Pacific Gas and Electric Company

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DOCKET
06-AFC-7
DATE NOV 1 2006
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VIA OVERNIGHT MAIL

November 1, 2006

Mr. B.B. Blevins
Executive Director
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Dear Mr. Blevins:

Re: Supplement in Response to Data Adequacy Review of the Application for Certification, Humboldt Bay Repowering Project (06-AFC-07)

In accordance with the provisions of Title 20, California Code of Regulations, Pacific Gas and Electric Company (PG&E) hereby submits this document titled "Supplement in Response to Data Adequacy Review of the Application for Certification, Humboldt Bay Repowering Project (06-AFC-07)." The Humboldt Bay Repowering Project is a 163 megawatt, natural gas-fired power plant to be located at the existing Humboldt Bay Power Plant in Humboldt County, California.

As an officer of PG&E, I hereby attest, under penalty of perjury, that the contents of this application are truthful and accurate to the best of my knowledge.

Dated this 1st day of November, 2006.

Sincerely,

Roy M. Kuga
Vice President – Energy Supply

Supplement

In Response to Data Adequacy Review

of the

Application for Certification

for the

Humboldt Bay Repowering Project

Humboldt County, California

(06-AFC-07)

Submitted to the

California Energy Commission

Submitted by

Pacific Gas and Electric Company™

With Technical Assistance by

CH2MHILL

Sacramento, California

November 2006

Contents

Attachments

SECTION 1.0

Introduction

This supplement to Pacific Gas and Electric Company's (PG&E's) Application for Certification (AFC) for the Humboldt Bay Repowering Project (HBRP) (06-AFC-07), responds to comments that California Energy Commission (CEC) staff have made as a result of their data adequacy review of the AFC. The intention of this supplement is to provide all additional information necessary for the CEC staff to find that the AFC contains adequate data to begin a power plant site certification proceeding under Title 20, California Code of Regulations and the Warren-Alquist Energy Resources Conservation and Development Act.

The format for this supplement follows the order of the AFC and provides additional information and responses to CEC information requests on Transmission System Engineering (Section 5.0) and Socioeconomics (Section 8.10). Only sections for which CEC staff posed requests or questions related to data adequacy are addressed in this supplement. If the response calls for additional appended material, it is included at the end of each subsection. Appended material is identified by the prefix "DA" indicating an item submitted in response to a Data Adequacy comment, a number referring to the applicable AFC chapter, and a sequential identifying number. For example, the second attachment in response to a Transmission System Engineering comment would be Attachment DA5-2, because the AFC section describing electrical transmission is Section 5. Tables are also numbered in this way. Appended material is paginated separately from the remainder of the document.

Each subsection contains data adequacy questions or information requests, with numbers and summary titles and, in parentheses, the citation from Appendix B, Title 22, California Code of Regulations (Regulations Pertaining to the Rules of Practice and Procedure and Power Plant Site Certification) indicating a particular information requirement for the AFC. Each item follows with the CEC staff comment on data adequacy for the item, under the heading "Information required to make AFC conform with regulations" followed by PG&E's response to the information request.

SECTION 5.0

Transmission System Engineering

SECTION 5.0

Transmission System Engineering

1. One-Line Diagrams (Appendix B [i][2][B])

A discussion of the extent to which the proposed electric transmission facilities have been designed, planned, and routed to meet the transmission requirements created by additional generating facilities planned by the applicant or any other entity.

Information required to make AFC conform with regulations:

1. *Provide a complete electrical one-line diagram of the HBRP Plant substation (legible hard copies or electronic copies in a CD) showing all the equipment for generators' interconnection with the substation including any bus duct connectors, 15 kV switchgear, breakers and disconnect switches on the low voltage side and their ratings. Also provide in the diagram continuous ratings of breakers, buses and disconnect switches on the 60 kV and 115 kV sides.*

2. *Provide an engineering drawing of poles or structures of the proposed new 500- to 700-foot-long 115 kV and 60 kV overhead lines within the fence lines of HBRP Plant substation showing ground clearances, insulators and their configuration, and size of conductors. Also provide engineering drawings for terminations of the new lines with the existing 60 kV and 115 kV lines. Show routes of the new lines in a diagram.*

Response:

(1) Interconnection Equipment Ratings—Appendix 5A of the AFC provides the electrical one-line diagram. Electronic copies were included on the CD-ROM copies of the AFC that were filed with the CEC. Provided under separate cover are two copies of the one-line diagram, plotted in larger size for better legibility. The tables that follow provide more detailed information regarding the medium-voltage (MV) circuit breakers, bus duct connectors, and horizontal medium-voltage (HMV) circuit breakers. Please note that these ratings are typical, representing PG&E's normal practice, and may be revised during detailed design engineering.

MV Circuit Breakers—Table DA5-1 provides MV circuit breaker specifications.

TABLE DA5-1
MV Circuit Breaker Specifications

MV Breaker	MV Breaker Designation	Nominal Voltage	Current Rating	Short Circuit Capacity
Generator Breaker 1	BAE011	13.8 kV	1,200 A	40 kA
Generator Breaker 2	BAE021	13.8 kV	1,200 A	40 kA
Generator Breaker 3	BAE031	13.8 kV	1,200 A	40 kA
Generator Breaker 4	BAE041	13.8 kV	1,200 A	40 kA
Generator Breaker 5	BAE051	13.8 kV	1,200 A	40 kA
Generator Breaker 6	BAE061	13.8 kV	1,200 A	40 kA

TABLE DA5-1
MV Circuit Breaker Specifications

MV Breaker	MV Breaker Designation	Nominal Voltage	Current Rating	Short Circuit Capacity
Generator Breaker 7	BAE071	13.8 kV	1,200 A	40 kA
Generator Breaker 8	BAE081	13.8 kV	1,200 A	40 kA
Generator Breaker 9	BAE091	13.8 kV	1,200 A	40 kA
Generator Breaker 10	BAE101	13.8 kV	1,200 A	40 kA
Outgoing Circuit Breaker 1	BAO901	13.8 kV	4,000 A	40 kA
Outgoing Circuit Breaker 2	BAO902	13.8 kV	4,000 A	40 kA
Outgoing Circuit Breaker 3	BAO903	13.8 kV	4,000 A	40 kA
Tie Breaker 1	BAB901	13.8 kV	4,000 A	40 kA
Tie Breaker 2	BAB902	13.8 kV	4,000 A	40 kA
Tie Breaker 3	BAB903	13.8 kV	4,000 A	40 kA
Station Service Feeder Breaker 1	BAA901	13.8 kV	1,200 A	40 kA
Station Service Feeder Breaker 2	BAA902	13.8 kV	1,200 A	40 kA
Station Service Feeder Breaker 3	BAA903	13.8 kV	1,200 A	40 kA

MV Duct Bus Cables – The HBRP will use MV power cables to connect the individual generators to the medium-voltage switchgear, as well as to feed the generator step-up transformers and the station service load (Table DA5-2). These are not currently shown on the one-line diagram. Selected cable sizes are estimates and may be revised at the point of detailed design engineering. Cable sizes consider a generator-rated current at power factor 0.8, aboveground cabling, and added design margin of 10 percent.

TABLE DA5-2
MV Duct Bus Cable Run Specifications

From	To	Type	Size	Cable-Run Net Current Capacity
Generator 1 (BAG011)	Generator Breaker (BAE011)	MV-90, 15 kV	2 x 500MCM Single conductor/phase	1,160 A
Generator 2 (BAG021)	Generator Breaker (BAE021)	MV-90, 15 kV	2 x 500MCM Single conductor/phase	1,160 A
Generator 3 (BAG031)	Generator Breaker (BAE031)	MV-90, 15 kV	2 x 500MCM Single conductor/phase	1,160 A
Generator 4 (BAG041)	Generator Breaker (BAE041)	MV-90, 15 kV	2 x 500MCM Single conductor/phase	1,160 A
Generator 5 (BAG051)	Generator Breaker (BAE051)	MV-90, 15 kV	2 x 500MCM Single conductor/phase	1,160 A
Generator 6 (BAG061)	Generator Breaker (BAE061)	MV-90, 15 kV	2 x 500MCM Single conductor/phase	1,160 A

TABLE DA5-2
MV Duct Bus Cable Run Specifications

From	To	Type	Size	Cable-Run Net Current Capacity
Generator 7 (BAG071)	Generator Breaker (BAE071)	MV-90, 15 kV	2 x 500MCM Single conductor/phase	1,160 A
Generator 8 (BAG081)	Generator Breaker (BAE081)	MV-90, 15 kV	2 x 500MCM Single conductor/phase	1,160 A
Generator 9 (BAG091)	Generator Breaker (BAE091)	MV-90, 15 kV	2 x 500MCM Single conductor/phase	1,160 A
Generator 10 (BAG101)	Generator Breaker (BAE0101)	MV-90, 15 kV	2 x 500MCM Single conductor/phase	1,160 A
Outgoing Breaker (BAO901)	Generator Step Up Transformer 1 (AET901)	MV-90, 15 kV	4 x 750MCM Single conductor/phase	2,920 A
Outgoing Breaker (BAO902)	Generator Step Up Transformer 2 (AET902)	MV-90, 15 kV	5 x 750MCM Single conductor/phase	3,650 A
Outgoing Breaker (BAO903)	Generator Step Up Transformer 3 (AET903)	MV-90, 15 kV	4 x 750MCM Single conductor/phase	2,920 A
Station Service Feeder Breaker (BAA901)	Station Transformer 1 (BFB901)	MV-90, 15 kV	1 x AWG #2 Single conductor/phase	170 A
Station Service Feeder Breaker (BAA901)	Station Transformer 2 (BFB902)	MV-90, 15 kV	1 x AWG #2 Single conductor/phase	170 A
Station Service Feeder Breaker (BAA901)	Station Transformer 3 (BFB903)	MV-90, 15 kV	1 x AWG #2 Single conductor/phase	170 A

HMV Circuit Runs—The rating of all HMV switchgear busses is 4,000 A. Table DA5-3 provides HMV circuit run specifications.

TABLE DA5-3
HMV Circuit Run Specifications

HV Breaker	HV Breaker Designation	Nominal Voltage	Current Rating	Short Circuit Capacity
Gen Tie No. 1	CB72	60 kV	1,200 A	40 kA
Gen Tie No. 2	CB82	60 kV	1,200 A	40 kA
Gen Tie No. 3	CB132	115 kV	2,000 A	40 KA

HV Disconnect Switches and Buses—The HBRP will use 60 kV, 1,200 A and 115 kV, 2,000 A air switches (breaker disconnects and breaker bypass if in the final design), and 3,000 A buses.

(2) **Transmission Connections** — Although the AFC specified that the lengths of the 60 kV and 115 kV transmission lines were less than 500 feet and 700 feet, respectively, the actual distances are significantly shorter. There are two 60 kV connections from the HBRP switchyard to the Humboldt Bay Power Plant switchyard. Each of these connections extends from a generator step-up transformer at the HBRP switchyard to a takeoff structure within the HBRP switchyard, across the HBRP boundary fence and into the Humboldt Bay Power Plant switchyard, where it attaches to a tubular steel pole. The lengths of these two connections are 82 and 117 feet, respectively. A typical tubular steel pole is depicted in AFC Figure 5.2-3, and the takeoff structures and poles are shown in profile in the elevation drawings of Figures 2.3-3 and 2.3-4.

There is a single 115 kV connection from the HBRP switchyard to the existing 115 kV transmission line. This connection extends from the generator step-up transformer at the HBRP switchyard to a takeoff structure within the HBRP switchyard and from there to a tubular steel pole that is located within the HBRP fence line, a distance of 166 feet. The 115 kV line then crosses the HBRP fence line and extends for an additional 330 feet to connect with an existing 115 kV transmission tower located near the existing gas compressor.

The only new transmission poles are the three take-off structures (two 60 kV and one 115 kV) and the three tubular support towers (two 60 kV and one 115 kV) identified and depicted in the AFC.

2. Facility Description (Appendix B [b][2][C])

A detailed description of the design, construction, and operation of any electric transmission facilities, such as power lines, substations, switchyards, or other transmission equipment, which will be constructed or modified to transmit electrical power from the proposed power plant to the load centers to be served by the facility. Such description shall include the width of rights of way and the physical and electrical characteristics of electrical transmission facilities such as towers, conductors, and insulators. This description shall include power load flow diagrams which demonstrate conformance or nonconformance with utility reliability and planning criteria at the time the facility is expected to be placed in operation and five years thereafter.

Information required to make AFC conform with regulations:

The AFC is for 163 MW net generation output from the proposed Humboldt Bay Repowering Project (HBRP) with a target on-line date of Summer/Fall 2009. But the System Impact Study (SIS) dated January 20, 2006 performed by PG&E is based on 2008 system conditions, not based on the expected first year of operation. In order to demonstrate conformance or non-conformance with the NERC/WECC, California Independent System Operator (CAISO) and/or Utility planning standards and reliability criteria, please submit a new or updated SIS (to demonstrate conformance with utility reliability and planning criteria) for the nominal 163-MW HBRP under 2009 Summer peak and off-peak and Winter system conditions. Alternately, provide review letters from PG&E and the CAISO verifying the validity of the submitted SIS for the aforesaid 2009 system conditions. In addition, as far as the submitted SIS or revised SIS is concerned, provide the following additional information:

a. List all major study assumptions in the base cases including imports and exports to the system, major Path flows (such as Path 15 & 26, COI), major generations including queue generation projects and hydro, and loads in the area systems (refer to Section 3 of the SIS).

b. *Reactive Power Analysis results indicate several low-voltage criteria violations under N-1 contingency conditions due to the addition of the proposed HBRP. List mitigation measures considered (required) including if any alternate planned PG&E mitigation measures or projects have been considered (like installing new lines or shunt capacitors) in the area (refer to section 10 of the SIS).*

c. *Dynamic Stability study results indicate stability and frequency criteria violations under contingency conditions. List mitigation measures considered (required) and those selected (if available) for all criteria violations (refer to section 7 of the SIS).*

d. *Provide electronic copies of *.sav and *.drw, *.dyd and *.swt GE PSLF files and EPCL contingency files in a CD (if available).*

Response — Attachment DA5-1 contains a letter from PG&E verifying the validity of the submitted SIS for the aforesaid 2009 system conditions.

(a) Study Assumptions — It is not possible to obtain electronic copies of the base cases that were used for the SIS at this time. The base case data will be provided to the CEC as soon as it becomes available. However, the major path flows from the base cases that were used for the SIS were obtained from the power flow plots in Appendix D of the SIS report, and are summarized in Table DA5-4 below.

The base cases that were used for the SIS were derived from the 2004 base case series. Due to the radial nature of the Humboldt system, the most critical parameters for the cases are the Humboldt Load and Generation Pattern. This information was not provided in the SIS report.

TABLE DA5-4
HMV Circuit Run Specifications

Major Path Flow	2008 Summer Peak	2008 Summer Off-peak	Winter Peak
Path 15	-1,616 MW (S-N)	4,944 MW (S-N)	3,536 MW (S-N)
Path 26	3,335 MW (N-S)	-1,785 MW (N-S)	-675 MW (N-S)
PDCI	3,104 MW (N-S)	-1,848 MW (N-S)	-1,845 MW (N-S)
COI	4,738 MW (N-S)	-3,636 MW (N-S)	-3,110 MW (N-S)

A copy of the load documentation for the 2004 base case series including key loading assumptions in the base case is described in *2004 Electric Transmission Grid Expansion Plan Study, Base Case Loads* (Attachment DA5-2). A summary of the Humboldt area load assumptions are shown in Table DA5-5 below. The summer off-peak loads used in the SIS would be significantly lower.

TABLE DA5-5
2004 Series Base Case Load Assumptions (2004)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Humboldt 1 in 10 Winter Peak	189	190	191	192	193	194	195	196	197	198	199	200
Humboldt 1 in 5 Summer Peak	-	114	116	119	121	123	125	126	128	129	131	132

Source: 2004 Electric Transmission Grid Expansion Plan Study, Base Case Loads

The generation level in the Humboldt area would be near its maximum in the SIS base cases to provide maximum stress for the area. Other potential generation additions are included in the transmission studies as per the CAISO interconnection queue. Those generation projects are identified in Attachment 1 of the SIS Study Plan.[1] The hydroelectric pattern in the SIS base cases reflects the standard pattern that is used for PG&E's base cases. For example, the Northern California hydroelectric generation is modeled at 87 percent of its maximum in the summer peak cases.[2] Hydroelectric generation assumptions, as well as other generation assumptions for locations outside of the Humboldt area, would not have a significant impact on the Humboldt area transmission studies.

(b) Reactive Power Mitigation Measures—As stated in the SIS, the low-voltage criteria violations identified are distant from the HBRP, and the HBRP has only a minor impact on the voltage performance at the stations forecasted to experience low voltages. As described in Section 10.2.1 of the SIS, these stations are forecasted to have voltage problems irrespective of the HBRP and, therefore, the HBRP is not required to provide mitigation. The mitigation will be part of the transmission grid expansion plan. Currently, the plan has identified the installation of a Static VAR Compensator (SVC). The description of the proposed SVC from the transmission expansion plan is included as Attachment DA5-3. The specifications of the SVC are currently under study by PG&E Electric Transmission and will be designed to mitigate the identified voltage problems.

(c) Dynamic Stability Mitigation—As stated on page 11 of the SIS (contained in Appendix 5 of the AFC), no physical changes to the transmission system are required for the project as mitigation measures. The sole mitigation measure identified is a special protection generating dropping scheme (SPS). The specification of the SPS will be completed once the SVC has been designed, because the SVC has the potential to reduce, and possibly eliminate, the need for dynamic stability mitigation. PG&E will provide additional information to the CEC as the information is made available.

(d) GE PSLF and EPCL Contingency Files—These files have been requested from PG&E transmission, but have not yet been received. The files will be provided when they become available.

[1] The SIS Study Plan is Appendix A of the System Impact Study, which is included as Appendix 5B of the AFC.

[2] Northern California hydroelectric generation level is typically increased to 95 percent of its maximum when studying the Northern and Central Valley areas or inter-area transfers.

3. CAISO Approvals (Appendix B [h][4])

A schedule indicating when permits outside the authority of the commission will be obtained and the steps the applicant has taken or plans to take to obtain such permits.

Information required to make AFC conform with regulations:

Inform when the CAISO preliminary and final approvals will be obtained.

Response – A letter dated April 13, 2006 from the CAISO to Mr. John Vardanian of PG&E Generation Interconnection Services granting preliminary interconnection approval to the HBRP is included as Attachment DA5-4. For clarification, the original SIS studies were initiated by the Ramco Generating Two Humboldt Energy Facility Project. The Humboldt repowering was bid into PG&E's 2004 long-term Request for Offers by a number of bidders. Ultimately, the Ramco project, which utilizes the Wärtsila equipment, was selected. Because the project will require close coordination with existing fossil and nuclear operations at the site, PG&E concluded that it was in the project's best interest to have the development and permitting by PG&E. As such, an Engineer-Procure-Construct agreement was signed with Wärtsila. On April 7, 2006 an agreement was executed between PG&E and Ramco that assigned all of the rights, title, and interest in the project facilities study plan and interconnection applications from Ramco to PG&E.

ATTACHMENT DA5-1

PG&E Letter Validating the SIS for 2009

Pacific Gas and Electric Company.

Karen Grosse
Supervisor
Electric Asset Strategy
Transmission Planning

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October 27, 2006

Mr. John Kessler
Project Manager
California Energy Commission
1516 9th Street, MS-15
Sacramento, CA 95814

RE: Ramco Generating Two Humboldt Energy Facility Project
System Impact Study Rev 1 January 20, 2006

Dear John:

The subject project has informed the California Independent System Operator (CAISO) and PG&E Transmission that the online date is now proposed for August 2009. While the subject study assumed an online date for the new Humboldt Project of August 2008, PG&E Transmission and CAISO have concurred that the results of the study would not be affected by the revised on line date.

Based upon the lack of any significant change between 2008 and 2009 in the generation and transmission scenarios in the Humboldt region and our review of the System Impact Study, the January 20, 2006 System Impact Study is sufficient for Transmission Planning's needs with regard to the Humboldt Bay Repowering Project. A restudy is not required.

Sincerely,

Karen R Grosse

Karen R. Grosse
Supervisor, Transmission Planning

ATTACHMENT DA5-2

Base Case Loads
2004 Electric Transmission Grid
Expansion Plan Study

2004 Electric Transmission Grid Expansion Plan Study

Base Case Loads

Introduction

As required by the CAISO, two sets of base case loads were developed. The system base case loads, which would be used to assess the bulk transmission system[1], represent the system peak demands of the 1-in-5 extreme weather conditions. The area base case loads, which would be used to assess the local area transmission systems, represent the local area peak demands of the 1-in-10 extreme weather conditions.

In this report, the base case loads refer to the loads that are modeled at the transmission buses[2] of the power flow base cases that are used in the annual expansion plan study. The base case loads include loads that are served by PG&E as well as by the municipal (muni) utilities in northern California. The aggregated (at division and higher levels) 2004-2014 1-in-5 system and the 1-in-10 area base case loads are summarized in the main body of this report. The loads at the transmission buses could be found in the power flow base cases. Supporting information such as the method used to develop the base case loads are described in the appendices listed below:

Appendix

- A Base Case Load Development Method
- B System Forecast
- C Distribution Forecast
- D Muni Forecast
- E 2004 Improvements
- F Glossary
    1. Area & Divisions
    2. Adverse Weather Conditions
    3. Temperature
    4. Load Temperature Factors
    5. Area Diversity Factors
    6. Conforming & Non-conforming Loads
    7. Self-generation and Generation-plant Loads
    8. Transmission Losses
    9. Load Characteristics

[1] Bulk transmission system comprises 500 and some 230 kV facilities. Local area transmission system comprises 60-115 and some 230 kV facilities.

[2] Due to significant transmission losses, it is important to distinguish the reference point for the load. If the load were measured at the generator, for example, the quantity would be much higher. Transmission losses are discussed in Appendix F, section 8.

1-in-5 System Base Case Loads

Table 1 summarizes the 1-in-5 system base case loads for the 20 PG&E divisions and the muni in northern California. Figure 1 is the graphical presentation of total load. The 2003 forecasted load is included in the Figure 1 for comparison.

Division	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
04(1in5 sys) HUMBOLDT	114	116	119	121	123	125	126	128	129	131	132
04(1in5 sys) NORTH COAST	844	857	872	886	900	914	929	945	962	978	993
04(1in5 sys) NORTH VALLEY	700	713	728	742	756	773	790	810	829	848	866
04(1in5 sys) SACRAMENTO	998	1,013	1,027	1,040	1,058	1,074	1,091	1,110	1,129	1,147	1,164
04(1in5 sys) SIERRA	904	940	978	1,012	1,048	1,088	1,131	1,179	1,229	1,278	1,325
04(1in5 sys) NORTH BAY	609	620	630	639	649	656	664	672	681	689	697
04(1in5 sys) EAST BAY	862	868	876	883	891	896	902	909	915	922	927
04(1in5 sys) DIABLO	1,684	1,690	1,711	1,736	1,757	1,773	1,790	1,809	1,829	1,847	1,864
04(1in5 sys) SAN FRANCISCO	845	855	865	875	885	892	900	909	918	926	934
04(1in5 sys) PENINSULA	927	938	950	961	970	978	985	994	1,002	1,010	1,018
04(1in5 sys) STOCKTON	1,163	1,182	1,207	1,229	1,252	1,273	1,294	1,319	1,343	1,367	1,389
04(1in5 sys) STANISLAUS	236	240	244	248	252	255	258	262	265	269	272
04(1in5 sys) YOSEMITE	798	819	828	837	847	854	862	870	879	887	894
04(1in5 sys) FRESNO	1,945	1,963	1,986	2,007	2,030	2,052	2,076	2,102	2,128	2,153	2,177
04(1in5 sys) KERN	1,420	1,433	1,449	1,464	1,479	1,499	1,520	1,543	1,567	1,589	1,611
04(1in5 sys) MISSION	1,251	1,277	1,299	1,315	1,331	1,343	1,356	1,371	1,385	1,399	1,412
04(1in5 sys) DE ANZA	849	861	870	880	896	909	923	938	954	969	983
04(1in5 sys) SAN JOSE	1,655	1,698	1,720	1,747	1,767	1,801	1,837	1,877	1,918	1,958	1,996
04(1in5 sys) CENTRAL COAST	620	634	647	659	671	681	692	703	714	725	736
04(1in5 sys) LOS PADRES	516	523	530	538	545	552	558	566	574	581	588
04(1in5 sys) Muni	5,816	5,976	6,113	6,250	6,383	6,517	6,654	6,790	6,925	7,064	7,201

Table 1. Division and Muni Loads in 1-in-5 System Base Cases

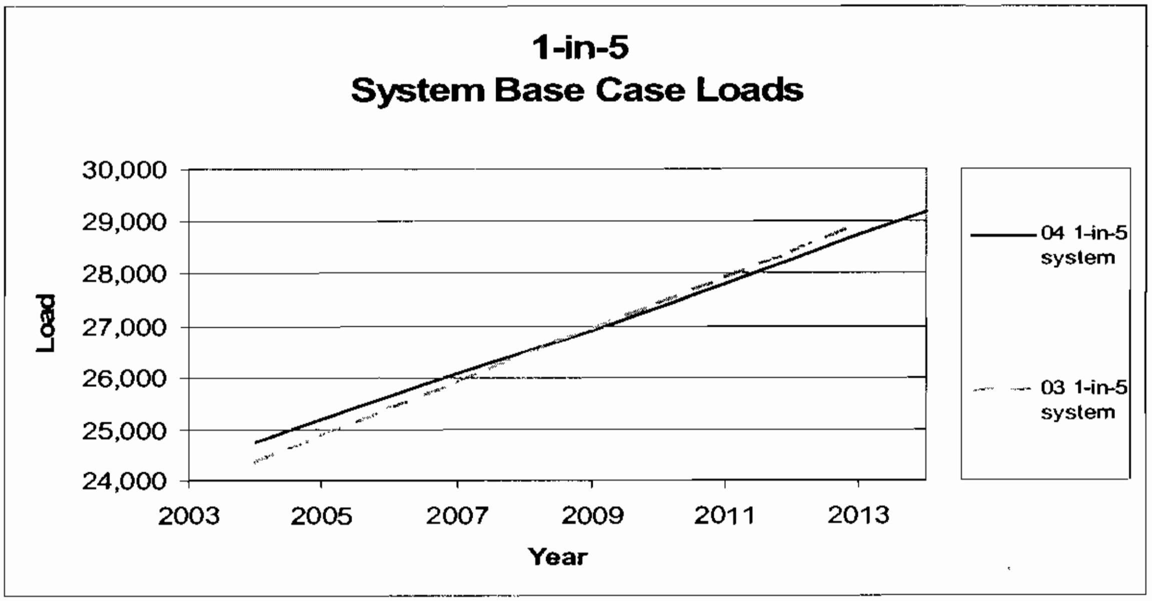


Figure 1. 1-in-5 System Base Case Loads

1-in-10 **Area Base Case Loads**

Table 2 summarizes the 1-in-10 loads for the 20 PG&E divisions. Figures 2-8 show the 1-in-10 coincident loads of the seven areas and the corresponding 2003 forecast for comparison.

Division	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
04 HUMBOLDT 1in10 win	190	191	192	193	194	195	196	197	198	199	200
04 NORTH COAST	895	908	925	940	956	971	986	1004	1022	1039	1055
04 NORTH VALLEY	823	837	853	868	883	901	920	940	962	982	1001
04 SACRAMENTO	1078	1094	1109	1124	1143	1160	1178	1199	1219	1239	1258
04 SIERRA	991	1030	1070	1108	1146	1189	1235	1288	1341	1395	1446
04 NORTH BAY	634	646	657	667	678	686	694	703	712	721	729
04 EAST BAY	892	899	907	915	923	930	936	943	950	957	963
04 DIABLO	1761	1767	1790	1817	1839	1857	1875	1895	1916	1935	1954
04 SAN FRANCISCO	916	925	936	947	957	966	974	983	993	1002	1010
04 PENINSULA	988	998	1012	1024	1033	1041	1050	1059	1068	1076	1084
04 STOCKTON	1180	1200	1226	1250	1274	1296	1320	1346	1372	1397	1422
04 STANISLAUS	240	243	248	252	256	260	263	267	271	274	278
04 YOSEMITE	820	842	853	862	873	881	890	899	908	917	925
04 FRESNO	1998	2018	2043	2067	2091	2116	2141	2170	2198	2226	2252
04 KERN	1528	1542	1560	1575	1592	1614	1636	1661	1686	1711	1734
04 MISSION	1349	1378	1401	1418	1435	1448	1462	1478	1493	1508	1522
04 DE ANZA	914	927	937	947	965	979	994	1010	1027	1043	1059
04 SAN JOSE	1660	1707	1730	1760	1782	1818	1857	1901	1945	1988	2030
04 CENTRAL COAST	760	774	788	801	815	825	836	849	861	873	884
04 LOS PADRES	511	518	526	534	541	549	556	564	572	580	588

Table 2. 1-in-10 Division Loads

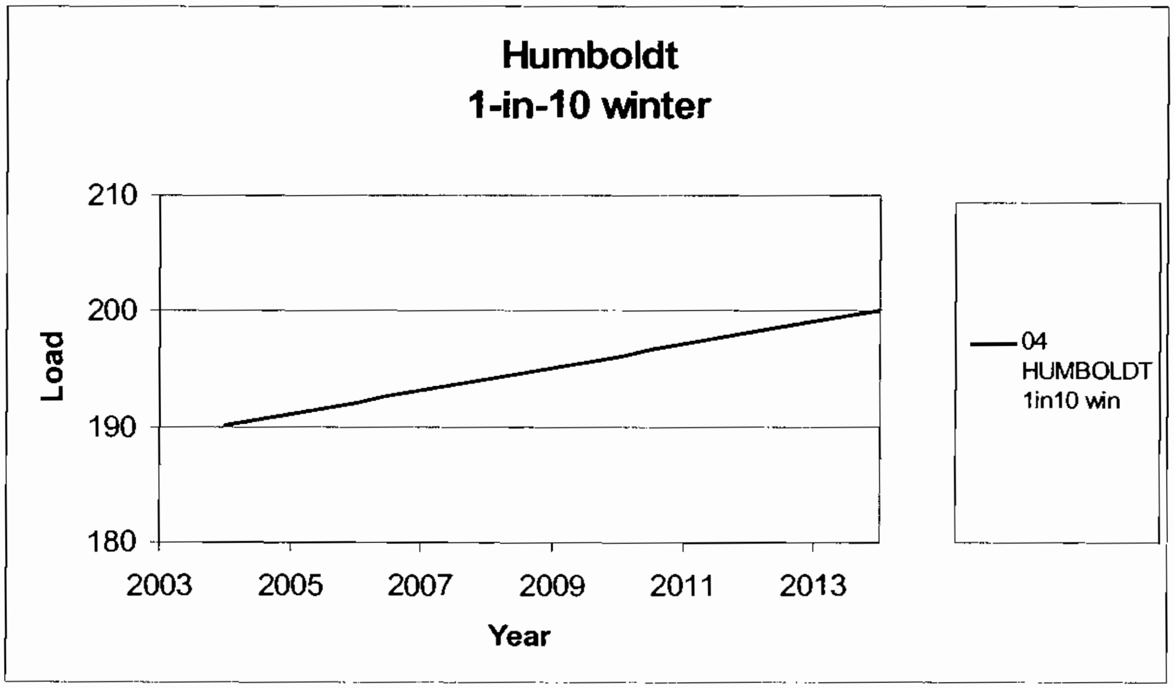


Figure 2. Humboldt 1-in-10 Area Loads

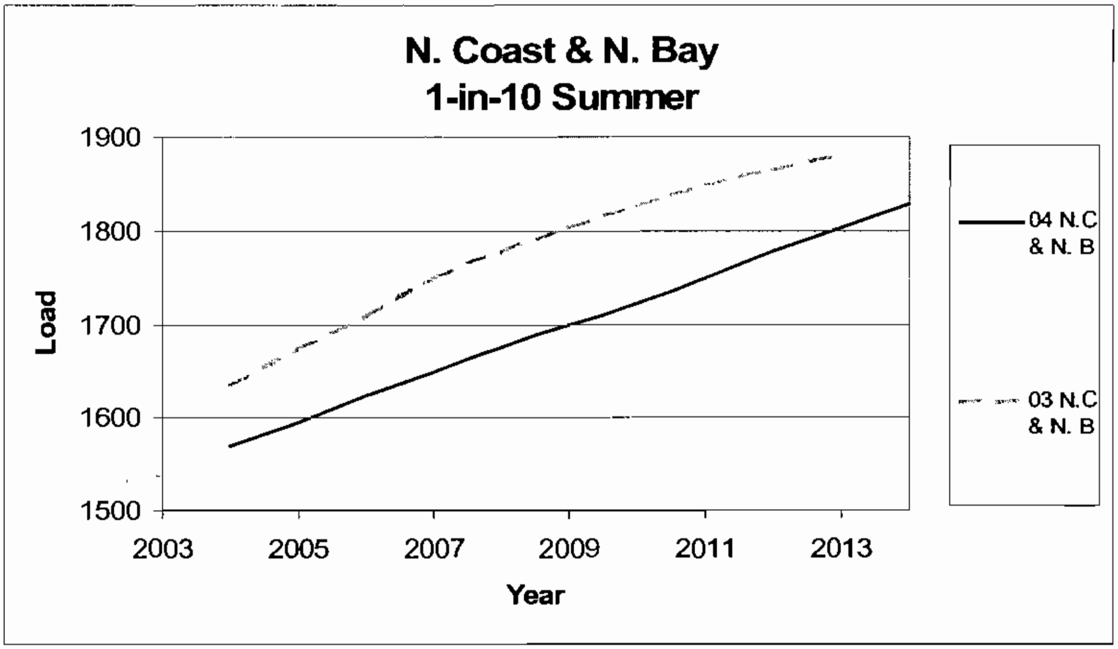


Figure 3. North Coast & North Bay 1-in-10 Area Loads

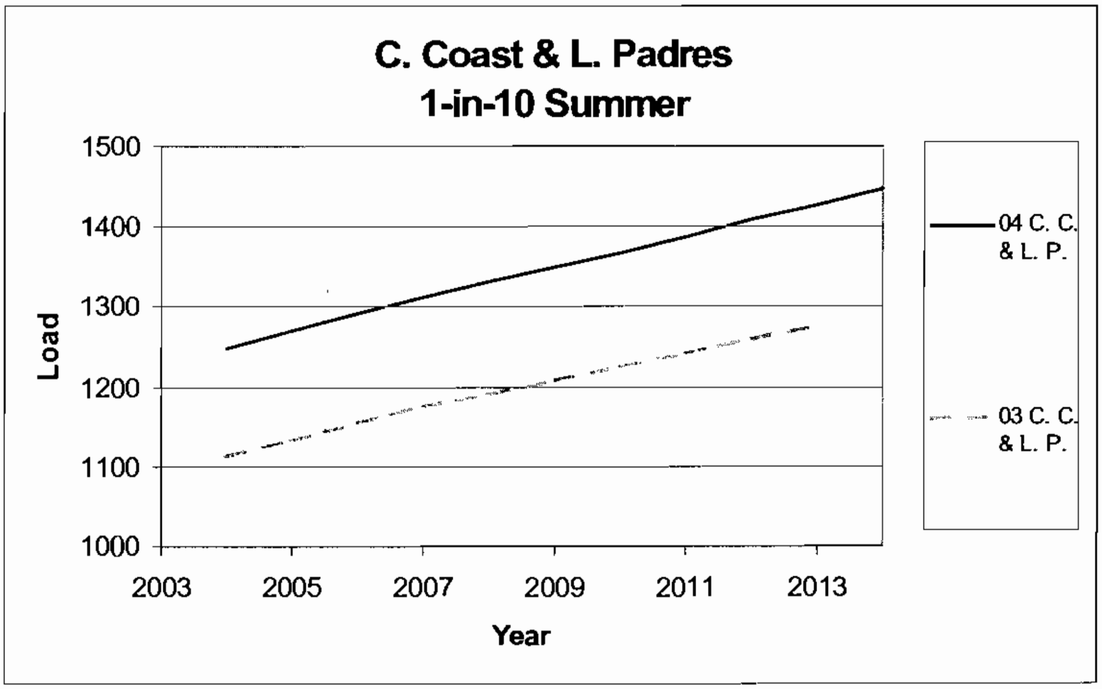


Figure 4. Central Coast & Los Padres 1-in-10 Area Loads

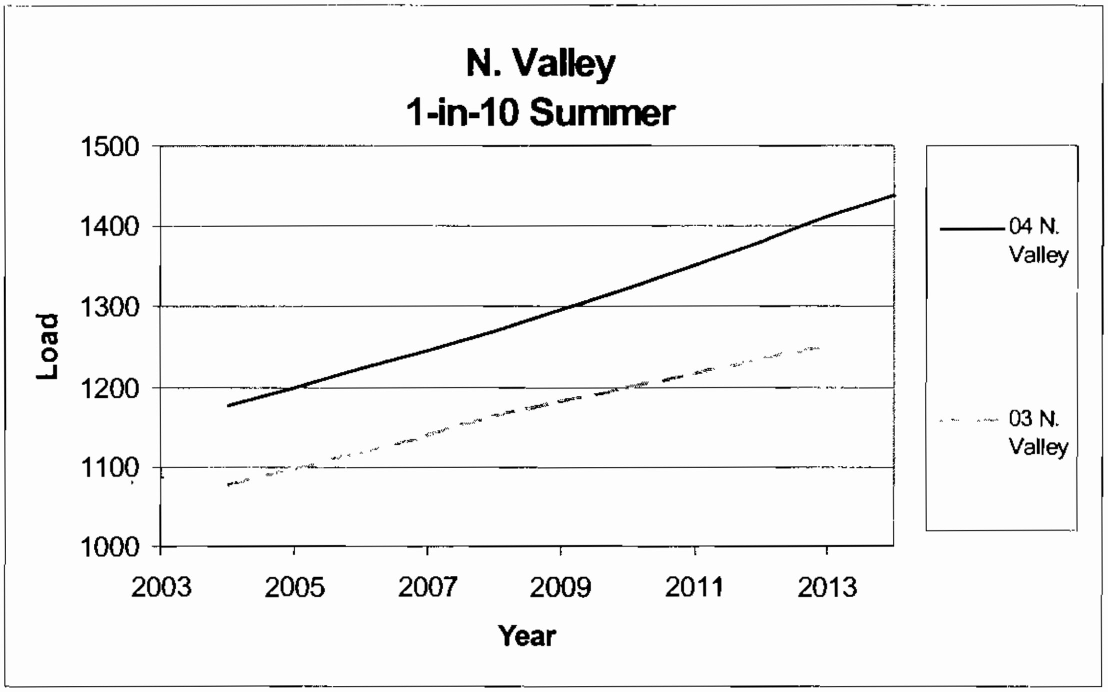


Figure 5. North Valley 1-in-10 Area Loads

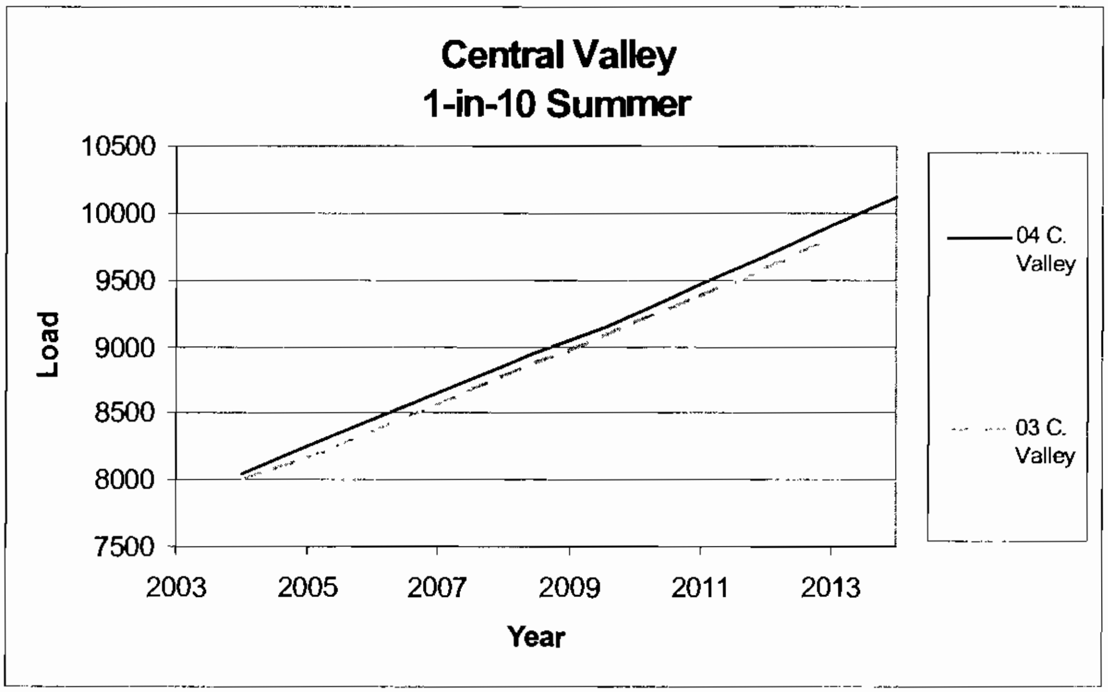


Figure 6. Central Valley 1-in-10 Area Loads

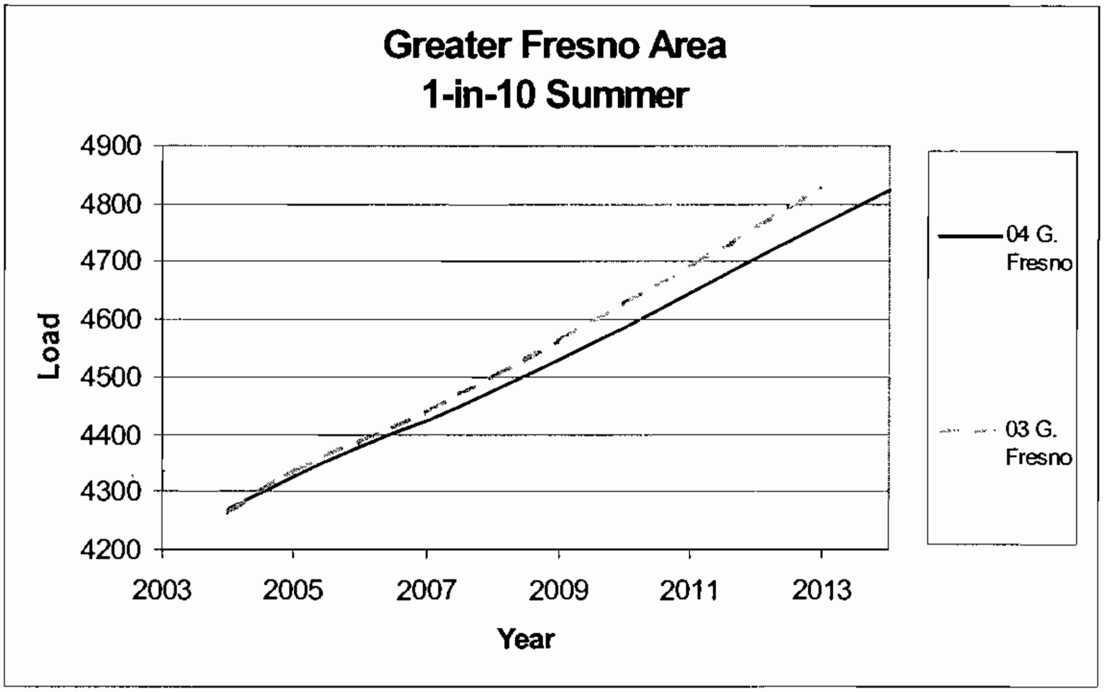


Figure 7. Greater Fresno Area 1-in-10 Area Loads

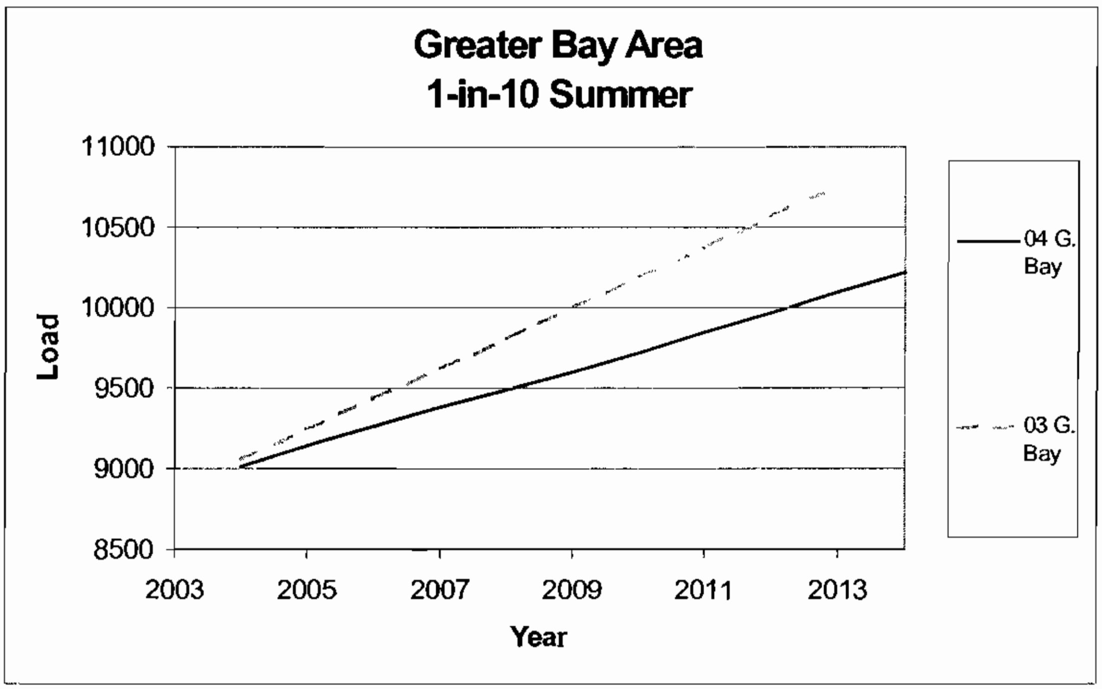


Figure 8. Greater Bay Area 1-in-10 Area Loads

Appendix A. Base Case Load Development Method

The method used to develop the base case loads is a melding process that extracts, adjusts and modifies the information from the system, distribution and muni forecasts. The melding process consists of two parts. Part 1 deals with the PG&E load. Part 2 deals with the muni load.

The method used to determine the PG&E loads was similar to the one used in the 2000-2003 studies. It starts with the determination of the annual division loads that would meet the requirements of 1-in-5 system or 1-in-10 area extreme weather conditions and ends with the allocation of the division load to the transmission buses.

Determination of Division Loads for 1-in-2 System Base Cases

The initial year (2003) division loads for the 1-in-2 system base case were determined as follows:

1. Retrieve the division load at 4 pm on July 17, 2003 (system peak) and the temperature for that day for each of the 20 divisions.
2. Normalize each division load to the temperature expected on a 1-in-2 system peak day (based on the temperature difference between July 17, 2003 and the expected 1-in-2 system peak day and the load temperature factor.)
3. Scale each division load from step 2 such that the sum of the division loads would equal to the PG&E's portion of the 2003 1-in-2 system load.

The subsequent year division loads for the 1-in-2 system base case were determined as follows:

4. Determine the total PG&E load growth of the year by multiplying the projected 1-in-2 system load growth rate from Appendix B to the PG&E load.
5. Obtain the non-simultaneous division growths from distribution forecast.
6. Scale each division growth from step 5 such that the total division growths after scaling would equal to the total PG&E load growth determined in step 4.
7. Add the load growth from step 6 to the current year division load to obtain the next year's division load.

Determination of Division Loads for 1-in-5 System Base Cases

The initial year division loads for the 1-in-5 system base case were determined as follows:

8. Normalize each division load from step 3 to the 1-in-5 division temperature.
9. Scale each division load from step 8 such that the sum of the division loads would equal to the PG&E's portion of the 2003 1-in-5 system load.

Division loads for subsequent year would be determined in the same manner as steps 4-7, except that the 1-in-5 system loads and load growth rates would be used.

Determination of Division Loads for 1-in-10 Area Base Cases

The division load for the 1-in-10 area base case is determined by multiplying the load from step 7 (1-in-2 system base case loads) with a conversion factor. The conversion factor consists of two parts. The first part accounts the temperature changes from the 1-in-2 system peak condition to the 1-in-10 area peak condition. The second part (true-up factor) accounts for the differences from the result of the first part with the 1-in-10 load determined from peak load recorded for the year. The true-up factor is determined as follows:

10. Retrieve the highest load[3] recorded in May-September, 2003 and the temperature on that day.
11. Normalize the division load from step 10 to the expected 1-in-10 division temperature.
12. Determine the true-up factor by dividing the division load from step 11 by the division load from step 3 that has been normalized to 1-in-10 temperature.

Loads at Transmission Bus Level

Since the base case loads are modeled at the various transmission buses, the division loads developed would need to be allocated to those buses. The allocation process is different depending on the load types.

PG&E classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads as discussed in Appendix F, sections 6 & 7. Because of their variability[4], the generation-plant loads were not included in the division load. Thus no division load would be allocated to the generation-plant loads. The conforming, non-conforming and self-generation loads are included in the division load. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the 1-in-2 system, 1-in-5 system or the 1-in-10 area base cases of the same year. The remaining load (the total division load developed above less the quantity of non-conforming and self-generation load) is the conforming load. Unless specific study has been done (e.g., North Coast Division), the remaining load would be allocated to the transmission buses based on the relative magnitude of the distribution forecast.

[3] Because of data quality, the second highest loads for Sierra and Stockton/Stanislaus divisions were selected. For the Fresno division, the average of the top 5 daily loads, normalized to 1-in-10 temperature, was used.

[4] The generation-plant loads would be either on or off depending on the generator status, which could vary from year to year and from case to case within the same year.

Muni Loads in Base Cases

For the 1-in-2 system and the 1-in-5 system base cases, the respective 1-in-2 and 1-in-5 loads would be used. For the 1-in-10 area base cases, the 1-in-10 loads would be used if the muni loads are inside the area, otherwise, the 1-in-2 loads would be used.

Appendix B. System Forecast

In this Appendix B, the system forecast refers to the Line 9 load. The differences between the system forecast (Line 9) and the system base case loads are discussed in Appendix F, section 9. The 2004-2014 1-in-2 and 1-in-5 system forecasts are summarized in Table B1. Figure B1 is the graphical presentation of the 2004 forecast of 1-in-2 loads, historical loads (normalized to 1-in-2 temperature), 2003 forecast and the most recent CEC forecast (2003 Integrated Energy Policy Report proceedings) included for comparison.

PG&E uses an econometric equation to forecast the system load. The predominant parameters affecting the system load are (1) number of households, (2) economic activity (gross metropolitan products, GMP), (3) temperature and (4) customer response to conservation and energy efficiency programs. The temperature effects are accounted explicitly as stated as the 1-in-2 or the 1-in-5 system forecast.

For the 2004 forecast, household growth would contribute about 1.5-1.6% to the annual system load growth. GMP would contribute about 0.2-0.3%. On the other hand, increased conservation and distributed generation activities above the historical level would reduce the growth by about 0.3%. The forecast did not incorporate the effects of the future programs and activities such advanced metering, peak demand reduction, electricity price, enhanced building and efficiency standards.

Year	System Forecast (Line 9) 1-in-2	System Forecast (Line 9) 1-in-5
2004	24,066	24,688
2005	24,449	25,083
2006	24,833	25,479
2007	25,198	25,856
2008	25,567	26,238
2009	25,931	26,615
2010	26,311	27,007
2011	26,736	27,445
2012	27,166	27,888
2013	27,584	28,318
2014	27,980	28,727

Table B1. 1-in-2 & 1-in-5 System Forecasts (Line 9)

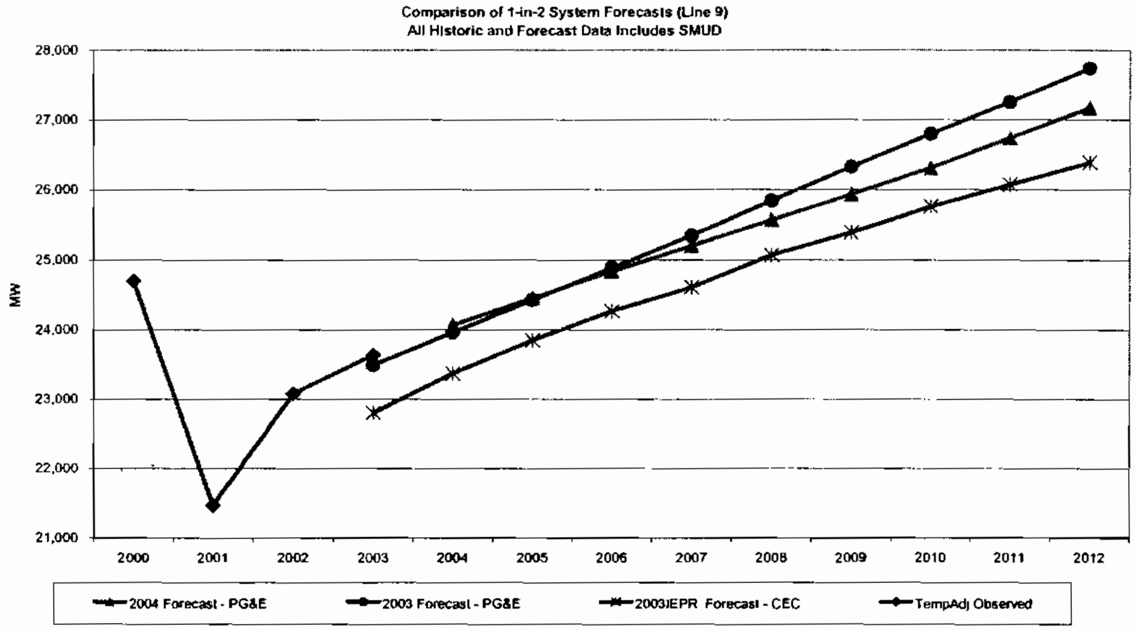


Figure B1. Comparison of 1-in-2 System Forecasts (Line 9)

Appendix C. Distribution Forecast

Table C1 summarizes the distribution forecasts. Distribution forecast is for the conforming loads. The forecast, which is conducted for each distribution planning area (DPA), is based on "least square" linear regression analysis of the non-simultaneous peak transformer loadings in the DPA. If the "least square" analysis does not produce statistically confident results, the DPA load would be determined from the 2003 peak loads which are then adjusted for temperature and applying the applicable Bay or Non Bay area growth rate. The DPA load would then be adjusted for large block load increases (>1.5% of the DPA load) and any planned load transfers.

Division	2004	2005	2006	2007	2008	2009
Humboldt	124	126	129	131	133	135
N. Coast	848	865	881	898	915	934
N. Valley	818	833	847	862	876	897
Sacramento	981	1,000	1,015	1,030	1,050	1,072
Sierra	1,137	1,183	1,222	1,261	1,300	1,355
North Bay	717	732	743	755	766	777
East Bay	727	736	744	753	762	770
Diablo	1,302	1,309	1,332	1,361	1,384	1,407
S.F.	975	987	998	1,009	1,020	1,031
Peninsula	862	875	888	900	910	921
Stockton	1,215	1,241	1,269	1,297	1,324	1,355
Stanislaus	253	258	263	268	273	277
Yosemite	742	769	780	791	803	813
Fresno	1,964	1,988	2,014	2,040	2,066	2,099
Kern	1,312	1,329	1,346	1,362	1,379	1,406
Mission	1,353	1,388	1,411	1,430	1,448	1,465
De Anza	732	748	757	769	787	806
San Jose	1,566	1,627	1,652	1,686	1,710	1,762
Central Coast	810	826	838	850	862	875
Los Padres	501	510	519	528	537	546

Table C1. Distribution Forecast of Division Loads

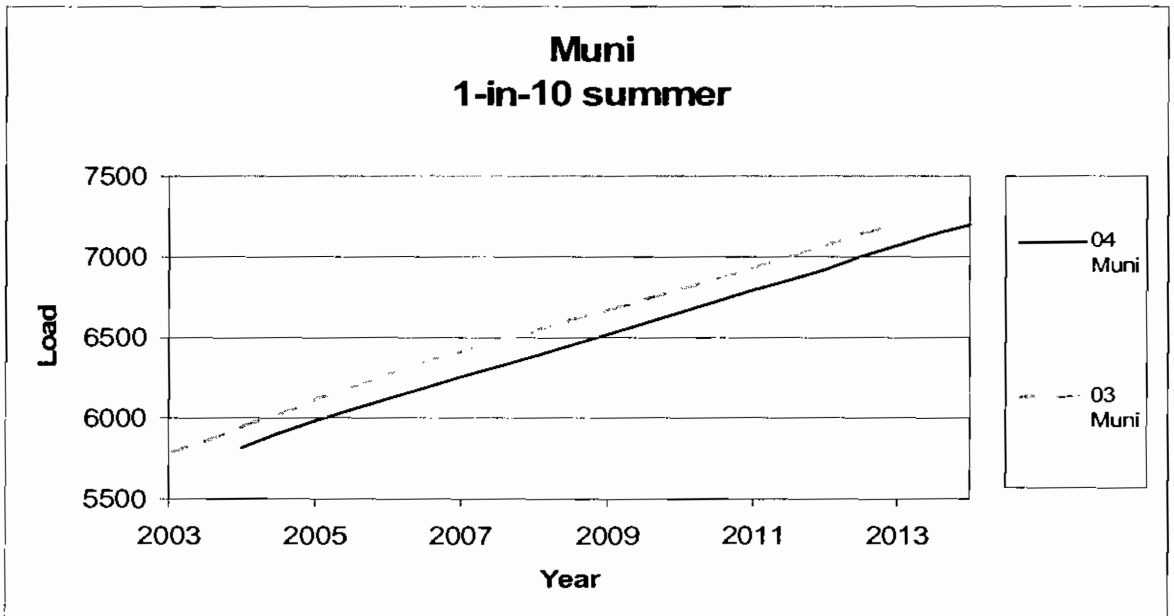
Appendix D. Muni Forecast

Table D1 summarizes the 1-in-10 muni loads. Figure D1 is the graphical presentation of the 1-in-10 muni loads with the similar load from the 2003 forecast included for comparison.

With few exceptions, the munis provided the information in Table D1. PG&E would supplement such forecast if no information were provided. For example, if a muni provided only the 1-in-10 loads, PG&E would determine the 1-in-2 and 1-in-5 loads by adjusting the 1-in-10 loads for temperature in the same way that PG&E would for its load in that area.

Entity	2004 1-in-10 summer	2005 1-in-10 summer	2006 1-in-10 summer	2007 1-in-10 summer	2008 1-in-10 summer	2009 1-in-10 summer	2010 1-in-10 summer	2011 1-in-10 summer	2012 1-in-10 summer	2013 1-in-10 summer	2014 1-in-10 summer
ST CLARA	439	448	457	466	471	478	484	491	497	504	511
SMUD	3,047	3,112	3,179	3,244	3,309	3,374	3,440	3,504	3,566	3,628	3,692
MID	691	715	734	760	786	814	842	870	899	930	956
TID	522	563	575	586	596	607	616	627	636	647	657
WAPA	188	189	191	196	197	197	197	197	197	198	198
LMUD	28	28	29	29	30	30	31	32	32	33	34
NCPA	507	514	523	530	537	544	551	558	566	573	580
Roseville	303	312	325	339	352	366	381	396	412	429	446
Redding	251	257	264	270	277	284	291	298	305	313	320

Table D1. Muni 1-in-10 Loads



Appendix E. 2004 Improvements

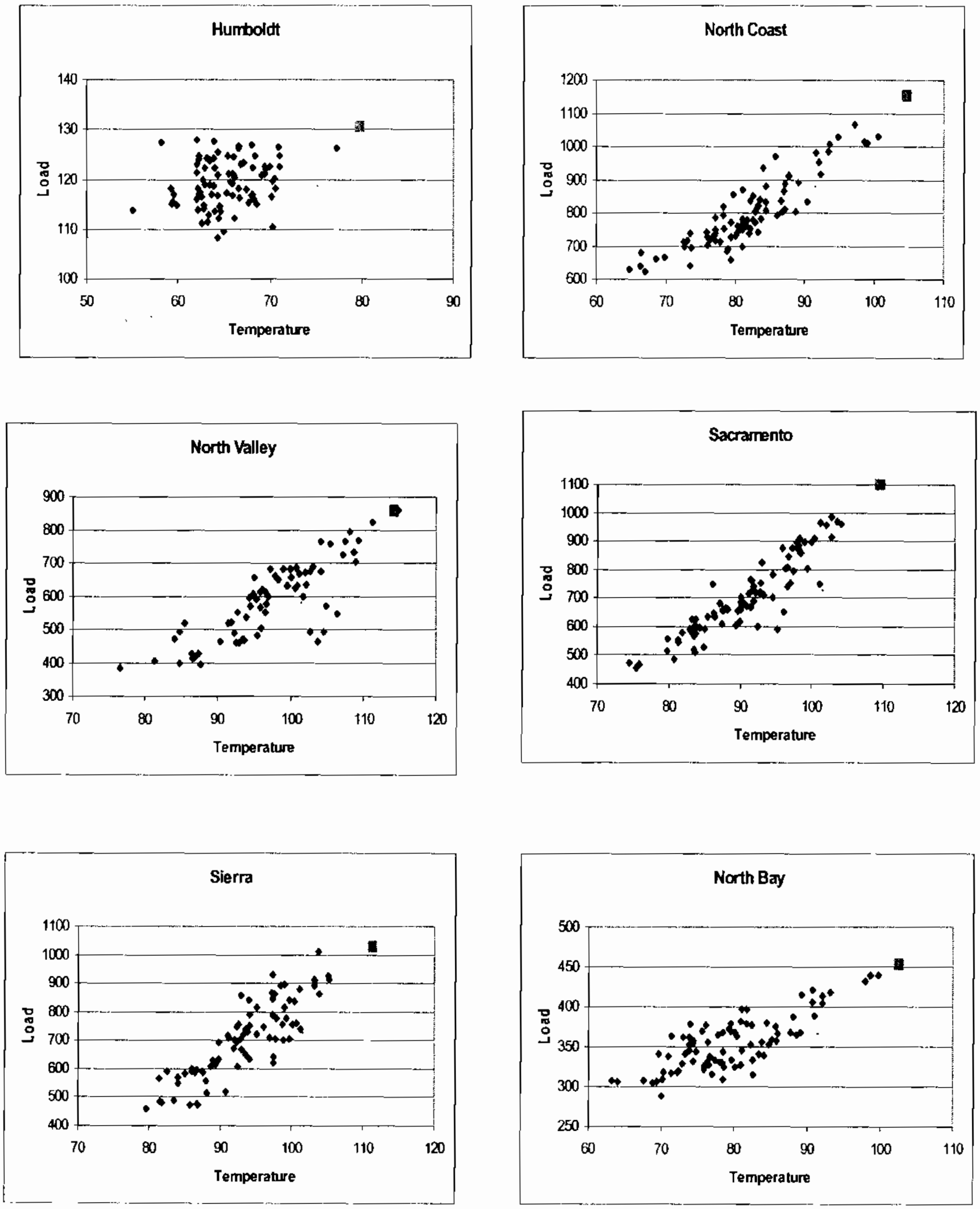
There were several improvements made to the 2004 forecast: (1) the initial year 1-in-10 division loads; (2) updated load temperature factors and (3) development of area diversity factor.

As discussed in Appendix A, the initial year 1-in-10 division load was based on the highest recorded loads that were normalized to the 1-in-10 temperature with the updated load temperature factor[5]. As shown in Figure E1, the resultant initial year 1-in-10 loads were very reasonable. The small diamonds in Figures E1 are the recorded 2003 loads (no week ends or holidays) and the large square is the estimated 1-in-10 load.
As discussed in Appendix F, section 4, an updated load temperature factors were used in the 2004 forecast. The updated factors included the information derived from 2003 data.

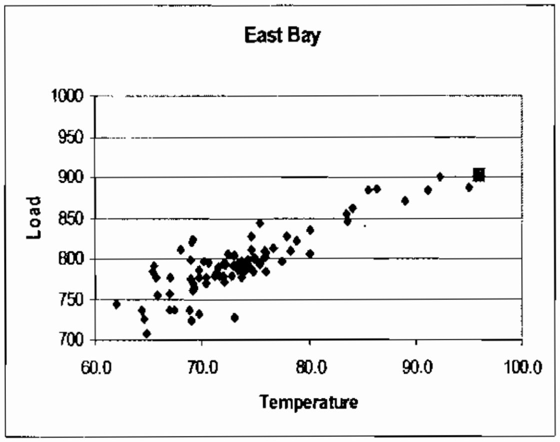
In 2004 forecast, the coincident loads of the divisions in the same area are determined. The area diversity factors as described in Appendix F, section 5 are used to create the coincident area loads.

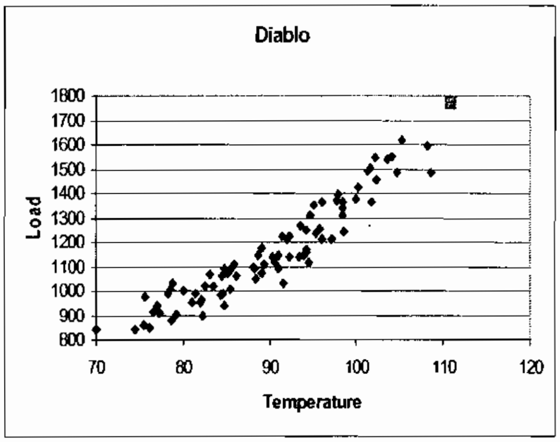
[5] In previous years the 1-in-10 division load was determined from the system peak day data.

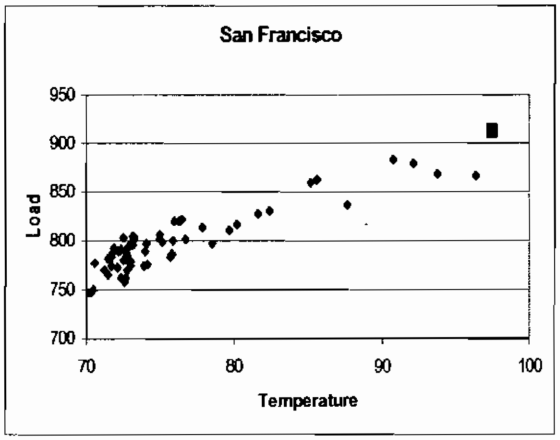
Figure E1. 2003 Division Load and Temperature Scatter Plots

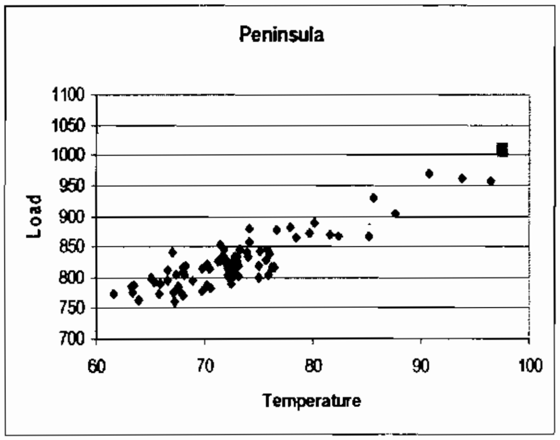


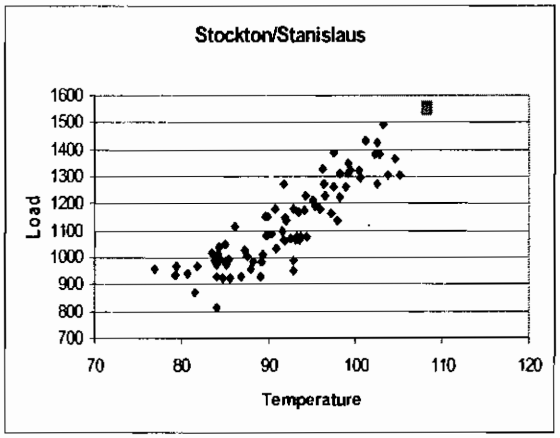
2004 base case loads

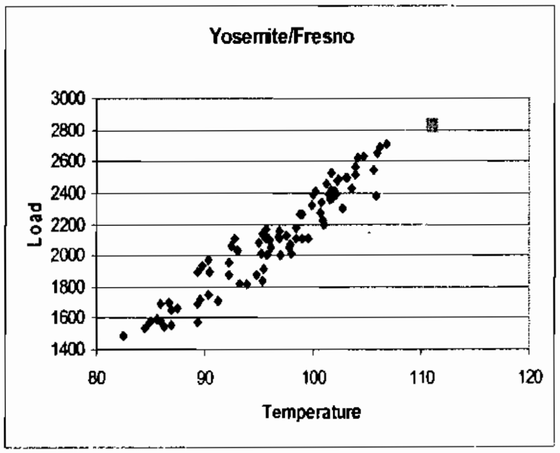




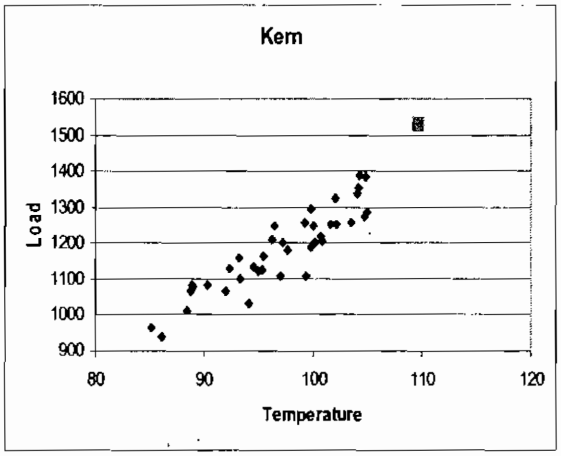


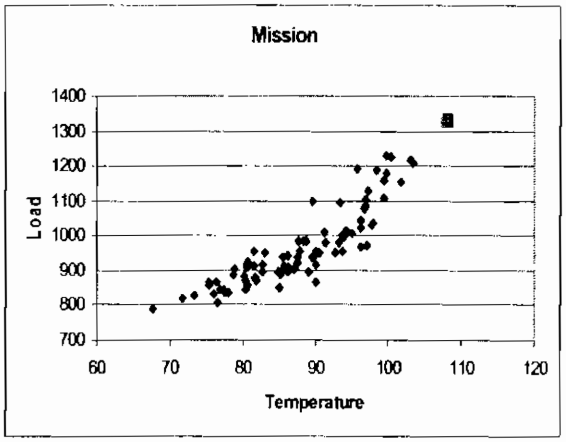


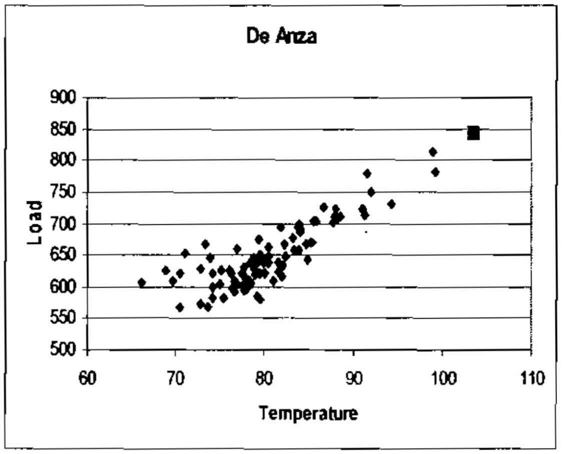


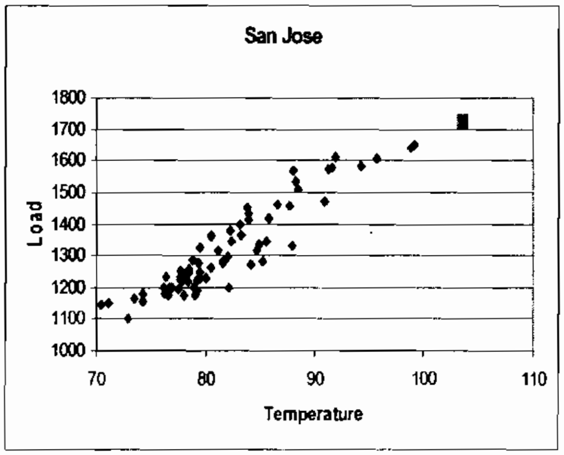


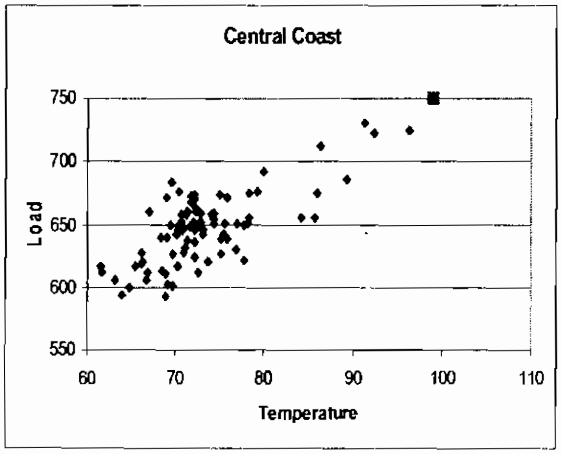
2004 base case loads

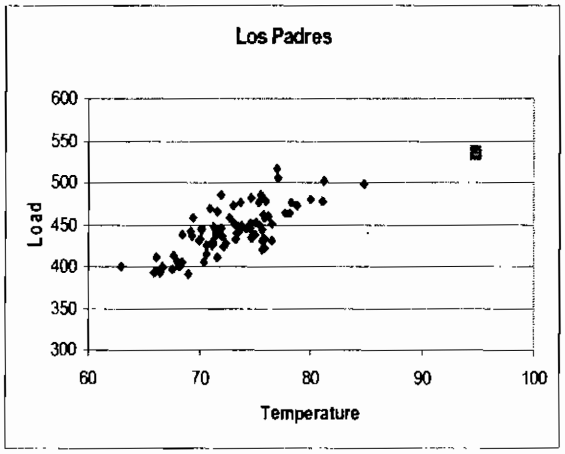












Appendix F. Glossary

1. Area & Divisions

PG&E divides its service territory into 20 divisions for planning studies and data collection[6]. These 20 divisions are then aggregated to form seven areas. Figure F1 shows the divisions and areas.

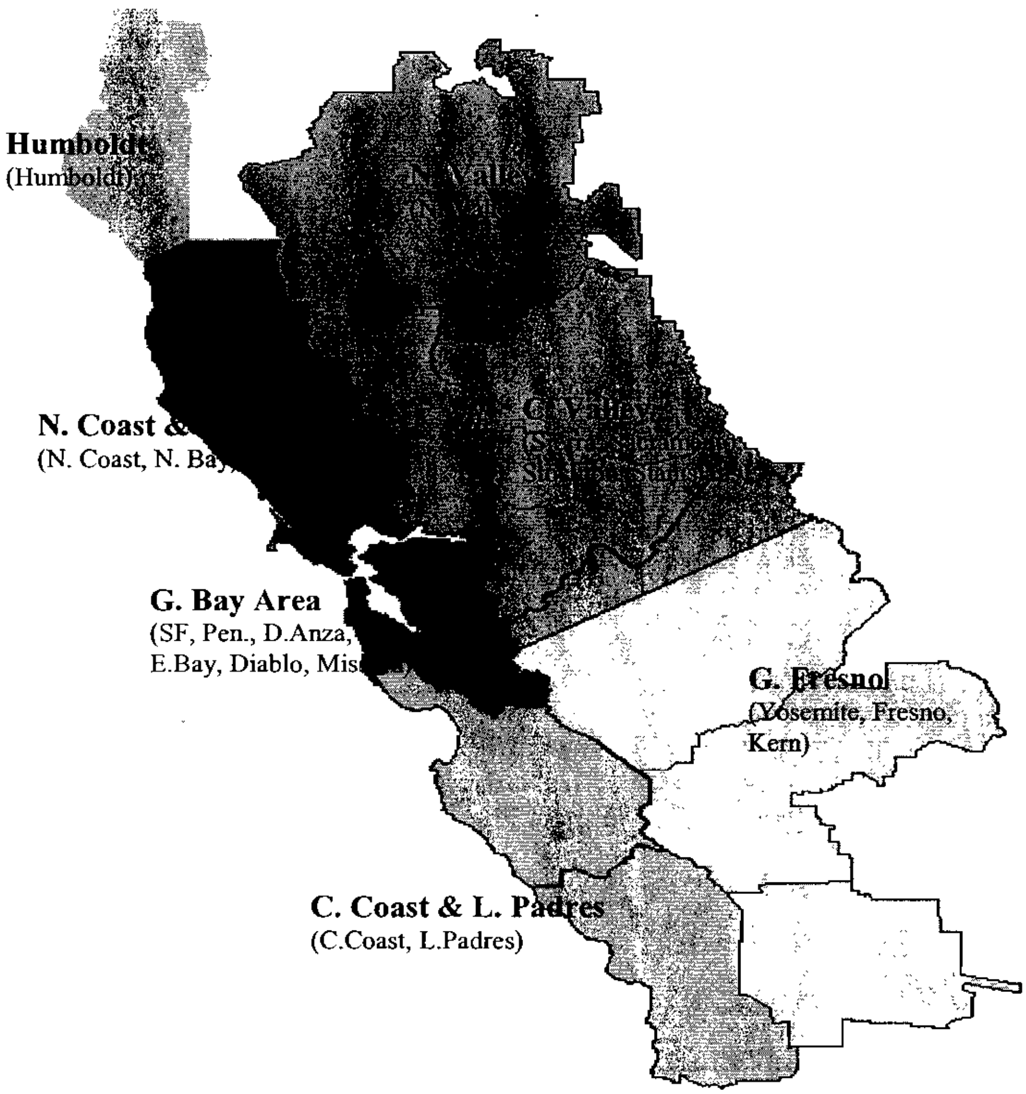


Figure F1. Divisions and Areas

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[6] For data collection, Stockton and Stanislaus divisions were lumped together; so are Yosemite and Fresno divisions.

2. Adverse Weather Condition Loads

Except for Humboldt division, peak division loads occur in summer, driven by the air conditioning load. As shown in Figure E1, load correlates well with temperature. Thus temperature is selected as the proxy to determine the extreme weather condition load as stipulated by the CAISO. Thus one of the key components of the melding process is to adjust the load to the appropriate temperatures expected for the 1-in-2 system, 1-in-5 system or 1-in-10 area conditions.

Similarly, the peak Humboldt load occurs in winter. The main driver for the peak load is heating load as there is no nature gas service in Humboldt. Based on the study[7] done in 2000, the 1-in-10 Humboldt division load was determined and agreed to by the CAISO. Since the load or its drivers such as number of households and GMP in Humboldt have not experienced any significant changes, the 2000 forecast would continue to be used.

3. Temperature

In this report, temperature refers to the 3-day weighted temperature (daily maximum) as shown below. :

> 0.1 * temperature (2-day prior) + 0.2 * temperature (1-day prior)
> + 0.7 * temperature of the day.

The expected temperature for each division corresponding to the 1-in-2 system peak load condition was determined by averaging the temperatures recorded on the peak days for the years 1989-2003. The expected temperature for each division corresponding to the 1-in-10 area peak load was determined as follows:

> For the divisions in the area - based on the average temperature for the 4^{th}, 5^{th} and 6^{th} hottest annual temperature (based on 50 years of data) for that division.
>
> For the division outside the area - based on the average temperature on the same days from above. (For area with more than one division, the average depends on more than three temperatures. For example, if there are two divisions in the area, this average is based on temperatures of six days.)

Table F1 showed the division temperatures expected on the 1-in-2 system peak and the 1-in-10 area peak conditions, as well as the weather stations used for these divisions.

[7] The 1-in-10 Humboldt load determined in 2000 was based on an analysis on how the recorded Humboldt load varied with heating degree-day and the estimated load growth. That forecast was used in subsequent years.

Division	Weather Station	Temperature @ 1-in-2 System Peak Day (TS2i)	1-in-10 Division Temperature (TA10i)
Humboldt	Eureka	65.9	79.8
N. Coast	Santa Rosa	98.5	104.7
N. Valley	Redding	108.1	114.3
Sacramento	Sacramento	104.3	109.5
Sierra	Marysville	106.6	111.3
N. Bay	San Rafael	95.8	102.6
E. Bay	Oakland	82.7	96.0
Diablo	Concord	105.6	110.9
S. F.	SF downtown	81.2	97.6
Pen.	SFO	82.2	97.5
Stockton	Stockton	104.6	108.3
Stanislaus	Stockton	104.6	108.3
Yosemite	Fresno	105.5	111.1
Fresno	Fresno	105.5	111.1
Kern	Bakerfield	104.2	109.7
Mission	Livermore	103.0	108.1
D. Anza	San Jose	95.7	103.6
San Jose	San Jose	95.7	103.6
C. Coast	Salinas	79.0	99.1
Los Padres	Santa Maria	79.3	94.9

Table F1. Temperatures and Weather Stations

4. Load Temperature Factors

The load temperature factor estimates how a division load would increase with rise in temperature. The load temperature factor is determined from the regression analysis of the recorded load and temperature (weekday only and no holidays) for the summer months (May-September) of the same year. As shown pictorially in Figure E1, the load temperature factors and the correlation coefficients for hot inland divisions would be higher than the mild coastal divisions. For the 2004 forecast, the load temperature factors were based on the average of two factors, one based on 2000 data and the other based on 2003 data. Table F2 summarized the load temperature factors used in the 2004 forecasts.

Division	Factor based on 2003 data	Factor based on 2000 data	Load Temperature Factor (load change per degree temperature)
Humboldt	0.23%	0.00%	0.11%
N. Coast	1.21%	0.98%	1.09%
N. Valley	1.87%	1.56%	1.72%
Sacramento	1.82%	1.66%	1.74%
Sierra	1.97%	1.61%	1.79%
N. Bay	0.82%	0.64%	0.73%
E. Bay	0.51%	0.47%	0.49%
Diablo	1.75%	1.71%	1.73%
S. F.	0.34%	0.21%	0.28%
Pen.	0.70%	0.55%	0.62%
Stockton	1.63%	1.32%	1.48%
Stanislaus	1.63%	1.32%	1.48%
Yosemite	1.92%	1.74%	1.83%
Fresno	1.92%	1.74%	1.83%
Kern	2.44%	1.46%	1.95%
Mission	0.98%	0.91%	0.94%
D. Anza	0.88%	0.73%	0.81%
San Jose	1.11%	0.90%	1.00%
C. Coast	0.45%	0.25%	0.35%
Los Padres	0.72%	0.25%	0.49%

Table F2. Load Temperature Factors.

5. Area Diversity Factors

The area diversity factor, Table F3, is ratio of the coincident peak load for all the divisions in an area to the sum of the non-coincident peak loads of those divisions. This factor is applied to the division and muni loads in the area to obtain the coincident loads.

Area	Diversity factor	Divisions	Muni
Humboldt	1.000	Humboldt	
N. C. & N. B.	0.993	N. Coast, N. Bay	Healdsburg, Ukiah
C. C. & L. P.	0.967	C. Coast, L. Padres	Lompoc
N. Valley	1.000	N. Valley	Lassen MUD, Biggs, Gridley, Plumas Sierra, Redding, Shasta, Knauf
C. Valley	0.970	Sacramento, Sierra, Stockton, Stanislaus	SMUD, Roseville, Lodi, TID, MID, Tracy Pumps, Mt. House,
G. Fresno	0.981	Yosemite, Fresno, Kern	O'Neill Pumps
G. Bay	0.976	S.F., Peninsula, De Anza, San Jose, E. Bay, Diablo, Mission	Santa Clara, Palo Alto, Alameda and LLNL

Table F3. Area Diversity Factors

6. Conforming & Non-conforming Loads

Conforming loads consist of mostly residential and small commercial and industrial loads. These loads follow a typical daily load shape and load growth pattern. Non-conforming loads are generally large commercial and industrial loads. Many of these loads are served at transmission voltages (> 50 kV.) The non-conforming loads behave very differently from the conforming loads. They have different daily or seasonal patterns. They do not vary significantly with temperature. Their growths are driven by parameters that are very different from the macro economic parameters as the system load. Their forecasts are based on information from various sources such as the account/customer representatives, billing data and/or operation data. For the 1-in-2 system, 1-in-5 system or the 1-in-10 area base cases, the non conforming loads are assumed to be the same.

7. Self-generation and Generation-plant Loads

Self-generation or generation-plant load refers to the load that is served by the generation at the site. Generation-plant load normally refers to the auxiliary load of the generators. Self-generation load refers to the load other than the auxiliary load (which is generally very small) such as the refinery load of a petroleum processing plant. Even though self-generation load has the same characteristics as non-conforming load, it has a unique designation because it is generally not observable due to the net metering (generation minus load) used at the location.

The self-generation loads are based on information from various sources such as the account/customer representatives, billing data and/or operation data. The generation-plant loads are normally determined from the generator specifications. Only large thermal generators would have generation-plant loads of significance. Generation-plant load would be either on or off depending on the status of the generator. Self-generation loads could be independent of the generator status and are assumed to be the same in the 1-in-2 system, 1-in-5 system or the 1-in-10 area base cases.

8. Transmission Losses

Loss is a significant item. Based on power flow base cases, transmission losses from generation (generator output) to transmission buses where the loads are modeled (correspond to the high side of the distribution transformers) are shown in Table E4. These losses are used to adjust the recorded data if necessary. Please note that the system loss is larger than the sum of division losses because the system loss includes those of the 500 kV system, munis and self-generations.

Division	Adjustment	Losses
Humboldt	21	7
North Coast	-53	35
North Valley	3	49
Sacramento	20	53
Sierra	-5	71
North Bay	0	12
East Bay	-11	5
Diablo	14	36
San Francisco	0	6
Peninsula	-6	32
Stockton/Stanislaus	-103	51
Yosemite/Fresno	11	81
Kern	2	46
Mission	54	49
De Anza	82	17
San Jose	-50	38
Central Coast	25	31
Los Padres	-16	17
System	0	958

9. Load Characteristics

There are several loads and load data discussed in this report. Their characteristics are described below:

- Base case loads (1-in-2 system, 1-in-5 system or 1-in-10 area) refer to loads modeled at the transmission buses (equivalent to the high side of the distribution transformers.) The base case loads include PG&E (conforming, non conforming, self-generation and generation-plant loads) and muni loads.

- System (Line 9) loads are based on the sum of the interchange and the net generation outputs in northern California. They include PG&E and muni loads. Line 9 load, but excludes self-generation and generation-plant loads. Other than the self-generation and generation-plant loads, system losses should be subtracted from the Line 9 value to obtain the comparable base case load.

- Recorded division load is based on the SCADA data for the transmission line flows into the division and generations within the division. The recorded division load differs from that modeled in base cases in two aspects. (1) The recorded division load includes losses. (2) The recorded load division load may include or exclude some loads due to the SCADA configurations (e.g., self-generation load). The losses and the adjustments that should be applied to the recorded division load to obtain the comparable load modeled in the base cases are summarized in Table E4.

- Distribution loads are based on the highest loads recorded at the high side of the distribution transformers (equivalent to the transmission buses and thus do not include transmission losses.) Distribution loads are non-simultaneous conforming loads.

ATTACHMENT DA5-3

PG&E Voltage Support Device Installation Plan

Humboldt Reactive Support

TARGETED IN-SERVICE DATE

December 2008

PURPOSE AND BENEFIT

Reliability and Required Must Run Requirements Reduction – This project increases electric transmission reliability and decreases required must run requirements for the Humboldt.

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to install a voltage support device within the Humboldt transmission system.

This project is expected to cost between $5M and $10M.

BACKGROUND

Electric customers in Humboldt County, which is along California's northern coast, are served by local generation plants and two over 100 miles long transmission lines. In addition, there are two synchronous condensers at Humboldt Substation that provide a limited amount of reactive support. These two condensers are over 40 years old and are starting to show signs of aging and deterioration.

This project would replace the Humboldt Substation condensers with a new Static Var Compensator with rating at about 100 MVAR. The completion of this project would improve voltage stability in Humboldt County and would also reduce RMR requirements.

BASE CASE AND STUDY ASSUMPTIONS

The base cases that were developed as part of the expansion plan process were used for this study. All base cases developed as part of the expansion plan process were concurred with CAISO and interested stakeholders.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects – TBD

ATTACHMENT DA5-4

CAISO Interconnection Approval

California ISO
Your Link to Power

California Independent
System Operator

Gary DeShazo
Director of Regional Transmission – North
(916) 608-5880

April 13, 2006

Mr. John Vardanian
PG&E Generation Interconnection Services
245 Market Street, Room 775, Mail Code N7L
San Francisco, CA 94105-1814

Subject: Ramco Generating Two Humboldt Energy Facility Project Preliminary Interconnection Approval

Dear Mr. Vardanian:

The California ISO (CAISO) has reviewed the System Impact Study (SIS) for the Ramco Generating Two, Humboldt Energy Facility Project located in Humboldt county, California. The SIS was conducted by Pacific Gas and Electric Company (PG&E) at the request of the Ramco Generating Two (Ramco) to replace the existing PG&E's Humboldt Bay plant. The project consists of ten reciprocating engine generators, each rated at 16.638 MW, with a plant auxiliary load of 3.65 MW, for a maximum net output to the grid of 162.73 MW. The project's requested COD is August, 2008.

Based on the results of the SIS, the CAISO is granting preliminary interconnection approval to the Humboldt Energy Facility Project.

Please note that this letter approving the interconnection of the project allows the project to connect to the CAISO Controlled Grid and to be eligible to deliver the project's output using available transmission. However, it does not establish the generation project's level of deliverability for purposes of determining its Net Qualifying Capacity under the CAISO Tariff and in accordance with CPUC-adopted Resource Adequacy Rules. Therefore, this letter makes no representation, and Ramco cannot rely on any statements herein, regarding the ability, or amount, of the output of the project to be eligible to sell Resource Adequacy Capacity. We encourage you to follow the baseline deliverability studies ongoing at the CAISO. For more information on generation deliverability, please reference the web links provided in the attachment to this letter.

If you have questions about the CAISO review of this study, please contact Paul Didsayabutra at (916) 608-1281 (mailto:pdidsaybutra@caiso.com) or myself at (916) 608-5880 (mailto:gdeshazo@caiso).

Sincerely,

Original signed by Gary L. DeShazo

Gary DeShazo
Director of Regional Transmission - North

cc: Gary Veerkamp (Ramco via e-mail mailto:garyveer@sbcglobal.net)
Kent Fickett (Ramco via e-mail mailto:k.fickett@comcast.net)
Karen Grosse (PG&E via e-mail, mailto: KRG6@pge.com)
John Vardanian (PG&E via e-mail, mailto: JAV7@pge.com)
Albert Wong (PG&E via e-mail, mailto: AYW1@pge.com)
Madeline Aldridge (PG&E via e-mail, mailto: MEG5@pge.com)

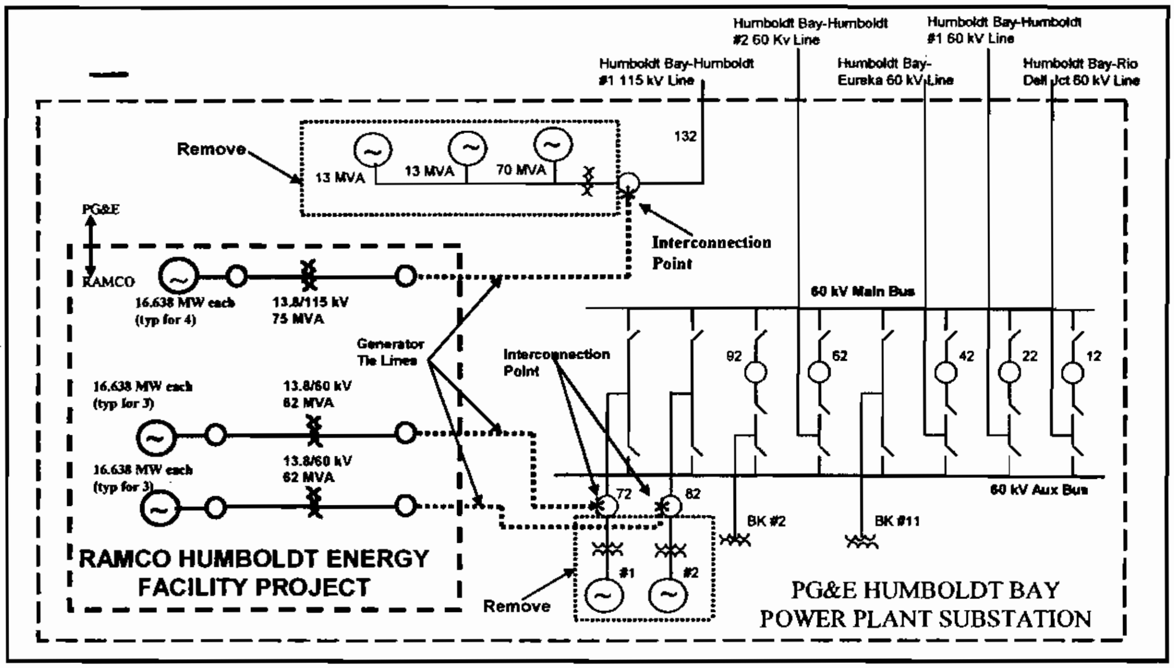
Armando Perez (ISO)
Dariush Shirmohammadi (ISO)
Donna Jordan (ISO via e-mail)
Judy Nickel (ISO via e-mail)
Gary Brown (ISO via e-mail)
Tom French (ISO via e-mail)
Regional Transmission - North (ISO via e-mail)

Attachment

The attachment provides a summary of the project, along with CAISO comments.

Project Overview:

The proposed Humboldt Energy Facility Project will replace the existing PG&E's Humboldt Bay plant. The project consists of ten reciprocating engine generators, each rated at 16.638 MW, with a plant auxiliary load of 3.65 MW, for a maximum net output to the grid of 162.73 MW. The project's requested COD is August, 2008.



Conceptual One-line Diagram

Summary of the System Impact Study (SIS) Results

The SIS concluded that the addition of the project would not cause normal (N-0) overloads to existing transmission facilities. However, the project could cause one new Category "B" and one new Category "C" emergency overload on the Humboldt-Trinity 115 kV Line # 1 under summer off-peak conditions. The mitigation plans could involve reducing number of generators on the 115 kV system from 4 to 3 (total generation reduction of16.63 MW) or reconductoring the Humboldt-Trinity 115 kV line #1.

In addition to the new overloads, the project would exacerbate five pre-existing Category C as shown in the next page. These pre-existing overloads are mitigated by either the existing operation solutions or existing PG&E projects.

- The Humboldt Bay-Eureka 60 kV Line #1. The project could exacerbate the overload on this line up to 2% under summer and winter peak conditions.

- The Humboldt 115/60 kV Transformer #1. The project could exacerbate the overload on this line by 4% under winter peak conditions.

- The Humboldt 115/60 kV Transformer #2. The project could exacerbate the overload on this line by 7% under winter peak conditions.

- The Bridgeville 115/60 kV Transformer #1. The project could exacerbate the overload on this line by 6% under winter peak conditions.

The short circuit; system protection and substation evaluation identified no breakers or substation equipment that would become overstressed due to the addition of the project.

The dynamic stability study results determined that the addition of the project would cause frequency criteria violations at several 60 kV buses. In addition, the outages of Humboldt 115 kV bus outage and Humboldt-Rio Dell 60 kV line outage could cause transmission system unstable. The mitigation plans for dynamic problems will be developed in the facility study phase as a requirement for receiving final approval.

CAISO Comments:

Based on the results of the SIS, the CAISO is granting preliminary interconnection approval to the Humboldt Energy Facility Project.

Please note that this letter approving the interconnection of the project allows the project to connect to the CAISO Controlled Grid and to be eligible to deliver the project's output using available transmission. However, it does not establish the generation project's level of deliverability for purposes of determining its Net Qualifying Capacity under the CAISO Tariff and in accordance with CPUC-adopted Resource Adequacy Rules. Therefore, this letter makes no representation, and Ramco cannot rely on any statements herein, regarding the ability, or amount, of the output of the project to be eligible to sell Resource Adequacy Capacity.

We encourage you to follow the baseline deliverability studies ongoing at the CAISO. For more information on generation deliverability, please reference the following web links:

http://www.caiso.com/1796/17969a066d030.pdf

http://www.caiso.com/docs/2005/05/03/2005050317085664l0.pdf

http://www.caiso.com/docs/2005/05/03/200505031704315525.pdf

PO Box 639014 Folsom, California 95763-9014 Telephone: 916 351-4400

SECTION 8.10

Socioeconomics

SECTION 8.10

Socioeconomics

1. Year for economic estimates (Appendix B [g][1])

...provide a discussion of the existing site conditions, the expected direct, indirect and cumulative impacts due to the construction, operation and maintenance of the project, the measures proposed to mitigate adverse environmental impacts of the project, the effectiveness of the proposed measures, and any monitoring plans proposed to verify the effectiveness of the mitigation.

Information required to make AFC conform with regulations:

Please indicate the year for all economic estimates.

Response – All construction estimates are in 2006 dollars and all operation estimates are in 2009 dollars.

2. ***Operation Payroll*** **(Appendix B [g][7][B][vii])**

An estimate of the total construction payroll and an estimate of the total operation payroll.

Information required to make AFC conform with regulations:

Please provide an estimate of the total operation payroll.

Response – The total operation payroll is estimated to be $2.1 million per year. Please note that the existing Humboldt Bay Power Plant (Units 1 and 2) will cease operation once the HBRP facilities come on line. Therefore, all of the $7.3 million operation and maintenance costs specified in the AFC (Section 8.10.2.3.4) pertain to the new facilities of the HBRP.

3. ***Locally Purchased Materials During Operation*** *(Appendix B [g][7][B][viii]):*

An estimate of the expenditures for locally purchased materials for the construction and operation phases of the project.

Information required to make AFC conform with regulations:

Please provide an estimate for locally purchased materials for the operation phase of the project.

Response – The HBRP expenditures for locally purchased materials during the operations phase will be about $150,000 per year.

4. Tax Revenues (Appendix B [g][7][B][ix]):

An estimate of the capital cost of the project [and] of the potential impacts on tax revenues from construction and operation of the project.

Information required to make AFC conform with regulations:

Please provide a quantitative estimate of the potential impact on tax revenues from the operation of the project (i.e., sales and use tax and property tax).

Response – The annual materials and supplies costs are estimated to be about $5.2 million per year ($7.3 million operations and maintenance minus $2.1 million payroll). The sales and

use tax rate in Humboldt County is 7.25 percent; therefore, the total tax revenue to the County during the operations phase would be about $377,000 annually.

The property tax assessed to PG&E is 1.159 percent annually (Joe Mellett, Humboldt County Senior Accountant, personal communication). This amount varies based on the bonds outstanding at any one time; however, 1 percent always goes to Humboldt County and the remainder goes to pay bond debt. Assuming that the capital cost of the HBRP will be $250 million, then the increase in improvements would be $250 million. Using the 1.159 percent tax rate, the tax revenue would be $2.8 million annually.