu concentration would increase, being locally higher near where the bacteria colonies would thrive. Testing with tube samples and saline solutions would be necessary to predict copper concentration levels inside idle heat exchangers exposed to stagnant seawater. Depending on the results of these studies, corrective actions to prevent exceeding the Cu concentration limit in the effluent stream could be complex and expensive, exceptionally so for the nuclear safety related CCW System. Necessity for replacement of heat exchanger tube bundles with non copper containing alloy tubes for any of the systems would result in substantial additional project costs.

2) Liquid Radwaste Effluents Management

Processed water from Liquid Radwaste (LRW) is presently batch released at 60 gpm and is diluted by the large circulating water flow. Due to the concentration limits of tritium and other isotopes, retrofitting with cooling towers would result in most of DCPP’s LRW streams being limited to a 10 gpm release rate limit. In order to empty tanks of 10,000 gallons, this would take 17 hours. For the 50,000 gallon capacity tanks that have pure water with some tritium, emptying the tanks would take up to four days. During outages, extra LRW water produced would present a management and scheduling challenge.

With a cooling tower retrofit, the reduced discharge rates to the ocean would significantly change the way LRW streams are managed and discharged. However with appropriate planning, effective implementation of reduced discharge rates during routine operations is potentially achievable. Availability of an additional wastewater holding tank onsite during outages might be required. Additional analysis is necessary to fully address retrofitting impacts to LRW management.

3) Seawater Reverse Osmosis System Effluents

The existing seawater reverse osmosis reject (2X normal seawater salinity at a maximum flow of 1000 gpm and an average flow of 240gpm) is directed to the suction forebay of the Unit 1 ASW screen wash pumps. In addition to high salinity, the effluent may contain residual water treatment chemicals and/or suspended solids from filter backwashing. Remaining seawater cooling flow projected for the ASW and SCW systems would be available to dilute the SWRO effluent. However, that flow would also be combined with several other existing plant waste streams prior to discharge to the ocean (Reference Other Plant System Effluents).

Adequate water quality at the point of outfall for the remaining once-through cooling system would need to be assured under all operating conditions. Therefore, the SWRO effluent would potentially need to be directed to the cooling tower blowdown diffuser array. Discharge via the ocean floor diffusion system would be the most prudent configuration to dispose of the relatively continuous and high concentration SWRO waste stream in the absence of main circulating water pump dilution flow. However this configuration, and potential effects on final discharge water quality, would require further evaluation.

4) Other Plant System Effluents

If the high saline wastewater from the facility's Seawater Reverse Osmosis Unit is directed to the cooling tower blowdown diffuser system, and facility sewage effluents treated to more conservative specifications, the proposed remaining plant once-through cooling flow of 43mgd (ASW and SCW systems) could be used to dilute most other remaining plant wastewater streams facilitating discharge to the Pacific Ocean.

Other major existing relatively continuous plant wastewater effluents include the Unit 1 and Unit 2 Steam Generator Blowdown (SGBD 160,000 gpd-average), the Turbine Building Sump System (TBS 44,000 gpd-average), Unit 1 and Unit 2 Condensate Regeneration System effluent (CDR 48,000 gpd-average), and the Makeup Water Treatment System effluent (MWTS 92,000 gpd-average). When mixed with estimated post retrofit once-through cooling system flow, collective potential contaminates in these waste streams (suspended solids, soluble salts and metals) may not result in challenges to State Ocean Plan requirements at plant outfall. Combined system effluents of 239 gpm (averaged) would represent only 1.3% of the total discharge flow. Actual individual system discharge rates can vary substantially however dependent on multiple operating factors. As these systems are in continuous use, routine discharge would be a necessity, and the large volumes involved would preclude other options than discharge to receiving waters. In the event any system could not be discharged in the modified plant configuration, upgrades to directly treat the effluent from that system would likely be required, and increase associated project scope and costs. Additional evaluation is required to fully explore this issue.

SGBD effluents are also routinely elevated in temperature, initially ranging from 120 to 190 °F. The need to dilute this wastewater stream thermally would provide another reason to maintain the discharge of once-through cooling flow separate from the cooling tower blowdown. In a combined discharge, the heat content of relatively high volumes of SGBD could further challenge plant thermal compliance during periods when the Pacific Ocean receiving waters are very cold, and/or when ambient wet-bulb temperatures are high (and cooling tower blowdown would already be projected to exceed thermal discharge limits).

Additional lower volume, and intermittent, discharges also occur from the power plant, and are currently diluted by the existing once-through system. These include chemically treated freshwater coolants within the closed cooling systems (SCW & CCW), water storage tank drain downs, condensate hot well reject during startup, the Waste Holding and Treatment (WHAT) system effluents, and several additional minor discharges. These periodic streams could likewise be combined with remaining once-through cooling flow with precautions to insure constituent limitations were not exceeded at final outfall. If this was determined to be problematic however (most likely for freshwater coolants), system effluents would need to be alternatively managed. This could entail draining systems to transportable tankers, and removing the industrial wastewater from the site for treatment and disposal at an appropriate facility. The requirement to do this would result in additional ongoing operational and maintenance costs, and increase truck traffic and associated transportation fuel combustion.