Exhibit 12

Mankato Energy Center Start profile for winter months

No Auxilary Boiler						**With Auxilary Boiler**					
			Hot						**Hot**		
Hour	CT Gas	AXB Gas	CT %load	STG % load		Hour	CT Gas	AXB Gas	CT %load	STG % load	
1	1200	0	60	0		1	1200	0	60	0	
2	1450	0	60	35	AGC Available	2	1450	0	60	35	AGC Available
Fuel	2650	0		Total Fuel	2650	Fuel	2650	0		Total Fuel	2650
			Warm						**Warm**		
	CT Gas	AXB Gas	CT %load	STG % load			CT Gas	AXB Gas	CT %load	STG % load	
1	1000	0	30	0		1	0	70	0	0	
1.55	1450	0	60	0		2	1000	70	30	0	
2	1450	0	60	0		2.55	1450	70	60	0	
3	1450	0	60	10		3	1450	5	60	10	
4	1450	0	60	35	AGC Available	4	1450	5	60	35	AGC Available
Fuel	6800	0		Total Fuel	6800	Fuel	5350	220		Total Fuel	5570
			Cold						**Cold**		
	CT Gas	AXB Gas	CT %load	STG % load			CT Gas	AXB Gas	CT %load	STG % load	
1	1000	0	30	0		1	0	70	0	0	
2	1000	0	30	0		2	0	70	0	0	
3.05	1450	0	60	0		3	1000	70	30	0	
4	1450	0	60	0		4	1000	70	30	0	
5	1450	0	60	10		5.05	1450	5	60	10	
6	1450	0	60	20		6	1450	5	60	20	
6.5	675	0	60	35	AGC Available	6.5	675	5	60	35	AGC Available
Fuel	8475	0		Total Fuel	8475	Fuel	5575	295		Total Fuel	5870

Hot = Steam turbine offline less than 8 hours - CT in compliance within 60 minutes
Warm = Steam turbine offline between 8 and 48 hours - CT in compliance within 95 minutes
Cold = Steam turbine offline more than 48 hours - CT in compliance within 185 minutes

Fuel is based on 20 degrees F ambient and in the units of MMBTU

Summary:
Total fuel to AGC in MMBTU

	W/O AXB	W/AXB
Hot	2650	2650
Warm	6800	5570
Cold	8475	5870

Above "Assume starts" is based on a plant dispatch of 3 time a week.

CO	Nox	CO lbs saved	Nox saved
		869.8144752	79.30856585
1329.031	95.62531605		
1319.158	94.84090405		
1309.285	94.05649205		
1299.411	93.27208004		
1289.538	92.48766804		
1279.665	91.70325604		
1269.791	90.91884404		
1259.918	90.13443203		
1250.044	89.35002003		
1240.171	88.56560803		
1230.298	87.78119602		
1220.424	86.99678402		
1210.551	86.21237202		
1200.678	85.42796002		
1200.678	85.42796002		
1200.678	85.42796002		
1200.678	85.42796002		
1200.678	85.42796002		
1200.678	85.42796002		
1200.678	85.42796002		
1200.678	85.42796002		

\

LMEC Aux Boiler		320	mmbtu/hr	
				lb/mmbtu
	Nox Hourly	3.5		0.0109375
	Co hourly	11.8		0.036875

Emissions from Aux Boiler Cold Start

4 hours	3.0625	Nox
	10.325	CO
4 hours	3.0625	
	10.325	

Cold Start Emissions Saved

CO	859	lbs
Nox	76	lbs

505

Total Savings for 6 starts	5156.936851	CO
	457.4763951	Nox

	Emissions Saved from Cold Star lbs	6 cold starts lbs	Aux Boiler Emissions Cold Starts	Aux Boiler Emission: 6 Cold Starts	Total Saved lbs	Emissions Saved Warm Starts*	Emissions 50 Warm Starts	Aux Boiler Emissions Warm Start	Total Aux Boiler 50 starts	Total Warm Start Emission
CO lbs saved	870	5219	10	62	5157	405	20250	10.325	516.25	19734
Nox	79	476	3	18	457	30	1500	3.0625	153.125	1347

	CO	Nox
Total Emissions Saved	**24891**	**1804**
Tons	**12.44534343**	**0.902175698**

* Warm start emissions savings are based on the difference in warm and hot starts on the SU/SD spreadsheet.

1200.678	85.42796002
1200.678	85.42796002
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1200.678	85.42796002
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1200.678	85.42796002
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1200.678	85.42796002
1200.678	85.42796002
1200.678	85.42796002
1200.678	85.42796002
1189.541	85.43575788
1178.405	85.44355575
1167.269	85.45135362
1156.133	85.45915149
1144.997	85.46694936
1133.861	85.47474722
1122.725	85.48254509
1111.589	85.49034296
1100.453	85.49814083
1089.317	85.50593869
1078.18	85.51373656
1067.044	85.52153443
1055.908	85.5293323
1044.772	85.53713017
1033.636	85.54492803
1022.5	85.5527259
1011.364	85.56052377
1000.228	85.56832164
989.0917	85.5761195
977.9556	85.58391737
966.8195	85.59171524
955.6834	85.59951311
944.5473	85.60731098
933.4112	85.61510884
922.2751	85.62290671
911.139	85.63070458
900.0029	85.63850245
888.8668	85.64630032
877.7307	85.65409818
866.5946	85.66189605
850.5137	85.00047651
834.4328	84.33905698
818.3519	83.67763744
802.271	83.01621791
786.1901	82.35479837
770.1092	81.69337883
754.0282	81.0319593
737.9473	80.37053976
721.8664	79.70912022
705.7855	79.04770069
689.7046	78.38628115
673.6237	77.72486161
657.5428	77.06344208
641.4619	76.40202254
625.381	75.74060301
609.3	75.07918347
593.2191	74.41776393
577.1382	73.7563444
561.0573	73.09492486

544.9764	72.43350532
528.8955	71.77208579
512.8146	71.11066625
496.7337	70.44924671
480.6528	69.78782718
464.5718	69.12640764
448.4909	68.46498811
432.41	67.80356857
416.3291	67.14214903
400.2482	66.4807295
384.1673	65.81930996
384.1673	65.81930996
384.1673	65.81930996
384.1673	65.81930996
382.5264	65.13730136
380.8854	64.45529276
379.2445	63.77328415
377.6036	63.09127555
375.9627	62.40926695
374.3218	61.72725835
372.6809	61.04524975
371.0399	60.36324115
369.399	59.68123254
367.7581	58.99922394
366.1172	58.31721534
364.4763	57.63520674
362.8354	56.95319814
361.1944	56.27118954
359.5535	55.58918093
357.9126	54.90717233
356.2717	54.22516373
354.6308	53.54315513
352.9899	52.86114653
351.3489	52.17913793
104377.7	9517.027902
869.8145	79.30856585

Exhibit 13

Poloncarz, Kevin

From: Poloncarz, Kevin
Sent: Thursday, April 02, 2009 8:00 PM
To: 'Alexander Crockett'
Cc: 'bbunger@baaqmd.gov'; Kissinger, William D.
Subject: RCEC: Startup/Shutdown Analysis of Annual Limits, Auxiliary Boiler and CO BACT

Attachments: SU-SD analysis final 4-1-09.pdf; Aux Boiler emissions; RE: Aux Boiler emissions cost effectiveness; CO Average Cost effectiveness 4-2-09.xls; CO Icremental 4-2-09.xls; Support for CO cost effectiveness.xls

Sandy:

Attached are various pieces of technical information supporting the BACT analysis for startup emissions, including estimated operating scenarios as a basis for the annual limits on emissions.

Assumed Operating Scenario/Basis for Annual Emissions Limits: The attached table, "SU-SD analysis final 4-1-09.pdf", is intended to illustrate a typical operating profile, wherein the facility is operated six days a week, sixteen hours a day (i.e., "6x16"). This provides a conservatively high estimate of startup events and emissions, e.g., it assumes 6 cold startup events per year for the facility, which, based upon Calpine's experience at its other facilities is highly unlikely. This provides the basis for proposing a lower annual limit on emissions of CO and uses the following assumptions for predicting annual emissions. (Note that this number is larger than in the last draft of the analysis I sent you because there was a problem with the spread-sheet that kept it from summing-up warm startup emissions; it is still 50 tons per year lower than it was in the Draft Permit.)

- For NOx, the emissions for both baseload/peak operations and startup/shutdown events reflect the permit limits.
- For CO, the emissions during baseload/peak operation are based upon the reduced limit of 2 ppmvd CO.
- For cold startup events, CO emissions are based upon the permit limit of 5,028 lbs, given that the CO catalyst will not be achieving significant reductions during cold startup events.
- For hot startup events, CO emissions were estimated at 50% of the highest annual average for all hot startup events recorded at Delta Energy Center during the past four calendar years, as shown on the bottom part of the table. This is based upon Calpine's assessment that, during hot startup events, the catalyst should still be able to achieve emissions 50% lower than the average annual emissions of CO for all events recorded at Delta in calendar year 2008. (Delta does not have a catalyst; hence, 50% efficiency of the catalyst at the less than peak temperature would achieve 50% reductions.)
- For warm startup events, CO emissions are based upon 50% of the maximum recorded during a hot startup event at Delta during the past four calendar years (2,446 lbs CO). This is because Calpine believes the catalyst will still achieve substantial reductions during warm startups, but is not as comfortable that this will be as high as during hot startups (given the longer down-time); hence, it has taken the maximum record hot startup event as the basis for then applying the 50% reduction.
- For shutdown events, the CO emissions are based upon 50% of the average CO emissions observed at Delta during shutdown events during the past four calendar years, as shown on the table.

Auxiliary Boiler BACT Analysis: Also attached are two emails from Barbara McBride providing an analysis of the emissions reductions and costs associated with use of an auxiliary boiler to achieve reductions in startup emissions. Barbara's emails provide an explanation for the basis for calculating reductions that would be achieved during startup by an auxiliary boiler, using Los Medanos Energy Center's emissions profile as the basis for the small offsetting increase in emissions from the auxiliary boiler itself. This emissions estimate is based upon the same operating profile/scenario as illustrated by the table described above and therefore represents a conservatively high estimate of the reductions that might be achieved, e.g., it assumes 6 cold startup events per year at the facility, which is unlikely.

<u>CO BACT Analysis</u>: I have also attached an average and incremental cost-effectiveness analysis for CO, along with supporting information showing calculation of the emissions reductions achieved through use of an oxidation catalyst to achieve emissions of 1.5 ppmvd CO @ 15% O2. Again, the emissions estimate is conservatively high, since it is based upon the same 6X16 operating scenario and set of assumptions described above on the reductions that will be achieved by the catalyst during hot and warm startup and shutdown events (when most of the CO emissions will occur).

The cost effectiveness analysis indicates that the incremental cost-effectiveness to achieve a limit of 1.5 rather than 2.0 ppmvd CO is $45,400 per ton. The average cost-effectiveness is $4,200 per ton of CO. While the Air District has not established a cost-effectiveness threshold for CO BACT, this is more than ten times higher than the cost-effectiveness thresholds developed and applied by other agencies for purposes of the CO BACT analysis.

- South Coast Air Quality Management District has adopted average and incremental “maximum cost-effectiveness criteria” for major sources of $400 and $1,150 per ton of CO reduced (respectively). (SCAQMD, Best Available Control Technology Guidelines, August 17, 2000, revised July 14, 2006, at 29.)
- San Joaquin Valley Air Pollution Control District has adopted a “recommended cost threshold” for BACT analysis of $300 per ton of CO. (Memorandum, David Warner, Director of Permit Services, to Permit Services Staff, Subject: “Revised BACT Cost Effectiveness Thresholds”, May 14, 2008.)
- I did a search on U.S. EPA’s clearinghouse and only identified only one recent CO BACT permitting decision for the source category which was based on cost-effectiveness: It imposed a CO limit of 1.8 ppmvd (3-hr average), based upon an average cost-effectiveness of $1,750 per ton of CO. (Clearinghouse ID No. GA-0127; Plant McDonough Combined Cycle, Permit No. 4911-067-0003-V-02-2, January 7, 2008.)
- There were only two other CO BACT decisions for the source category in the past four calendar years where an oxidation catalyst was required based upon cost-effectiveness:
    - In one, an average and incremental cost-effectiveness were $2,736 and $5,472 per ton of CO (respectively). (Clearinghouse ID No. NV-0035; Sierra Pacific Power Company Tracey Substation Expansion Project, Permit No. AP4911-1504, August 16, 2005.)
    - In the other, average cost-effectiveness was $1,161 per ton of CO. (Clearinghouse ID No. OR-0041; Wanapa Energy Center, Permit No. R10PSD-OR-05-01, August 8, 2005.)

In summary, the average cost-effectiveness of 1.5 ppmvd is more than ten times higher than either SCAQMD's or SJVAPCD's cost-effectiveness threshold and significantly higher than any of the other three decisions I could find (in the past four calendar years) where a oxidation catalyst was required based upon cost-effectiveness. The incremental cost-effectiveness is many times higher than SCAQMD's threshold or the one decision where a CO catalyst was required for a similar facility based upon incremental cost-effectiveness analysis. A decision that BACT constitutes the 2.0 ppmvd level, rather than 1.5 ppmvd, based upon this analysis is, in my view, perfectly consistent with the holding of the EAB in *In re General Motors, Inc*., PSD Appeal No. 01-30 10 Env. Admin. Dec. 360 (2002).

Please let me know if you have any questions.

Thanks.

SU-SD analysis fina 4-1-09.pd...   Aux Boiler emissions   RE: Aux Boiler emissions cost ...   CO Average Cost effectiveness ...   CO Icremental 4-2-09.xls   Support for CO cost effectiven...

Kevin Poloncarz
Partner
T 415.393.2870
F 415.393.2286
kevin.poloncarz@bingham.com

BINGHAM
Bingham McCutchen LLP
Three Embarcadero Center
San Francisco, CA 94111-4067

Exhibit 14

Poloncarz, Kevin

From: Poloncarz, Kevin
Sent: Wednesday, February 24, 2010 6:45 PM
To: 'Helen Kang'
Cc: 'Alexander Crockett'; 'weyman@baaqmd.gov'; 'Barbara McBride'
Subject: FW: RCEC Public Records Request

Attachments: FD3 FD2 G Flex 10 Plant Efficiency Comparison Chart.pdf; RCEC efficiency numbers.xls

FD3 FD2 G Flex 10 Plant Effici... RCEC efficiency numbers.xls (2...

Helen:

As per our conversation yesterday, I have attached an Excel file that provides the basis for comparisons of the thermal efficiency of the proposed Russell City Energy Center's (RCEC) equipment and configuration, with that of similarly sized plants using different technology. The third spreadsheet also shows the difference in efficiency between RCEC's unfired and duct-fired scenarios.

These spreadsheets were prepared by Alex Prusi, PE, Principal Engineer and Director, Calpine. I had asked Mr. Prusi to prepare the long-hand back-up calculations supporting the basis for the efficiency increase associated with the upgrade to FD3 turbine technology, as shown by the attached PDF file. However, Mr. Prusi was never asked to provide similar long-hand back-up calculations for his other plant efficiency comparisons. Rather, the attached spreadsheets, which have the formulae and calculations embedded within them, were used to provide the basis for these other comparisons.

Would you please confirm by replying to all if this satisfies Ken Kloc's request to the Air District for additional supporting information concerning these comparisons?

Please let me know if you have any questions. Thank you in advance for your cooperation.

Kevin Poloncarz
Partner
T 415.393.2870
F 415.393.2286
kevin.poloncarz@bingham.com

B I N G H A M
Bingham McCutchen LLP
Three Embarcadero Center
San Francisco, CA 94111-4067

-----Original Message-----
From: Barbara McBride [mailto:Barbara.McBride@calpine.com]
Sent: Tuesday, February 23, 2010 2:42 PM
To: Alex Makler; Alex Prusi; Rick Thomas; Poloncarz, Kevin

Cc: Jeanne McKinney; Rosemary Antonopoulos
Subject: FW: RCEC Public Records Request

Can we provide them with this data?

Barbara McBride

Director, Environmental, Health and Safety

Calpine Corporation

(925)-570-0849

-----Original Message-----
From: Weyman Lee [mailto:Weyman@baaqmd.gov]
Sent: Tuesday, February 23, 2010 11:33 AM
To: Barbara McBride
Subject: FW: RCEC Public Records Request

Hi Barbara-

Just got a call from Ken Kloc of GGU asking if calculations for the 501G and Flex 10 thermal effeciencies are available for the attached comparison table. The attached calcs are only for the FD2 and FD3 plants. Thanks for your help.

Weyman

> -----Original Message-----
> From: Weyman Lee
> Sent: Monday, February 22, 2010 4:47 PM
> To: 'HKang@ggu.edu'
> Cc: Alexander Crockett; Public Records
> Subject: RCEC Public Records Request
>
> Helen-
>
> Here is the plant efficiency comparison table cited in footnote #67 of the Responses to Public Comments.
>
> > <<FD3 FD2 G Flex 10 Plant Efficiency Comparison Chart.pdf>>

RCEC
Output limit 612800 kW

Configuration	Gross Plant Efficiency, LHV	Gross Plant Efficiency, HHV	Net Plant Efficiency, LHV	Net Plant Efficiency, HHV
RCEC - 501 FD2	55.3%	50.7%	53.3%	48.9%
RCEC - 501 FD3	56.4%	51.7%	54.4%	49.9%
RCEC - 501 G	49.8%	45.7%	48.3%	44.3%
RCEC - Flex 10	49.3%	47.8%	45.2%	43.9%

Note the use of the 501G results in steam turbine that limited to 143 MW which results in an inefficient bottoming cycle.

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NYSE CPN

Russell City - Comparison of FD2 and FD3 Configurations

Iso Conditions - 59°F, 60% Relative Humidity
- Unfired Heat Recovery Steam Generator

FD2 = Net Output 556,668 KW
Auxiliary Power 20,392 KW
Heat Input = 3,881 MMBTU (HHV) HR
= 3,561 MMBTU (LHV) HR

Determine Net Plant Efficiency (HHV Basis)

$$= \frac{\text{Net Plant Out(KW)} \times \overbrace{3413 \text{ KW/BTU/HR}}^{\text{(Conversion Factor)}}}{\text{Heat Input MMBTU (HR)} \times 10^6}$$

$$= \frac{556{,}668\ (3413)}{3881 \times (10^6)} = 0.48954 \times 100 = \boxed{48.9\ \%}$$

LHV Basis

$$\frac{556{,}668 \times 3413}{3561 \times (10^6)} = 0.53353 = \boxed{53.3\%}$$

Gross Plant Efficiency

Gross Plant Out = Net Plant + Aux Power

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NYSE CPN

$$(HHV)\ \text{Gross plant Eff} = \frac{(556{,}668 + 20{,}392) \times 3413}{3881 \times (10^6)}$$

$$= 0.5074 = \boxed{50.7\%}$$

$$\text{LHV GROSS PLANT Eff} = \frac{(556{,}668 + 20{,}392) \times 3413}{3561 \times 10^6}$$

$$= 0.55307 = \boxed{55.3\%}$$

FD3 CONFIGURATION

NET Output = 574,456 KW
AUX POWER = 21,143 KW
HEAT INPUT = 3,928 MMBTU HHV
= 3,604 MMBTU LHV

$$\text{NET PLANT EFF}_{HHV} = \frac{574{,}456 \times 3413}{3928 \times 10^6}$$

$$\doteq 0.49913 = \boxed{49.9\%}\ \text{HHV}$$

$$\text{NET PLANT EFF}_{LHV} = \frac{574{,}456 \times 3413}{3604\ (10^6)}$$

$$= 0.54401 = \boxed{54.4\%}\ \text{LHV}$$

CALPINE® NYSE CPN

FD3 GROSS PLANT EFF. = $\frac{\text{NET POWER} + \text{AUX } \cancel{\text{POWER}}}{\text{HEAT INPUT}} \times 100\%$

HHV BASIS = $\frac{(574{,}456 + 21{,}143)(3413)}{3{,}928 \times 10^6 \text{ (HHV)}}$

$= 0.5175 = \boxed{51.7\% \quad \text{HHV}}$

LHV BASIS = $\frac{(574{,}456 + 21{,}143)(3413)}{3{,}604 \times 10^6}$

$= 0.56403 = \boxed{56.4\%}$

SUMMARY OF RESULTS

CONFIGURATION	GROSS PLANT LHV	GROSS PLANT HHV	NET PLANT LHV	NET PLANT HHV
FD2	55.3%	50.7%	53.3%	48.9%
FD3	56.4%	51.7%	54.4%	49.9%
Δ	1.09%	1.00%	1.01	1%

RCEC
Output limit 612800 kW

Configuration	Gross Plant Efficiency, LHV	Gross Plant Efficiency, HHV	Net Plant Efficiency, LHV	Net Plant Efficiency, HHV
RCEC - 501 FD2	55.3%	50.7%	53.3%	48.9%
RCEC - 501 FD3	56.4%	51.7%	54.4%	49.9%
RCEC - 501 G	49.8%	45.7%	48.3%	44.3%
RCEC - Flex 10	49.3%	47.8%	45.2%	43.9%

Note the use of the 501G results in steam turbine that limited to 143 MW which results in an inefficient bottoming cycle.

Russell City Energy Center

Configuration	Gross Plant Efficiency, LHV	Gross Plant Efficiency, HHV	Net Plant Efficiency, LHV	Net Plant Efficiency, HHV	Output kW
RCEC - 501 FD2	55.3%	50.7%	53.3%	48.9%	556,668
RCEC - 501 FD3	56.4%	51.7%	54.4%	49.9%	574,456
Delta	1.09%	1.00%	1.05%	0.96%	3.20%

54.1%

Russell City Energy Center

Configuration	Gross Plant Efficiency, LHV	Gross Plant Efficiency, HHV	Net Plant Efficiency, LHV	Net Plant Efficiency, HHV
RCEC - 501 FD3	56.45%	51.7%	54.4%	49.9%
RCEC - 501 FD3 Duct Burner	56.44%	50.84%	54.3%	49.0%
Delta	0.01%	0.86%	0.06%	0.95%

Exhibit 15

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 2
290 BROADWAY
NEW YORK, NY 10007-1866

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

APR 07 2006

Ross D. Ain
Senior Vice President
Caithness Long Island, LLC.
565 Fifth Avenue, 29th Floor
New York, NY 10017

Re: Prevention of Significant Deterioration of Air Quality (PSD)
Caithness Long Island Energy Center

Dear Mr. Ain:

On October 5, 2005, the U.S. Environmental Protection Agency (EPA), Region 2 Office, received a complete PSD application from Caithness Long Island, LLC to construct a new 346 MW combined cycle electric generating facility in Brookhaven, New York known as the Caithness Long Island Energy Center (CLIEC).

On December 16, 2005, EPA issued a preliminary determination, subject to public review, to approve the PSD permit. The 30-day public comment period for this draft permit commenced upon publication of EPA's preliminary determination in *Newsday* on Monday, December 19, 2005 and extended until Wednesday, January 18, 2006. The EPA received comments submitted by TRC Environmental Corporation on your behalf dated January 19, 2006. Since these comments were submitted after the close of the public comment period, they are not considered timely. EPA has, however, reviewed your comments, responded, and where appropriate made changes to the permit conditions as reflected in this final permit. However, while we have exercised our discretion to consider your comments, they are not timely and cannot serve as a basis for appeal.

The EPA concludes that this final permit meets all applicable requirements of the PSD regulations codified at 40 CFR §52.21, and the Clean Air Act (the Act). Accordingly, I hereby approve CLIEC's PSD permit for a 346 MW electric generating facility. This letter and its attachment represent EPA's final permit decision. The permit conditions are delineated in Enclosure I. Enclosure II contains EPA's response to comments on the draft permit.

This final permit decision may be challenged under the Consolidated Permit Regulations, codified at 40 C.F.R. Part 124 which apply to EPA's processing of this permit decision. However, since no comments were submitted during the public comment period administrative review is available only to the extent of the changes from the draft to the final permit. Any petition for review under this part must be made within thirty (30) days of the service of notice of the final permit decision. The petition for review shall include a statement for the reasons supporting that review and shall adhere to the standards outlined in 40 C.F.R. § 124.19(a)(1) and (2).

All persons petitioning for administrative review must file the original and one (1) copy of the petition for review with the Environmental Appeals Board at the following address:

For Regular Mail:
U.S. Environmental Protection Agency
Clerk of the Board, Environmental Appeals Board (MC 1103B)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001

For Hand-Carried and Federal Express Mail:
Colorado Building
1341 G. Street, NW
Suite 600
Washington, D.C. 20005

Phone number: (202) 233-0122

A copy of the administrative review request must also be sent to:

Steven C. Riva, Chief
Permitting Section
Air Programs Branch
U.S. Environmental Protection Agency
Region 2
290 Broadway – 25th Floor
New York, NY 10007-1866
(212) 637-4074

For purposes of judicial review under the Act, final agency action occurs when a final PSD permit is issued or denied and the administrative review procedures are exhausted. Notice of the Agency's final action with respect to this permit will be published in the Federal Register. Judicial review of this final action is available by the filing of a petition for review in the United States Court of Appeals for the appropriate circuit within 60 days of the date of the Federal Register notice. Only those persons who petitioned EPA under the administrative procedures may petition for review in the Court of Appeals. Under section 307(b) of the Act, this final agency action shall not be subject to judicial review in civil or criminal proceedings for enforcement.

Since changes were made to the draft permit, this final permit will become effective 30 days after the service of notice unless review is requested under §124.19. If a petition for review of the final agency action is filed, the permit will not become effective until a decision on the petition is rendered by the Environmental Appeals Board.

If you have any questions regarding this letter, please call Mr. Steven C. Riva, Chief, Permitting Section, Air Programs Branch, at (212) 637-4074.

Sincerely,

Walter E. Mugdan, Director
Division of Environmental Planning and Protection

Enclosures

cc: Kevin Kispert, NYSDEC
Kevin Maher, TRC

bcc: S. Riva, DEPP-APB
C. Adduci, DEPP-APB
A. Coulter, DEPP-APB
F. Mills, ORC-AB
J. Siegel, ORC-AB
File

ENCLOSURE I

CAITHNESS LONG ISLAND, LLC
CAITHNESS LONG ISLAND ENERGY CENTER

Final Permit

The Caithness Long Island Energy Center (CLIEC) Project is subject to the following conditions.

I. Permit Expiration

This PSD Permit shall become invalid if construction:

A. has not commenced (as defined in 40 CFR Part 52.21(b)(9)) within 18 months of the effective date of this permit;
B. is discontinued for a period of 18 months or more; or
C. is not completed within a reasonable time.

II. Notification of Commencement of Construction and Startup

The Regional Administrator (RA) shall be notified in writing of the anticipated date of initial startup (as defined in 40 CFR Part 60.2) of the facility not more than sixty (60) days nor less than thirty (30) days prior to such date. The RA shall be notified in writing of the actual date of both commencement of construction and startup within fifteen (15) days after such date.

III. Plant Operations

All equipment, facilities, and systems installed or used to achieve compliance with the terms and conditions of this PSD Permit, shall at all times be maintained in good working order and be operated as efficiently as possible so as to minimize air pollutant emissions. The continuous emission monitoring systems required by this permit shall be on-line and in operation 95% of the time when the emissions sources are operating. CLIEC shall demonstrate initial and continuous compliance with the operating, emission and other limits according to the performance testing and compliance assurance and all other requirements of this permit.

IV. Right to Entry

Pursuant to Section 114 of the Clean Air Act (Act), 42 U.S.C. §7414, the Administrator and/or his/her authorized representatives have the right to enter and inspect for all purposes authorized under Section 114 of the Act. The permittee acknowledges that the Regional Administrator and/or his/her authorized representatives, upon the presentation of credentials shall be permitted:

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A. to enter at any time upon the premises where the source is located or in which any records are required to be kept under the terms and conditions of this PSD Permit;

B. at reasonable times to access and to copy any records required to be kept under the terms and conditions of this PSD Permit;

C. to inspect any equipment, operation, or method required in this PSD Permit; and

D. to sample emissions from the source relevant to this permit.

V. Transfer of Ownership

In the event of any changes in control or ownership of facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. The applicant shall notify the succeeding owner and operator of the existence of this PSD Permit and its conditions by letter, a copy of which shall be forwarded to the Regional Administrator.

VI. Operating Requirements and Stack Parameters

A. Combustion Turbine and Duct Burner

1. The Siemens Westinghouse 501F combustion turbine shall be limited to a maximum design heat input rate of 2,221 million British Thermal Units per hour (mmBtu/hr) when firing natural gas and 2,125 mmBtu/hr when firing distillate oil, based on the higher heating value (HHV) of the fuel.

2. Except for startup and shutdown, the combustion turbine shall only be allowed to operate at or above 75% load.

3. While the combustion turbine (CT) is firing natural gas, the Heat Recovery Steam Generator (HRSG) may combust natural gas in the duct burner up to a maximum heat capacity of 494 mmBtu/hr, HHV.

4. While the combustion turbine is firing fuel oil and during fuel switching, the HRSG may combust natural gas in the duct burner up to a maximum heat input capacity of 369 mmBtu/hr, HHV.

5. The duct burner may operate a maximum of 4,380 hours during any 12-month consecutive period.

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6. For the purposes of this PSD permit, startup and shutdown shall be defined as:

   a. Startup for the combustion turbine is defined as the period beginning with the initial firing of fuel in the combustion turbine combustor and ending at the time when the load has increased to 75% of base load. Startups with the auxiliary boiler are defined as those starts in which the auxiliary boiler is operating and the air cooled condenser pressure is less than 15 inches of mercury absolute, the HP drum pressure is greater than or equal to 75 pounds per square inch (psig) and the IP drum pressure is at least 35 psig.

   b. For any startup without the auxiliary boiler, the duration shall not exceed 199 minutes for any given cold startup (>48 hours since shutdown), 199 minutes for any given warm startup (between 12 to 48 hours since shutdown) and 102 minutes for any given hot startup (12 hours or less since shutdown). For any startup with the auxiliary boiler, the duration shall not exceed 115 minutes for any given cold startup or warm startup and 102 minutes for any given hot startup.

   c. Shutdown for the combustion turbine is defined as the period of time beginning with the load decreasing from 75% of peak rated load and ending with the cessation of operation of fuel flow to the combustion turbine. The duration of any shutdown shall not exceed 90 minutes.

   d. During startup and shutdown of the combustion turbine, CLIEC shall comply with all mass emission limits in Section VIII of this permit except for NO_X, CO and PM/PM-10. CLIEC shall also comply with the opacity limit during each startup and shutdown. For NO_X, CO and PM/PM-10, CLIEC must comply with the emission limits specified in items e through l below during startup and shutdown. The total number of startup-shutdown cycles for the combustion turbine shall be limited to 260 during any consecutive 12-month period, out of which a maximum of 20 can be on oil.

   e. For natural gas startups without the auxiliary boiler, NO_X, CO and PM/PM-10 total emissions shall be limited to 488 lbs, 2,813 lbs and 75 lbs, respectively for cold and warm startups. Compliance shall be determined by taking the total pounds per event as measured by the CEMS for NO_X and CO.

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f. For natural gas startups with the auxiliary boiler, NO_X, CO and PM/PM-10 total emissions shall be limited to 191 lbs, 1,083 lbs and 51 lbs, respectively for cold and warm startups. Compliance shall be determined by taking the total pounds per event as measured by the CEMS for NO_X and CO.

g. For natural gas startups with or without the auxiliary boiler, NO_X, CO and PM/PM-10 total emissions shall be limited to 127 lbs, 891 lbs and 26 lbs, respectively for a hot startup.

h. For fuel oil startups without the auxiliary boiler, NO_X, CO and PM/PM-10 total emissions shall be limited to 1,136 lbs, 3,757 lbs and 745 lbs, respectively for cold and warm startups. Compliance shall be determined by taking the total pounds per event as measured by the CEMS for NO_X and CO.

i. For fuel oil startups with the auxiliary boiler, NO_X, CO and PM/PM-10 total emissions shall be limited to 413 lbs, 1,781 lbs and 557 lbs, respectively for cold and warm startups. Compliance shall be determined by taking the total pounds per event as measured by the CEMS for NO_X and CO.

j. For fuel oil startups with or without the auxiliary boiler, NO_X, CO and PM/PM-10 total emissions shall be limited to 277 lbs, 1,520 lbs and 266 lbs, respectively for a hot startup.

k. For each shutdown while the combustion turbine is firing fuel oil, NO_X, CO and PM/PM-10 total emissions shall not exceed 156 lbs, 850 lbs and 113 lbs, respectively.

l. For each shutdown while the combustion turbine is firing natural gas, NO_X, CO and PM/PM-10 total emissions shall not exceed 77 lbs, 511 lbs and 12 lbs, respectively.

7. At all times, including periods of startup, shutdown, and malfunction, CLIEC shall use best practices to maintain and operate the combustion turbine, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA and/or NYSDEC which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the plant.

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8. Exhaust gases from the combustion turbine/duct burner shall be directed to a single stack that rises to 170 feet above grade with a flue diameter of 20 feet.

B. Auxiliary Boiler

1. The auxiliary boiler shall be limited to a maximum design heat input rate of 29.4 million British Thermal Units per hour (mmBtu/hr) when firing natural gas and 28.0 mmBtu/hr when firing fuel oil.

2. The auxiliary boiler may operate up to a maximum of 4,800 hours during any 12-month consecutive period.

3. As part of the total 4,800 hours of operation, the auxiliary boiler may fire fuel oil for a maximum of 400 hours during any 12-month consecutive period.

4. Exhaust gases from the auxiliary boiler shall be directed to a stack that rises to 170 feet above grade with a flue diameter of 2.0 feet.

C. Fuel Gas Heater

1. The fuel gas heater shall be limited to a maximum design heat capacity of 4.32 million British Thermal Units per hour (mmBtu/hr).

2. Exhaust gases from the fuel gas heater shall be directed to a stack that rises to 26 feet above grade with a flue diameter of 1.33 feet.

D. Emergency Diesel Fire Pump

1. The emergency diesel fire pump shall be limited to a maximum design heat capacity of 2.24 million British Thermal Units per hour (mmBtu/hr).

2. The emergency diesel fire pump may operate up to a maximum of 4 hours per day and 375 hours during any 12-month consecutive period.

3. Exhaust gases from the emergency diesel fire pump shall be directed to a stack that rises to 7.25 feet above grade with a flue diameter of 0.5 feet.

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VII. Fuel Requirements

A. Combustion Turbine and Duct Burner

1. The combustion turbine shall only burn natural gas and/or low sulfur distillate oil.
2. The duct burner shall only burn natural gas.
3. The natural gas burned in the combustion turbine and duct burner shall have a maximum sulfur content of 0.35 grains per 100 standard cubic feet (gr/dscf).
4. The sulfur content of the distillate oil burned in the combustion turbine shall not exceed 0.04 percent by weight.
5. The maximum amount of distillate oil burned in the combustion turbine shall not exceed 10,928,571 gallons during any consecutive 12-month period.

B. Auxiliary Boiler

1. The auxiliary boiler shall only burn natural gas and/or low sulfur distillate oil.
2. With the exception of turbine startups, the auxiliary boiler shall not operate simultaneously with the combustion turbine.
3. The natural gas burned in the auxiliary boiler shall have a maximum sulfur content of 0.35 grains per 100 standard cubic feet.
4. The sulfur content of the distillate oil burned in the auxiliary boiler shall not exceed 0.04 percent by weight.
5. The maximum amount of distillate oil burned in the auxiliary boiler shall not exceed 95,714 gallons during any 12-month consecutive period.

C. Fuel Gas Heater

1. The fuel gas heater shall only burn natural gas with a maximum sulfur content of 0.35 grains per 100 standard cubic feet.

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D. Emergency Diesel Fire Pump

1. The emergency diesel fire pump shall burn low sulfur fuel oil with a maximum sulfur content of 0.04 percent by weight.

2. The maximum amount of fuel oil burned in the fire pump shall not exceed 6,000 gallons during any 12-month consecutive period.

VIII. Emission Limitations

A. Combustion Turbine and Duct Burner

1. Oxides of Nitrogen (NO_X)

   a. The concentration of NO_X in the exhaust gas during natural gas firing of the CT both with and without supplemental firing of the HRSG shall not exceed 2.0 parts-per-million by volume on a dry basis (ppmvd), corrected to 15% oxygen and 0.0076 lbs/mmBtu.

   b. The NO_X concentration in the exhaust gas during fuel oil firing of the CT with no supplemental firing of the HRSG shall not exceed 6.0 ppmvd, corrected to 15% oxygen and 0.025 lbs/mmBtu.

   c. The NO_X concentration in the exhaust gas during fuel oil firing of the CT and supplemental firing of the HRSG shall not exceed 6.8 ppmvd, corrected to 15% oxygen and 0.027 lb/mmBtu.

2. Carbon Monoxide (CO)

   a. The concentration of CO in the exhaust gas during natural gas firing of the CT and no supplemental firing of the HRSG shall not exceed 2.0 ppmvd, corrected to 15% oxygen and 0.0047 lb/mmBtu.

   b. The concentration of CO in the exhaust gas during natural gas firing of the CT with supplemental firing of the HRSG shall not exceed 2.0 ppmvd, corrected to 15% oxygen and 0.0046 lb/mmBtu.

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c. The concentration of CO in the exhaust gas during fuel oil firing of the CT at loads between 90% and 100% load and no supplemental firing of the HRSG shall not exceed 2.0 ppmvd, corrected to 15% oxygen and 0.0050 lb/mmBtu.

d. The concentration of CO in the exhaust gas during fuel oil firing of the CT at loads greater than or equal to 75% and less than 90% load with no supplemental firing of the HRSG shall not exceed 4.0 ppmvd, corrected to 15% oxygen and 0.010 lb/mmBtu.

e. The concentration of CO in the exhaust gas during fuel oil firing of the CT and supplemental firing of the HRSG shall not exceed 4.0 ppmvd, corrected to 15% oxygen and 0.010 lb/mmBtu.

3. Particulate Matter/Particulate Matter with an aerodynamic diameter of less than or equal to 10 micrometers (PM/PM-10)

a. The mass emission rate of PM/PM-10 in the exhaust gas during natural gas firing of the CT and no supplemental firing of the HRSG shall not exceed 11.7 lb/hr and 0.0055 lb/mmBtu.

b. The mass emission rate of PM/PM-10 in the exhaust gas during natural gas firing of the CT and supplemental firing of the HRSG shall not exceed 17.0 lb/hr and 0.0066 lb/mmBtu.

c. The mass emission rate of PM/PM-10 in the exhaust gas during fuel oil firing of the CT at loads between 90% and 100% load and no supplemental firing of the HRSG shall not exceed 98.3 lb/hr and 0.051 lb/mmBtu.

d. The mass emission rate of PM/PM-10 in the exhaust gas during fuel oil firing of the CT at loads greater than or equal to 75% and less than 90% load with no supplemental firing of the HRSG shall not exceed 98.3 lb/hr and 0.061 lb/mmBtu.

e. The mass emission rate of PM/PM-10 in the exhaust gas during fuel oil firing of the CT and with supplemental firing of the HRSG shall not exceed 100.3 lb/hr and 0.041 lb/mmBtu.

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4. Sulfur Dioxide (SO_2)

   a. The gas fired mass emission rate of SO_2 in the exhaust gas with no supplemental firing of the HRSG shall not exceed 2.4 lb/hr and 0.0011 lb/mmBtu.

   b. The gas fired mass emission rate of SO_2 in the exhaust gas during supplemental firing of the HRSG shall not exceed 2.9 lb/hr and 0.0011 lb/mmBtu.

   c. The oil fired mass emission rate of SO_2 in the exhaust gas with no supplemental firing of the HRSG shall not exceed 88.9 lb/hr and 0.042 lb/mmBtu.

   d. The oil fired mass emission rate of SO_2 in the exhaust gas during supplemental firing of the HRSG shall not exceed 89.3 lb/hr and 0.036 lb/mmBtu.

5. Sulfuric Acid Mist (H_2SO_4)

   a. The gas fired mass emission rate of H_2SO_4 in the exhaust gas with no supplemental firing of the HRSG shall not exceed 0.9 lb/hr and 0.0004 lb/mmBtu.

   b. The gas fired mass emission rate of H_2SO_4 in the exhaust gas during supplemental firing of the HRSG shall not exceed 1.1 lb/hr and 0.0004 lb/mmBtu

   c. The oil fired mass emission rate of H_2SO_4 in the exhaust gas with no supplemental firing of the HRSG shall not exceed 31.8 lb/hr and 0.015 lb/mmBtu.

   d. The oil fired mass emission rate of H_2SO_4 in the exhaust gas during supplemental firing of the HRSG shall not exceed 31.9 lb/hr and 0.0128 lb/mmBtu.

6. Opacity

   Opacity of emissions shall not exceed 20% except for one period of not more than 6 minutes in any 60-minute interval when the opacity shall not exceed 27%.

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B. Auxiliary Boiler

1. Oxides of Nitrogen (NO_X)

   a. NO_X emissions during natural gas firing of the auxiliary boiler shall be controlled through the use of low NO_X burners and flue gas recirculation to a rate no greater than 0.011 lbs/mmBtu.

   b. NO_X emissions during fuel oil firing of the auxiliary boiler shall be controlled through the use of low NO_X burners and flue gas recirculation to a rate no greater than 0.10 lbs/mmBtu.

2. Carbon Monoxide (CO)

   a. CO emissions during natural gas firing of the auxiliary boiler shall be controlled through good boiler design and good combustion practices to a rate no greater than 0.036 lb/mmBtu.

   b. CO emissions during fuel oil firing of the auxiliary boiler shall be controlled through good boiler design and good combustion practices to a rate no greater than 0.039 lb/mmBtu.

3. Particulate Matter/Particulate Matter with an aerodynamic diameter of less than or equal to 10 micrometers (PM/PM-10)

   a. PM/PM-10 emissions during natural gas firing of the auxiliary boiler shall be controlled through the use of low sulfur fuels and shall not exceed 0.0033 lb/mmBtu.

   b. PM/PM-10 emissions during fuel oil firing of the auxiliary boiler shall be controlled through the use of low sulfur fuels and shall not exceed 0.015 lb/mmBtu.

4. Sulfur Dioxide (SO_2)

   a. SO_2 emissions during natural gas firing of the auxiliary boiler shall be controlled through the use of low sulfur fuels and shall not exceed 0.0005 lb/mmBtu.

b. SO_2 emissions during fuel oil firing of the auxiliary boiler shall be controlled through the use of low sulfur fuels and shall not exceed 0.041 lb/mmBtu.

5. Opacity

Opacity of emissions shall not exceed 20% except for one period of not more than 6 minutes in any 60-minute interval when the opacity shall not exceed 27%.

C. Fuel Gas Heater

1. Oxides of Nitrogen (NO_X)

NO_X emissions from the heater shall be controlled with forced draft low NO_X burners to a rate not to exceed 0.050 lb/mmBtu.

2. Carbon Monoxide (CO)

CO emissions shall be controlled by the use of good combustion controls and shall not exceed 0.098 lb/mmBtu.

3. Particulate Matter/Particulate Matter with an aerodynamic diameter of less than or equal to 10 micrometers (PM/PM-10)

PM/PM-10 emissions shall be controlled through the use of low sulfur fuel to a rate no greater than 0.0088 lb/mmBtu.

4. Sulfur Dioxide (SO_2)

SO_2 emissions shall be controlled by the use of low sulfur fuels to a rate no greater than 0.0011 lb/mmBtu.

5. Opacity

Opacity of emissions shall not exceed 20% except for one period of not more than 6 minutes in any 60-minute interval when the opacity shall not exceed 27%.

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D. Emergency Diesel Fire Pump

1. Oxides of Nitrogen (NO_X)

   NO_X emissions shall be controlled by the use of good combustion practices and shall not exceed 1.97 lb/mmBtu.

2. Carbon Monoxide (CO)

   CO emissions shall be controlled by the use of good combustion practices and shall not exceed 0.09 lb/mmBtu.

3. Particulate Matter/Particulate Matter with an aerodynamic diameter of less than or equal to 10 micrometers (PM/PM-10)

   PM/PM-10 emissions shall be controlled by the use of low sulfur fuels and shall not exceed 0.03 lb/mmBtu.

4. Sulfur Dioxide (SO_2)

   SO_2 emissions shall be controlled by the use of low sulfur fuels and shall not exceed 0.040 lb/mmBtu.

5. Opacity

   Opacity of emissions shall not exceed 20% except for one period of not more than 6 minutes in any 60-minute interval when the opacity shall not exceed 27%.

IX. Pollution Control Equipment and Opacity Measurement

1. Each unit shall operate in accordance with its design specified parameters. This includes continuously operating all proposed control devices in a manner consistent with good air pollution control practice for minimizing emissions.

2. For the combustion turbine and duct burner, CLIEC shall install and utilize low NO_X burners for natural gas firing and a water injection system for fuel oil firing. CLIEC shall monitor the water to fuel ratio to ensure proper control of NO_X emissions. In addition to

the low NO_X burners and water injection system, CLIEC shall install and continuously operate a Selective Catalytic Reduction (SCR) system for NO_X control.

3. CLIEC shall install an oxidation catalyst in the HRSG to control CO and VOC emissions from the combustion turbine and duct burner. The oxidation catalyst shall be utilized whenever the combustion is operating.

4. CLIEC shall install low NO_X burners and flue gas recirculation to control NO_X emissions from the auxiliary boiler. These controls shall be used at all times when the auxiliary boiler is operating.

5. CLIEC shall install forced draft low NO_X burners to control NO_X emissions from the fuel gas heater. The forced draft low NO_X burners shall operate whenever the fuel gas heater is operating.

6. While firing gaseous fuels, CLIEC shall conduct monthly opacity observations at the turbine, auxiliary boiler, and fuel gas heater emission points in accordance with 40 CFR Part 60, Method 9. The opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Alternatively, CLIEC may install and operate a Continuous Opacity Monitoring System that meets the requirements of 40 CFR Part 60.

7. While firing distillate fuel oil, CLIEC shall conduct daily opacity observations at the turbine and auxiliary boiler emission points in accordance with 40 CFR Part 60, Method 9. The opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Alternatively, CLIEC may install and operate a Continuous Opacity Monitoring System that meets the requirements of 40 CFR Part 60.

8. Each time the fire pump is tested for operational readiness, CLIEC shall use 40 CFR Part 60, Method 22 to determine if visible emissions are present. In addition, CLIEC shall conduct annual opacity observations at the fire pump emission point in accordance with 40 CFR Part 60, Method 9.

X. Continuous Emission Monitoring (CEM) Requirements

1. Prior to conducting the initial performance tests required by Section XI of this permit and thereafter, CLIEC shall install, calibrate, maintain, and operate:

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a. a CEM to measure and record stack gas carbon monoxide concentrations from the combustion turbine and duct burner stack. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specification 4, and Appendix F).

b. a CEM to measure and record stack gas NO_x (as measured as NO_2) concentrations from the combustion turbine and duct burner stack. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specification 2, and Appendix F).

c. a CEM to measure and record stack gas oxygen concentrations from the combustion turbine and duct burner stack. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specification 3, and Appendix F).

d. a continuous monitoring system to measure and record stack gas temperatures, fuel flow rate and water to fuel ratios from the combustion turbine. These systems shall meet all applicable EPA monitoring performance specifications.

e. a continuous monitoring system to measure and record fuel flow to the duct burner, fuel gas heater and auxiliary boiler. Upon EPA or NYSDEC request, CLIEC shall conduct a performance evaluation of the monitors.

2. Not less than 90 days prior to the date of startup of the combustion turbine/duct burner, CLIEC shall submit a written report to EPA of a Quality Assurance Project Plan for the certification of the combustion turbine and duct burner's monitoring systems. Any comments provided to CLIEC by EPA on the written plan shall be responded to in an expeditious manner. Performance evaluation of the monitoring systems may not begin until the Quality Assurance Project Plan has been approved by EPA.

3. CLIEC shall conduct performance evaluations of the continuous monitoring systems during the initial performance testings required under this Permit or within 30 days thereafter in accordance with the applicable performance specifications in 40 CFR Part 60, Appendix B, and 40 CFR Part 52, Appendix E. CLIEC shall notify EPA at least 15 days in advance of the date upon which demonstration of the monitoring system(s) performance will commence.

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4. CLIEC shall submit a written report to EPA of the results of all monitor performance specification evaluations conducted on the monitoring system(s) within 60 days of the completion of the tests. The monitoring systems must meet all the requirements of the applicable performance specification test in order for the monitors to be certified.

XI. Performance Testing Requirements

1. CLIEC shall conduct initial performance tests for the combustion turbine and duct burner, the auxiliary boiler and the fuel gas heater. Within 60 days after achieving the maximum production rate of each unit, but no later than 180 days after initial startup as defined in 40 CFR Part 60.2, CLIEC shall submit the results of the performance tests for NO_X, CO, PM/PM-10, SO_2 and H_2SO_4. Once the initial performance tests are complete, CLIEC shall conduct additional stack testing once every five years from the date of the initial performance test for the combustion turbine/duct burner and auxiliary boiler (for those pollutants for which a CEM is not required). All performance tests shall be conducted at base load conditions, with and without supplemental firing of the HRSG (for the combustion turbine), 75% load conditions and/or other loads specified by EPA.

2. Three test runs shall be conducted for each load condition and compliance for each operating mode shall be based on the average emission rate of these runs.

3. At least 60 days prior to actual testing, CLIEC shall submit to the EPA a Quality Assurance Project Plan detailing methods and procedures to be used during the performance stack testing. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require a re-test.

4. CLIEC shall use the following test methods, or a test method which would be applicable at the time of the test and detailed in a test protocol approved by EPA:

   a. Performance tests to determine the stack gas velocity, sample area, volumetric flow rate, molecular composition, excess air of flue gases, and moisture content of flue gas shall be conducted using 40 CFR Part 60, Appendix A, Methods 1, 2, 3, and 4.

   b. Performance tests for the emissions of PM-10 shall be conducted using 40 CFR Part 51, Appendix M, Method 201 (exhaust gas recycle), Method 201A (constant flow rate) or Method 5, and Method 202. PM-10 emissions shall be the sum of noncondensible emissions determined using Method 201, 201A or Method 5 and condensible emissions determined using Method 202.

c. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60, Appendix A, Method 10.

d. Performance tests for the emissions of NO_x shall be conducted using 40 CFR Part 60, Appendix A, Method 7E.

e. Performance tests for the emissions of SO_2 shall be conducted using 40 CFR Part 60, Appendix A, Method 6 or 6C.

f. Performance tests for the emissions of H_2SO_4 shall be conducted using 40 CFR Part 60, Appendix A, Method 8.

g. Performance tests for the visual determination of the opacity of emissions from the stack shall be conducted using 40 CFR Part 60, Appendix A, Method 9 and the procedures stated in 40 CFR Part 60.11, or using a Continuous Opacity Monitoring system meeting the requirements of 40 CFR Part 60.

5. Test results indicating that emissions are below the limits of detection shall be deemed to be in compliance.

6. Additional performance tests may be required at the discretion of the EPA or NYSDEC for any or all of the above pollutants.

7. For performance test purposes, sampling ports, platforms and safe access shall be provided by CLIEC on each unit in accordance with 40 CFR Part 60.8(e).

8. CLIEC shall submit a written report to EPA of the results of all emission testing within 60 days of the completion of the performance test, but in any event, no later than 180 days after initial startup of each unit.

9. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test.

XII. Fuel Sampling Requirements

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1. CLIEC shall verify that the sulfur content of the fuels being burned meets the specifications outlined in Section VII of this permit.

2. CLIEC shall not accept any distillate fuel oil with a sulfur content greater than 0.04% by weight. Prior to unloading the oil from the supplier, CLIEC shall verify that the sulfur content of the oil being delivered is no greater than 0.04% by weight by evaluating the fuel oil analyses conducted by the supplier and/or by independently analyzing and confirming the sulfur content of the fuel oil.

3. Compliance with the sulfur content standards for liquid and gaseous fuels shall be determined using the testing methods established in 40 CFR 60.335(b)(10). Compliance with the natural gas sulfur content requirement shall be determined monthly.

XIII. Record keeping Requirements

1. Logs shall be kept and updated daily to record the following:

   a. the gallons of fuel oil fired in the combustion turbine, auxiliary boiler and diesel fire pump;

   b. the hours of operation of the duct burner, auxiliary boiler and diesel fire pump;

   c. the fuel flow to the duct burner and the maximum heat input capacity using a natural gas heating value of 22,685 Btu/lb (HHV);

   d. the beginning, duration and completion of each startup and shutdown for the combustion turbine;

   e. the total pounds of NO_X and CO, as measured by the CEM, for each startup and shutdown of the combustion turbine;

   f. the gallons of fuel burned in the diesel fire pump as determined by measuring the tank level before and after each run;

   g. any adjustments and maintenance performed on the combustion turbine/duct burner, auxiliary boiler, fuel gas heater and diesel fire pump;

   h. any adjustments and maintenance performed on monitoring systems;

i. all fuel sampling results; the distillate fuel oil supplier's or CLIEC's analyses verifying that the sulfur content is no greater than 0.04%; and

j. all calculations, opacity readings, CEM summaries and information related to emission determinations

2. All monitoring records, fuel sampling test results, calibration test results and logs must be maintained for a period of five years after the date of record, and made available upon request. All rolling averages shall be computed as required in this permit.

XIV. Reporting Requirements

1. CLIEC shall submit a written report of all excess emissions to EPA for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each quarter and shall include the information specified below:

   a. The magnitude of excess emissions computed in accordance with 40 CFR Part 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions and whether the excess emissions occurred during startup, shutdown or malfunction.

   b. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measures adopted shall also be reported.

   c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

   d. When no excess emissions have occurred or the monitoring systems have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

   e. Results of quarterly monitor performance audits, as required in 40 CFR Part 60, Appendix F (including the Data Assessment Report) and all information required by the reporting requirements in 40 CFR 60.7 including excess emissions and CEMS downtime summary sheets.

   f. Any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner which results in an increase in emissions above any

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allowable emission limit stated in this permit and any corrective actions and/or preventative measures taken on any unit must be reported by telephone within 2 business days to:

Air Compliance Branch
Division of Enforcement and Compliance Assistance
U.S. Environmental Protection Agency
Region 2
290 Broadway - 21st Floor
New York, New York 10007-1866
(212)637-3000

g. In addition, the U.S. EPA's Air Compliance Branch shall be notified in writing within fifteen (15) days of any such failure referenced in item g above. This notification shall include a description of the malfunctioning equipment or abnormal operation; the date of the initial failure; the period of time over which emissions were increased due to the failure; the cause of the failure; the estimated resultant emissions in excess of those allowed under this permit; and the methods utilized to restore normal operations. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violations of this permit or of any law or regulations which such malfunction may cause.

2. All reports and Quality Assurance Project Plans required by this permit shall be submitted to:

   Chief, Air Compliance Branch
   U.S. Environmental Protection Agency
   Region 2
   290 Broadway - 21st Floor
   New York, New York 10007

3. Copies of all reports and Quality Assurance Project Plans shall also be submitted to:

   Chief, Air Programs Branch - Permitting Section
   U.S. Environmental Protection Agency
   Region 2
   290 Broadway - 25th Floor
   New York, NY 10007

ENCLOSURE I

CAITHNESS LONG ISLAND, LLC
CAITHNESS LONG ISLAND ENERGY CENTER

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Region 2 CEM Coordinator
U. S. Environmental Protection Agency
Air and Water Q/A Team
Monitoring & Assessment Branch
2890 Woodbridge Avenue - MS - 220
Edison, New Jersey 08837-3679

Regional Air Pollution Control Engineer
New York State Department of Environmental
Conservation
Region 1
SUNY at Stony Brook
Campus Loop Road
Building 40, Room 121
Stony Brook NY 11790-2356

XV. Other Requirements

1. CLIEC shall meet all other applicable federal, state and local requirements, including but not limited to those contained in the New York State Implementation Plan (SIP) and the Provisions of the New Source Performance Standards (NSPS) (40 CFR Part 60, Subparts A, GG, Da, Dc and Kb) and Part 61.

ENCLOSURE II

CAITHNESS LONG ISLAND, LLC
CAITHNESS LONG ISLAND ENERGY CENTER

Responsiveness Summary

The Region 2 Office of the U.S. Environmental Protection Agency (EPA) held a public comment period from December 19, 2005 until January 18, 2006 with respect to the Prevention of Significant Deterioration of Air Quality (PSD) permit application submitted by Caithness Long Island Energy Center (CLIEC) for the construction and operation of a new electric generating facility in Brookhaven, Suffolk County, New York. The purpose of the public comment period was to solicit comments from the public on EPA's preliminary determination to approve CLIEC's PSD permit and offer the public the opportunity to request a public hearing.

EPA received comments submitted by TRC Environmental Corporation dated January 19, 2006 on the applicant's behalf. Since these comments were submitted after the close of the public comment period, they are not considered timely. EPA does not have an obligation to respond to comments submitted after the close of the public comment period. However, EPA has discretion to consider late comments in reaching its final permit decision. We are, therefore, including responses to these comments in this responsiveness summary to avoid unnecessary permit modification requests.

Comment 1 – Fact Sheet

In the most recent submittal to USEPA (revised air modeling on October 4, 2005), the potential to emit (PTE) for NO_X and CO were 90.3 and 270.9 tons/year, respectively, which is slightly lower than the PTE stated for those parameters in the fact sheet. The values in the draft permit are from a previous submittal to USEPA (response to additional comments on August 12, 2005). Thus, the PTE values in the PSD permit for NO_X and CO should be lowered to 90.3 and 270.9 tons/year, respectively to match the worst-case annual emissions scenario presented in the October 4, 2005 submittal.

Response 1

The PTE values included in the fact sheet are considered estimates and are provided for informational purposes only. The fact sheet does not contain PSD permit conditions. These annual PTE estimates are not carried over into the PSD permit. Rather the PSD permit contains short-term emission limits. These limits match the most recent values provided in the October 4, 2005 submittal. Therefore, EPA does not consider this comment relevant to the permitting decision. However, we have included the updated estimates in the Fact Sheet for the final permit.

ENCLOSURE II

CAITHNESS LONG ISLAND, LLC
CAITHNESS LONG ISLAND ENERGY CENTER

Responsiveness Summary

Comment 2 – Condition III

Based on the proposed allowable operation of the combined cycle unit, a maximum of 260 start-ups could occur per year, which corresponds to one start per day for five days per week, 52 weeks per year. The number of permitted start-ups for the facility creates an inherent problem with respect to Caithness's ability to comply with Condition II, as drafted. Mandatory CEM system daily calibrations typically have a duration of approximately 20 minutes; because the resulting data gap is longer than 15 minutes, this causes exclusion of an entire operating hour from the valid data reported by the CEM.

The way the PSD permit condition is written, the operating hours lost due to calibration checks are not excluded from calculations to show compliance with the 95% data capture requirement. As stated above, the permit provides for as many as 260 start-ups of this unit per year. The actual number of starts, up to the permitted limit, will be due to, among other things, the dispatch of the unit as may be dictated by LIPA under a power supply agreement. As an example, it is reasonably anticipated that there may be extended periods of time during which the unit is dispatched for an average of eight hours of operation per weekday. In this scenario, loss of one hour of data due to a calibration check corresponds to downtime of 12.5% of the source operating time, or a maximum CEM on-line time of 87.5%, well below the 95% criteria. This example does not account for additional CEM downtime that may occur due to quarterly linearity checks, semiannual RATAs, maintenance, routine repairs and replacements, and other unforeseen circumstances.

Caithness is proposing either of the two following modifications to the PSD permit condition to accommodate the permitted number of start-ups and daily calibrations:

1) Replace the text "shall be on-line and in operation 95% of the time when the emission sources are operating" with "shall be on-line and in operation except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d) and shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period". This language is consistent with the language specified in 40 CFR 60.13.

2) Add the following underlined text at the end of the sentence "The continuous emission monitoring systems required by this permit shall be on-line and in operation 95% of the time when the emission sources are

ENCLOSURE II

CAITHNESS LONG ISLAND, LLC
CAITHNESS LONG ISLAND ENERGY CENTER

Responsiveness Summary

> operating excluding periods removed due to calibration checks, zero and span adjustments, linearity checks and relative accuracy testing."

Response 2

After consideration of Caithness's comment, EPA is retaining the original language. From EPA's experience with other similar facilities, calibration can be done in less than 15 minutes. If at least one CEMS reading is recorded in a 15-minute period before or after the daily calibration, that 15-minute period will be considered valid data. Caithness must work with the CEMS vendor to minimize the duration of the daily calibration. Even if the calibration time cannot be reduced, calibration can be scheduled for times when the unit is not likely to be in operation. Quarterly linearity checks are very similar to the daily calibration checks, with additional calibration gases. One calibration gas can be checked in each 15 minute period. In this way the quarterly check can be completed without loss of any data. The relative accuracy audit is a check of the CEMS against a reference method monitor. There is no need for the CEMS to be off-line for this determination. Routine maintenance, repairs, and replacements must be scheduled for periods when the generating unit is not in use. PSD permits do not contain exclusions for unforeseen circumstances. In any event, these unforeseen events should not be greater than 5% of the time that the emission source is operating.

Comment 3 – Condition IX.7

Based on the proposed operating schedule of the fire pump, the unit will only be used during periods of emergency or for weekly/monthly testing. If the fire pump were operated during an emergency (a fire), fulfilling the requirement of a certified EPA Method 9 reader taking opacity readings is an unreasonable and impractical requirement because it is likely that the Method 9 observer, as part of the facility staff, would be required to evacuate, would be involved in fire-fighting or rescue, or would otherwise be unable to conduct readings due to hazardous conditions attendant to the emergency at hand.

Section 2.4 of EPA Method 9 requires that opacity observations shall be recorded to the nearest 5 percent at 15-second intervals on an observational record sheet. A minimum of 24 observations shall be recorded. Each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period. 24 x 15-second measurements equates to 6 minutes. Caithness expects to conduct the fire pump weekly/monthly testing for less than 30 minutes. Thus, requiring an EPA Method 9 certified opacity reader to be present for each weekly/monthly test totaling 30 minutes per test should also be considered overly burdensome.

Caithness performs an annual tune-up test on the fire pump in accordance with its insurance policy requirements and is proposing to perform an EPA Method 9 test during the annual tune-up testing. This approach would reflect the fact that the fire pump is a piece of emergency equipment that would not be expected to operate other than for emergency or testing purposes. Caithness therefore proposes the following alternative compliance language to replace the first sentence:

"While firing distillate fuel oil, CLIEC shall conduct daily opacity observations at the turbine, and auxiliary boiler emission points in accordance with 40 CFR Part 60, Method 9. When firing distillate fuel oil, CLIEC shall conduct an opacity observation, in accordance with 40 CFR Part 60, Method 9, at the emergency fire pump emission point once per calendar year."

Response 3

Since the fire-pump is a piece of emergency equipment and will not operate other than for emergency and testing purposes and each test is conducted for less than 30 minutes, EPA has revised the monitoring for opacity at the unit. The new monitoring will require a Method 22 reading during each weekly/monthly test and an annual Method 9 observation during the fire pump's annual tune-up. Method 22 is less stringent than Method 9 since it requires only the determination of whether a visible emission occurs and does not require that opacity levels be determined or that a certified opacity reader be present.

Comment 4 – Condition XII.3

The following referenced requirement does not exist in the 2005 version of the Code of Federal Regulations. For reference, the regulation used to read:

Sec. 60.335: Test methods and procedures.

(d) The owner or operator shall determine compliance with the sulfur content standard in Sec. 60.333(b) as follows: ASTM D 2880-71, 78, or 96 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80 or 90 (Reapproved 1994), D 3031-81, D 4084-82 or 94, or D 3246-81, 92, or 96 shall be

ENCLOSURE II

CAITHNESS LONG ISLAND, LLC
CAITHNESS LONG ISLAND ENERGY CENTER

Responsiveness Summary

used for the sulfur content of gaseous fuels (incorporated by reference-see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Caithness is proposing to change the reference to match the current standard requirements at 40 CFR 60.335(b)(10) which reads:

(10) If the owner or operator is required under Sec. 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

Response 4

The permit has been updated to reflect the most current test methods.

Comment 5 – Condition XIV.1.f.

Under 40 CFR Part 60, the use of CEM systems for continuous compliance is not certified until after completion of initial emissions compliance performance testing. As such, we propose addition of the following text to this condition:

"Demonstration of continuous compliance with the PSD permit limits is not required until completion of the PSD compliance testing, or within 180 days of start-up,

ENCLOSURE II

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CAITHNESS LONG ISLAND ENERGY CENTER

Responsiveness Summary

whichever date comes first. However, the permittee shall take all reasonable steps to minimize emissions during startup and equipment testing prior to completion of compliance testing. For purposes of this PSD permit, excess emissions indicated by monitoring systems shall be considered credible evidence of violations of the applicable emission limits."

The above suggested language, which mirrors language from PSD permits previously issued by NYSDEC, will provide for the same shakedown period allowed under NSPS prior to CEM certification and compliance stack testing while still requiring CLIEC to operate the units and controls in such a way as to minimize emissions.

Also, Caithness believes that even after the shakedown period, excess emissions indicated by monitoring systems should not be considered definitive regarding whether a violation has occurred, as there may be other credible evidence or factors that would show a violation has not occurred. All credible evidence should be considered by the agency before a determination of whether a violation has occurred is made. Therefore, Caithness proposes that "shall be considered violations of the applicable emission limits" be changed to read "shall be considered credible evidence of a violation of an applicable emission limit." Under appropriate circumstances, this would allow Caithness to submit relevant information to demonstrate that a violation has not occurred.

Response 5

After reviewing the permit condition on which this comment was based, EPA has decided to remove condition XIV.1.f. from the permit. In this way EPA reserves our authority to rely on any credible evidence, including CEMS, to determine if a violation has occurred and we can exercise discretion regarding possible violations.

Exhibit 16

Long Island Power Authority
Caithness Long Island Energy Center

Final Environmental Impact Statement

Submitted to:
Long Island Power Authority

Submitted by:
Caithness Long Island, LLC

June 2005

This Chapter provides a detailed description of the proposed Caithness Long Island Energy Center. This includes information on surrounding land uses; the physical characteristics of the proposed site; the type, size and use of the proposed facility; and the anticipated project schedule.

2.1 SITE DESCRIPTION

The proposed Caithness Long Island Energy Center would be located adjacent to the Sills Industrial Park within the Town of Brookhaven's Empire Development Zone. Figure 2-1 identifies the site boundary on a New York State Department of Transportation (NYSDOT) 7.5-minute map (Bellport, New York Quadrangle). Hamlets surrounding the proposed site include Medford, Gordon Heights, Yaphank, Patchogue, Shirley and Bellport.

The project site is approximately 15 acres within a larger 96-acre parcel controlled by Caithness. The 15-acre area is located south of the Sills Road interchange (Exit 66) of the Long Island Expressway (LIE). It is situated east of Old Dock Road, north of Horse Block Road and south of the Long Island Rail Road (LIRR). The Patchogue-Yaphank Road (County Route 101) interchange with the LIE is located approximately 1,600 feet (0.3 miles) north of the property. An additional 28 acres within the 96-acre parcel would be temporarily disturbed during construction for materials lay down, equipment storage, and construction parking.

Figure 2-2 shows an aerial view of the proposed site illustrating site boundaries, the proposed facility fence line, and the proposed location of electric and gas interconnections. The project would interconnect with LIPA's 138-kilovolt (kV) transmission system within the 96-acre parcel via a newly constructed 138 kV switchyard. The new switchyard would be located adjacent to LIPA's Holbrook to Brookhaven transmission line right-of-way, approximately 1,500 feet from the project's step-up transformers. It is contemplated that natural gas would be delivered to the project site through one of several pipeline projects that have been proposed as independent projects by several pipeline developers and that would, once permitted by relevant regulatory agencies, serve both the facility and other Long Island users.

The project site is located in the Town of Brookhaven's L-1 Industrial District, which permits electric generating facilities by Special Use permit. Land uses nearby and adjacent to the site are mainly light industrial, commercial, and undeveloped. Small industries, warehouses, and commercial buildings are located adjacent to the 96-acre parcel's western and southern boundaries, while undeveloped land is located to the north and east. Six residences are within ½ mile of the project site to the south and west. Other residential developments within the project vicinity are located approximately 1 mile south and northwest.

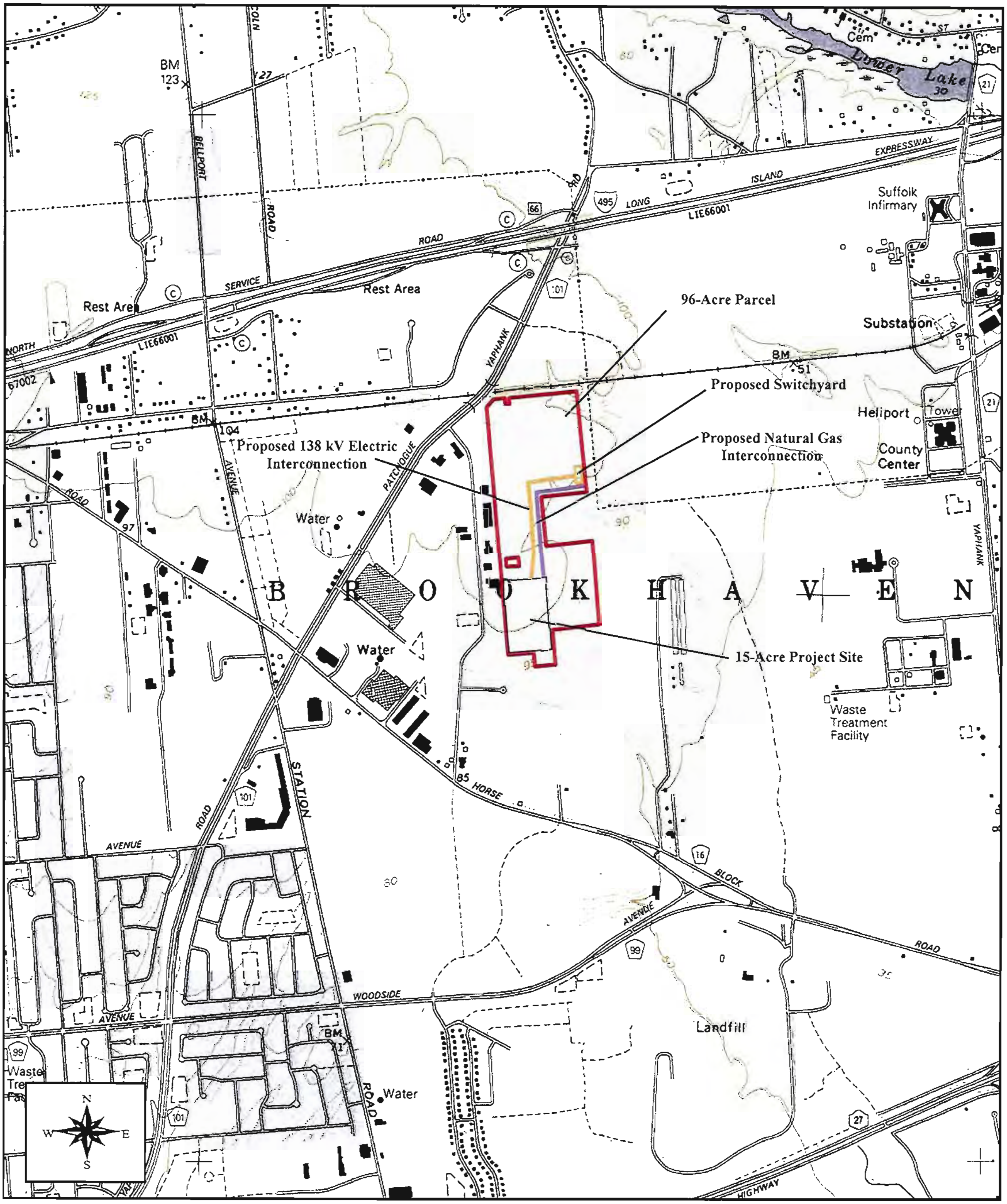
Surface elevations across the 96-acre parcel range from approximately 95 feet (ft) above mean sea level (MSL) to 110 ft above MSL. Elevations within the 15-acre project site of development range from approximately 95 ft above MSL to 106 ft above MSL. The base elevation following development (i.e., within the facility fence line) is expected to be about 100 ft above MSL.

2.2 PLANT OVERVIEW

The proposed combined-cycle facility would generate approximately 350 megawatts (MW) of electricity. Approximately 215 MW of this power would be produced using a Siemens Westinghouse Power Corporation 501F combustion turbine generator set. Exhaust heat from the combustion turbine would then be sent to a heat recovery steam generator (HRSG) to produce steam to drive a steam turbine generator. The steam turbine generator would provide approximately 135 MW, the balance of the plant output. The HRSG would include a 45 MW natural gas-fired duct burner (supplemental firing system). Selective catalytic reduction technology (SCR) and an oxidation catalyst would be used to control oxides of nitrogen (NO_x) and carbon monoxide (CO) emissions, respectively. Exhaust steam from the steam turbine would be cooled (i.e., condensed) and then returned to the HRSG using an air-cooled condenser. Air-cooled condensing would be employed to minimize water use and eliminate potential cooling tower plume impacts. The facility would be designed to operate as a baseload electric generating plant.

Natural gas would be used as the primary fuel with low sulfur distillate oil serving as a back-up fuel. Use of the back-up fuel would be limited to 30 days per year, but would serve to enhance electrical distribution system reliability in the event that natural gas supplies are needed to meet residential heating or other demands. To accommodate short-term operation on low sulfur distillate, the proposed project would include a 750,000-gallon fuel oil storage tank and associated off-loading facilities. Consistent with New York State and Suffolk County Department of Health Services requirements, the storage tank would be equipped with secondary containment capable of retaining 110 percent of the storage tank capacity. In addition, fuel delivery piping outside of the containment area would be double walled. Fuel oil would be delivered to the site via tanker truck. The fuel off-loading facilities would be capable of handling two trucks simultaneously and would have its own containment capacity.

Auxiliary equipment at the facility would include an auxiliary boiler, a fuel gas dew point heater, a combustion turbine inlet air evaporative cooler, fuel gas compressors, power transformers, a water demineralization system, an electric fire pump, and an emergency diesel fire pump. The 32.7 Million British Thermal Units per hour (mmBtu/hr) auxiliary boiler would primarily be used during the winter months to maintain HRSG water chemistry and to keep the HRSG warm during periods of turbine shutdown. The boiler would be capable of firing natural gas and low sulfur distillate fuel. The fuel gas dew point heater would be natural gas fired and used to prevent the natural gas from condensing into a liquid. The emergency diesel fire pump would provide back-up to the electric fire pump for on-site fire-fighting capability in case of power failure and would only be tested for brief durations during normal operations. The demineralization system



Proposed 138 kV Electric Interconnection

Proposed Natural Gas Interconnection

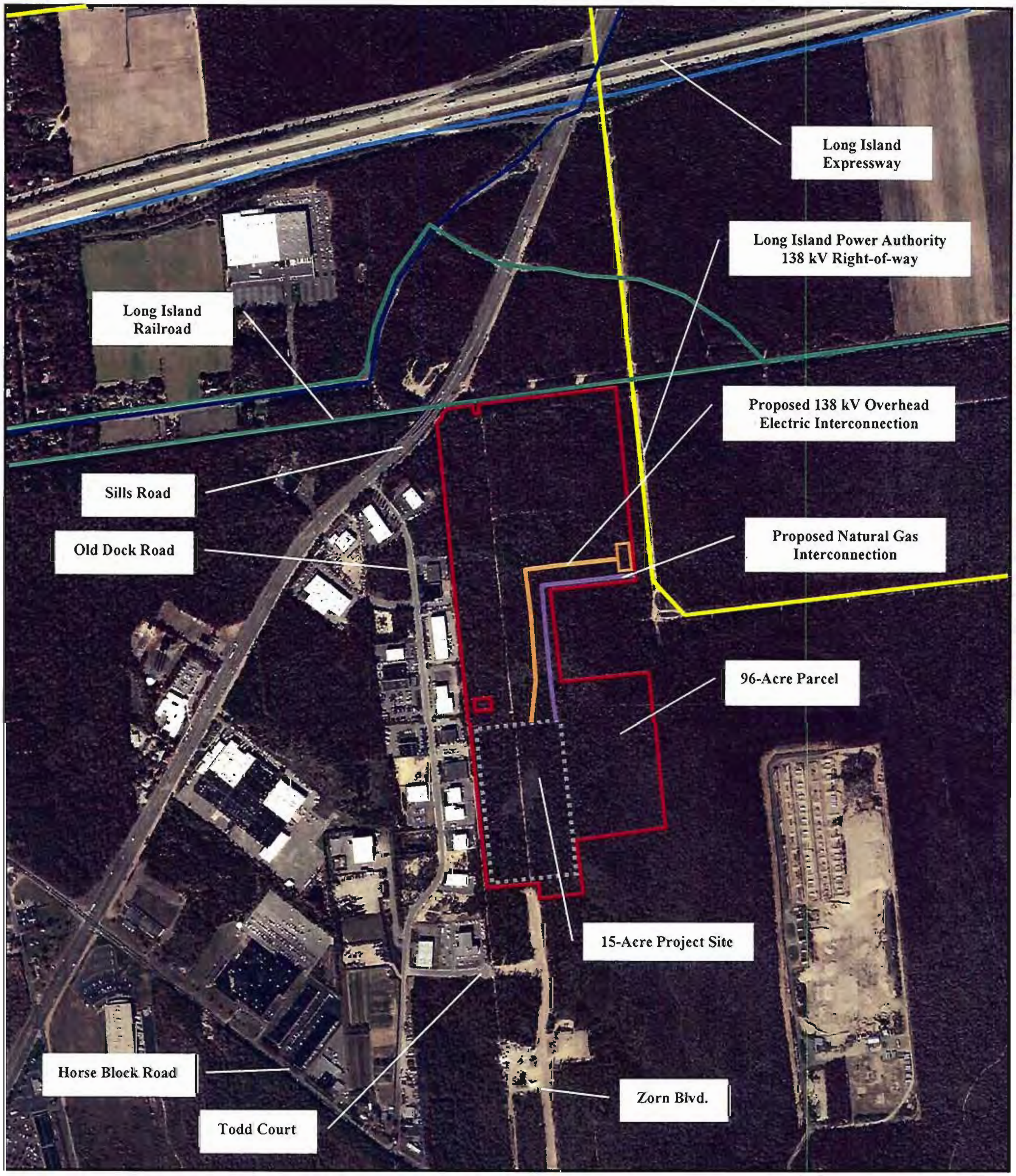
96-Acre Parcel

15-Acre Project Site

Caithness Long Island, LLC
Caithness Long Island Energy Center
Town of Brookhaven, Suffolk County, NY

Figure 2-1. Site Location Map
Scale 1:24,000

Source: New York State Department of Transportation.
Bellport Quadrangle, 1991.



96-Acre Parcel
15-Acre Project Site
Gas Transmission Line (20-inch service)
Gas Transmission Line (8-inch service)
Overhead Electric Transmission Line (138kV)
Overhead Electric Transmission Line (69kV)
Proposed Overhead Electric Interconnection (138kV)
Proposed natural gas Interconnection

Caithness Long Island, LLC
Caithness Long Island Energy Center
Town of Brookhaven, Suffolk County, NY

Figure 2-2: Site Aerial Photograph, October 2000
Approximate Scale: 1" = 1,000'

Source: GlobeXplorer, LLC Online

would be used to further purify the public water supply from the municipal distribution system for use as HRSG makeup.

2.3 OVERVIEW OF COMBINED-CYCLE OPERATION

Figure 2-3 shows a conceptual flow diagram of the proposed combined cycle operation.

The process of utilizing both the power generated from a combustion turbine generator and a steam turbine generator is referred to as "combined-cycle" electric generation. A combined-cycle plant uses waste heat from a combustion turbine to serve as the heat input to a conventional steam turbine. The combustion turbine consists of a compressor, combustor, and turbine sections. The fuel (natural gas or low sulfur distillate) is fired in the combustor section with high-pressure air. The resulting exhaust gases created by the combustion process are expanded through the turbine section. The expanding exhaust gas causes the turbine blades and shaft to rotate. A generator is coupled to the turbine shaft to convert rotational mechanical energy into electrical energy.

After combustion, the hot combustion turbine exhaust gases are routed via ductwork to the HRSG. Heat from the exhaust gases is transferred to the water/steam tubes that are immersed in the HRSG gas flow path, first to boil the water into steam and then to superheat the steam for use in the steam turbine. The expansion of the steam in the steam turbine rotates the turbine shaft. A generator is coupled to the turbine shaft to convert rotational mechanical energy into electrical energy. Exhaust gases exit the HRSG through a stack. Steam exhausting from the steam turbine is sent to an air-cooled condenser, where it is converted back into water and pumped to the HRSG for reuse.

The "combined-cycle" technology is approximately 30 percent more efficient than conventional electric generator technologies. Since a combined-cycle plant uses less fuel than either a steam turbine or a gas turbine to generate a kilowatt-hour of electricity, the savings in fuel costs and energy supply are significant.

2.4 PLANT LAYOUT

The Caithness Long Island Energy Center would be designed to be compatible with the nearby and surrounding land uses. An artist's rendering of the proposed facility is presented in Figure 2-4. Figure 2-5 shows the location of proposed facility structures in relation to the 96-acre parcel. Figure 2-6 provides a general arrangement of facility buildings and sub-systems, including the main power generation building, station transformers, air cooled condenser, gas metering and compression station and distillate fuel oil and water storage tanks. Figures 2-7 and 2-8 provide elevation or cross-sectional views of the facility. A set of site plan drawings for the project are included as Appendix C.

2.4.1 BUILDINGS AND STRUCTURES

The combustion turbine, the steam turbine and the steam turbine generator would be housed in a building referred to as the generation building. The generation building encloses the major power generation equipment, combustion turbine, the steam turbine and the steam turbine generator (STG). The generation building also encloses other mechanical equipment, such as pumps, piping and electrical equipment needed for plant operation. The building would have overhead cranes to facilitate major equipment maintenance activities. Elevated platforms would be provided for access to equipment and piping. The roof of the structure would be designed to support metal decking and insulating panels. The walls would be insulated metal siding supported on a steel frame.

An administration building containing office space, a meeting room, kitchen, storage area and restroom facilities would be located east of the generation building. A maintenance shop/warehouse building would be located immediately south of the administration building.

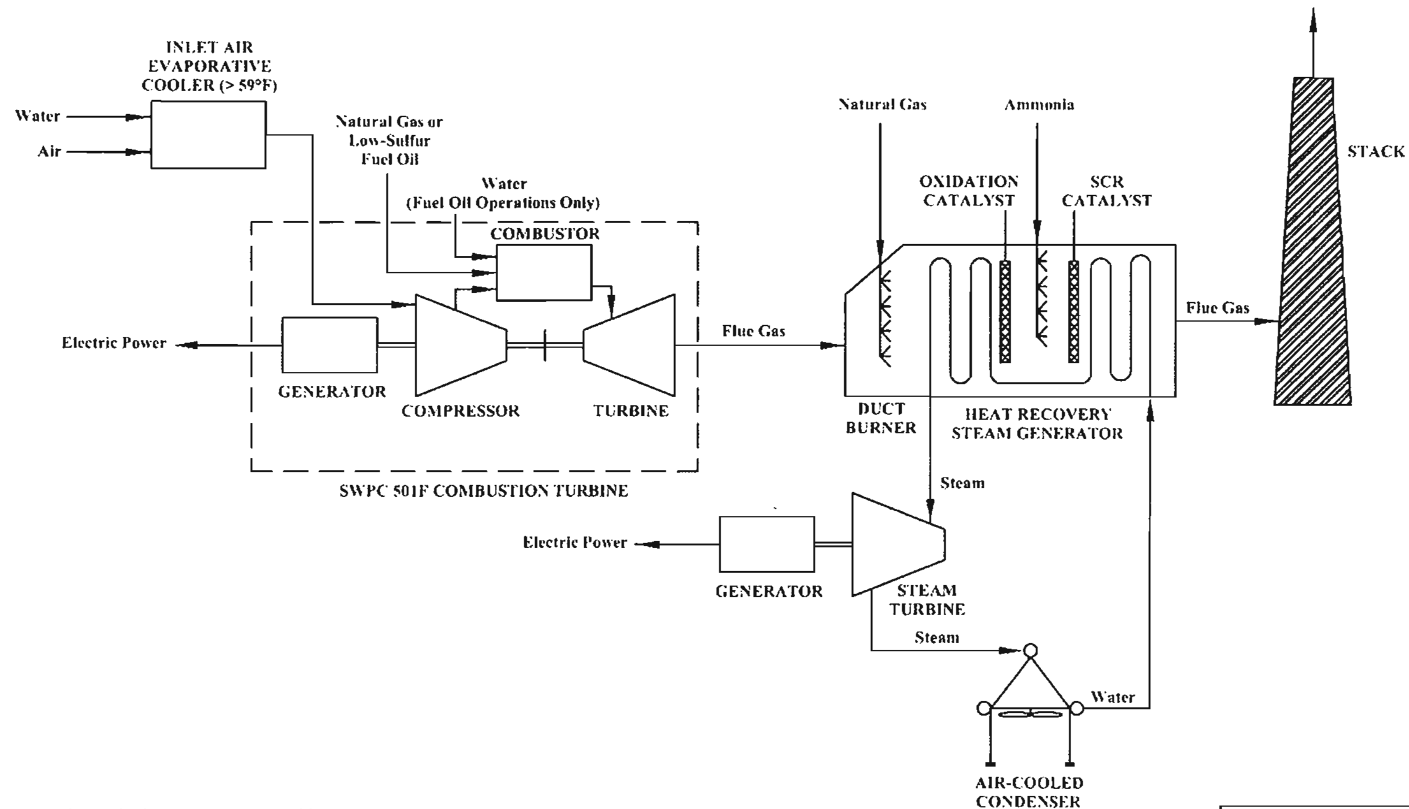
Approximate building dimensions and heights for major facility components are as follows:

• Generation Building (High-Bay)	190 feet by 45 feet by 75feet height
• Generation Building (Low-Bay)	104 feet by 51 feet by 50 feet height
• HRSG	135 feet by 43 feet by 85 feet height
• Control Administration Building	115 feet by 40 feet by 16 feet height
• Gas Turbine Inlet Filter	46 feet by 28 feet by 45 feet height
• Glycol Fin Fan Cooler	88 feet by 50 feet by 30 feet height
• Generator Step Up Transformer	30 feet by 24 feet by 22 feet height
• Ammonia Storage Building	20 feet by 20 feet by 35 feet height
• Maintenance/Warehouse Building	100 feet by 36 feet by 29 feet height
• Two Gas Compressor Enclosure(s)	40 feet by 15 feet by 18 feet height (each)
• Air Cooled Condenser	278 feet by 135 feet by 85 feet height
• Fuel Gas Compressor Cooler	35 feet by 60 feet by 15 feet height
• Demin Water Storage Tank	60 foot diameter with 23 foot height
• Raw-Fire Water Storage Tank	60 foot diameter with 35 foot height
• Fuel Oil Storage Tank	60 foot diameter with 35 foot height
• Fuel Oil Delivery Facilities	32 feet by 57 feet

Major generation equipment is further described in the sections that follow.

2.4.2 POWER GENERATION EQUIPMENT

The major pieces of equipment include a combustion turbine generator with an evaporative inlet air cooler, a HRSG with duct burner, a steam turbine, an air-cooled condenser (main cooling system), a fin-fan cooler (auxiliary cooling system), a fuel gas dew point heater, electric and emergency diesel fire pumps, an auxiliary boiler, and a combustion turbine exhaust stack. Additional support systems and equipment include, but are not limited to, the following:



Footnote:
The inlet air evaporative cooler is only operated at ambient temperatures greater than 59° F.

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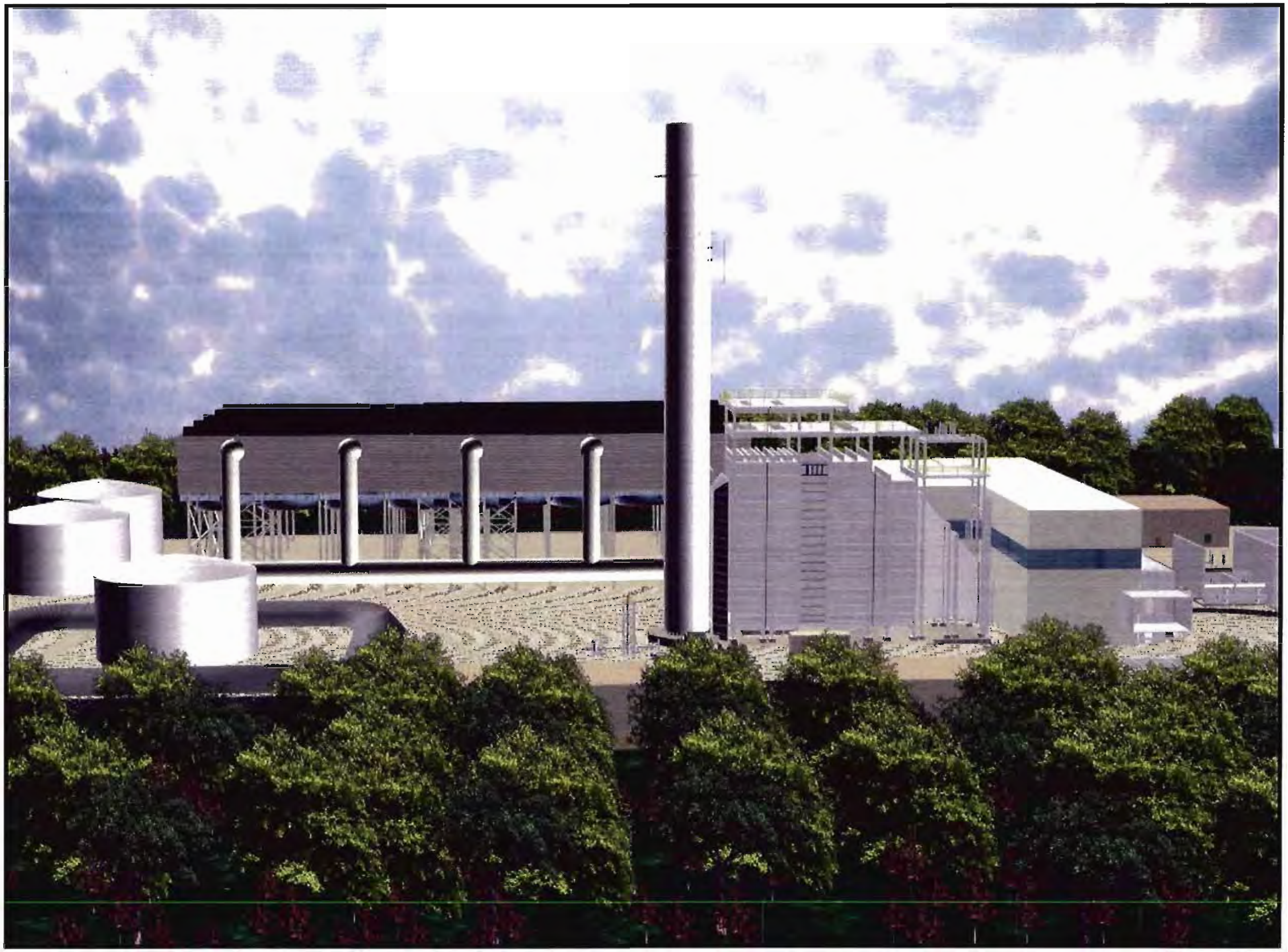
Town of Brookhaven, Suffolk County, NY

Figure 2-3. Combined Cycle Conceptual Flow Diagram

Source: TRC Environmental Corp. 03-2005



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Caithness Long Island Energy Center
Town of Brookhaven, Suffolk County, NY

Figure 2-4. Project Rendering

TRC Environmental, December 2004

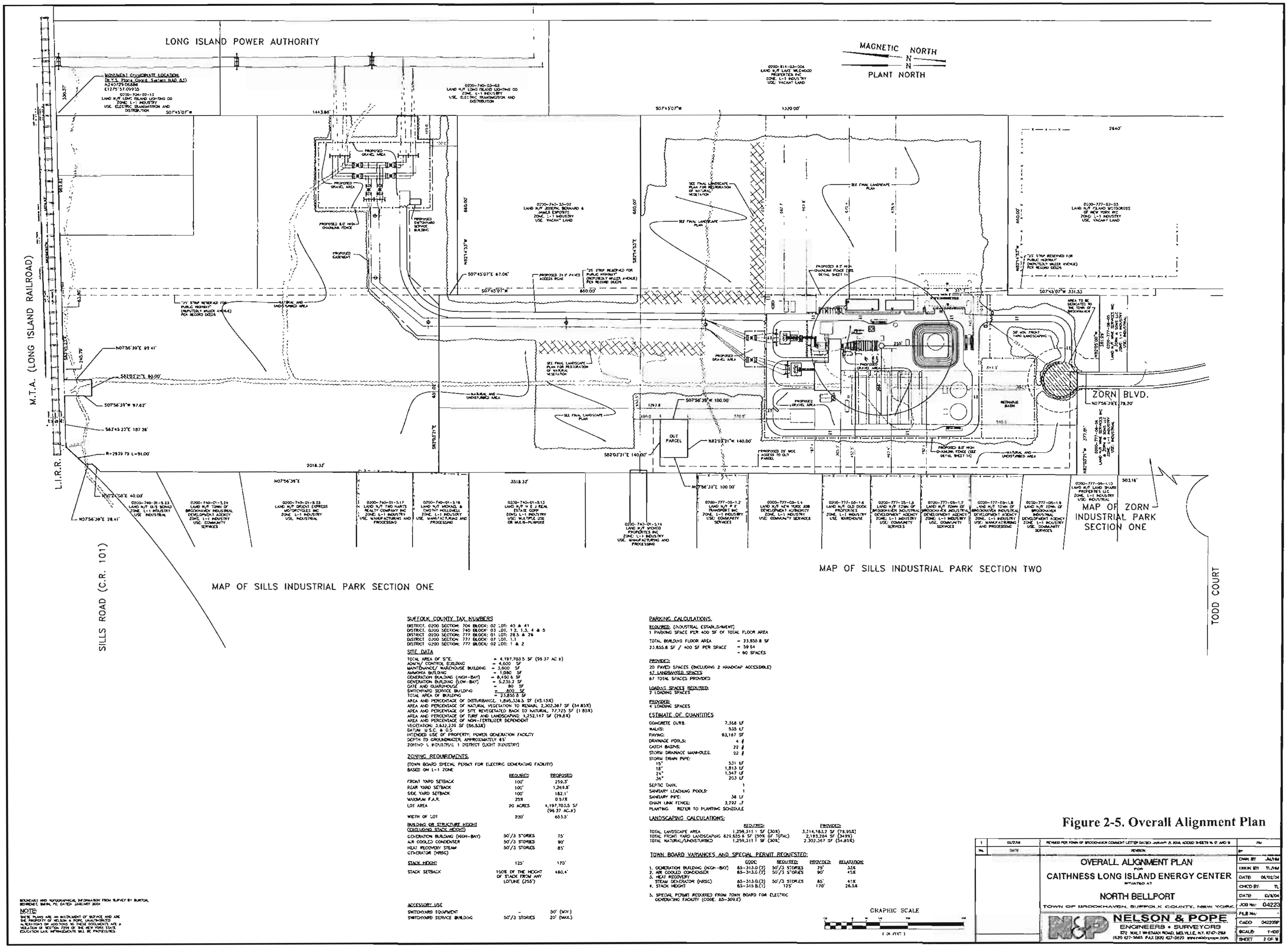


Figure 2-5. Overall Alignment Plan

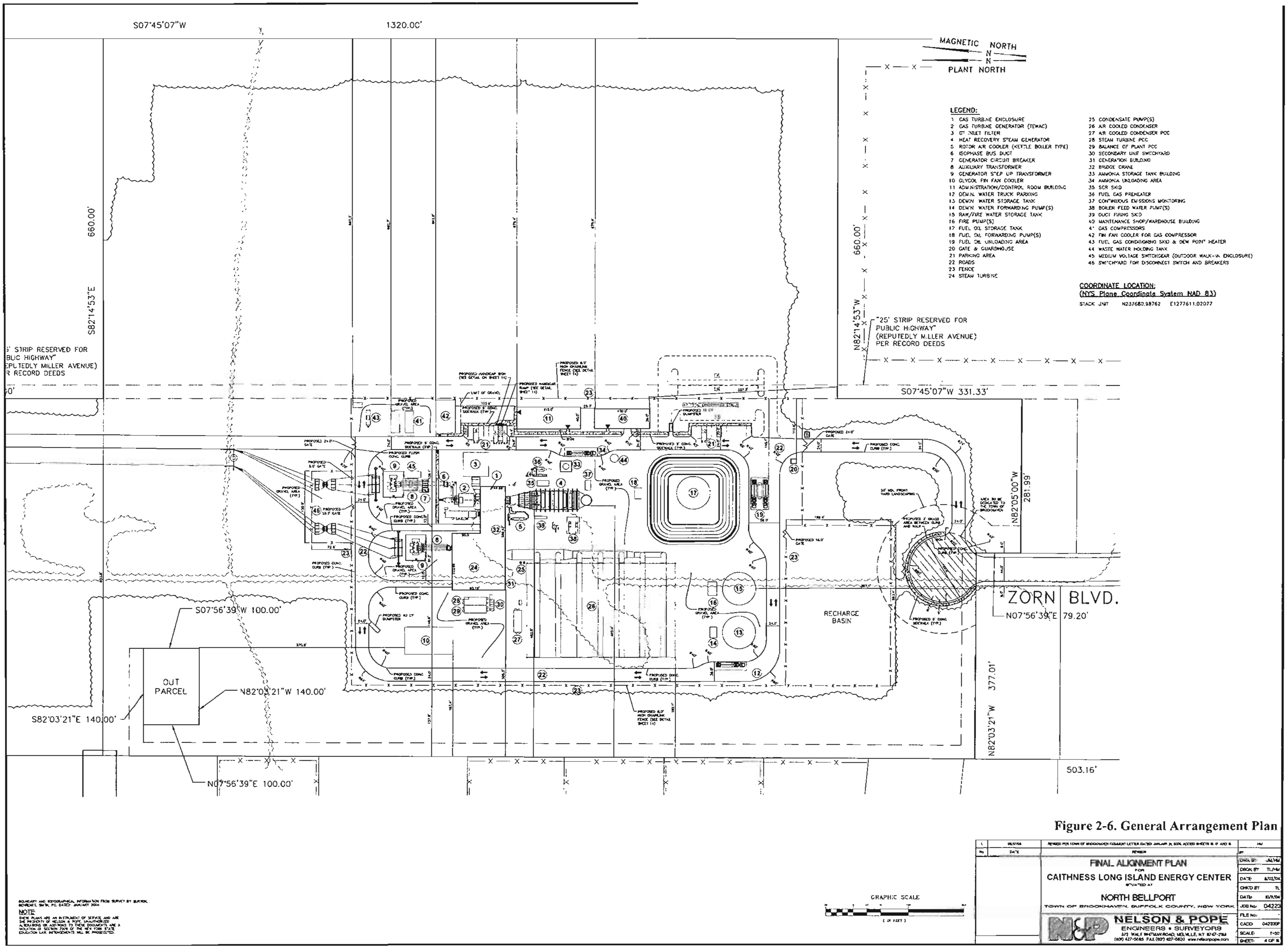
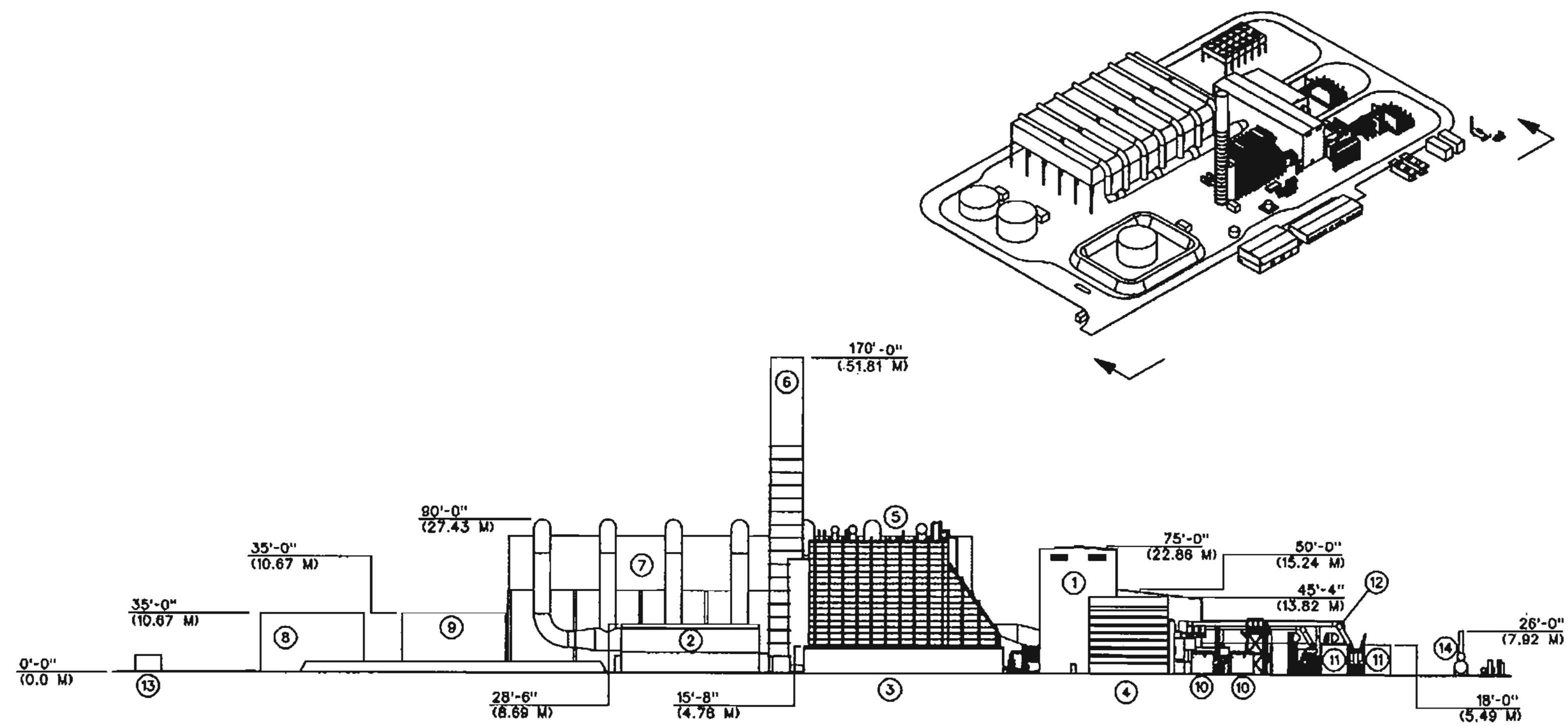


Figure 2-6. General Arrangement Plan



LEGEND

1 GENERATION BUILDING
2 MAINTENANCE/WAREHOUSE BUILDING
3 ADMIN./CONTROL ROOM BUILDING
4 GT INLET FILTER
5 HEAT RECOVERY STEAM GENERATOR
6 HRSG STACK
7 AIR COOLED CONDENSER
8 RAW/FIRE WATER STORAGE TANK
9 FUEL OIL STORAGE TANK
10 FG COMPRESSOR COOLER
11 FUEL GAS COMPRESSOR ENCLOSURE
12 ISOPHASE BUS DUCT
13 GUARD HOUSE
14 DEW POINT HEATER

NOTES

1. THE EQUIPMENT SHOWN IS REPRESENTATIVE INFORMATION. THIS DESIGN IS SUBJECT TO CHANGE AT THE DISCRETION OF SIEMENS WESTINGHOUSE.

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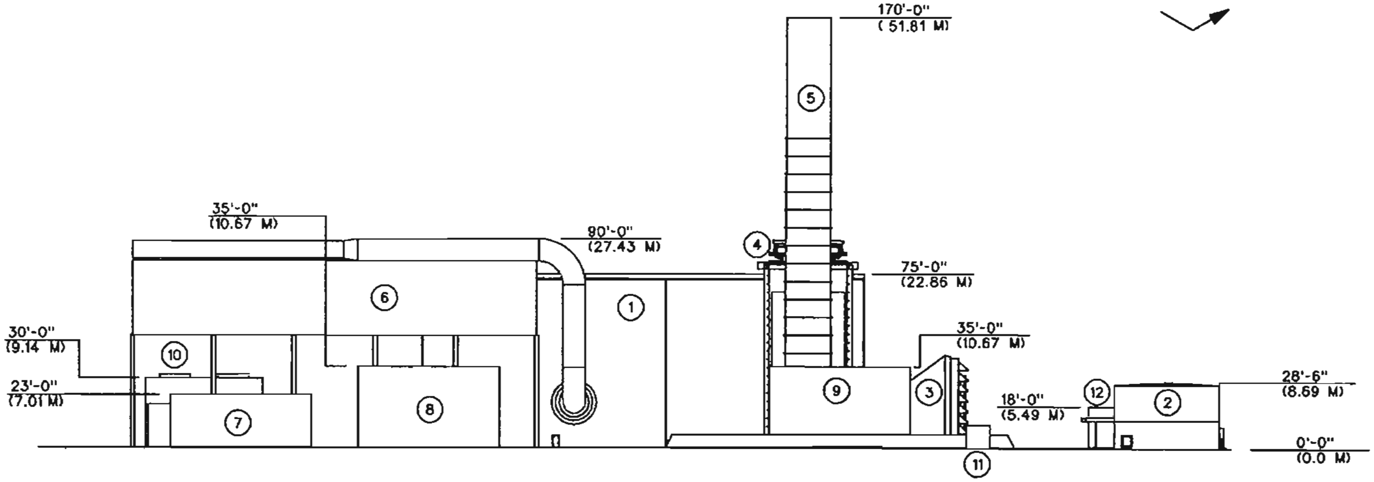
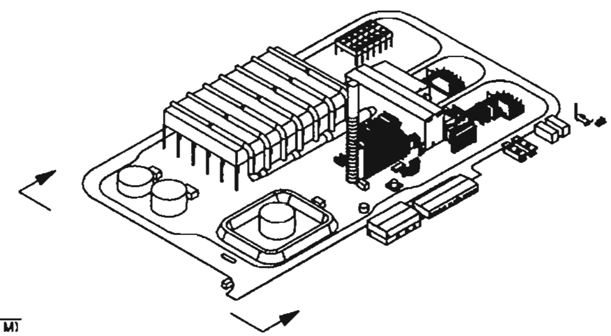
Caithness Long Island Energy Center
Town of Brookhaven, Suffolk County, NY

Figure 2-7. Facility Elevation

Source: Siemens Westinghouse Power Corp 12-2004





LEGEND

1 GENERATION BUILDING
2 MAINTENANCE/WAREHOUSE BUILDING
3 GT INLET FILTER
4 HEAT RECOVERY STEAM GENERATOR
5 HRSG STACK
6 AIR COOLED CONDENSER
7 DEMIN. WATER STORAGE TANK
8 RAW/FIRE WATER STORAGE TANK
9 FUEL OIL STORAGE TANK
10 GLYCOL FIN FAN COOLER
11 GUARD HOUSE
12 GAS COMPRESSOR FIN FAN COOLER

NOTES

1. THE EQUIPMENT SHOWN IS REPRESENTATIVE INFORMATION. THIS DESIGN IS SUBJECT TO CHANGE AT THE DISCRETION OF SIEMENS WESTINGHOUSE.

Caithness Long Island, LLC
Caithness Long Island Energy Center
Town of Brookhaven, Suffolk County, NY

Figure 2-8. Facility Elevation

Source: Siemens Westinghouse Power Corp. 12-2004

- Feed-water systems;
- Condensate system;
- Water treatment system including a water storage tank;
- Selective catalytic reduction (SCR) system;
- Oxidation (CO) catalyst;
- Chemical storage and injection system;
- Sanitary waste collection and discharge system;
- Fire protection system (including detection and alarm system);
- Domestic (potable) water distribution system;
- Instrument and service air systems;
- Heating, ventilating and air conditioning systems;
- Wastewater collection, treatment and discharge systems;
- Oil-water separators;
- On-site natural gas interconnection;
- On-site natural gas compressor and conditioning station;
- 138 kV overhead electrical transmission line;
- 138 kV switchyard; and
- Controls and instrumentation.

The primary equipment of the proposed facility is discussed in detail in the sections below.

A. COMBUSTION TURBINE GENERATOR

The combustion turbine generator is an internal combustion engine that operates with rotary motion (rotates a shaft to generate electricity) rather than reciprocating motion (i.e., vehicle engines). The turbine is composed of three major components: the compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 16 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section at high temperature. Energy from the hot exhaust gases, which expand in the power turbine section, is then recovered in the form of shaft horsepower (i.e., horsepower present at turbine shaft). More than 50 percent of the shaft horsepower is needed to drive the internal compressor and the balance of recovered shaft horsepower is available to drive the turbine and generate electricity (AP42, 2000).

Caithness is proposing to install a Siemens Westinghouse W501F combustion turbine generator firing primarily natural gas, with a maximum of 720-hours per year of operation on low sulfur distillate. The combustion turbine generator would nominally produce approximately 196 MW of electric power at an average ambient temperature of 59° Fahrenheit (F).

Additional auxiliary systems provided with the combustion turbine generator package include: static excitation system, electric starting system, inlet silencer, evaporative inlet air cooler, packaged electrical/control systems, FM 200 fire protection systems, vibration monitoring, compressor water wash skids, and engine lubricating oil systems.

B. HEAT RECOVERY STEAM GENERATOR (HRSG)

Exhaust gases in the range of 1,048° to 1,200° F would exit the combustion turbine generator and be routed to the HRSG via ductwork. In the HRSG, the heat from the exhaust gases is transferred to water/steam tubes that are immersed in the HRSG gas flow, first to boil the water into steam and then to superheat the steam for use in the steam turbine. The exhaust gases from the HRSG are routed to the stack.

The proposed HRSG is a multi-pressure, horizontal unit with reheat. The HRSG design includes the following:

- A multi-pressure level heat recovery system;
- An economizer;
- Reheater;
- Steam superheaters;
- Relief valves, stop and check valves and connections for blowdown;
- Chemical injection and drum level instrumentation isolation;
- Silencers for all safety relief valves and power operated start-up vent valves; and
- Boiler natural re-circulation system.

The HRSG would have supplemental fuel firing provided by an approximately 46 MW natural gas-fired duct burner. The HRSG would have a chemical feed system to maintain feedwater pH and oxygen levels in accordance with the Electrical Power Research Institute (EPRI) guidelines. The HRSG chemical feed system would include a phosphate/polymer feed skid and an oxygen scavenger and neutralizing amine feed skid.

C. STEAM TURBINE GENERATOR

Steam generated in the HRSG would be expanded through a steam turbine coupled with a generator (steam turbine generator) to generate additional electricity. The steam turbine generator would be a multi-stage, reheat, condensing turbine and would produce approximately 100 MW of electric power at an average ambient temperature of 51° F. The steam turbine generator would be designed for axial exhaust to an air-cooled condenser. The steam turbine generator would be designed to run continuously, but would also be capable of operating as a cycling unit. The steam turbine generator would be located in the generation building.

Provisions would be made in the design to minimize thermal expansion, stresses, distortion and vibration. The steam turbine would be designed to shut down under any of the following conditions: overspeed, high vibration, high thrust, high differential expansion, low lube oil pressure and high back pressure. A 100 percent high pressure/low pressure turbine steam bypass system would be provided to dump steam to the condenser, if necessary. The turbine bypass system would be utilized for temperature matching on warm and hot starts in addition to keeping the gas turbine in operation in the event of a steam turbine trip.

D. MAIN SYSTEM COOLING (AIR-COOLED CONDENSER)

An air-cooled condenser would be installed just south of the generation building to provide cooling for the steam exhausted from the steam turbine. The air-cooled condenser is located approximately 60 feet south of the generation building (High-Bay) and has dimensions of approximately 172 feet wide, 268 feet long, and 90 feet high.

The air-cooled condenser would rely solely on ambient air as a direct steam-cycle heat sink without the use of any water or other intermediary heat transfer medium. Steam would be routed from the steam turbine exhaust through ducts to a series of fin tube heat exchangers. The steam flows through the tubes and condenses inside the tubes forming condensate while air flows over the outer tube surface. Condensate would be discharged from the air-cooled condenser and returned to the HRSG after the latent heat of vaporization is transferred from the turbine steam directly to the air stream. Air is moved through the air-cooled condensers by a series of fans, with ambient air drawn from below the condenser and the heated warmer air discharged from the top of the condenser.

E. AUXILIARY SYSTEM COOLING (FIN-FAN COOLER)

A fin-fan cooler (auxiliary cooling system), separate and distinct of the air-cooled condenser, would be provided for cooling of plant equipment and sub-systems. The fin-fan cooler is west northwest of the generation building. The fin-fan cooler is approximately 88 feet long, 50 feet wide and 30 feet high.

The fin-fan cooler design is based on air-cooled heat exchange technology that rejects heat from a fluid directly to ambient air using a series of tubes, fins and fans similar to an automobile radiator. Propylene glycol, a non-hazardous regulated coolant, would be used rather than ethylene glycol (antifreeze), which is classified as hazardous. The fin-fan cooling system would be designed to support base load capability of the plant up to an ambient temperature of 105° F. This system would be controlled remotely from the plant control room.

The following equipment and sub-systems would be served by the fin-fan cooler:

- Steam Turbine Generator (STG) Coolers;
- Combustion Turbine Generator (CTG) Coolers;
- STG and CTG Lube Oil Coolers;
- STG and CTG Auxiliaries;
- STG Hydraulic Power Unit Coolers
- Sample Coolers;
- Service and Instrument Air Compressors and Aftercoolers (if water-cooled); and
- HRSG Feed Pump Oil Coolers;

In addition, a second smaller fin fan cooler, also utilizing propylene glycol would be installed east of the generation building to cool the project's gas compressor.

F. EVAPORATIVE COOLER

Combustion turbine generators produce up to 20 percent less power during hot weather than in cold weather without the use of an inlet air cooling system; therefore, a cooling system would be incorporated at the air inlet of the combustion turbine generator, downstream of the air filtering system for power enhancement. The basic theory of an inlet air cooler is that a combustion turbine is a constant volume machine, and at a given shaft speed, the combustion turbine would move the same volume of air. Because the power output of a turbine depends on the flow of mass through it, on hot days when the air is less dense, the power output falls off. By feeding cooler air into the combustion turbine, the mass flow is increased, resulting in higher output.

The inlet air cooler would operate when temperatures exceed 52° F in order to maximize plant efficiency. Evaporative coolers lower the compressor inlet air temperature and increase CT performance. Water is pumped into the evaporative cooling media. The evaporative cooler media is a cellulose-based material. It is mounted at the inlet of the inlet filter house. The water trickles down and soaks the media, while inlet air is passed through. This causes evaporation of water, causing cooling of the air passing through. The water supply requirements of the inlet air cooler are projected to be a maximum of 25 gallons per minute (gpm) or 36,000 gallons per day (gpd) when operating 24 hours on a hot summer day. Other water demands are explained in Chapter 12, "Infrastructure".

G. AUXILIARY BOILER

A 25,000 pound per hour (lb/hr) auxiliary boiler would primarily be used during the winter months to keep the HRSG warm during periods of turbine shutdown and provide sealing steam to the steam turbine in case of warm and hot shutdowns. The auxiliary boiler would be primarily fired by natural gas with low-sulfur distillate oil as a backup fuel. Total boiler hours for the facility would be limited to 4,800 hours per year, of which not more than 400 hours would be oil fired. Air pollution control systems for the auxiliary boilers would include a low-NO_x burner and flue gas recirculation.

H. FUEL GAS DEW POINT HEATER

The fuel gas dew point heater would be used to maintain the natural gas above its dew point temperature prior to input to the turbine and duct burner. Heating of the gas above its dew point temperature reduces the possibility of the gas "slushing" or condensing into a liquid due to change in pressure and temperature. The temperature of the gas supplied to the gas turbine would be maintained at a temperature of 50°F or more above the dew point of the gas.

The fuel gas dew point heater would have a low-NO_x forced draft burner to reduce NO_x emissions.

I. EMERGENCY DIESEL FIRE PUMP

A diesel fuel pump would be located at the facility. The fire pump would be used only to maintain on-site fire fighting capability if electric power was not available from the utility grid. Except for occasional testing to ensure the fire pump is operating properly, the fire pump would not normally operate. To account for short-term testing of the fire pump, it would be permitted to operate up to a maximum of 4 hours per day and a cumulative total of 375 hours per year.

J. STACK

The exhaust gas from the HRSG would flow into one 170-foot (above grade) stack with a flue diameter of 20 feet, located south of the generation building. The exhaust stack would include the following accessories and features:

- Galvanized test platform; stack lighting platform, if necessary; and intermediate platforms;
- Test ports and connections for the Continuous Emissions Monitoring System (CEMS);
- Galvanized ladder with cage to the test platform and stack lighting platform, if necessary;
- Access opening; and
- Silencers for noise abatement.

2.5 AIR QUALITY CONTROL SYSTEMS

The advanced dry low NO_X W501F combustion system would control NO_X emissions from the combustion turbine. The dry low NO_X combustion limits NO_X formation by controlling the combustion process through air/fuel optimization. Water injection would be used to control NO_X emissions when the combustion turbine is operating on low sulfur light distillate oil.

The combustion turbine will primarily operate on natural gas for a maximum of 8,760 hours per year. The combustion turbine will also have the ability to operate on low sulfur distillate fuel oil up to 720 hours per year. Additionally, a natural gas-fired duct burner will produce additional steam in the HRSG for a maximum of 4,380 hours per year. Operation of the duct burner would result in an approximately 46 MW increase in the facility's generating capacity. Oil-fired operation of the facility duct burner is not proposed. The facility's NO_X emissions are further reduced to the lowest achievable emission rates (LAER) by post combustion treatment with a selective catalytic reduction (SCR) system. Low concentration (19 percent) aqueous ammonia would be injected into the flue gas, upstream of the SCR catalyst, where it would mix with the NO_X in the presence of the SCR catalyst to form nitrogen and water vapor. Ammonia that does not react would pass through the HRSG and out of the stack. This phenomenon is termed "ammonia slip." The SCR system would reduce NO_X concentrations to 2.0 parts per million dry volume (ppmvd) at 15 percent oxygen (O_2) (natural gas firing with and without duct firing), 6.0 ppmvd at 15 percent O_2 (low-sulfur light distillate oil firing without duct firing) and 8.0 ppmvd at 15 percent O_2 (low-sulfur light distillate oil firing with duct firing) with an average ammonia slip of 5 parts per million (ppm) or less for both fuels. Emissions expressed in ppm are corrected to 15 percent O_2 to reflect the accepted standard amount of dilution used by regulatory agencies to put different combustion turbines on the same basis.

After combustion control, the carbon monoxide (CO) emissions from the combustion turbine unit would be reduced using an oxidation catalyst (also referred to as a CO catalyst). Exhaust gases from the turbine are passed over a catalyst bed where excess air oxidizes the CO to carbon dioxide (CO_2). The oxidation catalyst system would reduce CO concentrations to 2.0 ppmvd at 15 percent O_2 (natural gas firing with and without duct firing), 2 ppmvd at 15 percent O_2 (low sulfur light distillate oil firing without duct firings) and 4.0 ppmvd at 15 percent O_2 (low-sulfur light distillate oil firing with duct firing).

Natural gas does not contain appreciable amounts of sulfur, so sulfur dioxide (SO_2) emissions would be minimal without additional controls.

Upon leaving the HRSG, turbine exhaust gases would be directed to the exhaust stack. The stack would be equipped with a Continuous Emissions Monitoring System (CEMS) to monitor the concentrations of NO_x, O_2, and CO. A monitoring system to measure ammonia slip would also be provided. The stack would have a platform to provide access to the monitoring equipment.

The CEMS measures and reports (in appropriate units) the emissions products/release rates of the plant in accordance with the requirements of applicable state and federal codes and standards. Alarms would be generated, printed and displayed on the CEMS monitor for high levels and exceedances for each monitored emission parameter. The CEMS would be designed as a stand-alone system with the capabilities to extract/condition the exhaust gas, transport it to the analyzers, perform the appropriate analysis, record the findings and generate the required reports and alarms.

The proposed facility would incorporate data acquisition and control systems, which would optimize combustion performance. These same systems would minimize pollutant emissions through a combination of operator and software-driven process adjustments and notifications.

2.6 WATER USE/WASTEWATER GENERATION AND CHEMCIALS

The proposed facility design minimizes both water supply and wastewater discharge requirements through use of an air-cooled condenser for main system cooling, a fin-fan cooler for auxiliary cooling and internal recycle/reuse of process wastewater. The proposed facility's water supply requirements would typically range from approximately 43,200 gallons per day (gpd) (30 gallons per minute [gpm]) to 80,640 gpd (56 gpm) depending on ambient temperature. Waste streams which cannot be reused would be collected for subsequent off site treatment and disposal by a licensed waste hauler. Site stormwater runoff would be routed to an on-site recharge basin. Sanitary wastewater would be directed to an on-site subsurface disposal system.

Figures 12-1, 12-2 and 12-3 in Chapter 12, "Infrastructure," present the preliminary water balance diagrams for the anticipated range of operating scenarios. The diagrams illustrate the primary water supply and wastewater effluent pathways through the facility. Table 2-1 provides a summary of the various operating scenarios represented in the water balance diagrams.

Table 2-1
Summary of Water Balance

Operating Condition	Turbine Load Condition (Percent)	Inlet Air Cooler (Fogger)	Water Supply (gpm)	Wastewater Discharge (gpm)	Evaporative Loss (gpm)
Average Annual Case	100	Off	35	5	29
Summer Natural Gas Fired Case	100	On	50	5	44
Winter Oil Fired Case	100	Off	56	5	50
Notes: gpm = gallons per minute; 1 gpm equals 1,440 gpd.					

General features of the proposed design are as follows:

- All cases are based on 100 percent load for maximum electrical power production.
- The primary and auxiliary cooling systems are air-cooled and therefore do not require water for system operation and do not generate wastewater.
- Water condensing from the HRSG (called blowdown) (about 30 gpm) would be sent to a cartridge filter and then to the raw water tank for reuse in order to reduce the overall water supply requirements.
- Remaining wastewater would be collected in facility floor drains, routed through an oil water separator, and directed to a wastewater holding tank for off-site disposal.
- Sanitary wastewater, averaging 1 gpm, would be directed to an on-lot subsurface disposal system.
- Site stormwater runoff would be collected and conveyed to an on-site recharge basin. Stormwater from secondary containment basins would be visually inspected prior to release to the stormwater collection system (i.e., operated on an inspect and release basis). Stormwater from potentially oily areas at the site (i.e., secondary containment basins for the oil storage tank and station transformers) would be routed through an oil water separator.

Water to support the proposed facility would be obtained from the Suffolk County Water Authority (SCWA) via a new interconnect to the existing 12-inch distribution main located along Zorn Boulevard. Caithness submitted a letter to the SCWA requesting confirmation of the availability of water in sufficient volumes to meet the facility's water supply and fire flow requirements. To confirm that adequate capacity is available to meet fire flow requirements, the SCWA conducted a flow test of the system and concluded that the it can meet both the 1,810 gpm fire flow requirement and the day-to-day operational water demands of the facility provided that overnight demands (i.e., between the hours of 12:00 midnight and 9:00 a.m.) do not exceed a withdrawal rate of 150 gpm. As indicated in SCWA's response letter, Caithness would be required to install a flow control valve to limit overnight flows as requested by the Authority. A copy of the letter request and the SCWA's response is provided in Appendix D. Chapter 12, "Infrastructure", of this document provides a detailed description of the projected water requirements of the proposed facility and a demonstration that the construction and operations of the proposed facility would not impact the operations of the SCWA's distribution system.

A new 12-inch pipe from the proposed facility to the 12-inch main located within Zorn Boulevard would be needed to satisfy facility water supply requirements. On-site water storage is also incorporated into the facility design. This would include installation of 750,000 gallon combination raw water/fire water storage tank and a 500,000 gallon demineralized water storage tank.

The potable water distribution and sanitary systems would serve areas used by operations staff or visitors. The maximum design flow would be 1,440 gpd (1 gpm) for the facility's potable water and sanitary systems. The potable water distribution and sanitary systems would be designed in accordance with all applicable state and local codes, including the New York State Uniform Fire Prevention and Building Code and Sanitary Code, the Suffolk County Sanitary Code (Articles 6, 7 and 12) and the Town of Brookhaven Building Code.

The potable water and sanitary systems would consist of the following:

- Two (2) on-lot subsurface disposal systems;
- Potable water distribution systems;
- Sanitary plumbing fixtures and drinking fountains;
- Emergency showers and eye wash stations; and
- Backflow prevention device(s).

The potable water system would be designed and constructed to provide potable water, both hot and cold, at the proper pressure, flow rate and temperature, to all plumbing fixtures and equipment listed above. Hot water heaters would be provided in addition to isolation valves, check valves, and balancing valves.

The on-site subsurface disposal systems for the proposed facility would be a gravity flow system. In accordance with Article 7 of the Suffolk County Code, the project would have a dual plumbing system installed on-site, one for sanitary wastes and one for industrial wastes. Cross-connection to any other drainage or water supply system would not be permitted. A backflow prevention system that conforms to the SCWA's backflow cross-connection program would be installed. As part of the Drought Contingency Plan for the proposed facility, all sanitary fixtures at the facility would be equipped with low volume flush toilets and all sinks, showers, and faucets would be fitted with water saving devices.

2.6.1 DEMINERALIZATION TREATMENT SYSTEM

Demineralized water is required for process water to prevent scale formation and minimize corrosion of internal system components. During initial startup after construction, demineralized water would be used for hydrostatic testing, chemical cleaning, displacement flushes and wet storage. During operations, demineralized water would be used for HRSG feedwater makeup (continuous), and on-line and off-line compressor cleaning operations (intermittent).

The demineralized water requirements for operations are estimated to range from approximately 20 gpm under gas firing to 60 gpm when firing low sulfur distillate fuel. The demineralized water requirements would be met using a leased demineralization system to remove the naturally occurring dissolved salts and minerals from the raw water source. Demineralization would be performed using one or more demineralization trailers with off-site ion exchange regeneration by the vendor.

During a trailer change out, initial rinse water and drain down water from the cation and anion exchange vessels would either be routed back to the raw water storage tank or directed to the stormwater collection system for recharge to the aquifer. If discharge to the on-site recharge basin is selected during final design, this waste stream would be included as a permitted outfall under the facility's SPDES permit.

Caithness would provide the piping, electrical, and control system interfaces between the mobile demineralizer and the power plant including a concrete pad for the trailer(s), hose connections for the service water system and the 500,000 gallon demineralized water storage tank. The location of the demineralized water storage tank is illustrated in previous Figure 2-6. The demineralized water tank would be built in accordance with industry standards and governmental regulations.

2.6.2 CHEMICAL FEED SYSTEMS

A chemical feed system is needed to supply water-conditioning chemicals to the condensate system and the HRSG. The chemical feed system would consist of an oxygen scavenger injection subsystem and an amine injection subsystem. Each subsystem would be skid-mounted and consist of chemical solution tanks, solution mixers, pumps, piping, instrumentation and controls.

The oxygen scavenger subsystem would be used to minimize corrosion by reducing the dissolved oxygen levels in the condensate system. The oxygen scavenger injection rate would be automatically adjusted according to the level of dissolved oxygen in the condensate. The amine injection subsystem would be used to maintain a high pH level through the injection of amines (alkaline compounds) directly into the steam. Amines injection is used in many energy supply systems to prolong system life. Typical amines include morpholine, diethylaminoethanol, and cyclohexylamine. The neutralizing amine injection rate would be automatically adjusted according to condensate conductivity. The oxygen scavenger and neutralizing amine would each be shipped to the plant in 400-gallon tanks.

2.6.3 AMMONIA INJECTION SYSTEM

A complete ammonia injection system would be provided for the HRSG that would take ammonia forwarded from the ammonia storage vessel, vaporize the ammonia, and inject it into the exhaust gas at the proper location and in the proper proportions. All equipment provided with the HRSG would be mounted on an ammonia injection skid, except for the ammonia injection header. All equipment would be accessible from grade and mounted adjacent to the HRSG to minimize the length of the ammonia injection lines. The ammonia injection skid would be pre-piped, pre-wired, and insulated with aluminum lagging provided. A solenoid operated (125V DC) emergency shut-off valve would be provided for any ammonia supply line or steam supply line to the injection system. This valve would be capable of being operated locally.

2.6.4 LIQUID WASTE STREAMS

The liquid waste streams generated at the facility would be low volume and would include HRSG blowdown, off-line compressor washwaters, building floor washwater and miscellaneous wastewater collected in the floor drain system (floor drains). Other than for rinse and draindown waters, the leased demineralization system does not generate a concentrated waste stream due to its off-site regeneration.

A description of each low volume waste stream is provided in the sections below.

A. HRSG BLOWDOWN

Periodic blowdown of the boiler is required in order to protect against scale formation and internal corrosion. The typical blowdown rate for the HRSG is estimated to be 20 gpm. The chemical conditioners added to the boiler are as follows: an oxygen scavenger to minimize corrosion by reducing the dissolved oxygen; and an amine inhibitor to raise pH. Because of the high water quality of the HRSG blowdown, the boiler blowdown would be conveyed to a flash tank and filtered and returned to the raw water storage tank for reuse. Any HRSG blowdown collected during sampling would be sent to the wastewater holding tank for off-site disposal. The wastewater holding tank would be primarily used to collect wastewater from the transformer containment pit areas and floor drains in the generation building. Fuel oil false start drains and compressor washwaters would be collected in a separate false start drains tank for off-site disposal. Because the facility's design incorporates the recycle/reuse of the HRSG blowdown and disposes the wastestream generated during HRSG blowdown sampling off-site, there would be no HRSG blowdown discharged to the recharge basin.

During construction, start-up, and major facility outages (likely not more than once per year), HRSG cleaning wastes would be collected in the wastewater holding tank and trucked off-site for proper disposal at an appropriately licensed facility.

B. ON-LINE AND OFF-LINE COMPRESSOR CLEANING

Compressor washwater is used to remove fouling deposits (such as dirt, oil mist, and industrial or other atmospheric contaminants) that accumulate on compressor blades. These deposits reduce airflow, lower compressor efficiency and lower compressor pressure ratio, which reduce thermal efficiency and output of the unit. Compressor cleaning removes these deposits to restore performance and slows the progress of corrosion in the process, thereby increasing blade wheel life.

On-line cleaning is the process of injecting cleaning solution (water and/or detergent) into the compressor while operating. During an on-line wash, demineralized water would be evaporated in the combustion turbine exhaust stream. The advantage of on-line cleaning is that washing can be done without having to shut down the unit. However, on-line washes are not as effective as off-line washes. Therefore, on-line washes would be used only to supplement off-line washes, not to replace them.

Off-line cleaning is the process of injecting cleaning solution into the compressor while it is being turned. The periodic off-line wash rate is about 41 gpm for 20 minutes. Off-line combustion turbine washes are anticipated to occur about 10 times per year. The off-line waste stream would be collected in the wastewater holding tank and trucked off-site after each wash by a licensed contractor responsible for removal and proper disposal.

C. FLOOR DRAINS

A floor drain collection system would be provided for the generator building to collect miscellaneous waste streams generated during plant operation and maintenance activities. All floor drains would be directed to an oil/water separator prior to discharge to the wastewater holding tank for removal and proper disposal.

2.7 STORMWATER MANAGEMENT

Impervious surfaces would be added to the site as a result of the facility; therefore, an increase in stormwater runoff volume can be anticipated. A Stormwater Pollution Prevention Plan (SWPPP) would be prepared for both construction and operation in compliance with all local stormwater and erosion and sediment control guidelines. A detailed discussion of the facility's stormwater management practices including soil erosion and sediment control, site grading and drainage, infiltration basin design, outfall locations, etc., is provided in Chapter 12, "Infrastructure".

Caithness would be required to obtain a State Pollutant Discharge Elimination System (SPDES) Permit to discharge stormwater to an infiltration basin during operations. A SPDES Permit Application will be submitted to the NYSDEC as part of the environmental review. A discussion of the SPDES Permit Application is provided in Chapter 12, "Infrastructure" and a copy of the SPDES Permit Application is provided as Appendix J. Because no stormwater would be discharged to surface waters during construction activities, a notice of intent seeking coverage under NYSDEC's General SPDES Permit for Stormwater Discharges from Construction Activities (Permit No. GP-93-06) is not required.

2.8 INSTRUMENTATION/CONTROL DEVICES

Instrumentation and control devices would be used to sense, indicate, transmit and control process variables as required for safe, efficient and reliable operation of the plant and its systems and components. A Distributed Control System (DCS) would be installed at the facility to monitor the combustion turbine generator and the steam turbine generator and other associated equipment (i.e., gas compressors, boiler feed pumps, etc.). The DCS system would implement both closed and open loop control to bring the plant from cold start up, to the desired operating condition, and back to cold shutdown.

The DCS system would also be used to monitor, display and record process data received from field sensors and through communication links. This information would then be used for general process supervision, execution of plant equipment and performance calculations, historical record keeping/trending including sequence of events recording and diagnostics for management and maintenance of the plant.

Other process instrumentation and control devices include:

- Control valves;
- Flow instruments (venturies, orifice plates and averaging pitot tubes);
- Level instruments (level indicators, level switches and level transmitters);
- Pressure and differential Pressure Indicators (gauges and switches);
- Process analyzers; and
- Temperature instruments (indicators and sensors).

2.9 ELECTRIC TRANSMISSION INTERCONNECTION

The project would interconnect to LIPA's 138-kilovolt (kV) transmission system within the 96-acre parcel via an overhead transmission line to be constructed between the project's step up transformers and a new 138 kV switchyard to be constructed in the northern portion of the project's 96-acre parcel. The new switchyard would be located adjacent to LIPA's Holbrook-to-Brookhaven transmission line right-of-way, approximately 1,500 feet from the project's step-up transformers.

A System Reliability Impact Study (SRIS) to evaluate proposed project's impact on the LIPA bulk power system and systems in Southeast New York has been prepared. The SRIS demonstrates that the project would not have a significant impact on the LIPA bulk transmission system, or on any neighboring systems. The SRIS was submitted to NYISO on or about May 17, 2005. On June 9, 2005, the NYISO Transmission Planning Advisory Subcommittee recommended approval of the SRIS, and final approval of the report by the NYISO Operating Committee is expected on or about June 30, 2005.

2.10 NATURAL GAS PIPELINE

The facility would utilize clean burning natural gas as its primary source of fuel. The natural gas would be delivered to the project from one of several pipeline projects that are currently under review. It is contemplated that any new natural gas pipeline lateral would be developed by an entity other than LIPA or Caithness and would be available to the proposed project as well as other users in eastern Long Island. Any new pipeline project would require separate approval from either the New York State Public Service Commission (PSC) under Article VII of the Public Service Law or the Federal Energy Regulatory Commission (FERC) under its Section 7(c) certificate authority.

One potential supply of natural gas could occur with an extension of the Iroquois Interstate Pipeline. The Iroquois Interstate Pipeline currently terminates in Commack, Suffolk County, New York. This pipeline could be extended from this termination point for an approximate 22 miles generally along the right-of-ways (ROWs) of the Sunken

Meadow Parkway and the LIE and then along the existing LIPA transmission ROW to the project site. Such pipeline lateral extension would be subject to a separate environmental impact review under the National Environmental Policy Act (NEPA) as part of the FERC licensing.

Another possible alternative would be for the project to connect with the proposed Islander East pipeline. This proposed pipeline has received FERC approval but still requires certificates and approvals from the State of Connecticut. If constructed, the terminus of this pipeline lateral is proposed to be located approximately 4,000 feet north of the project site, along the eastbound service road of the LIE. If this were to become the source of natural gas, a natural gas lateral (or pipeline spur) would need to be constructed, which would leave the northeastern portion of the 96-acre parcel and follow LIPA's transmission line ROW to the proposed Islander East Pipeline terminus located along the LIE. This pipeline spur would also require either PSC or FERC approval.

Other providers of natural gas could also be utilized for the project. For instance, an upgrade could be considered to KeySpan Energy Delivery Corporation's existing natural gas local distribution network pipeline that serves eastern Long Island. However, to date, no specific engineering and design details have been developed for this to be a viable fuel source.

The licensing of a natural gas pipeline lateral ultimately used to provide a natural gas supply to the project is not part of this SEQRA review because, as an independent project, it would go through its own separate environmental review and approval process. Nevertheless, Chapter 19, "Natural Gas Lateral," provides a general overview of the conceptual design of alternative sources of natural gas supply that could serve the project and a discussion of the possible environmental studies that would be undertaken by the pipeline developer under either PSC or FERC environmental reviews.

2.11 SECURITY

Prior to commencement of construction, a comprehensive security plan would be developed and implemented. The security plan will be provided to the Suffolk County Police Department and the Suffolk County Department of Fire, Rescue, and Emergency Services for review.

The perimeter of the project site will be secured with a chain link fence, sliding gates and surveillance equipment so as to permit only authorized access to the facility's service drive, structures and operations. One gate would provide access into the project site, thereby restricting access to this area. The gate would be locked during normal operations with access provided by facility personnel. Normal plant lighting and emergency temporary lighting would be provided throughout the facility. Security personnel would be on site 24 hours per day, 7 days per week, 365 days per year. All site security personnel would be equipped with communication equipment to maintain contact with construction and operations management personnel and/or the Suffolk County Police Department and the Suffolk County Department of Fire, Rescue, and Emergency Services.

2.12 FIRE PROTECTION

A complete fire protection system, designed in accordance with NFPA Code 1, Code 850 and NFPA Code 30; Factory Mutual Data Sheets 7-10 and 504; the Town of Brookhaven Building Code; and the New York State Building Codes would be installed at the proposed facility. The fire water system capacity would be determined in accordance with the criteria in NFPA 850 and would be at least equal to the flow rate required for the largest single fire hazard. Preliminary analysis indicates the system would be sized to deliver 1,810 gpm.

The primary source of water for fire protection would be the 750,000 gallon raw water and fire protection storage tank that would be constructed on-site to minimize the impacts to the local water supply system. The raw water and fire protection storage tank would be built in accordance with industry standards and governmental regulation. They would present no risk of harm to the community. The SCWA would be used as the back-up source of water for fire protection. During operations, the plant personnel would be trained as an on-site fire brigade, working cooperatively with the local fire department, to function as the first line of defense in the event of a fire at the plant.

2.13 SCHEDULE

It is expected that the environmental review, planning and preliminary engineering would take place in 2005. After receiving all approvals and financing, long lead items would be ordered. Construction activities for the proposed project are anticipated to commence approximately spring of 2006 and project operations approximately summer of 2008. ✳

Exhibit 17

SECOND AMENDED AND RESTATED

POWER PURCHASE AND SALE AGREEMENT

between

PACIFIC GAS AND ELECTRIC COMPANY

(as "Buyer," as further defined herein)

and

RUSSELL CITY ENERGY COMPANY, LLC

(as "Seller")

a. Both Units are operating:	195 MW
b. One Unit is operating:	100 MW

Ancillary Services, at ISO conditions, Continuous Duct Firing Mode:

Minimum load one Unit:	178 MW (Estimated value, not guaranteed)
Maximum load one Unit:	299 MW
Minimum load two Units:	362 MW (Estimated value, not guaranteed)
Maximum load two Units:	601 MW

1. Spinning Reserves:

a. Both Units are operating:	233 MW (Estimated value, not guaranteed)
b. One Unit is operating:	118 MW (Estimated value, not guaranteed)

2. Regulating Reserves:

a. Both Units are operating:	233 MW (Estimated value, not guaranteed)
b. One Unit is operating:	118 MW (Estimated value, not guaranteed)

Minimum Load of Each Unit

Refer to Ancillary Services above.

Emissions Restrictions

The Units must be operated in a manner that permits their compliance with the Authority to Construct (“ATC”) issued by the Bay Area Air Quality Management District (“BAAQMD”). Seller will obtain an amended ATC from the BAAQMD, allowing the Units to be constructed at a slightly modified site, with no material adverse alteration to the allowable emissions currently permitted under the ATC.

The ATC shall allow for up to 50 weeks of operation on Buyer’s behalf in “6x16” mode per year, where the Units are started and operated for up to 16 hours, and subsequently shut down each day for 6 days per week. The ATC shall also allow for operation on Buyer’s behalf up to 8264 hours per year, with each duct burner operating up to 4,000 hours per year at full output, with the number of Start-Ups and Shut-Downs that would result in this level of operation.

Exhibit 18

GOLDEN GATE UNIVERSITY School of Law

Environmental Law and Justice Clinic

September 16, 2009

By E-Mail and U.S. Mail
weyman@baaqmd.gov
Weyman Lee, P.E.
Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: August 2009 Draft PSD Permit for Russell City Energy Center

Dear Mr. Lee:

We are writing on behalf of Citizens Against Pollution (CAP) to provide supplemental comments on the draft prevention of significant deterioration (PSD) permit for the proposed Russell City Energy Center (RCEC). CAP appreciates that BAAQMD issued an Additional Statement of Basis for the changed draft permit conditions. Earthjustice is submitting a separate letter, also on behalf of CAP, and we are incorporating the comments in that letter by reference.

As before, the draft permit once again fails to meet federal PSD, and therefore BAAQMD should not issue the permit as proposed. In addition to complying with the Clean Air Act's PSD provisions, BAAQMD should take care to ensure compliance with the nonattainment new source review (NSR) requirements. BAAQMD has failed in responding to CAP's comments as to NSR even though BAAQMD has a regulatory responsibility over the Act's NSR requirements. BAAQMD's statement – that any appeal period for challenging the NSR provisions has expired – is irresponsible. The public who will bear the burden of breathing pollution from the proposed power plant deserves a meaningful response, not a legalistic and technical response. BAAQMD should provide a response befitting its role as a public health and regulatory agency with the responsibility over NSR compliance, particularly given that asthma is a serious concern to residents nearby and students at Chabot-Las Positas Community College District, and asthmatics are susceptible to adverse health impacts from exposure to ground-level ozone, a pollutant governed by the NSR provisions.

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I. THE DISTRICT'S BACT ANALYSIS SUFFERS FROM THE FUNDAMENTAL MISTAKE THAT *ACHIEVABLE* MEANS *ACHIEVED* LIMITS (WITH OPERATING DATA OVER A LONG TIME, PLUS A LARGE COMPLIANCE MARGIN).

The Supreme Court has noted that in establishing National Ambient Air Quality Standards, the Clean Air Act amendments were intended to be "technology-forcing." *Train v. Natural Resources Defense Council*, 421 U.S. 60, 91 (1975). The Act's requirements "are expressly designed to force regulated sources to develop pollution control devices that might at the time appear to be economically or technologically infeasible." *Union Elec. Co. v. E.P.A.*, 427 U.S. 246, 257 (1976). Consistent with the Act, BACT is thus "principally a technology-forcing measure that is intended to foster rapid adoption of improvements in control technology." *In re: Columbia Gulf Transmission*, 1989 EPA App. LEXIS 26, *10. *See also In re: Tennessee Valley Auth*., 2000 EPA App. LEXIS 25, *78-79 ("the program Congress established was particularly aggressive in its pursuit of state-of-the-art technology at newly constructed sources"). Thus, the best *achieved* control technology is not necessarily the best *achievable* technology, and therefore does not constitute BACT.

The proposed emissions are not technology forcing and therefore do not comply with the Act's BACT requirements. In determining BACT limits, the District improperly relied not only on emissions limits *achieved* at existing facilities but on *maximum* achieved limits. Moreover, the District added a "compliance margin" of unexplained origin on top of those maximum achieved emissions limits. In so doing, BAAQMD rejected realistically *achievable* limits. It is hard to imagine how technological improvements envisioned by BACT requirements would ever be incorporated into new sources, if permitting authorities solely rely on maximum achieved emissions, with a wide compliance margin, to set BACT. The District's BACT analysis suffers from this defect throughout.

A. CO Limits

BAAQMD examined the permit conditions for several other facilities, and concluded that 2.0 ppm was the "emerging consensus" and seemingly achievable. Additional Statement of Basis for Draft Federal "Prevention of Significant Deterioration" Permit (August 3, 2009) [ASOB] at 47, *available at* http://www.baaqmd.gov/pmt/public_notices/2008/15487/index.htm. This determination was based on already existing facilities, however, and ignores that lower BACT limits for CO have been issued to other similar facilities, such as Kleen Energy Systems and CPV Waren. *Id.* Again, it is improper to rely on an assumption that the lowest achieved limits are the lowest achievable.

BAAQMD justifies ignoring the lower limits in existing permits by explaining that "the mere issuance of a permit [does not establish] that limit as BACT, without some further demonstration that the limit is achievable." *Id.* BAAQMD states that facilities with lower CO limits are not yet built, and therefore there is no operating data on which to determine achievability. *Id.*

The District has misapprehended its burden. To reject existing limits as BACT, the District must do more: “a permit requiring the application of a certain technology or emission limit to be achieved for such technology usually is sufficient justification to assume the technical feasibility of that technology or emission limit.” New Source Review Workshop Manual (Draft Oct, 1990) [NSR Manual], at B.7. The NSR Manual explains that, where a permit limit has been established elsewhere, a permitting agency must rely on more than simply that there are no operating data to reject the limit:

> A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude [implementation].
>
> For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., . . . the project was canceled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control . . . may be eliminated from further consideration.

NSR Manual at B.7.

The Manual goes on to give other examples of circumstances where a limit higher than has previously been required may be appropriate, *id.* at B.23:

> [T]he consideration of a lower level of control for a given technology may be warranted in cases where past decisions involved different source types [or] where the applicant can demonstrate to the satisfaction of the permit agency that other considerations show the need to evaluate the control alternatives at a lower level of effectiveness.
>
> Manufacturers’ data, engineering estimates and the experience of other sources provide the basis for determining achievable limits.
>
> [I]t is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise.

Id. at B.24.

Neither the applicant nor the District has met the burden that is required for a higher limit than that already contained in other permits. If the District could simply reject established permit limits because of lack of operating data, one could never rely on permit limits in proposed projects because operating data necessarily do not exist in those cases. But the regulations and the NSR Manual make clear that such permit limits are to be considered BACT. Thus, the absence of operating data alone is not an adequate justification for rejecting such limits as BACT. That approach indeed makes sense: BACT is not backward looking, based on operating data of other facilities. It is intended to be technology forcing, focused on the best technology for pollution control.

B. PM Limits

In determining the BACT limit for particulate matter (PM), BAAQMD relied on testing from similar facilities to determine BACT to be 7.5 lb/hr. ASOB at 51. The average PM emissions from these source tests varied from 4.58 lb/hr to 10.65 lb/hr. *Id*. BAAQMD eliminated the highest 5% of the test results, believing them to be anomalies, and based BACT on the remaining 95% of results, but the District does not explain the basis for choosing this percentage. *Id*. Again, neither the applicant nor the District has pointed to any source-specific factors for relying on such a lenient standard. *See* NSR Manual at B.7, B.23-24.

Furthermore, total PM emissions from certain facilities – which were built long ago – were well below the 7.5 lb/hr limit, which the District determines is BACT. *See* "Summary of Filterable PM_{10}" (the spreadsheet referenced in ASOB at 51 n.98). The District has not explained why a newly proposed facility could not meet the lower range of those emissions.

Once again, BACT cannot properly be determined based solely on the operating data of facilities that have been built long ago. In addition, BACT cannot ignore the lowest limit currently achieved by such power plants.

C. GHG Limits

The facility is estimated to emit nearly 2 million metric tons per year of CO_2 equivalents. ASOB at 27. The emission limits for GHGs are set assuming approximately 9% total degradation over the lifetime of the equipment. *Id*. at 28. What is the basis for this large degradation figure?

II. THE DISTRICT'S BACT ANALYSIS FOR STARTUP AND SHUTDOWN DOES NOT COMPLY WITH PSD AND NSR REQUIREMENTS.

A. Startup and Shutdown Emissions Limits Are Backward Looking Rather than Technology Forcing and Therefore Do Not Comply with the Clean Air Act's BACT Requirements.

As with other limits, in determining startup NOx limits, BAAQMD improperly relied on *maximum* limits *achieved* at existing facilities and added a compliance margin. In so doing, BAAQMD rejected realistically *achievable* limits set at other facilities.

1. NOx Limits

<u>*Cold Startup Limits*</u>

In determining the NOx startup limits (as NO_2), BAAQMD dismissed limits that have been achieved in fact and are lower than the proposed limit of 480 lbs. per startup event. The facilities, even those where construction commenced as long ago as 2000, have demonstrated that they can emit as low as 86 pounds. *See* Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit (Dec. 8, 2008), [SOB] at 45, *available at* http://www.baaqmd.gov/pmt/public_notices/2008/15487/index.htm. The average emissions per startup event are in the range of 183 to 193 lbs. *See* ASOB at 61. The proposed limit of 480 lbs is in fact the second highest emissions demonstrated at Sutter, which commenced construction in 1999. SOB at 45. In explaining its rejection of lower emissions performance levels in the range, BAAQMD states that a compliance margin is reasonable to "accommodate the variability in emissions among startup events over time." ASOB at 62. BAAQMD's analysis, however, makes no effort to determine any cause of such variability, such as practices that might have contributed to the range.

BAAQMD's analysis does not meet BACT requirements because it fails to demonstrate that there are "source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification" to increase the limit from the emissions levels in the lower range of those that are achieved in fact by other power plants. NSR Manual at B.24 ("Control Techniques with a Wide Range of Emissions Performance Levels"). There is nothing in the SOB or the ASOB that attempts a source-specific explanation other than the unexplained need to provide a compliance margin. BAAQMD fails even to explain why the margin must be so wide, or why BAAQMD could not have set both an average and maximum emissions limit, rather than a limit that is effectively a maximum limit that is generally higher than all of the maximum emissions.[1]

Hot Startup Limits

As with cold startup limits, the District ignored average emissions from even the 2000-vintage plants like Delta (25 to 29.8 lbs) to set the proposed limit at 95 lbs. ASOB at 62-63.[2] Rather, the District relied on maximum emissions and then provided an unexplained margin to set BACT. The proposed limit is thus three times the average NOx emissions. And yet there is no justification provided for this large margin. For all of the reasons that the District failed to comply with BACT requirements as to cold

[1] The data BAAQMD has gathered for cold startup emissions (lbs per startup) from vintage power plants (other than Palomar, which is of more recent vintage) are summarized as follows:

Power Plant	**Average Emissions**	**Maximum Emissions**
RECE	-----	480
Palomar	182.8	375 or 437, depending on calculation
Metcalf	185 (low of 86, SOB)	281
Delta	193 (low of 86, SOB)	335
Sutter (271-499, with 480 being the highest)		

[2] When we refer to commencement of construction dates of other power plants in California, we have drawn that information from the website maintained by the California Energy Commission. *See* http://www.energy.ca.gov/sitingcases/all_projects.html.

startup limits, the District has failed to comply with BACT requirements as to hot startup limits.

2. Use of Auxiliary Boiler

BAAQMD rejects auxiliary boilers as BACT, even though they are demonstrated as feasible since they are used at the Lake Side and Caithness plants, and "data show that using the auxiliary boiler will reduce fuel usage (and consequently emissions) by approximately 18% for warm startups and approximately 31% for cold startups." ASOB at 69.

BAAQMD's explanation for rejecting the use of auxiliary boilers is its cost-effectiveness analysis. The analysis does not comply with BACT requirements because it is based on a faulty and baseless assumption about the number of cold startups and warm startups. BAAQMD assumes "an annual operating profile containing 6 cold startups and 100 warmup startups." ASOB at 69. But there is no limit to startup and shutdown events, and therefore it is unclear how the District derived these numbers. Even assuming that daily NOx and CO limits provide an upper limit to the number of daily startup events, calculations show that CO limits prove to be the more limiting factor. (The maximum daily CO limit divided by the maximum CO emissions from a startup and shutdown event yields 2.8 startup and shutdown events. Assuming 2 startup and shutdown events per day there could be far more than 700 warm startup and shutdowns per year. Since the District's data show that not all startup events produce the maximum emissions proposed in the draft permit, 700 warm startup and shutdowns are rather conservative as an estimate.)

Thus, the assumption on which BAAQMD relies to calculate the cost-effectiveness is faulty, and the District's BACT analysis therefore does not meet the BACT requirements of the Act.

3. Flex Plant 10 Technology

BAAQMD claims that Flex Plant 10 technology is inappropriate because it is for peaking to intermediate-duty baseload operations. This claim begs the question. Neither the applicant nor the District has provided a credible startup and shutdown scenario. Various scenarios are possible: from two daily startup and shutdown of varying kinds (cold, warm, or hot); 52 cold starts and 260 hot starts per year; and 365 hot startups and shutdowns per year. See our comments dated February 5, 2009; *see also* CEC Staff Assessment - Part 1 and 2 Combined (June 29, 2007), *available at* http://www.energy.ca.gov/2007publications/CEC-700-2007-005/CEC-700-2007-005-FSA.PDF, at 4.1-8. The District has now added another scenario, although without any reference to its source: 6 cold startups and 100 warm startups. ASOB at 69. Unless there is a credible determination of the likely scenario of startup and shutdown events, no one can legitimately evaluate which technology should be applied to achieve the lowest emissions mandated by BACT requirements.

4. Startup and Shutdown Durations

BAAQMD argues that startup and shutdown durations are not subject to BACT requirements. ASOB at 66. On the contrary, such durations should be subject to BACT because they are a “devise or technique” (BAAQMD Regulation 2-2-206) or a method, system, work practice, or operational standard (NSR Manual at B.1-B.2) and therefore are covered in the definition of BACT.

Despite its initial argument that startup and shutdown durations are not subject to BACT, BAAQMD nevertheless has provided a substantive reason for failing to set the durations as permit limits or to set shorter durations. BAAQMD explains that the emissions limits are regardless of the duration of the startup and shutdown events and therefore the duration should not matter.

BAAQMD is right on this matter only if the hourly emissions during a shorter startup duration are higher than the hourly emissions during a longer duration. The District has provided nothing to back up this assumption.[3] Indeed, logic would dictate that a longer startup duration means that the limits applicable during normal operations do not apply for that much longer. As the District has acknowledged, “there may be partial or no abatement for NOx and Co for a portion of the startup period.” SOB at 38; *see also* 2007 CEC Staff Report at 4.1-8 (“hourly start-up emissions rates are six, seven and 68 times higher than normal operations for NOx, POC and CO, respectively”). Thus, the District’s assumption that the duration has no impact on the emissions limit is unsupported. (If the District is right, why did the Colusa permit pick the shorter duration?)

In fact, if durations are not set based on what the best technology can achieve, how will the District be able to know when the pollution controls can work at its optimum and therefore the source should comply with limits applicable during non-startup operations?

BAAQMD also states that the shorter startup duration in the Colusa permit does not provide any “hard evidence” on which to conclude that such durations are achievable. ASOB at 67 n.119. BAAQMD states that there are no actual operating data showing that the limits are achievable and that the permitting agency explained that the “limits might not turn out to be achievable,” and if so they will be reevaluated. *Id.* Based on this explanation, BAAQMD fails to set a shorter startup duration. More is necessary to come to that conclusion, according to the NSR Manual. *See* NSR Manual at B.7.

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[3] The following example illustrates this problem. The first scenario makes the assumption the District makes.

	1st Hr.	2d Hr	3d Hr	Total Emissions
2 hours of startup	95/2 = 47.5	95/2 = 47.5	16.5	111.5 lbs
3 hours of startup	95/3 = 31.7	95/3 = 31.7	95/3 = 31.7	95 lbs

If, however, the two hours of startup, the emissions are the same as the hourly rates of 31.7 lb, then the total emission equal 70.9 lbs [that is, 31.7+31.7+16.5), which is less than 95 lbs.

BAAQMD has documented only speculation. BAAQMD has not documented that equipment that meets BACT is physically unable to achieve a shorter startup duration. On the contrary, the NSR Manual dictates that the Colusa permit is sufficient justification to assume the technical feasibility of the shorter duration.

B. CEC's Staff Analysis

The District's protestations to the contrary, the BACT analysis is skewed to retaining the applicant's equipment, which it already has purchased without ever having had a valid PSD permit. The District should in fact review the CEC's staff analysis about the various alternative equipment and explain the differences in the two agencies' positions.

For example, the CEC staff opined that because of high startup emissions, various alternatives be implemented:

> Staff found that if the project used the Siemens-Westinghouse Benson Once-Through boiler technology, start-up and shutdown emissions would be significantly reduced . . . . Alternatively, some projects have incorporated an auxiliary boiler or solar array to provide steam that can shorten start-up times.
>
> According to a vendor of this technology, the Siemens-Westinghouse, Benson Once-Through or Fast-Start technology can be designed to fit the proposed 501 FD combustion turbines without additional capital costs above that of the standard, off-the-shelf, HRSG that the project owner has proposed. If the project is built with the aforementioned Fast-Start technology, the project start-up NOx emissions are expected to be reduced . . . to 22 lbs for each cold start-up event, and . . . 28 lbs for hot or warm start-up events. This represents a 95 percent and 88 percent emission reduction of NOx for cold, and hot or warm start-up events, respectively.

CEC Staff Report at 4.1-8 to 9; *see also* discussion on Palomar.

III. DRY COOLING SHOULD HAVE BEEN CONSIDERED IN THE COOLING TOWER ANALYSIS.

Nowhere does the District analyze whether dry cooling should be considered BACT. The District simply states that the applicant is proposing to use a wet cooling tower system and does not evaluate alternative technologies. As the District's Air Pollution Control Officer has stated, however, either dry cooling or wet/dry cooling would be technically feasible. *See* letter from Jack P. Broadbent to Bruce Wolfe, Executive Officer, San Francisco Bay Regional Water Quality Control Board, dated September 25, 2006 (attached). "[U]nlike dry cooling, wet/dry cooling uses an evaporative cooling process that vents vapor containing fine particulate matter (PM_{10}) to the atmosphere." *Id.* The draft permit fails to meet BACT requirements without the required analysis of alternatives to wet cooling.

IV. THE DISTRICT SHOULD REDO ANY NONATTAINMENT NSR REVIEW THAT IS MORE THAN 18 MONTHS OLD.

The District fails to respond to any comments about non-attainment NSR. The District ought to respond to public comments in a timely fashion. If the District believes that it should respond outside of the PSD process, that would be acceptable to Citizens Against Pollution. But the District must respond.

We look forward to your responses to our comments. Thank you for considering them.

Very truly yours,

/s/ Helen Kang

/s/ Eric Kaplan

Helen Kang
Eric Kaplan
John Harrington
Shufan Sung

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

September 25, 2006

Bruce Wolfe, Executive Officer
San Francisco Bay Regional Water Quality Control Board
1515 Clay Street, Suite 1400
Oakland, CA 94612

Subject: **Dry cooling investigation, Mirant Potrero Power Plant NPDES permit, Regional Board Order R2-2006-0032**

Dear Mr. Wolfe:

It has come to my attention that the Regional Water Quality Control Board has recently adopted permit conditions that seek to phase out once-through cooling of Potrero Unit 3 unless the facility demonstrates it has no significant impact on San Francisco Bay. These conditions also require an assessment of alternative cooling technology by November 2007. The purpose of this letter is to request that the technology assessment include a thorough analysis of dry cooling. Dry cooling is an alternative to once-through cooling that could protect the Bay while avoiding potential air quality problems.

You may remember, Air District staff commented on this issue in the Bay Conservation and Development Commission review of proposed Potrero Unit 7. The Bay Commission's March 27, 2002 report to the Energy Commission found that either dry cooling or wet/dry cooling would be a feasible alternative to once-through cooling. However, unlike dry cooling, wet/dry cooling uses an evaporative cooling process that vents vapor containing fine particulate matter (PM_{10}) to the atmosphere. Wet/dry cooling for Unit 7 was projected to emit approximately eleven tons of PM_{10} annually. The new emissions would occur in an area where PM_{10} exceeds ambient air quality standards. These considerations led the Bay Commission to believe that dry cooling would be preferable to wet/dry cooling.

If you have any questions, please contact Mr. Peter Hess, Deputy Air Pollution Control Officer at (415) 749-4971. Thank you for your consideration of this request.

Sincerely,

Jack P Broadbent

Jack P. Broadbent
Air Pollution Control Officer/ Executive Officer

cc: Greg Karras

Exhibit 19

Weyman Lee, P.E., Senior Air Quality Engineer
Bay Area Air Quality Management District
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(415) 749-4796 weyman@baaqmd.gov.

Comments of Robert Sarvey on the Draft PSD permit for the Russell City Energy Center Application Number 15487

Dear Mr. Lee,

Thank you for the opportunity to comment on the Draft PSD permit for the Russell City Energy Center Application Number 15487. The Statement of Basis is very confusing since the amended FDOC was issued on June 19, 2007 and contradicts many of the values that are presented in Amended PSD permit which was circulated on December 8, 2008 almost 18 months later. The District should reopen the FDOC to reflect the changes that are presented in the Amended PSD Permit. These permits are extremely technical and difficult for the public to understand and when different values are presented for the same impacts members of the public lose confidence in the District and the EPA process. Furthermore since the amended FDOC was issued several air pollution laws including the California NO2 standard have changed. Compliance with these new laws may be demonstrated in the Amended PSD permit but not reflected in the Amended FDOC.

California NO2 Standard

Page 159 of the air quality impact analysis demonstrates that the project violates the California 1 hour Ambient Air Quality Standard for NO_2. The California Ambient Air Quality standard for NO2 is 338 ug/m_3, while the projects impact combined with background is 370 ug/m3 (as shown in table 6 on page 159). The California Air Resource Board has promulgated new standards and established that deleterious health effects occur when NO2 concentrations exceed 338 ug/m3. (http://www.arb.ca.gov/research/aaqs/no2-rs/no2-doc.htm) Page 92 states that the project does not violate the state 1 hour NO2 standard because the projects maximum impacts are 130 ug/m_3 and background is 130 ug/m_3. The statement is unsupported by any analysis in the statement of basis. The statement of basis should provide an analysis demonstrating compliance with the NO2 standard since the air quality impact analysis contradicts the values presented on page 92. The new NO2 analysis and amended FDOC should be recirculated to the public for comment.

Ammonia Transportation

Page 26 of the permit states, “A second potential environmental impact that may result from the use of SCR involves ammonia transportation and storage. The proposed facility will utilize aqueous ammonia in a 29.4% (by weight) solution for SCR ammonia injection, which will be transported to the facility and stored onsite in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. This risk will be addressed in a number of ways under safety regulations and sound industry safety codes and standards, including the implementation of a Risk Management Program to prevent and respond to accidental releases.”

The project, if allowed to use SCR, can eliminate the impact from transportation accidents by utilizing a technology called NOxOUT ULTRA®. There are dozens of systems in service, one in Southern California at UC Irvine. Most of the UC campuses have decided not to risk bringing ammonia tankers through campus or having to offload or store ammonia. NOxOUT ULTRA is being specified for new units at UCSD, University of Texas and Harvard. The NOxOUT ULTRA system requires a tank for the urea. The urea is usually in a 50 to 32 % solution. Urea has no vapor pressure and no smell. If it spills, the evaporated water will leave behind a pile of crystal salts. There are no hazards to labeling or training required for the operator and absolutely no risk to adjacent facilities or neighbors. Like aqueous ammonia, NOxOUT ULTRA needs controls to manage the input from the power plant indicating how much reagent the SCR requires. Like aqueous ammonia, the system requires an air blower and heater to heat the air. The heated air goes to a decomposition chamber instead of a vaporizer. In the decomposition chamber, the urea solution is added. The water in the urea solution is vaporized and the additional heat required will then decompose the urea to ammonia. The gas/carrier air is then swept to the AIG and to the SCR. If the urea pump is stopped and air is left in service, the chamber is swept clear of ammonia in less than seven seconds. So in an emergency, there is very little, if any, ammonia exposure. Other than the seven seconds between the chamber and the AIG, the only exposure is the harmless urea. Since the ammonia will be transported through an environmental Justice community, all precautions should be taken since the community already has a high number of toxic and hazardous materials stored and transported through it. Attachment 1 contains a brochure on the NOxOUT ULTRA system.

<u>Secondary Particulate Formation</u>

Page 26 of the permits BACT analysis states, “The Air District also evaluated the potential for ammonia slip emissions to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. Moreover, the Air District has found that the formation of ammonium nitrate in the Bay Area air basin appears to be constrained by the amount of nitric acid in the atmosphere and not driven by the amount of ammonia in the atmosphere, a condition known as being “nitric limited". Where an area is nitric acid limited, emissions of additional ammonia will not contribute to secondary particulate matter formation because there is not enough nitric acid for it to react with. Therefore, ammonia emissions from the SCR system are not expected to contribute significantly to the formation of secondary particulate matter. Any potential for secondary particulate matter formation is at most speculative, and would not provide a reason to eliminate SCR as a control alternative."

The District has based its conclusion that the project area is nitric limited on a BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel (footnote 21) , "A First Look at NOx/Ammonium Nitrate Tradeoffs, dated September 8, 1997." The District memorandum outlines two objectives. One, whether the Bay Area is ammonia limited, and two, to what extent reducing NOx emissions would reduce ammonium nitrate. Among the findings presented in this memorandum, the District staff believes that " San Jose and Livermore are not ammonia limited' during wintertime high particulate matter conditions; rather, these two areas are nitric acid limited. Other findings stated in the memorandum include recognition that the District analyses do not provide solid "footing to do planning or to provide guidelines to industry for such tradeoffs [between NOx and ammonium nitrate]." Thus, the District memorandum is very specific to say that San Jose and Livermore, not the entire Bay Area air basin or the project location, are nitric acid limited, and that no guidelines have been formed to address the ammonia induced PM10lPM2.5 problem. This project is located in the Hayward area of Alameda County, which is outside of the area where the District has made the determination; therefore, the Districts contention that the increase in ammonia emissions from this facility would not cause any increase in PMlOlPM2.5 emission impacts is not supported by the District memorandum. The District needs a site specific study to make such broad conclusions and an analysis needs to be conducted not only to evaluate the use of SCR, but also to assess environmental impacts of secondary particulate and its effect on the deterioration of air quality in the BAAQMD. The project's PM 2.5 impacts may be much larger than modeled and subject to additional analysis.

The District needs to conduct a BACT analysis on the ammonia emission slip limit. Several Projects including the ANP Blackstone Project have 2ppm ammonia slip limits, which are designed to prevent additional particulate matter formation and limit the transportation of ammonia though the surrounding communities.

<u>CO BACT</u>

The statement of basis concludes that a CO limit of 4ppm over 3 hours is BACT. (Page 32) This conclusion was determined by analyzing emissions data from the Metcalf Energy Center. The Metcalf Energy Center does not utilize an oxidation catalyst for CO emissions, so to base the permit decision on a project that contains no CO abatement device when the proposed Russell City Project will have an oxidation catalyst is an inappropriate comparison. The USEPA, in a June 18th 2001 letter to the San Luis Obispo County Air Pollution Control District has commented that the BACT limit for gas turbines should be set at 2 ppm for NOx on an hourly basis while the NH3 slip maintained at 5 ppm. In addition, the EPA stated that BACT for CO should be set at 2 ppm on a 3-hour rolling average.

Several Projects have achieved a lower CO emissions rates in conjunction with a 2ppm NOx limit. One is the Salt River Project in Arizona, which meets a 2ppm NOx limit and a 2ppm CO limit that has been verified by source testing. (http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=25662&procnum=102130) The Las Vegas Cogeneration facility has a 2ppm NOx limit and a 2ppm CO limit. (http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=26002&Procnum=103714) Based on available information, the district should choose a 2ppm CO limit for this project to comply with BACT.

Start up and Shutdown Emission Limits

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The District states on page 65 of the statement of basis, "Another important consideration that the Air District evaluated is environmental justice. The Air District is committed to implementing its permit programs in a manner that is fair and equitable to all Bay Area residents regardless of age, culture, ethnicity, gender, race, socioeconomic status, or geographic location in order to protect against the health effects of air pollution. The Air District has worked to fulfill this commitment in the current permitting action."

Other than issue the public notice in Spanish on its website for comments on this permit, the district has done nothing different from any other permitting action to evaluate the specific environmental justice impacts of this project on the minority community. The District believes by conducting a health risk assessment, which it does for every project or modeling criteria pollutant impacts, it has met its environmental justice obligations in the permitting process. The District's reasoning is that since the modeling they performed meets their requirements for the general population, the minority community can't possibly be harmed by the projects emissions. The very purpose of the environmental justice evaluation is to identify the minority population's health vulnerabilities and existing pollution and hazardous materials sources and identify how the project affects the minority community, not the general population. The District evaluation falls short of even the basic environmental justice analysis.

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In the two zip codes near the site 94544 and 94545 residents have a high mortality rate and on average they live five years less than the county- wide expectancy rate. Death rates from air pollution-associated diseases such as coronary heart disease, chronic lower respiratory disease, are substantially and statistically significantly higher than those for the County, representing an ongoing, excess burden of mortality. The rate of death from chronic lower respiratory diseases was 43 percent higher and the rate from coronary heart disease was 16 percent higher than the County average. Hospitalizations due to air pollution- associated diseases are substantially higher in the two zip codes close to the proposed site. From 2003 to 2005 the hospitalization rates for coronary heart disease, chronic obstructive pulmonary disease, congestive heart failure and asthma in the two zip codes nearest the proposed site, 94544 and 94545, was statistically significantly higher than Alameda County rates which means they do not occur by chance. Specifically, hospitalization rates due to coronary heart disease was 60 percent higher; chronic obstructive pulmonary disease, 20 percent higher; congestive heart failure, 35 percent higher; and asthma hospitalization rates 14 percent higher than the County rate. The fact that rates of these illnesses are significantly higher in the proposed plant area than in the rest of the county suggests a level of vulnerability in this population that is higher than the rest of the county.

A proper Environmental Justice process begins with the demographic screening analysis which the CEC staff has performed and concluded that the majority of the community surrounding the RCEC is indeed minority. At that point in the analysis the public participation process should have been used to define and evaluate environmental justice concerns. Community leaders and community stakeholders should have been consulted to identify their concerns. The District should have consulted with the county health agencies to identify existing health concerns. Then the District should have examined the synergistic effects of existing pollution that already exists in the community. In this community there are multiple environmental stresses. There is a railroad which passes though the area, there are truck terminals and other heavy industries and a sewage treatment plant in the affected community. The District has not identified and examined the existing local sources of criteria pollutants and toxic emissions and evaluated their impacts in conjunction with the emissions form the RCEC.

Environmental Justice Guideline's emphasize the importance of reaching out to the community and involving them in the development of the mitigation measures and alternatives. A good example of how this process is done is the community outreach that was performed by the CCSF in the SFERP proceeding. In that proceeding over 20 community meetings were held and the community was engaged in deciding appropriate mitigation measures and alternatives. Public advocacy groups were consulted and included in the decision making. Air Quality Monitoring stations were set up in the community to examine existing air quality in the affected community.
(http://www.energy.ca.qov/sitin~cases/sanfrancisco/documents/applicant/data response 1Al2004-07-08 DATA RESPONSE-PDF)

The environmental justice argument against the RCEC is made even stronger by the fact that the risk assessment model may underestimate the health risk of substances that interact synergistically, as pointed out in the risk assessment guidelines. The potential for multiple and varied air and non-airborne pollutants to act synergistically, rather than additively as assumed by the risk assessment model, requires an analysis of the overall toxic burden associated with this Hayward location. Low-income, minority populations have historically been exposed to a much higher burden of environmental toxicity. The Districts Environmental Justice Analysis does not accept the existing ordinate disease nor does it adequately measure the health risks associated with potential, synergistic interactions among the substances, profoundly important aspects of environmental justice. Siting the Russell City Power plant in Hayward will disproportionately impact the geographic area, home to a comparatively high, non-white population that is already burdened by existing morbidity and mortality from diseases associated with air pollution or other existing environmental factors. It is that burden that must be analyzed to truly determine if the minority population near the proposed power plant will be affected. The district is required to address environmental justice issues in the PSD process.

Pack, Heidi K.

From: Hunt, Kelly [KHunt@Semprautilities.com]
Sent: Thursday, April 12, 2007 3:06 PM
To: Kellogg, Kellie; Pack, Heidi K.; Moore, Steve ; Miller, Taylor; Baerman, Daniel; Waller, Fred A.; Hardman, Charles; Blackburn, Suzanne; Annicchiarico, John; Haury, Evariste
Subject: Updated: Palomar Energy Center Variance Report - 4073 1st Quarter 2007
Attachments: Hearing Board Quarterly Report for 1st Quarter 2007.pdf

Ms. Kellogg,

Please find attached an updated copy of the 1st quarter report to the Hearing Board for 2007. This report **supersedes the submission made on 4/11/07 and** is intended for the Hearing Board meeting to be held on April 26, 2007. I apologize for any inconvenience this may have caused you. This report covers the items required by Condition F.3. of the Board's April 27, 2006 order for Variance 4073. In addition, this report covers Enforcement Condition 1 concerning compliance with required increment of progress.

If you have any questions, please feel free to call me at 760-432-2504.

Kelly Hunt
Generation Compliance Manager
San Diego Gas & Electric
2300 Harveson Place, SD1473
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Weyman Lee, P.E., Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street, San Francisco, CA, 94109
(415) 749-4796 weyman@baaqmd.gov.

Comments of Robert Sarvey on the Draft PSD permit for the Russell City Energy Center Application Number 15487

Dear Mr. Lee,

Thank you for the opportunity to comment on the Draft PSD permit for the Russell City Energy Center Application Number 15487. The Statement of Basis is very confusing since the amended FDOC was issued on June 19, 2007 and contradicts many of the values that are presented in Amended PSD permit which was circulated on December 8, 2008 almost 18 months later. The District should reopen the FDOC to reflect the changes that are presented in the Amended PSD Permit. These permits are extremely technical and difficult for the public to understand and when different values are presented for the same impacts members of the public lose confidence in the District and the EPA process. Furthermore since the amended FDOC was issued several air pollution laws including the California NO2 standard have changed. Compliance with these new laws may be demonstrated in the Amended PSD permit but not reflected in the Amended FDOC.

California NO2 Standard

Page 159 of the air quality impact analysis demonstrates that the project violates the California 1 hour Ambient Air Quality Standard for NO_2. The California Ambient Air Quality standard for NO2 is 338 ug/m_3, while the projects impact combined with background is 370 ug/m3 (as shown in table 6 on page 159). The California Air Resource Board has promulgated new standards and established that deleterious health effects occur when NO2 concentrations exceed 338 ug/m3. (http://www.arb.ca.gov/research/aaqs/no2-rs/no2-doc.htm) Page 92 states that the project does not violate the state 1 hour NO2 standard because the projects maximum impacts are 130 ug/m_3 and background is 130 ug/m_3. The statement is unsupported by any analysis in the statement of basis. The statement of basis should provide an analysis demonstrating compliance with the NO2 standard since the air quality impact analysis contradicts the values presented on page 92. The new NO2 analysis and amended FDOC should be recirculated to the public for comment.

Ammonia Transportation

Page 26 of the permit states, “A second potential environmental impact that may result from the use of SCR involves ammonia transportation and storage. The proposed facility will utilize aqueous ammonia in a 29.4% (by weight) solution for SCR ammonia injection, which will be transported to the facility and stored onsite in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. This risk will be addressed in a number of ways under safety regulations and sound industry safety codes and standards, including the implementation of a Risk Management Program to prevent and respond to accidental releases.”

The project, if allowed to use SCR, can eliminate the impact from transportation accidents by utilizing a technology called NOxOUT ULTRA®. There are dozens of systems in service, one in Southern California at UC Irvine. Most of the UC campuses have decided not to risk bringing ammonia tankers through campus or having to offload or store ammonia. NOxOUT ULTRA is being specified for new units at UCSD, University of Texas and Harvard. The NOxOUT ULTRA system requires a tank for the urea. The urea is usually in a 50 to 32 % solution. Urea has no vapor pressure and no smell. If it spills, the evaporated water will leave behind a pile of crystal salts. There are no hazards to labeling or training required for the operator and absolutely no risk to adjacent facilities or neighbors. Like aqueous ammonia, NOxOUT ULTRA needs controls to manage the input from the power plant indicating how much reagent the SCR requires. Like aqueous ammonia, the system requires an air blower and heater to heat the air. The heated air goes to a decomposition chamber instead of a vaporizer. In the decomposition chamber, the urea solution is added. The water in the urea solution is vaporized and the additional heat required will then decompose the urea to ammonia. The gas/carrier air is then swept to the AIG and to the SCR. If the urea pump is stopped and air is left in service, the chamber is swept clear of ammonia in less than seven seconds. So in an emergency, there is very little, if any, ammonia exposure. Other than the seven seconds between the chamber and the AIG, the only exposure is the harmless urea. Since the ammonia will be transported through an environmental Justice community, all precautions should be taken since the community already has a high number of toxic and hazardous materials stored and transported through it. Attachment 1 contains a brochure on the NOxOUT ULTRA system.

<u>Secondary Particulate Formation</u>

Page 26 of the permits BACT analysis states, “The Air District also evaluated the potential for ammonia slip emissions to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. Moreover, the Air District has found that the formation of ammonium nitrate in the Bay Area air basin appears to be constrained by the amount of nitric acid in the atmosphere and not driven by the amount of ammonia in the atmosphere, a condition known as being “nitric limited”. Where an area is nitric acid limited, emissions of additional ammonia will not contribute to secondary particulate matter formation because there is not enough nitric acid for it to react with. Therefore, ammonia emissions from the SCR system are not expected to contribute significantly to the formation of secondary particulate matter. Any potential for secondary particulate matter formation is at most speculative, and would not provide a reason to eliminate SCR as a control alternative.”

The District has based its conclusion that the project area is nitric limited on a BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel (footnote 21) , “A First Look at NOx/Ammonium Nitrate Tradeoffs, dated September 8, 1997.” The District memorandum outlines two objectives. One, whether the Bay Area is ammonia limited, and two, to what extent reducing NOx emissions would reduce ammonium nitrate. Among the findings presented in this memorandum, the District staff believes that " San Jose and Livermore are not ammonia limited' during wintertime high particulate matter conditions; rather, these two areas are nitric acid limited. Other findings stated in the memorandum include recognition that the District analyses do not provide solid "footing to do planning or to provide guidelines to industry for such tradeoffs [between NOx and ammonium nitrate]." Thus, the District memorandum is very specific to say that San Jose and Livermore, not the entire Bay Area air basin or the project location, are nitric acid limited, and that no guidelines have been formed to address the ammonia induced PM10lPM2.5 problem. This project is located in the Hayward area of Alameda County, which is outside of the area where the District has made the determination; therefore, the Districts contention that the increase in ammonia emissions from this facility would not cause any increase in PMlOlPM2.5 emission impacts is not supported by the District memorandum. The District needs a site specific study to make such broad conclusions and an analysis needs to be conducted not only to evaluate the use of SCR, but also to assess environmental impacts of secondary particulate and its effect on the deterioration of air quality in the BAAQMD. The project’s PM 2.5 impacts may be much larger than modeled and subject to additional analysis.

The District needs to conduct a BACT analysis on the ammonia emission slip limit. Several Projects including the ANP Blackstone Project have 2ppm ammonia slip limits, which are designed to prevent additional particulate matter formation and limit the transportation of ammonia though the surrounding communities.

<u>CO BACT</u>

The statement of basis concludes that a CO limit of 4ppm over 3 hours is BACT. (Page 32) This conclusion was determined by analyzing emissions data from the Metcalf Energy Center. The Metcalf Energy Center does not utilize an oxidation catalyst for CO emissions, so to base the permit decision on a project that contains no CO abatement device when the proposed Russell City Project will have an oxidation catalyst is an inappropriate comparison. The USEPA, in a June 18th 2001 letter to the San Luis Obispo County Air Pollution Control District has commented that the BACT limit for gas turbines should be set at 2 ppm for NOx on an hourly basis while the NH3 slip maintained at 5 ppm. In addition, the EPA stated that BACT for CO should be set at 2 ppm on a 3-hour rolling average.

Several Projects have achieved a lower CO emissions rates in conjunction with a 2ppm NOx limit. One is the Salt River Project in Arizona, which meets a 2ppm NOx limit and a 2ppm CO limit that has been verified by source testing. (http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=25662&procnum=102130) The Las Vegas Cogeneration facility has a 2ppm NOx limit and a 2ppm CO limit. (http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=26002&Procnum=103714) Based on available information, the district should choose a 2ppm CO limit for this project to comply with BACT.

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Included as attachment 2 to these comments are three more Hearing Board Variance 4073; Quarterly Reports that were acquired through a public records request. By utilizing earlier ammonia injection and utilizing the OP flex system, the Russell City Power Projects start up emissions can be reduced drastically. It must be required as BACT since it has been proved in operation for over a year, and it will reduce the project's potential to violate the new California NO2 standard and eliminate the deficient daily emission reduction credits needed for the facility, as explained below.

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http://www.epa.gov/compliance/resources/policies/ej/ej_permitting_authorities_memo_120100.pdf

The 1998 EPA guidelines require Agencies to consider a wide range of demographic, geographic, economic, human health and risk factors. One of the three most important factors identified in the 1998 EPA guidelines is "whether communities currently suffer or have historically suffered from environmental health risks and hazards." The 1998 EPA Guidelines require the agencies conducting an Environmental Justice Analysis to define the sensitive receptor analysis to the actual unique circumstances affecting the minority community not a generic definition of sensitive receptor that was utilized by the District and the CEC.

Soils and Vegetation Analysis Nitrogen Deposition

Nitrogen deposition consists of the input of reactive nitrogen species from the atmosphere to the biosphere. Pollutants that contribute to nitrogen deposition derive mainly from nitrogen oxides and ammonia emissions, which the RCEC would emit during normal operation. Emissions of NOx and ammonia contribute to nitric acid deposition that occurs via precipitation and fog and in dry deposition as well. Acute exposures to ammonia can adversely affect plant growth and productivity, resistance to drought and frost, responses to insect pests and pathogens, mycorrhizal and other beneficial root associations, and inter-specific competition and biodiversity in sensitive plant communities. Of particular concern for the RCEC project is the effect on serpentine soil plant communities, which are know to be particularly sensitive to nitrogen deposition. Serpentine soils in the San Francisco Bay Area support native grassland plant communities that can provide habitat for rare and endemic species. Nonnative annual grasses have invaded most grassland communities in California, but highly specialized plant species that are adapted to nutrient-poor serpentinitic soils can thrive in soils that are deficient in nitrogen, potassium, phosphorus, and other nutrients due to a competitive advantage over the faster growing non-native annual species. The competitive advantage of these specialized plant species can be lost when nitrogen deposition from air pollution fertilizes serpentine plant communities and nitrogen ceases to be a limiting nutrient for plant growth. Increased nitrogen levels often allow non-native annual grasses to out-compete the native species.

The nearest serpentine plant community to the project area is Fairmont Ridge in Lake Chabot Regional Park, approximately four miles northeast of the RCEC. Fairmont Ridge is located in the East Bay Hills adjacent to Lake Chabot. The California Native Grasslands Association identifies this area as a Purple Needlegrass Grassland community, and is noted as an area of serpentine soil in the USFWS's 1998 Recovery Plan for Serpentine Soil Species of the San Francisco Bay Area.

The BAAQMD and the CEC have failed to analyze the projects nitrogen deposition impacts on serpentine soil plant communities in the Bay Area.

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April 11, 2007

Ms. Catherine Santos
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Santos and Members of the Board:

Set forth below is SDG&E's 2007 first quarter report to the Hearing Board. This report will cover the items required by Condition F. 3. of the Board's April 27, 2006 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

The increments of progress table attached to the Board's order is included with this letter as Attachment 1. The primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E timely filed the permit application on May 31, 2006. A rule amendment concerning Rule 69.3.1 is still under consideration by District staff and SDG&E and District staff met on February 16, 2007 to discuss the matter further.

Petitioner has timely satisfied all increments of progress within Petitioner's control. The increments of progress table also includes District staff and other third-party actions concerning rule development and permit processing. These actions were included in the increments of progress solely to describe the third-party actions necessary to resolve the regulatory issues prompting the variance. SDG&E will defer to District staff to provide an update to the Board on District's processing of SDG&E's permit application submittal, rule development and a possible revised schedule.

2. Engineering or operational alternatives [Order, Condition F.3 (1)]

Information concerning engineering or operational alternatives considered by Petitioner to ensure maximum control of emissions as recommended by District staff was included in the application for amended permit conditions submitted on May 31, 2006. SDG&E included information concerning reductions related to early ammonia injection and installation of a new software program being developed by General Electric for turbines such as those operating at Palomar ("OpFlex"). SDG&E also included information concerning seven other potential alternatives as requested by District staff.

On December 20, 2006, at District staff's request, Petitioner provided additional information regarding engineering and operational alternatives, including additional evaluation of early ammonia injection and economic impacts of several potential alternatives.

In addition, OpFlex, a General Electric turbine control system software was installed in mid-October, 2006. The turning process allows combustion turbines to minimize emissions between 20 and 60% load, by optimizing the fuel flow to the four gas stages in each combustion can. This precisely controls the flame for optimum combustion to minimize emissions. There were no equipment or hardware changes.

3. NOx Emissions Data [Order, Condition F.3 (2)]

Information concerning NOx emissions from the facility during the period of the 1 year variance to present is included in attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.3 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data

A summary how the plant has reduced NOX emissions by various controls that it has established since the inception of the variance is included as attachment 3.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

SAN DIEGO AIR POLLUTION CONTROL DISTRICT HEARING BOARD

Palomar Energy Center

PROPOSED INCREMENTS OF PROGRESS
(As of 4/11/07)

MILESTONE **DATE**

	Description	Permit Modification	Rule Change	Variance(s)
1	Variance 4068 hearing for 90-day issued			2/9/06
2	Emergency Variance 4069 for condition 21 issued to enable early ammonia injection.			2/23/06
3	*Palomar submits request for Rule Change to APCD*		*3/6/06*	
4	*APCD requests more data for rule change*		*3/14/06*	
5	*Mtg. with APCD concerning Data Requests*		*3/30/06*	
6	*Additional mtg. with APCD (Steve Moore) concerning Data Requests*		*4/4/06*	
7	*SDG&E submits requested data to APCD (Moore)*		*4/7/06*	
8	SDG&E submits summary of requested Permit Modification topics to APCD (covering matters of concern to staff beyond start up)	4/7/06		
9	Mtg. with APCD – QA/QC Plan Addendum (relating to some permit amendment topics)	4/11/06		
10	Request for Permit Modification Fee Estimate submitted to APCD by SDG&E	4/11/06		
11	*APCD (Moore) submits new data request to SDG&E (replaces 3/30 & 4/4 requests)*		*4/14/06*	
12	*Data submitted to APCD (Moore)*		*4/25/06*	
13	Variance 4073 Hearing			4/27/06
14	*Mtg. scheduled with APCD and CEC (in response to 4/7 letter from SDG&E) to discuss permit and rule amendment issues*	5/3/06 (COMPLETED 5/3/06)	*5/3/06* (COMPLETED 5/3/06)	
15	Proposed Permit Pre-application Mtg. with APCD and CEC –	5/19/06 (COMPLETED		

			5/9 & 5/23/06)		
16	Proposed Permit Application Submittal		5/31/06 (COMPLETED 5/31/06)		
17	Quarterly Progress Update (April – June) to Hearing Board				July 27, 2006 (Completed)
18	APCD Permit Application Completeness Review	Respond to APCD data requests while in process	June – July 2006 (Completed)		
19	*APCD drafts rule change*			*April – June 2006*	
20	Quarterly Progress Update (July - September)to Hearing Board				October 27, 2006 (Completed)
21	*APCD holds public workshop on rule amendment*			*July 2006*	
22	*APCD publishes draft rule for public comment*	*30-day public notice required*		*August 2006*	
23	*APCD prepares final rule adoption documents*	*Final rule and "staff report" are prepared for County Board of Supervisors review and adoption*		*September 2006*	
24	*Air Quality Advisory Committee*	*Appointed committee reviews and advises the Board*		*October 2006*	
25	*Board adoption of rule*	*Upon adoption, SDAPCD considers rule to be the version for compliance*		*October 2006*	
26	Proposed Permit Modification (ATC/PDOC) published for public comment	30-day public comment period	October 2006		
27	Final ATC/FDOC revisions	Final language that incorporates public comments is developed	November 2006		
28	Final ATC/FDOC Issued		November 2006		

29	SDG&E petitions CEC for companion amendment of Conditions of Certification (CoC)		December 2006		
30	Quarterly Progress Update (October - December) to Hearing Board				Completed January 25, 2007
31	CEC issues amendment of CoC		March 2007		
32	Quarterly Progress Update (January - March) to Hearing Board				April 26, 2007

Attachment 2

CT1 YTD Summary

	Tons	#
2Q06	9.23	18,460
3Q06	8.61	17,220
4Q06	8.63	17,260
1Q07	8.88	17,760
Total	35.35	70,700

Note: Total NOx includes startup emissions.

CT2 YTD Summary

	Tons	#
2Q06	9.28	18,560
3Q06	8.95	17,900
4Q06	9.70	19,400
1Q07	8.73	17,460
Total	36.66	73,320

Note: Total NOx includes startup emissions.

CT1 Startup YTD Summary

	Tons	#
2Q06	3.19	6,380
3Q06	1.38	2,760
4Q06	0.52	1,040
1Q07	0.38	760
Total	5.47	10,180

CT2 Startup YTD Summary

	Tons	#
2Q06	3.64	7,280
3Q06	1.10	2,200
4Q06	0.52	1,040
1Q07	0.43	860
Total	5.69	10,520

[1] Data gathered from CEMS Startup/Shutdown Incident Reports

[2] Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

OPFLEX AND EARLY AMMONIA INJECTION EFFECTS ON STARTUP EMISSIONS PALOMAR ENERGY CENTER

Subject:

This Evaluation assesses the effects of two major Palomar Energy Center efforts to reduce startup emissions.

Discussion:

Early Ammonia Injection is a SDG&E project to minimize NOx emissions during the startup process by reducing and optimizing the temperature at which ammonia is injected to the SCR's, thereby reducing NOx emissions during the startup process. The original control system allowed ammonia injection when the temperature at the SCR increased to 550 deg F during the plant startup process. This temperature was chosen to provide a safety margin above the required SCR operating temperature. If ammonia is injected at too low of a temperature, the SCR is not effective, there can be elevated ammonia slip, and there is potential for poisoning of the SCR catalyst.

Palomar personnel have analyzed the temperature requirements for the SCR and evaluated the risks associated with low temperature ammonia injection, along with the benefits of emissions reductions obtained by lowering the injection temperature. The evaluation indicated that a significant lowering of the temperature was possible, as long as close attention was paid to the environmental conditions at all locations surrounding the catalyst. The temperature set point for ammonia injection was lowered in two steps as a prudent sequence to confirm the benefits and minimize risk. The first setpoint was lowered during the summer 2006. The setpoint was lowered again to 485 deg F in October 2006.

OpFlex is a General Electric proprietary software improvement that manages the fuel splits and fuel temperature control to minimize NOx and CO emissions at part load, and significantly reduces NOx during the startup process. The turbines can now be operated down to approximately 45% load and remain in compliance with all operating emissions limitations. The NOx produced during the startup process is also minimized approximately 25% to 45%, although not to the point of compliance with the 2.0 ppmvd@15% O2 permit limit.

OpFlex was installed in mid-October, 2006. Subsequent to the installation, Palomar Operations has studied the emissions enhancements OpFlex provides, and has made adjustments to the startup process to take advantage of these enhancements to reduce startup emissions. There have been no extended startups since the installation of OpFlex, so the extended startup procedure has not yet been optimized.

Results:

OpFlex and the final adjustment to the enhanced ammonia injection setpoint were implemented at approximately the same time in mid October, so the emissions improvements attributable to each are somewhat difficult to assign. However, this analysis endeavors to separate the projects and summarize the success of each.

With the SCR at normal operating temperature, ammonia injection can lower startup-related NOx concentrations by approximately 10.0 ppm. At base load, this equates to approximately 45 lbs/hr reduction of NOx mass emissions. This mass emissions reduction remains relatively constant even at reduced operating loads if sufficient NOx is present in the exhaust stream from the turbine.
During a typical hot start following a nightly shutdown, the enhanced, lowered temperature setpoint for ammonia injection allows the ammonia to be injected approximately 60 to 90 minutes earlier than the original setpoint (550 deg F) would have allowed. This provides for a reduction of at least 45 lbs NOx produced during the hot startup. The early ammonia injection NOx reduction for an extended startup will be even greater, conservatively estimated to be 60 lbs NOx per extended start.

OpFlex lowers the NOx produced by the turbine during the startup process at all loads above approximately 25%. The NOx is lowered enough above 45% load that in conjunction with the SCR, the stack emissions are reduced below the permit limit of 2.0 ppmvd@15% O2.

Plant Operations personnel have optimized the startup process to take advantage of this reduction of NOx above 25%. When plant conditions allow, the turbine is immediately ramped to approximately 43%, so that the turbine exhaust emissions are high only for the first 20 – 30 minutes of operation, and the magnitude of these high emissions are greatly reduced above 25%.

Recent normal startups following a typical nightly shutdown have resulted in NOx emissions of 28 lbs NOx, and 10 lbs. CO. For NOx, these results are the combination of OpFlex and early ammonia injection. Prior to the OpFlex and early ammonia projects, a typical regular startup would have produced approximately 120 lbs of NOx and 35 lbs of CO. (Note: Startups early in the project life produced highly variable emissions results). All of the CO reduction for recent startups is attributable to the shorter startup allowed by OpFlex, while 45 lbs. of NOx reduction are attributable to early ammonia injection, and 47 lbs. attributable to OpFlex. See the Summary Table below:

Summary:

Early ammonia injection and OpFlex have both been highly successful in reducing emissions during normal startups. The emissions during an extended startup will also be greatly reduced, although more testing and optimization is required before the results can be quantified. The table below is illustrative of starts after an overnight shutdown of one turbine, which has been a typical mode of operation during the past year. Somewhat higher emissions could occur for longer shutdowns.

Regular Startup Summary Table:

	Startup Emissions before Opflex/Early NH3	Reduction Attributable to Early NH3 Inj.	Reduction Attributable to OpFlex	Recent Regular Startup Results – Note 1 (Nov. 2006 – Feb. 2007)
NOx (lbs.)	120	45	47	28
CO (lbs.)	35	0	25	10

Note 1: Excludes startups after lengthy shutdown (>24 hours) or after HRSG forced cool down for maintenance.

Pack, Heidi K.

From: Hunt, Kelly [KHunt@Semprautilities.com]
Sent: Friday, April 13, 2007 8:54 AM
To: Waller, Fred A.; Pack, Heidi K.; Hartnett, Gary; LaBlond, Jason
Subject: FW: Palomar Energy Exceedances Covered Under Variance 4073, March 2007 YTD
Importance: High
Attachments: PEC Exceedance Covered Under Variance 4073 March 2007YTD.pdf

Please see email below.

Kelly Hunt
Generation Compliance Manager
San Diego Gas & Electric
2300 Harveson Place, SD1473
Escondido, CA 92029
760-432-2504 (Office)
760-432-2510 (Fax)
khunt@semprautilities.com

From: Waller, Fred A.
Sent: Friday, April 06, 2007 5:07 PM
To: Hunt, Kelly
Subject: Palomar Energy Exceedances Covered Under Variance 4073, March 2007 YTD
Importance: High

Kelly,
Please forward this Report of Violation to APCD Compliance (Mr. Jason LaBlond, Mr. Gary Hartnett and copy Ms. Heidi Gabriel-Pack).

Mr. LaBlond,
In a previous telephone conversation we discussed the reporting requirements of APCD Rule 19.2(d)(3)-Report of Violation. You indicated that an email notification to you will suffice to meet the reporting requirements. Additionally, Ms. Heidi Gabriel-Pack, approved monthly reporting of violations which are covered under Variance 4073.

In previous months in 2006, SDG&E had provided a monthly summary report of Violations/Exceedances covered under Variance 4073 to you and copied Mr. Gary Hartnett and Ms. Heidi Gabriel-Pack. SDG&E is submitting this summary report to notify the District of one exceedance in March 2007 covered by Variance 4073 which occurred at the Palomar Energy Center, 2300 Hārveson Place, Escondido, CA 92009 .

If you have any questions, please feel free to call.

Fred Waller
Environmental Specialist-Generation
Office: 760 432 2507
Cell: 619 778 6029

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
1	4/3/06	1	9:00	N/A	5 hrs 48 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
2	4/3/06	1	10:00	N/A	5 hrs 48 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
3	4/3/06	2	9:00	N/A	5 hrs 15 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
4	4/3/06	2	10:00	N/A	5 hrs 15 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
5	5/5/06	1	6:00	NOx	128.4	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
6	5/5/06	2	5:00	NOx	143.9	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
7	5/8/06	1	7:00	NOx	106.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
8	5/9/06	2	7:00	NOx	132.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
9	5/10/06	2	6:00	NOx	121.4	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
10	5/13/06	2	8:00	NOx	124.7	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
11	5/14/06	2	8:00	NOx	123.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
12	5/15/06	1	3:00	NOx	101.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
13	5/16/06	2	8:00	NOx	141.1	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
14	5/30/06	2	0:00	N/A	2 hrs 19 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	8/10/06
15	6/4/06	1	10:00	N/A	2 hr 26 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	7/9/06
16	6/13/06	1	19:00	NOx	117.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	7/9/06
17	6/13/06	1	19:00	N/A	2 hr 5 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	1/11/07

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
18	6/15/06	1	10:00	N/A	2 hr 9 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	7/9/06
19	~~6/16/06~~	~~2~~	~~6:00~~	~~N/A~~	~~2 hr 9 min~~	~~Hrs/Mins~~	~~AQ 40: 2 hour startup duration~~	~~Typical regular startup.~~	Reported in error. Was not a violation.	~~7/9/06~~
20	6/16/06	2	6:00	NOx	109.9	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	8/10/06
21	7/2/06	1	9:00	N/A	5 hrs 32 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
22	7/2/06	1	10:00	N/A	5 hrs 32 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
	Aug 2006: No events to report.									
	Sept 2006: No events to report.									
23	10/11/06	1	11:00	N/A	4 hr 45 min	Hrs/Mins	AQ 39: 4 hour startup duration	Extended startup.	Covered under Variance #4073	11/13/06
24	10/12/06	2	6:00	N/A	2 hr 20 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	11/13/06
25	10/12/06	2	6:00	NOx	223.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	11/13/06
26	10/12/06	1	3:00	NOx	127.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	11/13/06
27	November 2006: No events to report.									
28	December 2006: No events to report.									
29	January 2006: No events to report.									
30	February 2006: No events to report.									
31	03/21/07	1	15	N/A	2 hrs 2 min	Hrs/Mins	AQ 40: 2 hour startup duration	Regular startup with generator testing required by WECC.	Covered under Variance #4073	4/9/07

Events 1, 2, 3 and 4 (exceedance of Extended Startup duration limit) were not reported in April 2006 due to confusion over the Reporting requirment of Rule 19.2(d) and the existing Variance 4068.
Event 14 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
	Event 18 was not a violation of AQ 40: 2 hour Regular Startup duration limit. On 6/16/06 CTG 2 was actually started up within the 2 hour limit.									
	Event 17 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.									
	Event 19 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.									

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
There being no motion made, the Air Pollution Control District Hearing Board, unable to discuss the report due to a lack of a quorum, acknowledged the submission of the report and at the discretion of the Board, continued this item to a future date. Member Rodriguez would be provided a copy of the report to review and if she determined that there needs to be further discussion on this report, the Clerk of the Board will schedule a special meeting of the Hearing Board to address concerns.

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

____
Kellie C. Kellogg, Deputy Clerk

SDGE
A Sempra Energy company

COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

2007 JUL 13 AM 8: 44

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
Escondido, CA 92029
Tel: 760-432-2501
dbaerman@semprautilities.com

July 11, 2007

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's second quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

The increments of progress table attached to the Board's order is included with this letter as Attachment 1. The primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. SDG&E was informed on July 9, 2007 that the District intends to issue the final S/A no later than July 26, 2007. A rule amendment workshop concerning Rule 69.3.1 has been scheduled for August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

No further data has been requested by the Board at this time.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

Attachment 2

CT1 Quarterly Summary

	Tons	#
Apr-07	2.17	4,340
May-07	2.48	4,960
Jun-07	2.74	5,480
Total	7.39	14,780

Note: Total NOx includes startup emissions.

CT1 Startup Summary

	Tons	#
Apr-07	0.00	0.00
May-07	0.07	143.85
Jun-07	0.03	54.35
Total	0.10	198.20

CT2 Quarterly Summary

	Tons	#
Apr-07	2.65	5,300
May-07	2.69	5,380
Jun-07	2.52	5,040
Total	7.86	15,720

Note: Total NOx includes startup emissions.

CT2 Startup Summary

	Tons	#
Apr-07	0.03	63.13
May-07	0.15	307.98
Jun-07	0.14	271.20
Total	0.32	642.31

CT1 YTD Summary

	Tons	#
3Q06	8.61	17,220
4Q06	8.63	17,260
1Q07	8.88	17,760
2Q07	7.39	14,780
Total	33.51	67,020

Note: Total NOx includes startup emissions.

CT1 Startup YTD Summary

	Tons	#
3Q06	1.38	2,760
4Q06	0.52	1,040
1Q07	0.38	760
2Q07	0.10	200
Total	2.38	4,760

CT2 YTD Summary

	Tons	#
3Q06	8.95	17,900
4Q06	9.70	19,400
1Q07	8.73	17,460
2Q07	7.86	15,720
Total	35.24	70,480

Note: Total NOx includes startup emissions.

CT2 Startup YTD Summary

	Tons	#
3Q06	1.10	2,200
4Q06	0.52	1,040
1Q07	0.43	860
2Q07	0.32	640
Total	2.37	4,740

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

Exhibit 3

SAN DIEGO AIR POLLUTION CONTROL DISTRICT HEARING BOARD

COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

Palomar Energy Center

2007 MAY 14 AM 8:35

PROPOSED INCREMENTS OF PROGRESS

(As of4/26/07)

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

MILESTONE **DATE**

	Description	Permit Modification	Rule Change	Variance(s)
1	Variance 4068 hearing for 90-day issued			2/9/06
2	Emergency Variance 4069 for condition 21 issued to enable early ammonia injection.			2/23/06
3	*Palomar submits request for Rule Change to APCD*		*3/6/06*	
4	*APCD requests more data for rule change*		*3/14/06*	
5	*Mtg. with APCD concerning Data Requests*		*3/30/06*	
6	*Additional mtg. with APCD (Steve Moore) concerning Data Requests*		*4/4/06*	
7	*SDG&E submits requested data to APCD (Moore)*		*4/7/06*	
8	SDG&E submits summary of requested Permit Modification topics to APCD (covering matters of concern to staff beyond start up)	4/7/06		
9	Mtg. with APCD – QA/QC Plan Addendum (relating to some permit amendment topics)	4/11/06		
10	Request for Permit Modification Fee Estimate submitted to APCD by SDG&E	4/11/06		
11	*APCD (Moore) submits new data request to SDG&E (replaces 3/30 & 4/4 requests)*		*4/14/06*	
12	*Data submitted to APCD (Moore)*		*4/25/06*	
13	Variance 4073 Hearing			4/27/06
14	*Mtg. scheduled with APCD and CEC (in response to 4/7 letter from SDG&E) to discuss permit and rule amendment issues*	5/3/06 (COMPLETED 5/3/06)	*5/3/06* (COMPLETED 5/3/06)	
15	Proposed Permit Pre-application Mtg. with APCD and CEC –	5/19/06 (COMPLETED		

	Description		Permit Modification	Rule Change	Variance(s)
			5/9 & 5/23/06)		
16	Proposed Permit Application Submittal		5/31/06 (COMPLETED 5/31/06)		
17	Quarterly Progress Update (April – June) to Hearing Board				July 27, 2006 (Completed)
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20	Quarterly Progress Update (July - September)to Hearing Board				October 27, 2006 (Completed)
21	*APCD holds public workshop on rule amendment*			*July 2006*	
22	*APCD publishes draft rule for public comment*	*30-day public notice required*		*August 2006*	
23	*APCD prepares final rule adoption documents*	*Final rule and "staff report" are prepared for County Board of Supervisors review and adoption*		*September 2006*	
24	*Air Quality Advisory Committee*	*Appointed committee reviews and advises the Board*		*October 2006*	
25	*Board adoption of rule*	*Upon adoption, SDAPCD considers rule to be the version for compliance*		*October 2006*	
26	Proposed Permit Modification (ATC/PDOC) published for public comment	30-day public comment period	October 2006		
27	Final ATC/FDOC revisions	Final language that incorporates public comments is developed	November 2006		
28	Final ATC/FDOC		November		

	Description	Permit Modification	Rule Change	Variance(s)
	Issued	2006		
29	SDG&E petitions CEC for companion amendment of Conditions of Certification (CoC)	December 2006		
30	Quarterly Progress Update (October - December) to Hearing Board			Completed January 25, 2007
31	CEC issues amendment of CoC	March 2007		
32	Quarterly Progress Update (January - March) to Hearing Board			April 26, 2007;completed
33	**Extension of Regular Variance Granted**			**April 26, 2007**
34	See Tentative Rule Schedule for Rule 69.3.1, Exhibit 2 to Board Order Granted April 26, 2007.	May-December, 2007		
35	Quarterly Progress Update (April – June) to Hearing Board			July 26, 2007;
36	Quarterly Progress Update (October-December) to Hearing Board			January 17, 2008

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073

ACTION:
ON MOTION of Member Rodríguez, seconded by Member Reider, the Air Pollution Control District Hearing Board accepted the quarterly report and directed San Diego Gas & Electric to provide the Board with revised Increments of Progress, reflecting the testimony of County Counsel representing the APCD. The revision to the Increments of Progress Schedule (IOPS) pertained to the accurate reflection of issuance of authority to construct or permit to operate. The revised IOPS is to be submitted to the Air Pollution Control District Hearing Board for the meeting of October 25, 2007.

AYES: Rodríguez, Tonner, Reider
ABSTAIN: Rappolt
RECUSED: Gabrielson

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

By Kellie C. Kellogg
Kellie C. Kellogg
Deputy Clerk

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric/Palomar Energy Center per Condition No. F.3, and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
ON MOTION of Member Gabrielson, seconded by Member Tonner, the Air Pollution Control District Hearing Board accepted the report from San Diego Gas & Electric.

AYES: Rappolt, Gabrielson, Tonner
ABSENT: Rodriguez

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

Kellie C. Kellogg
Kellie C. Kellogg, Deputy Clerk

COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

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THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
Escondido, CA 92029
Tel: 760-432-2501
dbaerman@semprautilities.com

October 11, 2007

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's third quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

Referenced below are the increments of progress table attached to the Board's order; the primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. SDG&E was updated by the District on October 8, 2007 on the progress of the issuance of the final S/A. The District intends to issue to final S/A no later than November 30, 2007. A rule amendment workshop concerning Rule 69.3.1 was held on August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

SDG&E received a letter dated September 14, 2007 from the District requesting a cold start and source test. The cold start and source test is scheduled to occur during the period of October 21, 2007 and October 26, 2007. District staff will be onsite to witness the test.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

CT1 3q07 NOx Summary

	Tons	#
Jul-07	3.01	6,011
Aug-07	3.21	6,419
Sep-07	2.97	5,932
Total	9.18	18,362

Note: Total NOx includes startup emissions.

CT1 Startup Only Summary

	Tons	#
Jul-07	0.33	658
Aug-07	0.17	341
Sep-07	0.19	386
Total	0.69	1,386

CT2 3q07 NOx Summary

	Tons	#
Jul-07	3.38	6,766
Aug-07	3.26	6,513
Sep-07	3.20	6,410
Total	9.84	19,689

Note: Total NOx includes startup emissions.

CT2 Startup Only Summary

	Tons	#
Jul-07	0.09	180
Aug-07	0.10	208
Sep-07	0.09	173
Total	0.28	561

CT1 YTD NOx Summary

	Tons	#
4Q06	8.63	17,260
1Q07	8.88	17,760
2Q07	7.39	14,780
3Q07	9.18	18,362
Total	34.08	68,162

Note: Total NOx includes startup emissions.

CT1 YTD Startup Only

	Tons	#
4Q06	0.52	1,040
1Q07	0.38	760
2Q07	0.10	200
3Q07	0.69	1,386
Total	1.69	3,386

CT2 YTD NOx Summary

	Tons	#
4Q06	9.70	19,400
1Q07	8.73	17,460
2Q07	7.86	15,720
3Q07	9.84	19,689
Total	36.13	72,269

Note: Total NOx includes startup emissions.

CT2 YTD Startup Only

	Tons	#
4Q06	0.52	1,040
1Q07	0.43	860
2Q07	0.32	640
3Q07	0.28	561
Total	1.55	3,101

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
ON MOTION of Member Gabrielson, seconded by Member Rodriguez, the Air Pollution Control District Hearing Board accepted the report.

AYES: Rappolt, Rodriguez, Gabrielson, Tonner
ABSTAIN: None

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

By Kellie C. Kellogg
Kellie C. Kellogg
Deputy Clerk

COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

2008 JAN 14 AM 8:40

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

SDG&E®

A Sempra Energy company

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
Escondido, CA 92029
Tel: 760-432-2501
dbaerman@semprautilities.com

January 13, 2008

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's fourth quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

Referenced below are the increments of progress table attached to the Board's order; the primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. The District issued the final S/A on November 6, 2007. A rule amendment workshop concerning Rule 69.3.1 was held on August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 1. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

SDG&E received a letter dated September 14, 2007 from the District requesting a cold start and source test. The cold start and source test occurred on October 22, 2007. District staff was onsite to witness the test. The District has the source test report and raw data as requested.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

CT1 4q07 NOx Summary

	Tons	#
Oct 07	2.59	5,179
Nov 07	2.92	5,831
Dec 07	3.52	7,038
Total	9.02	18,048

Note: Total NOx includes startup emissions.

CT1 Startup Only Summary

	Tons	#
Oct 07	0.18	356
Nov 07	0.13	262
Dec 07	0.03	52
Total	0.34	670

CT2 4q07 NOx Summary

	Tons	#
Oct 07	2.63	5,255
Nov 07	3.47	6,949
Dec 07	3.37	6,732
Total	9.47	18,936

Note: Total NOx includes startup emissions.

CT2 Startup Only Summary

	Tons	#
Oct 07	0.00	0
Nov 07	0.29	573
Dec 07	0.09	173
Total	0.37	747

CT1 12-Mo NOx Summary

	Tons	#
1Q07	8.88	17,760
2Q07	7.39	14,780
3Q07	9.18	18,362
4Q07	9.02	18,048
Total	34.48	68,950

Note: Total NOx includes startup emissions.

CT1 12-Mo Startup Only

	Tons	#
1Q07	0.38	760
2Q07	0.10	200
3Q07	0.69	1,386
4Q07	0.34	670
Total	1.51	3,016

CT2 12-Mo NOx Summary

	Tons	#
1Q07	8.73	17,460
2Q07	7.86	15,720
3Q07	9.84	19,689
4Q07	9.47	18,936
Total	35.90	71,805

Note: Total NOx includes startup emissions.

CT2 12-Mo Startup Only

	Tons	#
1Q07	0.43	860
2Q07	0.32	640
3Q07	0.28	561
4Q07	0.37	747
Total	1.40	2,808

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

http://www.epa.gov/compliance/resources/policies/ej/ej_permitting_authorities_memo_120100.pdf

The 1998 EPA guidelines require Agencies to consider a wide range of demographic, geographic, economic, human health and risk factors. One of the three most important factors identified in the 1998 EPA guidelines is "whether communities currently suffer or have historically suffered from environmental health risks and hazards." The 1998 EPA Guidelines require the agencies conducting an Environmental Justice Analysis to define the sensitive receptor analysis to the actual unique circumstances affecting the minority community not a generic definition of sensitive receptor that was utilized by the District and the CEC.

Soils and Vegetation Analysis Nitrogen Deposition

Nitrogen deposition consists of the input of reactive nitrogen species from the atmosphere to the biosphere. Pollutants that contribute to nitrogen deposition derive mainly from nitrogen oxides and ammonia emissions, which the RCEC would emit during normal operation. Emissions of NOx and ammonia contribute to nitric acid deposition that occurs via precipitation and fog and in dry deposition as well. Acute exposures to ammonia can adversely affect plant growth and productivity, resistance to drought and frost, responses to insect pests and pathogens, mycorrhizal and other beneficial root associations, and inter-specific competition and biodiversity in sensitive plant communities. Of particular concern for the RCEC project is the effect on serpentine soil plant communities, which are know to be particularly sensitive to nitrogen deposition. Serpentine soils in the San Francisco Bay Area support native grassland plant communities that can provide habitat for rare and endemic species. Nonnative annual grasses have invaded most grassland communities in California, but highly specialized plant species that are adapted to nutrient-poor serpentinitic soils can thrive in soils that are deficient in nitrogen, potassium, phosphorus, and other nutrients due to a competitive advantage over the faster growing non-native annual species. The competitive advantage of these specialized plant species can be lost when nitrogen deposition from air pollution fertilizes serpentine plant communities and nitrogen ceases to be a limiting nutrient for plant growth. Increased nitrogen levels often allow non-native annual grasses to out-compete the native species.

The nearest serpentine plant community to the project area is Fairmont Ridge in Lake Chabot Regional Park, approximately four miles northeast of the RCEC. Fairmont Ridge is located in the East Bay Hills adjacent to Lake Chabot. The California Native Grasslands Association identifies this area as a Purple Needlegrass Grassland community, and is noted as an area of serpentine soil in the USFWS's 1998 Recovery Plan for Serpentine Soil Species of the San Francisco Bay Area.

The BAAQMD and the CEC have failed to analyze the projects nitrogen deposition impacts on serpentine soil plant communities in the Bay Area.

Exhibit 20

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814-5512

May 29, 2007

Mr. Jack P. Broadbent
Executive Officer/Air Pollution Control Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Dear Mr. Broadbent,

AMENDED PRELIMINARY DETERMINATION OF COMPLIANCE FOR THE RUSSELL CITY ENERGY CENTER, APPLICATION 15487

Thank you for the opportunity to comment on the Amended Preliminary Determination of Compliance (PDOC) for the proposed Russell City Energy Center (RCEC), a 600 MW combined cycle project located in the city of Hayward. In the Amended PDOC the District finds that, subject to specified permit conditions, the proposed project will comply with all applicable federal, state and Bay Area Air Quality Management District (District) rules and regulations.

In considering this project, we believe there may be better and more direct ways to reduce or avoid the cumulative impacts from ozone precursor emissions than those proposed by the project owner. We believe that there is current technology that the District should consider requiring as Best Available Control Technology (BACT) that will significantly limit the ozone precursor emissions that result from start-up and load following transitions. We believe that impact avoidance (i.e., preventing emissions) is generally a better approach than impact mitigation of air emissions through the provision of offsets when complying with the requirements of the California Environmental Quality Act.

<u>OFFSETS</u>

The planned operating profile of the project, frequent start-up and shutdown cycles, is creating a significant disparity between the daily emissions and the average daily offsets. The project owner is requesting that no District or Energy Commission conditions be attached to the project that would restrict the number of start-up and shutdown cycles or the annual hours of operation. They would, instead, accept a condition that would limit the facility's annual emissions to 134 tons per year (TPY) of oxides of nitrogen (NOx) and 28.5 TPY of precursor organic compounds (POC).

The Amended PDOC, per the District New Source Review (NSR) regulations, identified That RCEC will surrender emission reduction credits (ERC) in the amounts of 103 TPY of NOx and 80 TPY of POC to offset new emissions of 134 TPY of NOx and 28.5 TPY of POC. On a daily basis, including days that experience ozone violations, staff estimates that the project could emit up to 2,213 lbs of NOx, while the proposed emission reduction credits provided would amount to only 844 lbs per day. This offset amount mitigates approximately 38 percent (844 lbs/2,213 lbs) of the project's potential emissions for NOx on any given day. Thus on those days when violations of the ozone air quality standards occur, the project's emissions would contribute to violations of the standard.

BACT

According to the Amended PDOC, each unit of the RCEC must be equipped with BACT for NOx, carbon monoxide (CO), POC, particulate matter less than 10 microns (PM10), and oxides of sulfur (SOx). The Amended PDOC states that BACT for each unit is the use of selective catalytic reduction (SCR) and CO oxidation catalyst systems to control NOx, POC and CO emissions, and the use of natural gas as BACT for PM10 and SOx.

The SCR system will maintain a normal operation NOx emissions limit of 2.0 parts per million (ppm) averaged over a one-hour period. The District determined that this meets District guidelines for BACT. Missing from this determination is consideration of the facility's potential high daily NOx emissions from multiple start-up and shutdown cycles. Energy Commission staff estimates that the facility can potentially emit 2,213 pounds per day of NOx. The hourly emissions during start-up and shutdown events are much greater than during normal operation since the SCR and ammonia injection system are not at optimal conditions. The resulting daily emissions could have a significant effect on ozone and air quality in the Bay Area air basin because the proposed NOx emission reduction credits are approximately equivalent to 844 pounds per day, well below the potential emissions of 2,213 pounds per day of NOx.

Energy Commission staff recommends that the district consider requiring, as part of their BACT analysis, hardware and software modifications to the project that can shorten start-up and shutdown events and optimize emission control systems. There is evidence that start-up and shutdown emissions from the facility can be reduced significantly with design changes to the heat recovery steam generator (HRSG) units that can include the use of the once-through HRSG (Benson Boiler). The start-up time for each turbine/HRSG unit could be reduced from the proposed 6 hours to approximately one hour, resulting in a significant reduction in start-up emissions. If the project is built with the aforementioned Fast-Start technology, the project start-up NOx emissions are expected to be reduced from the proposed 480 lbs to 22 lbs for each cold start-up event, and from 240 lbs to 28 lbs for hot or warm start-up events. This represents 95 and 88 percent reductions in NOx emissions per cold and hot or warm start-up events, respectively. In addition to reducing the facility's NOx emission liabilities, the use of Fast-Start technology at the RCEC project would result in cost savings from less fossil fuel use to create steam that is vented during start-ups. Staff has not estimated the actual fuel saving because this cost will tie directly to how many start-up and shutdown cycles the facility has during a year. According to one manufacturer (Siemens), the cost for the design changes is not significantly higher than the cost of the standard, off the shelf, HRSG.

Alternatively, the 600 MW combined cycle Palomar Project in Escondido has installed a proprietary control system, OpFlex from General Electric, and injects ammonia earlier to shorten start-up times and reduce start-up emissions at the facility. Preliminary, non-optimized results from their March 7, 2007, Petition for Variance 4703 Extension indicated that they have reduced NOx emissions from 120 lbs to 28 lbs for hot or warm start-up events.

If design or process control changes to reduce the facility's start-up and shutdown emissions are implemented, the RCEC daily emissions can be reduced. These design changes could be found to be cost-effective and included as BACT for the proposed facility.

GENERAL COMMENTS

- Page 2 and page 36 of the Amended PDOC identifies the source S-5, the cooling tower, "with efficiency drift eliminators make and model to be determined" while on page 14 the drift is specified as 0.0005%.
- Page 4, Item 3.c. identifies the POC limit of 1 ppmvd @15% O_2. However, Table 1 on the same page identifies POC limit of 2 ppmv.
- Page 5, Table 2 identifies PM10 emissions from the cooling tower, although drift elimination efficiency was not specified on page 2 and the TDS limits are not provided.
- Page 13 and Condition 20(g) specifies that the project will burn natural gas in the turbine and heat recovery steam generator with an annual average of 0.25 grains sulfur per 100 standard cubic feet. What is the basis for this value and how will it be enforced?

Thank you for the opportunity to provide comments on the District Amended PDOC for the Russell City Energy Center. We believe that design changes to the project could significantly reduce the facility's daily potential to emit, and at the same time address the effectiveness of the applicant's proposed offset mitigation. If you have any questions regarding our comments, please contact Matt Layton at (916) 654-3868.

Sincerely,

Paul C Richins Jr.

PAUL C. RICHINS, JR
Environmental Protection Office Manager

cc: Docket (01-AFC-7)
Proof of Service List
Agency List

Exhibit 21

JOHN C. CRUDEN
Acting Assistant Attorney General
Environment and Natural Resources Division
United States Department of Justice
Washington, D.C. 20530

W. BENJAMIN FISHEROW
Deputy Chief,
Environmental Enforcement Section
BRADLEY R. O'BRIEN
Senior Attorney
Environmental Enforcement Section
Environment and Natural Resources Division
United States Department of Justice
601 D Street, N.W.
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Attorneys for Plaintiff United States of America

ORIGINAL FILED PM 12: 56 RICHARD W. WIEKING U.S. DISTRICT COURT NORTHERN DISTRICT OF CALIFORNIA

E-Filing

UNITED STATES DISTRICT COURT
NORTHERN DISTRICT OF CALIFORNIA

UNITED STATES OF AMERICA,

Plaintiff,

v.

PACIFIC GAS AND ELECTRIC COMPANY

Defendant.

CV 09 4503

Civil Action No. ____________

CONSENT DECREE

EMC

WHEREAS, Plaintiff United States of America, on behalf of the United States Environmental Protection Agency ("EPA"), is concurrently filing a complaint ("Complaint") initiating this action against Pacific Gas and Electric Company ("PG&E");

WHEREAS, the United States alleges that PG&E has constructed and commenced operation of its 530 megawatt combined cycle, natural gas-fired combustion turbine power plant located near Antioch, California, known as the Gateway Generating Station ("GGS"), in violation of the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act ("Act"), 42 U.S.C. § 7475, and the regulations promulgated thereunder as set forth at 40 C.F.R. 52.21;

WHEREAS PG&E's predecessor-in-interest, Mirant Delta, LLC ("Mirant"), commenced construction of GGS in late 2001 pursuant to an Authority to Construct ("ATC") issued by the Bay Area Air Quality Management District ("BAAQMD") on July 24, 2001, which ATC also constituted a PSD permit;

WHEREAS Mirant formally suspended construction of the facility in February, 2002;

WHEREAS on March 3, 2003, after making revisions to its federal PSD regulations, EPA withdrew the delegation of PSD authority from BAAQMD;

Whereas BAAQMD believed EPA's withdrawal of delegation of PSD authority did not affect its authority to extend existing PSD permits;

WHEREAS at the request of Mirant, BAAQMD extended the ATC twice, in 2003 and 2005, and believed, at those times, it was also extending the PSD permit;

WHEREAS PG&E acquired the unfinished GGS construction project from Mirant in November, 2006, and resumed construction of the project on February 5, 2007;

WHEREAS in January, 2007, BAAQMD transferred the ATC to PG&E and believed it was also transferring the still-effective PSD permit;

WHEREAS EPA alleges that BAAQMD was without authority to extend the PSD permit after March 3, 2003, and that the PSD permit expired by operation of law 18 months after Mirant ceased construction in February, 2002;

WHEREAS, PG&E denies the material allegations of the Complaint;

WHEREAS, this Consent Decree does not constitute an admission by PG&E of any facts or of any liability;

WHEREAS, the United States and PG&E (the "Parties") agree that settlement of the civil claims as alleged in the Complaint is in the public interest and that entry of this Consent Decree without further litigation is the most appropriate way to resolve this action;

THEREFORE, IT IS ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter of this action and over the Parties pursuant to section 113(b) of the Act, 42 U.S.C. § 7413(b), and 28 U.S.C. §§ 1331, 1345, 1355, and 1367. Venue is proper in this Court pursuant to 28 U.S.C. §§ 1391(b) and 1395, and 42 U.S.C. § 7413(b). PG&E consents to and shall not challenge entry of this Consent Decree or this Court's jurisdiction to enter, enforce, modify, or terminate this Consent Decree.

II. APPLICABILITY AND BINDING EFFECT

2. Each signatory to this Consent Decree certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the party for whom the signatory has signed.

3. The provisions of this Consent Decree shall apply to and be binding upon the United States and PG&E, its subsidiaries and divisions, and its successors and assigns. Any change in ownership or corporate status of PG&E, including, but not limited to, any transfer of assets or real or personal property, shall in no way alter PG&E's responsibilities under this Consent Decree.

III. CIVIL PENALTY

4. Within thirty (30) days after the entry of this Consent Decree, PG&E shall pay a civil penalty to the United States of twenty thousand dollars ($20,000.00). Payment shall be made by Electronic Funds Transfer ("EFT") to the United States Department of Justice in accordance with the current electronic funds transfer procedures, referencing DOJ Case Number 90-5-2-1-09753 and the civil action case name and case number. Payment shall be in accordance with written instructions which will be provided to PG&E by the Financial Litigation Unit of the United

States Attorney's Office for the Northern District of California following entry of this Consent Decree. PG&E shall provide notice of payment, referencing DOJ Case Number 90-5-2-1-09753 and the civil action case name and case number to EPA and the Department of Justice at the addresses set forth in Section IX (Form of Notice).

5. Upon entry of this Consent Decree, the United States shall be deemed a judgment creditor for purposes of collection of the penalties required by this Consent Decree and enforcement of this Consent Decree. In any collection proceeding, the validity, amount, and appropriateness of the civil penalty specified in this Consent Decree shall not be subject to review.

IV. INJUNCTIVE RELIEF

6. PG&E shall, within thirty (30) days after entry of this Consent Decree, submit to the California Energy Commission ("CEC") a Petition to Amend Conditions of Certification in the matter of Gateway Generating Station (00-AFC-1) requesting an Order to Amend the Energy Commission Decision in the matter of Gateway Generating Station (00-AFC-1). The amendments sought by PG&E shall: 1) immediately lower GGS' current limit for oxides of nitrogen ("NOx") emissions from the combined cycle units from 2.5 parts per million volume ("ppmv") to 2.0 ppmv on a dry basis corrected to 15% oxygen and averaged over any one-hour period; 2) immediately lower GGS' current limit for carbon monoxide ("CO") emissions from the combined cycle units from 6.0 ppmv to 4.0 ppmv on a dry basis corrected to 15% oxygen and averaged over any rolling three-hour period; and 3) lower GGS' rolling 12-month NOx emissions cap for the combined cycle units from 174.3 tons per year ("tpy") to 139.2 tpy beginning on June 1, 2010.

7. PG&E shall, within thirty (30) days after entry of this Consent Decree, submit an application to the Bay Area Air Quality Management District ("BAAQMD") requesting inclusion in the permit to operate and in the Title V Operating Permit for GGS of permit conditions which: 1) immediately lower the current limit for NOx emissions from the combined cycle units from 2.5 ppmv to 2.0 ppmv on a dry basis corrected to 15% oxygen and averaged over any one-hour period; 2) immediately lower the current limit for CO emissions from the combined cycle units

from 6.0 ppmv to 4.0 ppmv on a dry basis corrected to 15% oxygen and averaged over any rolling three-hour period; and 3) lower the rolling 12-month NOx emissions cap for the combined cycle units from 174.3 tpy to 139.2 tpy beginning June 1, 2010.

8. Beginning November 1, 2009, and notwithstanding any permitting action by the CEC and/or BAAQMD, NOx emissions from the combined cycle units at GGS shall not exceed 2.0 ppmv on a dry basis corrected to 15% oxygen and averaged over any one-hour period, and CO emissions from the combined cycle units at GGS shall not exceed 4.0 ppmv on a dry basis corrected to 15% oxygen and averaged over any rolling three-hour period.

9. NOx emissions during Natural-Gas Combustion Turbine Start-up Mode shall not be included in calculating compliance with the one-hour emission limit of 2.0 ppmv set forth in Paragraphs 6, 7, and 8. CO emissions during Natural-Gas Combustion Turbine Start-up Mode shall not be included in calculating compliance with the three-hour emission limit of 4.0 ppmv set forth in Paragraphs 6, 7, and 8. Natural-Gas Combustion Turbine Start-up Mode is the lesser of the first 256 minutes of continuous fuel flow to the natural gas-fired combustion turbine after fuel flow is initiated or the period of time from natural gas-fired combustion turbine fuel flow initiation until the natural gas-fired combustion turbine achieves two consecutive continuous emission monitor data points in compliance with the emission concentration limits set forth in Paragraphs 6, 7, and 8.

10. NOx emissions during Natural-Gas Combustion Turbine Shutdown Mode shall not be included in calculating compliance with the one-hour emission limit of 2.0 ppmv set forth in Paragraphs 6, 7, and 8. CO emissions during Natural-Gas Combustion Turbine Shutdown Mode shall not be included in calculating compliance with the three-hour emission limit of 4.0 ppmv set forth in Paragraphs 6, 7, and 8. Natural-Gas Combustion Turbine Shutdown Mode is the lesser of the 30 minute period immediately prior to the termination of fuel flow to the natural gas-fired combustion turbine or the period of time from noncompliance with the emission concentration limits set forth in Paragraphs 6, 7, and 8 until termination of fuel flow to the natural gas-fired combustion turbine.

11. Beginning no later than June 1, 2010, and notwithstanding any permitting action by

the CEC and/or BAAQMD, the rolling 12-month NOx emissions from the combined cycle units at GGS shall not exceed 139.2 tpy.

12. Beginning November 1, 2009, PG&E shall provide EPA, as provided in Section IX (Form of Notice), detailed excess emission reports for NOx and CO emissions as described at 40 C.F.R. § 60.7(c). These reports shall be submitted within 30 days after the end of each calendar quarter and shall cover that preceding calendar quarter. The first report shall cover the partial calendar quarter from November 1, 2009, through December 31, 2009.

V. ENVIRONMENTAL MITIGATION PROJECTS

13. By January 1, 2010, PG&E shall submit applications to the CEC and/or BAAQMD, as necessary, for the installation of the General Electric OPFLEX Turndown and OPFLEX Startup NOx products as described in Paragraphs 14 and 15, below.

14. By January 1, 2011, PG&E shall install and make fully operational at GGS' combined cycle units the General Electric OPFLEX Turndown product. EPA is requiring use of this product in order to allow the combined cycle units to run at low capacity, thereby avoiding shut downs, startups, and the higher NOx emissions associated with startups.

15. By January 1, 2011, PG&E shall install and make fully operational at GGS' combined cycle units the General Electric OPFLEX Startup product. EPA is requiring use of this product in order to reduce the higher NOx emissions associated with startups.

VI. STIPULATED PENALTIES

16. PG&E shall pay the following stipulated penalties for failure to comply with this Consent Decree:

(a) Failure to submit any of the applications as required pursuant to Paragraphs 6, 7, or 13 above: $500 per day for each failure to apply.

(b) Failure to submit any of the reports as required pursuant to Paragraph 12 above: $500 per day for each failure to submit.

(c) Failure to pay the civil penalty required pursuant to Paragraph 4 above: $500 per day.

(d) Failure to implement either of the projects required pursuant to Section V

(Environmental Mitigation Projects) above: $500 per day for each failure to implement.

(e) Failure to comply with the one-hour NOx emissions limitation of 2.0 ppmv in Paragraph 8: where the emission level constituting a violation is less than or equal to 3.0 ppmv, $500 per violation; where the emission level constituting a violation is greater than 3.0 ppmv and GGS has exceeded the 2.0 ppmv limit on 15 or fewer days in the existing calendar year, $2,000 per violation; where the emission level constituting a violation is less than or equal to 3.0 ppmv and GGS has exceeded the 2.0 ppmv limit on more than 15 days in the existing calendar year, $5,000 per violation; and where the emission level constituting a violation is greater than 3.0 ppmv and GGS has exceeded the 2.0 ppmv limit on more than 15 days in the existing calendar year, $10,000 per violation.

(f) Failure to comply with the three-hour CO emissions limitation of 4.0 ppmv in Paragraph 8: where the emission level constituting a violation is less than or equal to 6.0 ppmv, $500 per violation; where the emission level constituting a violation is greater than 6.0 ppmv and GGS has exceeded the 4.0 ppmv limit on 15 or fewer days in the existing calendar year, $2,000 per violation; where the emission level constituting a violation is less than or equal to 6.0 ppmv and GGS has exceeded the 4.0 ppmv limit on more than 15 days in the existing calendar year, $5,000 per violation; and where the emission level constituting a violation is greater than 6.0 ppmv and GGS has exceeded the 4.0 ppmv limit on more than 15 days in the existing calendar year, $10,000 per violation.

(g) Failure to comply with the rolling 12-month NOx emissions limitation in Paragraph 11: $20,000 per ton in excess of the applicable limit.

17. PG&E shall notify EPA in writing of any failure to meet Consent Decree requirements for which stipulated penalties may be due as soon as it has knowledge of such failure.

18. All stipulated penalties shall begin to accrue on the day after the complete performance is due or the day that a violation occurs, and shall continue to accrue through the final day of the completion of the activity or the correction of the noncompliance. Nothing herein shall preclude the simultaneous accrual of separate stipulated penalties for separate

violations of this Consent Decree. Penalties shall accrue regardless of whether EPA has notified PG&E of a violation.

19. Stipulated penalties owed to the United States shall be paid by certified or cashier's check, payable to the "U.S. Department of Justice," and referencing this Consent Decree by caption, civil action number, and DOJ Ref.# 90-5-2-1-09753. PG&E must deliver any such payments by certified mail with return receipt requested to:

United States Attorney
Northern District of California
Attention: Financial Litigation Unit
450 Golden Gate Ave, 10th Floor
San Francisco, California 94102

20. Concurrently with making any payment for stipulated penalties, PG&E must send notice of payment to EPA and DOJ directed to the addresses provided in Section IX (Form of Notice). The notice of payment shall also identify: (a) the specific provision of Section VI (Stipulated Penalties) related to such payment, and (b) a description of the violation(s) of this Consent Decree for which the stipulated penalties or interest are being tendered.

21. Any stipulated penalty accruing pursuant to this Consent Decree shall be payable upon demand and due not later than thirty (30) days from EPA's written demand. The United States may, in its unreviewable discretion, waive payment of any portion of stipulated penalties that may accrue under this Consent Decree.

22. If PG&E fails to pay stipulated penalties owed pursuant to this Consent Decree within thirty (30) days of receipt of a written demand, it shall pay interest on the late payment for each day of late payment after the initial thirty-day time period. The rate of interest shall be the most recent interest rate determined pursuant to 28 U.S.C. § 1961.

VII. FORCE MAJEURE

23. For purposes of this Consent Decree, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of PG&E, its contractors, or any entity controlled by PG&E that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite PG&E's best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using the best

efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay and any adverse environmental effect of the violation is minimized to the greatest extent possible.

24. Notice of Force Majeure Events. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which PG&E intends to assert a claim of Force Majeure, PG&E shall notify the United States in writing as soon as practicable, but in no event later than twenty-one (21) calendar days following the date PG&E first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay or violation. In this notice, PG&E shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by PG&E to prevent or minimize the delay and any adverse environmental effect of the violation, the schedule by which PG&E proposes to implement those measures, and PG&E's rationale for attributing a delay or violation to a Force Majeure Event. PG&E shall adopt all reasonable measures to avoid or minimize such delays or violations. PG&E shall be deemed to know of any circumstance which PG&E, its contractors, or any entity controlled by PG&E knew or should have known.

25. Failure to Give Notice. If PG&E fails to comply with the notice requirements of this Section, the United States may void PG&E's claim for Force Majeure as to the specific event for which PG&E has failed to comply with such notice requirement.

26. United States's Response. The United States shall notify PG&E in writing regarding PG&E's claim of Force Majeure within twenty (20) business days of receipt of the notice provided under Paragraph 24. If the United States agrees that a delay in performance has been or will be caused by a Force Majeure Event, the United States and PG&E shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement(s) by a period equal to the delay actually caused by the event. In such circumstances, an appropriate modification shall be made pursuant to Section XIII (Modification) of this Consent Decree.

27. Disagreement. If the United States does not accept PG&E's claim of Force Majeure,

or if the United States and PG&E cannot agree on the length of the delay actually caused by the Force Majeure Event, the matter shall be resolved in accordance with Section VIII (Dispute Resolution) of this Consent Decree.

28. Burden of Proof. In any dispute regarding Force Majeure, PG&E shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. PG&E shall also bear the burden of proving that PG&E gave the notice required by this Section and the burden of proving the anticipated duration and extent of any delay(s) attributable to a Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

29. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of PG&E's obligations under this Consent Decree shall not constitute a Force Majeure Event.

30. Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and PG&E's response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; malfunction of a combined cycle unit or emission control device; unanticipated natural gas supply or pollution control reagent delivery interruptions; acts of God; acts of war or terrorism; and orders by a government official, government agency, other regulatory authority, or a regional transmission organization, acting under and authorized by applicable law, that directs PG&E to supply electricity in response to a system-wide (state-wide or regional) emergency. Depending upon the circumstances and PG&E's response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of PG&E and PG&E has taken all steps available to it to obtain the necessary permit, including, but not limited to: submitting a complete permit application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after

expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority.

31. As part of the resolution of any matter submitted to this Court under Section VIII (Dispute Resolution) regarding a claim of Force Majeure, the United States and PG&E by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by the Court. PG&E shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule (provided that PG&E shall not be precluded from making a further claim of Force Majeure with regard to meeting any such extended or modified schedule).

VIII. DISPUTE RESOLUTION

32. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, provided that the Party invoking such procedure has first made a good faith attempt to resolve the matter with the other Party.

33. The dispute resolution procedure required herein shall be invoked by one Party giving written notice to the other Party advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with regard to such dispute.

34. The Party receiving such a notice shall acknowledge receipt of the notice, and the Parties shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

35. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between the Parties' representatives unless they agree in writing to shorten or extend this period.

36. If the Parties are unable to reach agreement during the informal negotiation period, the United States shall provide PG&E with a written summary of its position regarding the

dispute. The written position provided by the United States shall be considered binding unless, within forty-five (45) calendar days thereafter, PG&E seeks judicial resolution of the dispute by filing a petition with this Court. If PG&E seeks judicial resolution, the United States's written summary shall be deemed its initial filing with this Court regarding the dispute. The United States may submit a response to the petition within forty-five (45) calendar days of filing.

37. The time periods set out in this Section may be shortened or lengthened upon motion to the Court of one of the Parties to the dispute, explaining the Party's basis for seeking such a scheduling modification.

38. This Court shall not draw any inferences nor establish any presumptions adverse to either Party as a result of invocation of this Section or the Parties' inability to reach agreement.

39. As part of the resolution of any dispute under this Section, in appropriate circumstances the Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. PG&E shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule, provided that PG&E shall not be precluded from asserting that a Force Majeure Event has caused or may cause a delay in complying with the extended or modified schedule.

40. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes. In their filings with the Court under Paragraph 36, the Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

IX. FORM OF NOTICE

41. Unless provided otherwise in this Consent Decree, all written notification, reporting or communication among the Parties required by this Consent Decree shall be addressed as follows:

For the United States:

Section Chief
Environmental Enforcement Section
United States Department of Justice
P.O. Box 7611
Washington, DC 20044-7611
DJ Ref.# 90-5-2-1-09753

and

Allan Zabel
Senior Counsel
Office of Regional Counsel (ORC-2)
United States Environmental Protection Agency - Region IX
75 Hawthorne Street
San Francisco, CA 94015

and

Steve Frey
Senior Engineer
Air Division (Air-5)
United States Environmental Protection Agency - Region IX
75 Hawthorne Street
San Francisco, CA 94015

For PG&E

Randal S. Livingston
Vice President – Power Generation
Pacific Gas and Electric Company
P.O. Box 770000, Mail Code N11E
San Francisco, CA 94177

Ronald A. Gawer
Senior Plant Manager – Gateway Generating Station
Pacific Gas and Electric Company
3225 Wilbur Avenue
Antioch, CA 94509

David R. Farabee
Pillsbury Winthrop Shaw Pittman LLP
50 Fremont Street
San Francisco, CA 94105-2228

Matthew A. Fogelson
Pacific Gas and Electric Company
P.O. Box 7442, B30A
San Francisco, CA 94120-7442

The United States, EPA or PG&E may change the address to which notices shall be sent by notifying the Parties in writing at the above addresses.

42. Unless the United States and EPA agree to a different form of submission, notification to or communications with the United States or EPA shall be deemed submitted on the date they are (1) received or (2) sent, if sent by overnight express mail.

X. PUBLIC NOTICE REQUIREMENT

43. This Consent Decree shall be lodged with the Court for a period of not less than thirty (30) days for public notice and comment in accordance with 28 C.F.R. § 50.7. The United States reserves the right to withdraw or withhold its consent if the comments regarding the Consent Decree disclose facts or considerations that indicate that the Consent Decree is inappropriate, improper, or inadequate. PG&E consents to the entry of this Consent Decree without further notice.

44. If, for any reason, the Court should decline to approve this Consent Decree in the form presented, then this agreement is voidable at the discretion of any Party, and the terms of this Consent Decree may not be used as evidence in any litigation between the Parties.

XI. RESOLUTION OF PAST CIVIL CLAIMS

45. This Consent Decree resolves the civil claims of the United States for the violations alleged in the Complaint filed in this action through the date of lodging of this Consent Decree. The United States and EPA retain all authority and reserve all rights to take any and all actions authorized by law to protect human health and the environment.

46. Except as provided in Paragraph 45 above, the United States and EPA hereby reserve all statutory and regulatory powers, authorities, rights, and remedies, both legal and equitable, civil, criminal, or administrative, including those that may pertain to PG&E's failure to comply with any of the requirements of this Consent Decree.

XII. EFFECTIVE DATE AND TERMINATION

47. This Consent Decree will take effect on the date it is entered by the Court.

48. This Consent Decree shall terminate when all of the following conditions have been met:

(a) PG&E has satisfactorily complied with the requirements set forth in Section IV (Injunctive Relief) for a period of not less than 12 consecutive calendar months; and

(b) The BAAQMD has issued a permit to operate for GGS containing the limits set forth in Paragraph 7; and

(c) PG&E has completed the actions required by Section V (Environmental Mitigation Project); and

(d) PG&E has paid the civil penalty as set forth in Section III (Civil Penalty); stipulated penalties, if any, as specified in Section VI (Stipulated Penalties); and the United States' enforcement expenses, if any, as specified in Section XVII (Payment of Enforcement Expenses).

49. For purposes of Paragraph 48, PG&E shall be deemed to have satisfactorily complied with the requirements set forth in Section IV (Injunctive Relief) if the United States has not collected any stipulated penalties for violations of this Consent Decree occurring during the 12-month period, and during the 12-month period there are no unresolved demands for stipulated penalties for violations of this Consent Decree.

50. PG&E shall initiate termination of this Consent Decree by submitting a notification to the United States that all conditions for termination pursuant to Paragraph 48 above have been satisfied. If the United States agrees with PG&E's notification, then the Parties shall file a joint motion or stipulation for termination of this Consent Decree. If the United States does not agree that the Consent Decree may be terminated, PG&E may invoke Dispute Resolution under Section VIII of this Consent Decree.

XIII. MODIFICATION

51. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by the United States and PG&E. Where the modification constitutes a material change to any term of this Consent Decree, it shall be effective only upon approval by the Court.

XIV. RETENTION OF JURISDICTION

52. Until the termination of this Consent Decree pursuant to Section XII (Effective Date and Termination), this Court shall retain jurisdiction over this action and all disputes arising hereunder for the purposes of implementing, interpreting, and enforcing the terms and conditions of this Consent Decree.

XV. COSTS OF SUIT

53. Each Party shall bear its own costs and attorneys' fees incurred in this action through the date upon which this Consent Decree is entered.

XVI. PAYMENT OF ENFORCEMENT EXPENSES

54. Notwithstanding Section XV (Costs of Suit), PG&E shall pay the United States' enforcement expenses, including, but not limited to, reasonable attorneys' fees and costs, when the United States incurs such expenses to enforce the terms of this Consent Decree or to collect any unpaid balance of the civil penalty specified in Section III (Civil Penalty) and any unpaid balance of stipulated penalties to be paid in accordance with Section VI (Stipulated Penalties). PG&E shall not be liable for such enforcement expenses if the Court denies the underlying relief sought by the United States pursuant to this Section XVI.

XVII. SERVICE

55. PG&E hereby agrees to accept service of process by mail with respect to the Complaint and all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable local rules of this Court, including, but not limited to, service of a summons. PG&E shall identify, on the attached signature page, the name and address of an agent who is authorized to accept service of process with respect to the Complaint and all matters arising under or relating to this Consent Decree.

XVIII. FINAL JUDGMENT

56. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment of the Court as to the United States and PG&E. The Court finds

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that there is no just reason for delay and therefore enters this judgment as a final judgment under Fed. R. Civ. P. 54 and 58.

ORDER

IT IS SO ORDERED:

Dated:____________________________ ____________________________________

United States District Judge

Signature page for *United States of America v. Pacific Gas and Electric Company* Consent Decree

FOR UNITED STATES DEPARTMENT OF JUSTICE:

Respectfully submitted,

JOHN C. CRUDEN
Acting Assistant Attorney General
Environment and Natural Resources Division
U.S. Department of Justice
Washington, D.C. 20530

W. BENJAMIN FISHEROW
Deputy Chief
BRADLEY R. O'BRIEN
Senior Attorney
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice

Signature page for *United States of America v. Pacific Gas and Electric Company* Consent Decree

FOR UNITED STATES ENVIRONMENTAL PROTECTION AGENCY:

Respectfully submitted,

LAURA YOSHII
Acting Regional Administrator, Region 9
United States Environmental Protection Agency

Signature page for *United States of America v. Pacific Gas and Electric Company* Consent Decree

FOR PACIFIC GAS AND ELECTRIC COMPANY

Respectfully submitted,

Randal S. Livingston
Vice President – Power Generation

Exhibit 22

Weyman Lee, P.E.
Senior Air Quality Engineer,
Bay Area Air Quality Management District
939 Ellis Street, San Francisco, CA, 94109
(415) 749-4796

COMMENTS OF ROBERT SARVEY ON APPLICATION NUMBER 15487 ADDITIONAL STATEMENT OF BASIS DRAT GEDERAL PREVENTION OF SIGNIFCANT DETERIOATION PERMIT

Introduction

The proposed Russell City facility was initially licensed in 2002. The district issued an FDOC for the RCEC on March 18, 2002. On November 17, 2006 the project owner filed for an amendment to relocate the project so its permits had to be updated. The CEC and the Air District therefore reinitiated the permitting process to amend the initial permits to reflect the new location. The District prepared an Amended Determination of Compliance addressing the air quality issues raised (as well as a few minor changes in the operating conditions) by the permit amendment and submitted it to the Energy Commission for use in the licensing proceeding. The Energy Commission completed its CEQA-equivalent review of environmental impacts (including air quality issues) and ultimately approved the amendment on September 26, 2007.

On November 1, 2007, the Air District issued an amended Authority to Construct incorporating the Energy Commission's conditions of certification into a District-issued permit, and also issued the amended Federal PSD Permit for the project. The amended Authority to Construct and the amended Federal PSD Permit were issued jointly in the same document, in accordance with the Air District's administrative practice. At that time the original PSD and ATC were approximately five years old.

With respect to the Federal PSD Permit, one person Mr. Rob Simpson, resident of Hayward, at his own expense, appealed the permit to the Environmental Appeals Board raising issues concerning the RCEC air quality impacts including BACT and NO2 impacts, socioeconomic impacts and the public notice and comment process. On July 29, 2008 the Environmental Appeals Board ruled:

Held: The Board remands the Permit so that the District can renotice the draft permit in accordance with the notice provisions of 40 C.F.R. § 124.10.

(1) Mr. Simpson may raise his notice claims for Board consideration despite Mr. Simpson's "failure" to meet the ordinary threshold for standing under 40 C.F.R. § 124.19(a), which limits standing to those who participate in a permit proceeding by filing comments on the draft permit or participating in a public hearing on a draft permit. Denying Board consideration of fundamental notice claims would deny parties the opportunity to vindicate before the Board potentially meritorious claims of notice violations and preclude the Board from remedying the harm to participation rights resulting from lack of notice. Such denial would be contrary to the CAA statutory directive

emphasizing the importance of public participation in PSD permitting and section 124.10's expansive provision of notice and participation rights to the public.

(2) Mr. Simpson has not demonstrated that his affiliation with the Hayward Area Planning Association ("HAPA") entitled him to particularized notice of the draft permit because HAPA, as a private organization, does not qualify as a "comprehensive regional land use planning agency" entitled to such notice during PSD permitting pursuant to section 124.10(c)(1)(vii) and, even if it were, that does not mean Mr. Simpson was entitled to such notice.

(3) While the Board generally will not consider notice allegations in a petition where the sole deficiency alleged is failure to give notice to a particular person other than the petitioner, it nevertheless regards it as appropriate to consider claims of failure of notice to other persons within the scope of allegations of fundamental defects in the integrity of the notice process as a whole that may be prejudicial to the notice rights of the petitioner and others.

(4) While a delegated state agency may redelegate notice and comment functions to another state agency to the extent the federal delegation so permits, in all cases it is incumbent upon the delegated state agency to ensure strict compliance with federal PSD requirements.

(5) Mr. Simpson has demonstrated that the District, in redelegating outreach to CEC, failed to ensure compliance with the notice and outreach obligations of the PSD regulations, thereby narrowing the scope of public notice to which Mr. Simpson and other members of the public were entitled. In particular, the District failed to ensure compliance with the specific obligation at section 124.10(c)(1)(ix) to inform the public of the opportunity to be placed on a "mailing list" for notification of permitting actions through "periodic publication in the public press and in such publications as Regional and State funded newsletters, environmental bulletins, or State Law Journals."

(6) The District's almost complete reliance upon CEC's certification related outreach procedures to satisfy the District's notice obligations regarding the draft permit resulted in a fundamentally flawed notice process. By "piggybacking" upon the CEC's outreach, the District failed to exercise sufficient supervision over the CEC to ensure that the latter adapted its outreach activities to meet specific section 124.10 mandates. The inadequacy of the notice lists used by the CEC, the handling of public comments by the CEC, and the conduct of a public workshop by CEC with likely District participation during the PSD comment period at which air quality issues were discussed but no record of public comments made all demonstrate that the CEC merely folded the PSD notice proceeding into its ongoing process without attempting to ensure that the part 124 requirements for public participation were met.

(7) Contrary to the District's statements, the District's notice omissions do not constitute "harmless error." Such omissions affected more persons than Mr. Simpson, and even as to Mr. Simpson, the District's assumption that, even with the proper notice, he would not have participated, is purely speculative.

(8) The District's notice deficiencies require remand of the Permit to the District to ensure that the District fully complies with the public notice and comment provisions at section 124.10. Because the District's renoticing of the draft permit will allow Mr. Simpson and

other members of the public the opportunity to submit comments on PSD-related issues during the comment period, the Board refrains at this time from opining on such issues raised by Mr. Simpson in his appeal.

(9) Several of the issues raised in Mr. Simpson's Petition concern matters of California or federal law that are not governed by PSD regulations and, as such, are beyond the Board's jurisdiction during the PSD review process. The Board will not consider these issues if raised following remand.[1]

The Air District re-noticed the proposed amended Federal PSD Permit on December 18, 2008 and issued the "**Statement of Basis for Draft Amended Federal Prevention of Significant Deterioration" Permit** in response to the Remand Order. This document was the second revision to a permit that was issued on March 18, 2002. The Air District received over 50 comment letters on the proposed permit. Letters were submitted by several governmental agencies including The Alameda County Health Department and the Port of Oakland. Several environmental organizations including Earthjustice, Sierra Club, CBE, and CARE, also commented. In response to these comment letters from various governmental agencies, environmental organizations and individuals the District on August 3, 2009 issued the current "Additional Statement of Basis Draft Federal "Prevention of Significant Deterioration" Permit." This current document represents one of the most bifurcated analyses in the history of air permitting. This piecemeal analysis is virtually incomprehensible to an ordinary member of the public.

The District sates on page 3 of the current document that, This Additional Statement of Basis, the initial Statement of Basis published in December of 2008, the revised proposed permit conditions, the initial permit application and all subsequent data and information submitted by the applicant, and all other materials supporting the Air District's proposal to issue the Federal PSD Permit are available for public inspection at the Outreach and Incentives Division Office located on the 5th Floor of District Headquarters, 939 Ellis Street, San Francisco, CA, 94109. This project analysis includes the original FDOC issued in 2002, an amended FDOC/PSD in 2007, a revised PSD in 2008, and now a draft amended PSD permit in 2009. This analysis spans over seven years and four separate documents. In addition the projects "Index of Public Permitting Record Documents" contains over 300 separate documents available for review only by a trip to the District headquarters.[2]

As a member of the public it is almost impossible to effectively comment on this current draft PSD permit. Presumably one could make a trip to San Francisco and camp out in the Districts public records room and spend countless hours reviewing the 300 plus documents. Another option would be to pay ten cents a page for the entire permitting record which would cost several thousand

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[1] EAB ruling PSD Appeal No. 08-01 pages 1,2

[2] http://baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2009/15487/B3161_nsr_15487_index_080309.ashx

dollars. The District should provide electronic access to the 300 document permitting record and provide an additional 30 day comment period.

Soils and Vegetation Analysis

The soils and vegetation analysis fails to quantify the projects nitrogen deposition impacts from NOx and ammonia emissions. The analysis instead attempts to quantify the East Bay Regional Parks current nitrogen deposition impacts and fails to ever quantify the projects own impacts. This approach is flawed since the projects nitrogen deposition impacts will be felt throughout the BAAQMD. For example the nitrogen deposition impacts in hills above the Metcalf project have documented nitrogen deposition impacts.[3] Any nitrogen deposition impacts from the RCEC will impact an already burdened ecosystem.

Pm 2.5 PRE CONSTRUCTION MONITORING

EPA's PSD regulations require an applicant to provide preconstruction monitoring data for purposes of use in the Source Impacts Analysis. However, a source is exempt from this requirement if its modeled impact in any area is less than pollutant-specific "significant monitoring concentrations" ("SMC"), which EPA has generally established as five times the lowest detectable concentration of a pollutant that could be measured by available instrumentation. While the maximum offsite impact modeled to occur from RCEC (4.86 ug/m3) is below two of EPA's proposed Significant Monitoring Concentrations ("SMCs"), it would exceed the lowest of the three proposed SMCs. Accordingly, RCEC has proposed existing monitoring data from nearby Fremont, CA to satisfy the preconstruction monitoring requirement.[4] The district should require site specific pre construction monitoring data because the project is located in an area which is predominately a minority community subject to Federal and State environmental justice concerns. In the two zip codes near the site 94544 and 94545 residents have a high mortality rate and on average they live five years less than the county- wide expectancy rate. Death rates from air pollution-associated diseases such as coronary heart disease, chronic lower respiratory disease, are substantially and statistically significantly higher than those for the County, representing an ongoing, excess burden of mortality. The rate of death from chronic lower respiratory diseases was 43 percent higher and the rate from coronary heart disease was 16 percent higher than the County average. Hospitalizations due to air pollution- associated diseases are substantially higher in the two zip codes close to the proposed site. From 2003 to 2005 the hospitalization rates for coronary heart disease, chronic obstructive pulmonary

[3] http://www.energy.ca.gov/sitingcases/metcalf/documents/2000-03-03_METCALF_BIOLOGY.PDF
http://www.energy.ca.gov/sitingcases/metcalf/documents/2000-10-10_METCALF_FSA.PDF page 485,486

[4] http://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2009/15487/sb_062309/B3161_nsr_15487_pm_062309.ashx
PAGE 6

disease, congestive heart failure and asthma in the two zip codes nearest the proposed site, 94544 and 94545, was statistically significantly higher than Alameda County rates which means they do not occur by chance. Specifically, hospitalization rates due to coronary heart disease was 60 percent higher; chronic obstructive pulmonary disease, 20 percent higher; congestive heart failure, 35 percent higher; and asthma hospitalization rates 14 percent higher than the County rate. The fact that rates of these illnesses are significantly higher in the proposed project area than in the rest of the county suggests a level of vulnerability in this population that is higher than the rest of the county.

GREENHOUSE GAS EMISSIONS

The district states that, "the emergency diesel fire pump engine will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because it will combust a hydrocarbon fuel, just as with the gas turbines and heat recovery boilers. There are no effective combustion controls to reduce the greenhouse gas emissions from hydrocarbon fuel combustion, and there are no currently available post-combustion controls, as the District explained in its greenhouse gas analysis for the gas turbines. The Air District therefore concludes that the only achievable technological approach to reducing greenhouse gases from the fire pump engine is to use the most efficient engine that meets the stringent National Fire Protection Association ("NFPA") standards for reserve horsepower capacity, engine cranking systems, engine cooling systems, fuel types instrumentation and control and exhaust systems. As there is only one control technology to choose from, application of the 5 steps in the Top-Down BACT analysis results in the selection of that control technology." The district is incorrect an electric fire pump is feasible and cost effective mitigation and represents BACT for green house gasses. In addition it lowers the facilities NOx and PM 2.5 concentrations and emissions of diesel particulate.

The projects greenhouse gas emissions can also be lowered significantly by utilizing a fast start capability that is becoming common in new power plant applications.

Start up and Shutdown emissions

The BACT determination for start up and shut down emissions is based on old technology. Combined cycle turbines are currently being permitted which can achieve cold, warm, and hot starts taking no longer than 1-hour to demonstrate compliance with normal steady state emission limits.[5] These fast start machines are now being utilized in most new power plant applications such as the new proposed Contra Costa Generating Plant, the Willow Pass Generating Station and the Marsh Landing Project. It is startling that the BAAQMD is so unaware of

[5] http://www.energy.ca.gov/sitingcases/contracosta/documents/applicant/afc/Volume%201/CCGS_5.1_Air%20Quality.pdf page 5.17 Contra Costa Generating Plant 09-AFC-4

significant developments in the power plant industry. Especially since these projects have applications lodged with the District. The Contra Costa Generating Station utilizing a GE Model 7FA with fast start capability is capable of achieving cold starts in one hour with only 96 pounds of NO_2 emissions as illustrated on page 5.1-9, table 5.16, of the AFC. [6]

Similarly the Marsh Landing Facility employing Siemens Flex Plant 10 (FP10) technology is capable of startup times of less than 12 minutes and worst case startup emissions of 38.7 pounds for NO_2 and 279.8 pounds per hour for CO emissions for a cold start. [7]

Also the Willow Pass Generating stations expected emissions associated with CTG Cold startup and shutdown event is 38.7 pounds of NO_2 and 279.8 pounds of CO. Based on vendor information, startup (i.e., the period from initial firing to compliance with emission limits) of the FP10 units is expected to occur within 12 minutes. During a shutdown event, the efficiency of the emission controls will continue to function at normal operating levels down to a load of 60 percent for the FP10 units; thus, shutdown periods and emissions are measured from the time this load is reached.[8]

The Russell city Project according to testimony by PG&E in the LTPP has "operational flexibility that will help PG&E to integrate intermittent renewable resources into PG&E's resource portfolio." The RCEC is expected to be a fast ramping flexible combined cycle Project.[9]

Secondary Particulate Impacts From Ammonia Slip

On page 55 of the proposed permit the Air District states:

The Air District also received some comments suggesting that the potential for ammonia slip from the facility's NOx control equipment should be evaluated as a collateral environmental impact in terms of its potential for the ammonia slip to form secondary particulate matter. The Air District has considered that issue in detail as explained in the section on particulate matter emissions below. (See Section VI C.) As

[6] http://www.energy.ca.gov/sitingcases/contracosta/documents/applicant/afc/Volume%201/CCGS_5.1_Air%20Quality.pdf page 5.1-9 Contra Costa Generating Plant 09-AFC-4

[7] http://www.energy.ca.gov/sitingcases/marshlanding/documents/applicant/afc/Volume%20I/7_1%20Air%20Quality.pdf pages 7.1-49 table7.1-16, page 7.1-8 08-AFC-03

[8] http://www.energy.ca.gov/sitingcases/willowpass/documents/applicant/afc/Volume_01/7.1%20Air%20Quality.pdf page 7.1-9 08-AFC-6

[9] **APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR EXPEDITED APPROVAL OF AMENDED POWER PURCHASE AGREEMENT FOR THE RUSSELL CITY ENERGY COMPANY PROJECT page 11**

explained there, the Air District has concluded that ammonia slip emissions are not a significant contributor to secondary particulate matter formation and thus are not a significant collateral environmental impact that would rule out the selection of SCR as a control technology for NO_2 compared with EMx technology.[80] *The Air District examines collateral environmental impacts such as this on a case-by-case basis and does not have a bright-line rule for when a collateral impact would be considered "significant" or not. But certainly, in a case such as this one where the available evidence suggests that ammonia slip in fact will not cause significant secondary PM, the potential for such impacts would not be significant enough to eliminate a particular control technology.*

The Air District would like to take this opportunity to clarify its analysis in light of these comments. Although the comments are correct that the District's study finding nitric-acid limited conditions looked only at the San Jose and Livermore areas, which are south and east of the proposed project location, respectively, there is no indication that the same atmospheric conditions do not exist in the Hayward area as well. They are part of the same general airshed as Hayward, and the Air District is not aware of any data or other information to suggest that conditions may be materially different. The Air District therefore continues to believe that the evidence before it supports the conclusion that the air in the region of the proposed facility is nitric-acid limited, and that additional ammonia emissions in the form of ammonia slip are not likely to have any significant contribution to secondary particulate matter formation. If members of the public have data or information that the location of the proposed facility is in fact not nitric-acid limited, the Air District asks that the public submit it during the additional comment period so the District can consider it.

Moreover, secondary PM formation is a complex process that is not well understood at the present time. As EPA recently noted in its rulemaking on secondary particulate matter precursors, "Ammonia emission inventories are presently very uncertain in most areas, complicating the task of assessing potential impacts of ammonia emission reductions. In addition, data necessary to understand the atmospheric composition and balance of ammonia and nitric acid in an area are not widely available, making it difficult to predict the results of potential ammonia emission reductions." (73 Fed. Reg. 28321, 28330 (May 16, 2008).) Given this situation, the suggestion that ammonia slip from the facility may cause significant secondary Particulate Matter formation is speculative at most. EPA has made clear that it Federal PSD Permitting decisions should not be made based on potential impacts that are merely speculative in nature. (See In re Three Mountain Power, 10 E.A.D. at 57-58; see also In re Sutter Power Plant, fn. 13.) The Air District notes that the commenters' assertions about the areas in which the District's study could be made more comprehensive only highlight the uncertainties surrounding the issue of secondary Particulate Matter formation and the speculative nature of their claims that ammonia slip will cause additional Particulate Matter impacts.

For these reasons, the Air District concludes that the Federal PSD BACT requirement does not require an analysis of ammonia slip emissions, as would be required if ammonia slip was demonstrated to be a precursor to Particulate Matter formation and that it *would be emitted in significant amounts. If members of the public have additional information that may be relevant to these issues, the Air District invites the public to submit it during the additional comment period so the Air District can consider it further.*

I have discovered additional information that is relevant to the secondary particulate matter from ammonia slip. In attachment 1 of these comments there is evidence that BAAQMD expert staff has changed its position on the formation of secondary particulate matter from ammonia slip. A telephonic conference was held on August 8, 2008 between District Staff, PG&E and representatives of Sierra Research to discuss PSD permitting issues for the Gateway and Russell city Projects. The notes from the conference reveal that, "**Although previous District statements were that ammonia did not contribute to secondary particulate in the BAAQMD, some staff members were now reevaluating that position."[10]** In light of BAAQMD expert staff's new position a site specific analysis of secondary particulate from ammonia slip is warranted. In addition a Federal PSD BACT analysis for ammonia slip is necessary to determine the lowest achievable ammonia slip limit for this project.

BAAQMD PSD Delegation

Further examination of attachment 1 the email from Brian Lusher BAAQMD Engineer to Alexander Crocket BAAQMD Attorney reveals an apparent conspiracy between BAAQMD, PG&E and Sierra Research to circumvent EAB/ PSD review of the Gateway Generating Project in Antioch. The Gateway Generating Station filed a petition for amendment of their FDOC and PSD permit on December 18, 2007. The new FDOC/PSD permit sought to reflect the project as constructed eliminating a wet cooling tower and replacing it with a dry cooling system and adding a new diesel fired generator and substituting a smaller gas pre heater. The application lowered the facilities emission limits to current Best Available Control Technology reducing NOx emissions from 2.5ppm to 2.0 ppm the current BACT limit.

District Staff Counsel "Sandy Crockett provided a summary of the EAB decision on the Russell City Energy Center PSD permit amendment and the timing implications of the EAB appeal for *GGS.* The District was taken to task by EAB for not complying with noticing requirements of 40 CFR 124 and is concerned that the notice provided for the *GGS* amendment might also be viewed by EAB as deficient. Sandy is concerned that the EAB plaintiff in the RCEC case would appeal the GGS permit to the EAB on the same grounds. He indicated that the RCEC plaintiff had been in contact with Bob Sarvey, who had submitted public comments on the *GGS* draft permit.[11] He noted that power plant project opponents such as Sarvey appear *to* have discovered that the EAB

[10] Attachment 1 page 3

[11] http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Filings%20By%20Appeal%20Number/2641E6619FB4CC79852575AE006CE74E/$File/Exhibit%209...8.pdf

appeal process is an effective means of delaying projects since an EAB appeal stays the PSD permit for 6 months or more even if EAB ultimately rejects the appeal."[12]

The "District believes (hat it may *be* preferable to re-notice the amendment using a District wide rather than a countywide notice list, resulting in a 30-day delay for issuance of the amended PSD permit but eliminating the RCEC plaintiffs ability to appeal this issue to the EAB."

Sierra Researches "Gary Rubenstein indicated that we expect the permit to be appealed to the EAB by Sarvey anyway. He stated that since the time-critical element for PG&E was the commission-related permit conditions, and since an appeal would stay the permit whether it had any merit or not, it's not clear that any time would be saved by renoticing the draft permit." BAAQMD Attorney, "Sandy suggested that it may be easier for the EAB to dismiss the appeal without the notice issue."[13]

Sierra Researches Gary Rubenstein, "noted that under EPA policy, once a facility starts up, a non-major amendment no longer requires PSD review and public notice, so if amendment issuance were to be delayed until after startup the PSD issues could be moot. **However, the District would appear to be circumventing the regulatory process if it were to delay.[14]** If GGS were to withdraw the permit amendment until after commissioning it would be hard for District staff to support, and the Hearing Board to grant, a variance."

The BAAQMD for its part delayed approval of the amended PSD permit for 25 months so the Gateway project could become operational and avoid EAB PSD review. The BAAQMD allowed PG&E to construct and operate a project which had no PSD permit and had an ATC for a wet cooled power plant with an electric fire pump. The project as built has a dry cooling system, a 300 hp diesel fire pump and a smaller dew point heater of which the BAAQMD was aware of at all times since December 18, 2007. The project has also avoided adopting current BACT standards for NOx and CO which allows the Gateway Generating Station to emit 20% more NOx emission and 100% more CO emissions than if the PSD permit had been timely reviewed and approved.

The EPA issued an FNOV to PG&E on August 8, 2009 for lack of a PSD permit and violation of the California State Implementation Plan a violation which was seemingly aided and abetted by the BAAQMD to avoid PSD review. Mr. Alexander Crocket sent this FNOV to the EAB appeals Board requesting a dismissal of a PSD permit review initiated by Mr. Rob Simpson filed on May 11, 2009.[15] No public participation is allowed in enforcement actions by the EPA therefore the public right to comment and adjudicate PSD permit was lost when the District failed to act on the amended PSD permit filed by PG&EA on December 18, 2008.

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[12] Attachment 1 page 1
[13] Attachment 1 page 1
[14] Attachment 1 page 2
[15] http://yosemite.epa.gov/OA/EAB_WEB_Docket.nsf/Filings%20By%20Appeal%20Number/1979700DF807B14D8525762600672862/$File/Notification%20...50.pdf

The BAAQMD was established to enforce air quality laws and to reduce emissions in the air basin to promote the public health and welfare. The BAAQMD has apparently colluded with PG&E and Sierra Research and has violated the Clean Air Act, the State Implementation Plan and the public's right to participate in air permitting decisions. Their intentional inaction on the permit has caused a potential worsening of air quality by not requiring BACT for the Gateway Generating Station. In light of these facts I respectfully request that the BAAQMD abandon its PSD permitting authority and relinquish its PSD authority to the EPA.

Alexander Crockett

From: Brian Lusher
Sent: Thursday, August 07, 2008 11:59 AM
To: Alexander Crockett
Cc: Brian Bateman; Bob Nishimura
Subject: FW: Follow up GGS Air Permit
Attachments: BAAQMD teleconference notes 080408.doc

FYI

-----Original Message-----
From: Allen, Thomas [mailto:HTA1@PGE.COM]
Sent: Wednesday, August 06, 2008 10:51 AM
To: Allen, Thomas; Royall, Steve; Nancy L. Matthews; Gary Rubenstein; sgalati@gb-LLP.com; Andrea@agrenier.com; Maring, Jon; Royall, Steve; Espiritu, Angel B; Brian Lusher; Phung, Hoc
Cc: Farabee, David R.
Subject: RE: Follow up GGS Air Permit

<<BAAQMD teleconference notes 080408.doc>>
All

Here are notes from our previous meeting that Nancy prepared. Let Nancy and me know if there are questions or comments

Tom Allen
Project Manager
Gateway Generating Station
925-459-7201 cell 415-317-4463

From: Allen, Thomas
Sent: Thursday, March 03, 2005 12:17 PM
To: Royall, Steve; 'Nancy L. Matthews'; 'Gary Rubenstein'; 'Scott Galati (sgalati@gb-LLP.com)'; 'Andrea@agrenier.com'; Maring, Jon; Royall, Steve; Espiritu, Angel B; 'blusher@baaqmd.gov'; Phung, Hoc

Cc: Farabee, David R.
Subject: Follow up GGS Air Permit
When: Wednesday, August 06, 2008 11:00 AM-11:30 AM (GMT-08:00) Pacific Time (US & Canada).
Where: GGS Conference Callin 866-257-0480 *4159735105*

Gateway Generating Station Teleconference Notes
August 4, 2008

Participants:

BAAQMD	Alexander (Sandy) Crockett (staff attorney) Brian Bateman (head of Permit Services) Bob Nishimura (senior permitting engineer) Brian Lusher (permit engineer)
PG&E	Tom Allen Steve Royall Hoc Phung Angel Espiritu Teresa DeBono
Latham & Watkins	David Farabee
Sierra Research	Gary Rubenstein Nancy Matthews

Meeting Notes:

1. <u>Discussion of Environmental Appeals Board Decision in the Russell City Energy Center licensing proceeding.</u>

Sandy Crockett provided a summary of the EAB decision on the Russell City Energy Center PSD permit amendment and the timing implications of an EAB appeal for GGS. District was taken to task by EAB for not complying with noticing requirements of 40 CFR 124 and is concerned that the notice provided for the GGS amendment might also be viewed by EAB as deficient. Sandy is concerned that the EAB plaintiff in the RCEC case would appeal the GGS permit to the EAB on the same grounds. He indicated that the RCEC plaintiff had been in contact with Bob Sarvey, who had submitted public comments on the GGS draft permit. He noted that power plant project opponents such as Sarvey appear to have discovered that the EAB appeal process is an effective means of delaying projects since an EAB appeal stays the PSD permit for 6 months or more even if EAB ultimately rejects the appeal.

2. <u>Renoticing under Section Title 40 Part 124 requirements. Area lists of interested parties by Region.</u>

District believes that it may be preferable to renotice the amendment using a District-wide rather than a countywide notice list, resulting in a 30-day delay for issuance of the amended PSD permit but eliminating the RCEC plaintiff's ability to appeal this issue to the EAB.

Gary Rubenstein indicated that we expect the permit to be appealed to the EAB by Sarvey anyway. He stated that since the time-critical element for PG&E was the commission-related permit conditions, and since an appeal would stay the permit whether it had any merit or not, it's not clear that any time would be saved by renoticing the draft permit. Sandy suggested that it may be easier for the EAB to dismiss the appeal without the notice issue.

3. Public Meeting may be required under Title 40 Part 124.

District also noted that if amendment is renoticed, comments could request a public hearing. Gary and David Farabee recommended that if the permit is renoticed, PG&E should request a public hearing so the hearing notice period could run concurrently with the comment period, avoiding additional delays.

4. AC amendment considered a non-major modification of PSD permit.

There was a discussion of the need for amended CO emission limits during commissioning. Gary and Steve Royall explained that the limits in the current permit are not adequate; if amendment is delayed beyond project startup, GGS may need to request variance from Hearing Board. Gary and Tom Allen indicated that GGS is exploring ways of reducing CO emissions during commissioning to comply with current limits, such as installing oxidation catalyst before first fire. Gary noted that under EPA policy, once a facility starts up, a non-major amendment no longer requires PSD review and public notice, so if amendment issuance were to be delayed until after startup the PSD issues could be moot. However, District could appear to be circumventing the regulatory process if it were to delay. If GGS were to withdraw permit amendment until after commissioning it would be hard for District staff to support, and the Hearing Board to grant, a variance.

5. Basis of revised annual CO limit.

Brian Lusher said he had received information from Sierra on this topic; it appeared to address his questions and he will contact Sierra directly if he had additional questions.

6. Additional discussion on fast start/rapid start technology and the possible implementation of this technology for this project.

District staff believe they need to address startup BACT in response to comments. Brian Lusher noted that he had received some information from Sierra to address this. Gary noted that EPA had addressed this issue in the Colusa PSD permit; Brian will look at the information PG&E has already submitted, and may request additional information, to assist in preparing his response. There was a general discussion of the physical changes necessary to implement fast start technology – software changes alone are not adequate--and why this is not feasible for GGS at this point in project development.

Brian would like to include a warm startup time limit in the GGS permit as one way to address the BACT issue. There was a general discussion regarding the need to maintain the 900 lb/hr CO limit—that the hourly limits could not be lowered. The District understands this issue.

7. NH_3 Slip/Secondary PM

Brian Lusher indicated that the CEC staff was pressuring the BAAQMD staff on the proposal to raise the ammonia slip limit to 10 ppm. He had reviewed the District's studies on the contribution of ammonia to secondary particulate. Although previous District statements were that ammonia did not contribute to secondary particulate in the BAAQMD, some staff members were now reevaluating that position. He noted that many recent projects had accepted 5 ppm ammonia slip limits.

Gary pointed out that the 5 ppm slip limits for recent projects were proposed or accepted for other reasons, including BACT determinations (San Luis Obispo County APCD and SCAQMD), and these reasons are not relevant to GGS. He said that the District staff had been consistent in its position regarding the contribution of ammonia slip to secondary PM in the Bay Area, and that if the District staff changed the technical conclusions regarding atmospheric chemistry, GGS would accept that determination. However, the BAAQMD staff, not the CEC staff, were the experts on this air quality issue.

8. Excursion Language Necessary? Justification for Excursion Language?

Brian Lusher asked for some justification for the requested excursion language in the draft permit. Gary indicated that Sierra was working on an analysis of acid rain monitoring data to address the question, and that a summary of the analysis would be provided to the District when it was completed later this week.

9. CO_2 BACT

Brian Lusher said the District believes that CO_2 emissions need to be addressed in permit evaluations. Gary warned against including CO_2 emissions in a PSD permit evaluation because that could lead to making every project a major facility for CO_2. Sandy Crockett agreed with this concern.

Brian also indicated that the District was considering whether the modeling results for other non-PSD pollutants needed to be included in the public notice and engineering evaluation. Gary expressed concern that this could make it appear as if the entire PSD permit was subject to public notice, and not just the requested amendment. The District staff indicated that this was their intent, as a fallback position. Gary indicated that while PG&E could figure out a way to deal with delays related to the pending permit amendment, if there was even a slight chance that the public notice for the amendment could be construed as a renotice of the entire PSD permit, and hence an appeal could stay the effectiveness of the initial PSD permit, PG&E would withdraw the amendment request.

The District staff agreed to continue to review these issues internally. A follow-up conference call was scheduled for 11 am Wednesday, August 6.

Exhibit 23

February 5, 2009

Weyman Lee,
P.E., Senior Air Quality Engineer
Bay Area Air Quality Management District
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San Francisco, CA, 94109
(415) 749-4796
weyman@baaqmd.gov.

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1200 Pennsylvania Avenue, N.W.
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lisa.jackson@epa.gov

Table of Contents

I. INTRODUCTION

Thank you for the opportunity to comment[1] on the "amended" PSD permit for the Russell City Energy Center Application Number 15487. CAlifornians for Renewable Energy, Inc. ("CARE") objects to this permit. This also serves as a Complaint to Office of the Administrator of the U.S. Environmental Protection Agency (USEPA) and the California Air Resources Board (ARB) under 42 USC § 7604.[2] In the July 29, 2008 "Remand" of the United States Environmental Protection Agency (USEPA) Environmental Appeals Board ("EAB" or "Board") admonished the Bay Area Air Quality Management District ("BAAQMD" or "District") to "scrupulously adhere to all relevant requirements in section [40 C.F.R. § 124.10(d)] concerning the initial notice of draft PSD permits (including development of mailing lists), as well as the proper content of such notice" but the District failed to properly carry out this order.[3]

The District, like Pacific Gas and Electric (PG&E)[4] claim that when the EAB reviewed the original PSD permit appeal by Mr. Simpson "[t]he EAB, found no substantive defects in the PSD permit and its decision denied review of each of the substantive claims raised in the appeal." The remand order from the EAB decision does not deny review of the substantive PSD issues raised by Mr. Simpson but states that permit must be re-noticed and that the appeal board refrains from opining on the substantive PSD issues raised by Mr. Simpson "at this time."

> "The District's notice deficiencies require remand of the Permit to the District to ensure that the District fully complies with the public notice and comment provisions at section 124.10. Because the **District's renoticing of the draft permit will allow Mr. Simpson and other members of the public the opportunity to submit comments on PSD-related issues during the comment**

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[1] These comments were prepared by Michael E. Boyd, Bob Sarvey, and Rob Simpson. The comments on environmental justice are sponsored by Lynne Brown.

[2] This Complaint also includes an attached ratepayers citizens *Complaint Petition* filed before the California Public Utilities Commission (CPUC) in the *Application of Pacific Gas and Electric Company for Expedited Approval of the Amended Power Purchase Agreement for the Russell City Energy Company Project (U39E)* under Docket A.08-09-007 at: http://docs.cpuc.ca.gov/efile/CM/96544.pdf

[3] In re: Russell City Energy Center Permit No. 15487 USEPA EAB PSD Appeal No. 08-01

[4] See September 10, 2008 testimony at page 1-5 http://docs.cpuc.ca.gov/published/proceedings/A0809007.htm

period, the Board refrains at this time from opining on such issues raised by Mr. Simpson in his appeal."
Remand Order at page 3[5]

There are in fact several PSD related issues that the EAB appeals Board will have to review when the EAB is petitioned after the BAAQMD issues the draft permit. We have reviewed comments on the draft PSD permit from several major environmental organizations including the Sierra Club, Earth Justice, and Golden Gate University which we incorporate by this reference as if fully set forth by CARE and Rob Simpson. Despite claims otherwise the remand order from the EAB on the original Russell City PSD permit dismisses all substantive comments other than public notice requirement, this is simply not true. Major issues remain with this permit.

II. DISTRICT IS CIRCUMVENTING PUBLIC PARTICIPATION

The District continues to fail to implement 40 CFR 52.21, 40 CFR 124 and the Clean Air Act in its consideration of PSD permit for the Russell City Energy Center (RCEC). The District is circumventing public participation by failing to provide access to the administrative record. Petitioner(s)[6] have requested access to the record Since September 11 2008 without satisfaction. After no less than 10 requests in writing in person and by telephone the District has provided limited response providing no basis for the permitting. It has been impossible for the public to participate with no discernible docket for the facility as would be provided if the EPA issued the permit. When the EPA issues PSD permits there is an accessible docket and supporting documentation available on the EPA website. The Notice that was included for the PSD Permit at the District's website[7] failed to include a copy of the Application No. 15487.[8] With no discernable docket at the District there is no way that the public can identify the basis for permitting actions to effectively participate.

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[5] For a electronic copy of the *Remand Order*;
See:http://yosemite.epa.gov/OA/EAB_WEB_Docket.nsf/Filings%20By%20Appeal%20Number/EA6F1B6AC88CC6F085257495006586FB/$File/Remand...50.pdf
[6] Petitioner(s) are CARE, Rob Simpson, and Robert Sarvey.
[7] See http://www.baaqmd.gov/pmt/public_notices/2008/15487/index.htm
[8] A copy of the initial authority to construct (ATC) is also not provided on the District's website. On February 4, 2009 Rob Simpson request to see a copy of the Application No. 15487 at the District's Offices in San Francisco but none was provided.

The documents issued by the District are fatally flawed. The District has recently issued no less than 4 “fact sheets” for RCEC each in conflict with the others and none satisfying the requirements of 40 CFR 124.8.[9] The public can not rely on any of the “Fact Sheets” issued by the District. The District has also issued 2 different “Public Notices” and 2 different Statements of Basis, 3 of the 4 “Fact Sheets” the 2 different Public Notices and the 2 different Statements of Basis all make false claims of propriety by claiming that this is an amendment of a PSD permit when no such permit has ever been issued. “The Air District is proposing to incorporate the changes that have been made to the proposed project into the Federal PSD Permit that was initially issued in 2002, including the new project site.” Fact sheet 1 and 2. "The initial project, proposed by an affiliate of Calpine Corporation, received all necessary air quality permits and was licensed by the California Energy Commission (CEC) in 2002." Fact sheet #3

The "amended" Permit fails to comply with 40 CFR 51.166 (2) "Within one year after receipt of a complete application, the reviewing authority shall ... (vii) Make a final determination whether construction should be approved, approved with conditions, or disapproved".

In the December 10, 2008 *Corrected Notice of Public Hearing and Notice Inviting Written Public Comment on Proposed Amended PSD Permit* the District states " [t]he project will utilize the Best Available Control Technology to minimize emissions of these air pollutants as required by 40 C.F.R. Section 52.21. The proposed project will not consume a significant degree of any PSD increment." The Notice goes on to state:

> The proposed amended PSD Permit is a federal permit issued by the District on behalf of the United States Environmental Protection Agency (“EPA”). The District issues PSD permits under a Delegation Agreement with EPA. The District also participates in the California Energy Commission’s licensing process under state law and issues a District Authority to Construct incorporating the Energy Commission’s requirements. The District issued an Authority to Construct for the Russell City Energy Center jointly in the same document with the federal PSD Permit on November 1, 2007. District claims only the federal PSD Permit has been remanded, and only the federal PSD permit is being re-noticed. The Authority to Construct is not being reopened and this notice applies only to the proposed amended PSD permit.

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[9] 40 CFR 124.8 (3) For a PSD permit, the degree of increment consumption expected to result from operation of the facility or activity. (4) A brief summary of the basis for the draft permit conditions including references to applicable statutory or regulatory provisions.

CARE objects to this because the USEPA EAB revoked the PSD Permit on remand as was demonstrated in the second EAB Appeal[10] where the EAB found there was no federal PSD Permit to Appeal. So there is no PSD permit to amend and therefore the so-called "amended Permit" is a faux substitute for the "draft permit, providing public notice fully consistent with the requirements of 40 C.F.R. § 124.10.32" as directed by the EAB.

III. BACT IS PART OF THE CAA AND THE PDOC INCLUDES THE DISTRICT'S BACT ANALYSIS THEREFORE CLEARLY THE PDOC AND DRAFT PSD PERMIT ARE INTERDEPENDENT

Congress enacted the PSD provisions of the Clean Air Act (CAA) in 1977 for the purpose of, among other things, "insu[ring] that economic growth will occur in a manner consistent with the preservation of existing clean air resources."[11] The statute requires preconstruction approval in the form of a PSD permit before anyone may build a new major stationary source or make a major modification to an existing source[12] if the source is located in either an "attainment" or "unclassifiable" area with respect to federal air quality standards called "national ambient air quality standards" (NAAQS).[13] EPA designates an area as "attainment" with respect to a given NAAQS if the concentration of the relevant pollutant in the ambient air within the area meets the limits prescribed in the applicable NAAQS. CAA § 107(d)(1)(A), 42 U.S.C. § 7407(d)(1)(A). A "nonattainment" area is one with ambient concentrations of a criteria

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[10] See In re: Russell City Energy Center Permit USEPA EAB Appeal No. 08-07

[11] CAA § 160(3), 42 U.S.C. § 7470(3).

[12] The PSD provisions 2 that are the subject of the instant appeal are part of the CAA's New Source Review (NSR) program, which requires that persons planning a new major emitting facility or a new major modification to a major emitting facility obtain an air pollution permit before commencing construction. In addition to the PSD provisions, explained infra, the NSR program includes separate "nonattainment" provisions for facilities located in areas that are classified as being in nonattainment with the EPA's national Ambient Air Quality Standards. See infra; CAA §§ 171-193, 42 U.S.C. §§ 7501-7515. These nonattainment provisions are not relevant to the instant case.

[13] See CAA §§ 107, 160-169B, 42 U.S.C. §§ 7407, 7470-7492. NAAQS are "maximum concentration ceilings" for pollutants, "measured in terms of the total concentration of a pollutant in the atmosphere." See U.S. EPA Office of Air Quality Standards, New Source Review Workshop Manual at C.3 (Draft Oct. 1990). The EPA has established NAAQS on a pollutant-by-pollutant basis at levels the EPA has determined are requisite to protect public health and welfare. See CAA § 109, 42 U.S.C. § 7409. NAAQS are in effect for the following six air contaminants (known as "criteria pollutants"): sulfur oxides (measured as sulfur dioxide ("SO_2")), particulate matter ("PM"), carbon monoxide ("CO"), ozone

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pollutant that do not meet the requirements of the applicable NAAQS. *Id.* Areas "that cannot be classified on the basis of available information as meeting or not meeting the [NAAQS]" are designated as "unclassifiable" areas. *Id.* The PSD Regulations provide, among other things, that the proposed facility be required to meet a "best available control technology" ("BACT")[14] emissions limit for each pollutant subject to regulation under the Clean Air Act that the source would have the potential to emit in significant amounts.[15]

The District processes PSD permit applications and issues permits under the federal PSD program, pursuant to a delegation agreement with the USEPA. The District's regulations, among other things, prescribe the federal and State of California standards that new and modified sources of air pollution in the District must meet in order to obtain an "authority to construct" from the District.[16]

In addition to the substantive provisions for EPA-issued PSD permits, found primarily at 40 C.F.R. § 52.21, PSD permits are subject to the procedural requirements of Part 124 of Title 40 of the Code of Federal Regulations (Procedures for Decisionmaking), which apply to most EPA-issued permits.[17] These requirements also apply to permits issued by state or local governments pursuant to a delegation of federal authority, as is the case here. Among other things, Part 124 prescribes procedures for permit applications, preparing draft permits, and issuing final permits, as well as filing petitions for review of final permit decisions. *Id.* Also, of particular relevance to this proceeding, part 124 contains provisions for public notice of and public participation in EPA

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(measured as volatile organic compounds ("VOCs")), nitrogen dioxide ("NO2") (measured as NOx), and lead. 40 C.F.R. § 50.4-.12. See CAA §§ 107, 161, 165, 42 U.S.C. §§ 7407, 7471, 7475.

[14] BACT is defined by the CAA, in relevant part, as follows:

> The term "best available control technology" means an emissions limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant.

CAA § 169(3), 42 U.S.C. § 7479(3); see also 40 C.F.R. § 52.21(b)(12).

[15] CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); see also 40 C.F.R. § 52.21(b)(5).

[16] See Bay Area Air Quality Management District Regulation ("DR") New Source Review Regulation 2 Rule 2, 2-2-100 to 2-2-608 (Amended June 15, 2005), available at http://www.baaqmd.gov/dst/regulations/rg0202.pdf.

[17] See 40 C.F.R. pt. 124.5

permitting actions. See 40 C.F.R. § 124.10 (Public notice of permit actions and public comment period); *id.* § 124.11 (Public comments and requests for public hearings); *id.* § 124.12 (Public hearings).[18]

The District's Regulation 2 Rule 3 - 403 state "[w]ithin 180 days of accepting an [CEC Application for Certification] AFC as complete, the APCO shall conduct a Determination of Compliance [DOC] review and make a preliminary decision [PDOC] as to whether the proposed power plant meets the requirements of District regulations. If so, the APCO shall make a preliminary determination of conditions to be included in the Certificate, including specific BACT requirements and a description of mitigation measures to be required." Regarding the public notice requirement District's Regulation 2 Rule 3 - 404 goes on to state " [t]he preliminary decision [PDOC] made pursuant to Section 2-3-403 shall be subject to the public notice, public comment and public inspection requirements contained in Section 2-2-406 and 407 of Rule 2." Regulation 2 Rule 2 - 406 states " [t]he APCO shall make available for public inspection, at District headquarters, the information submitted by the applicant, and if applicable the APCO's analysis, and the preliminary decision to grant or deny the authority to construct including any proposed conditions... Furthermore, all such information shall be transmitted, upon the date of publication, to the ARB and the regional office of the EPA if the application is subject to the requirements of Section 2-2-405. Regulation 2 Rule 2 - 407 states " [i]f the application is for a new major facility or a major modification of an existing major facility, or requires a PSD analysis, or is subject to the MACT requirement, the APCO shall within 180 days following the acceptance of the application as complete, or a longer time period agreed upon, take final action on the application after considering all public comments. Written notice of the final decision shall be provided to the applicant, the ARB and the EPA..."

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[18] The requirement for EPA to provide a public comment period when issuing a draft permit is the primary vehicle for public participation under Part 124. Section 124.10 states that “[p]ublic notice of the preparation of a draft permit ... shall allow at least 30 days for public comment.” 40 C.F.R. § 124.10(b). Part 124 further provides that “any interested person may submit written comments on the draft permit ... and may request a public hearing, if no public hearing has already been scheduled.” Id. § 124.11.

In addition, EPA is required to hold a public hearing “whenever [it] ... finds, on the basis of requests, a significant degree of public interest in a draft permit(s).” Id. § 124.12(a)(1). EPA also has the discretion to hold a hearing whenever “a hearing might clarify one or more issues involved in the permit decision.” Id. § 124.12(a)(2).

Since BACT is part of the CAA and the PDOC includes the District's BACT analysis therefore clearly the PDOC[19] and draft PSD Permit are interdependent on the findings from the federal BACT analysis conducted by the District purportedly in 2002 and again in 2007. The PSD permitting procedures at the heart of this dispute were triggered by RCEC's application to the CEC, on November 17, 2006, to amend the CEC's original 2002 certification of RCEC's proposal to build a 600-MW natural gas-fired, combined cycle power plant in Hayward, California.[20] According to the District Air Quality Engineer who oversaw the RCEC's PSD permitting, the District, after conducting an air quality analysis, issued its PDOC/draft PSD permit, notice of which it published in the Oakland Tribune on April 12, 2007. Declaration of Wyman Lee, P.E. ("Lee Decl.") ¶ 2. RCEC originally filed for certification by the CEC in early or mid-2001, and was initially certified by the CEC on Sept. 11, 2002, pursuant to the *Warren-Alquist Act*, see supra. During the initial CEC certification process, which also incorporated the District permitting, the District issued a PDOC/Draft PSD Permit to RCEC in November 2001. However, the District did not proceed to issue a final PSD permit because RCEC withdrew plans to construct the project in the spring of 2003. See Letter from Gerardo C. Rios, Chief, Permits Office, U.S. EPA Region 9, to Ryan Olah, Chief Endangered Species Division, U.S. Fish and Wildlife Service (Jun. 11, 2007). The amended CEC certification and PSD permitting were required purportedly because RCEC afterwards proposed relocating the project 1,500 feet to the north of its original location[21].

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[19] The District's process for permitting power plants is integrated with the CEC's certification process to support the latter's conformity findings, as reflected in the District's regulations specific to power plant permitting. See DR, Power Plants Regulation 2 Rule 3 §§ 2-3-100 to 2- 3-405, available at http://www.baaqmd.gov/dst/regulations/rg0202.pdf. These regulations state that "[w]ithin 180 days of [the District's] accepting an [application for certification] as complete [for purposes of compliance review], the [District Air Pollution Control Officer] shall conduct a ... review [of the application] and make a "preliminary decision" as to "whether the proposed power plant meets the requirements of District regulations." Id. § 2-3-403. If the preliminary decision is affirmative, the District's regulations provide that the District issue a preliminary determination of compliance (PDOC) with District regulations, including "specific BACT requirements and a description of mitigation measures to be required." Id. The District's regulations further require that "[w]ithin 240 days of the [District's] acceptance of an [application for certification] as complete," the District must issue a final Determination of Compliance ("FDOC") or otherwise inform the CEC that the FDOC cannot be issued. Id. § 2-3-405.9

[20] See Declaration of J. Mike Monasmith ("Monasmith Decl.") 2, Att. A.

[21] See Final PSD Permit, Application No. 15487 ("Final Permit") at 3.

IV. DISTRICT FAILS TO CONSIDER GREENHOUSE GAS EMISSIONS AS REGULATED POLLUTANTS

CARE also disagrees with the subject permit because it does not consider greenhouse gas emissions as regulated pollutants. Carbon Dioxide, CO_2, and Nitrous Oxide, N_2O, are components of the emissions expected from the Russell City Energy Center and yet they are not included as regulated emissions. The United States Environmental Protection Agency (USEPA) website[22] recognizes the climate change impacts of these emissions and yet these impacts were not included as pollutants.

This project has been located so as to disparately place environmental burdens upon low-income, minority residents, and this project significantly increases emissions of greenhouse gases responsible for global warming. The United States Supreme Court has affirmed that "[t]he harms associated with climate change are serious and well recognized," *Massachusetts v. EPA*, 549 U.S. 497, 127 S. Ct. 1438, 1455 (April 2, 2007).

In that case, the Supreme Court ruled that the Clean Air Act (CAA or Act) authorizes regulation of greenhouse gases (GHGs) because they meet the definition of air pollutant under the Act.[23] This is the provision entitling CARE to commence a civil action against the

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22 http://epa.gov/climatechange/index.html

23 42 USC § 7604. Citizen suits

(a) Authority to bring civil action; jurisdiction

Except as provided in subsection (b) of this section, any person may commence a civil action on his own behalf—

(1) against any person (including (i) the United States, and (ii) any other governmental instrumentality or agency to the extent permitted by the Eleventh Amendment to the Constitution) who is alleged to have violated (if there is evidence that the alleged violation has been repeated) or to be in violation of (A) an emission standard or limitation under this chapter or (B) an order issued by the Administrator or a State with respect to such a standard or limitation,

(2) against the Administrator where there is alleged a failure of the Administrator to perform any act or duty under this chapter which is not discretionary with the Administrator, or

(3) against any person who proposes to construct or constructs any new or modified major emitting facility without a permit required under part C of subchapter I of this chapter (relating to significant deterioration of air quality) or part D of subchapter I of this chapter (relating to nonattainment) or who is alleged to have violated (if there is evidence that the alleged violation has been repeated) or to be in violation of any condition of such permit.

The district courts shall have jurisdiction, without regard to the amount in controversy or the citizenship of the parties, to enforce such an emission standard or limitation, or such an order, or to order the

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Administrator to perform such act or duty, as the case may be, and to apply any appropriate civil penalties (except for actions under paragraph (2)). The district courts of the United States shall have jurisdiction to compel (consistent with paragraph (2) of this subsection) agency action unreasonably delayed, except that an action to compel agency action referred to in section 7607 (b) of this title which is unreasonably delayed may only be filed in a United States District Court within the circuit in which such action would be reviewable under section 7607 (b) of this title. In any such action for unreasonable delay, notice to the entities referred to in subsection (b)(1)(A) of this section shall be provided 180 days before commencing such action.

(b) Notice

No action may be commenced—

(1) under subsection (a)(1) of this section—

(A) prior to 60 days after the plaintiff has given notice of the violation

(i) to the Administrator,

(ii) to the State in which the violation occurs, and

(iii) to any alleged violator of the standard, limitation, or order, or

(B) if the Administrator or State has commenced and is diligently prosecuting a civil action in a court of the United States or a State to require compliance with the standard, limitation, or order, but in any such action in a court of the United States any person may intervene as a matter of right.

(2) under subsection (a)(2) of this section prior to 60 days after the plaintiff has given notice of such action to the Administrator,

except that such action may be brought immediately after such notification in the case of an action under this section respecting a violation of section 7412 (i)(3)(A)or (f)(4) of this title or an order issued by the Administrator pursuant to section7413 (a) of this title. Notice under this subsection shall be given in such manner as the Administrator shall prescribe by regulation.

(c) Venue; intervention by Administrator; service of complaint; consent judgment

(1) Any action respecting a violation by a stationary source of an emission standard or limitation or an order respecting such standard or limitation may be brought only in the judicial district in which such source is located.

(2) In any action under this section, the Administrator, if not a party, may intervene as a matter of right at any time in the proceeding. A judgment in an action under this section to which the United States is not a party shall not, however, have any binding effect upon the United States.

(3) Whenever any action is brought under this section the plaintiff shall serve a copy of the complaint on the Attorney General of the United States and on the Administrator. No consent judgment shall be entered in an action brought under this section in which the United States is not a party prior to 45 days following the receipt of a copy of the proposed consent judgment by the Attorney General and the Administrator during which time the Government may submit its comments on the proposed consent judgment to the court and parties or may intervene as a matter of right.
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(d) Award of costs; security

The court, in issuing any final order in any action brought pursuant to subsection (a) of this section, may award costs of litigation (including reasonable attorney and expert witness fees) to any party, whenever the court determines such award is appropriate. The court may, if a temporary restraining order or preliminary injunction is sought, require the filing of a bond or equivalent security in accordance with the Federal Rules of Civil Procedure.

(e) Nonrestriction of other rights

Nothing in this section shall restrict any right which any person (or class of persons) may have under any statute or common law to seek enforcement of any emission standard or limitation or to seek any other relief (including relief against the Administrator or a State agency). Nothing in this section or in any other law of the United States shall be construed to prohibit, exclude, or restrict any State, local, or interstate authority from—

(1) bringing any enforcement action or obtaining any judicial remedy or sanction in any State or local court, or

(2) bringing any administrative enforcement action or obtaining any administrative remedy or sanction in any State or local administrative agency, department or instrumentality, against the United States, any department, agency, or instrumentality thereof, or any officer, agent, or employee thereof under State or local law respecting control and abatement of air pollution. For provisions requiring compliance by the United States, departments, agencies, instrumentalities, officers, agents, and employees in the same manner as nongovernmental entities, see section 7418 of this title.

(f) "Emission standard or limitation under this chapter" defined

For purposes of this section, the term "emission standard or limitation under this chapter" means—

(1) a schedule or timetable of compliance, emission limitation, standard of performance or emission standard,

(2) a control or prohibition respecting a motor vehicle fuel or fuel additive, or [1]

(3) any condition or requirement of a permit under part C of subchapter I of this chapter (relating to significant deterioration of air quality) or part D of subchapter I of this chapter (relating to nonattainment),,[2] section 7419 of this title (relating to primary nonferrous smelter orders), any condition or requirement under an applicable implementation plan relating to transportation control measures, air quality maintenance plans, vehicle inspection and maintenance programs or vapor recovery requirements, section 7545 (e) and (f) of this title (relating to fuels and fuel additives), section 7491 of this title (relating to visibility protection), any condition or requirement under subchapter VI of this chapter (relating to ozone protection), or any requirement under section 7411 or 7412 of this title (without regard to whether such requirement is expressed as an emission standard or otherwise); [3] or

(4) any other standard, limitation, or schedule established under any permit issued pursuant to subchapter V of this chapter or under any applicable State implementation plan approved by the Administrator, any permit term or condition, and any requirement to obtain a permit as a condition of operations[4] which is in effect under this chapter (including a requirement applicable by reason of section 7418 of this title) or under an applicable implementation plan.

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BAAQMD and CEC as its delegate. CARE intends to do so after the expiration of the 60 day waiting period.

V. SPECIFIC "AMENDED" PSD PERMIT COMMENTS

1. Pursuant to Regulation 2-2-306, a non-criteria pollutant PSD analysis is required for sulfuric acid mist emissions if the proposed facility will emit H_2SO_4 at rates in excess of 38 lb/day and 7 tons per year. According to the statement of basis RCEC has agreed to permit conditions limiting total facility H_2SO_4 emissions to 7 tons per year and requiring annual source testing to determine SO_2, SO_3, and H_2SO_4 emissions. If the total facility emissions ever exceed 7 tons per year, then the applicant must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions." The permit is silent on whether the project could emit 38 pounds per day therefore a PSD analysis of sulfuric acid mist must be considered.

2. Page 159 of the Statement of basis states that the California 1 hour Ambient air quality Standard for NO_2 is not violated by the project. This statement is false as the California ambient air quality standard for NO_2 is 338 $\mu g/m^3$ while the projects impact combined with background is 370 $\mu g/m^3$ as shown in table 6 on page 159. The California Air Resource Board has promulgated new standards and established that deleterious health effects occur when NO_2 concentrations exceed 338 $\mu g/m^3$.[24] The statement of basis on page 92 states the correct one

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(g) Penalty fund

(1) Penalties received under subsection (a) of this section shall be deposited in a special fund in the United States Treasury for licensing and other services. Amounts in such fund are authorized to be appropriated and shall remain available until expended, for use by the Administrator to finance air compliance and enforcement activities. The Administrator shall annually report to the Congress about the sums deposited into the fund, the sources thereof, and the actual and proposed uses thereof.

(2) Notwithstanding paragraph (1) the court in any action under this subsection to apply civil penalties shall have discretion to order that such civil penalties, in lieu of being deposited in the fund referred to in paragraph (1), be used in beneficial mitigation projects which are consistent with this chapter and enhance the public health or the environment. The court shall obtain the view of the Administrator in exercising such discretion and selecting any such projects. The amount of any such payment in any such action shall not exceed $100,000.

[24] See http://www.arb.ca.gov/research/aaqs/no2-rs/no2-doc.htm

hour NO_2 California standard.   Page 92 also states that the project does not violate the state 1 hour standard because the projects maximum impacts are 130 $\mu g/m^3$ and background is 130 $\mu g/m^3$. It is not clear in the permit which is the actual impact from NO_2 emissions.

3. Page 26 of the permit states, "A second potential environmental impact that may result from the use of SCR involves ammonia transportation and storage. The proposed facility will utilize aqueous ammonia in a 29.4% (by weight) solution for SCR ammonia injection, which will be transported to the facility and stored onsite in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. This risk will be addressed in a number of ways under safety regulations and sound industry safety codes and standards, including the implementation of a Risk Management Program to prevent and respond to accidental releases." The project if allowed to use SCR can eliminate the impact from transportation accidents by utilizing a technology called NO_xOUT ULTRA®.   There are   dozens of systems in service, one in Southern California at UC Irvine. The plant manager welcomes calls about the system (Jerry Nearhoof, 949 824 2781).   Most of the UC campuses have decided not to risk bringing ammonia tankers thru campus or having to offload or storing ammonia. NO_xOUT ULTRA is being specified for new units at UCSD, University of Texas and Harvard. For Aqueous systems you need a tank, a control module, pumps, carrier air, and a vaporizer. The vaporizer requires some heat input to allow the system to drive off or vaporize the water. The resultant ammonia gas and carrier air is sent to an ammonia injection grid (AIG) which uniformly injects the ammonia in the flue gas just ahead of the SCR catalyst. In comparison, the NO_xOUT ULTRA system requires a tank for the urea. The urea is usually in a 50 to 32 % solution.   Urea, has no vapor pressure. Has no smell. If it spills the evaporated water will leave behind a pile of crystal salts. There are no hazards labeling or training required for the operator and absolutely no risk to adjacent facilities or neighbors. Like aqueous ammonia NO_xOUT ULTRA needs controls to manage the input from the power plant indicating how much reagent the SCR requires. Like aqueous ammonia the system requires an air blower and heater to heat the air. The heated air goes to a decomposition chamber instead of a vaporizer. In the decomposition chamber, the urea solution is added. The water in the urea solution is vaporized and the additional heat required will then decompose the urea to ammonia. The gas/carrier air is then swept to the AIG and to the SCR. If the urea is pump is stopped and air is left in service the

chamber is sweep clear of ammonia in less than 7 seconds. So in an emergency, there is very little if any ammonia exposure. Other than the 7 seconds between the chamber and the AIG, the only exposure is the harmless urea. There is a premium for urea solutions vs. aqueous ammonia and the capital cost for the process vs. an aqueous ammonia system is competitive. The cost for a decomposition chamber is higher than an ammonia vaporizer, but the cost of urea storage is less than an ammonia tank due to all the hazard considerations. Since the ammonia will be transported thru an Environmental Justice community all precautions should be taken since the community already has a high number of toxic and hazardous materials stored and transported through it. Attachment 1 contains a brochure on the NO_xOUT ULTRA system.

4. Page 26 of the permits BACT analysis states,

> The Air District also evaluated the potential for ammonia slip emissions to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. Moreover, the Air District has found that the formation of ammonium nitrate in the Bay Area air basin appears to be constrained by the amount of nitric acid in the atmosphere and not driven by the amount of ammonia in the atmosphere, a condition known as being “nitric limited”. Where an area is nitric acid limited, emissions of additional ammonia will not contribute to secondary particulate matter formation because there is not enough nitric acid for it to react with. Therefore, ammonia emissions from the SCR system are not expected to contribute significantly to the formation of secondary particulate matter. Any potential for secondary particulate matter formation is at most speculative, and would not provide a reason to eliminate SCR as a control alternative.

The District has based its conclusion that the project area is nitric limited on a BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel, “A First Look at NO_x/Ammonium Nitrate Tradeoffs, dated September 8, 1997. The District memorandum outlines two objectives. One, whether the Bay Area is ammonia limited, and two, to what extent reducing NOx emissions would reduce ammonium nitrate. Among the findings presented in this memorandum, the District staff believes that ". . . San Jose and Livermore are not ammonia limited' during wintertime high particulate matter conditions; rather, these two areas are nitric acid limited. Other findings stated in the memorandum include recognition that the District analyses do not provide solid "...footing to do planning or to provide guidelines to industry for such tradeoffs [between NO_x and ammonium nitrate]." Thus, the District memorandum is very specific to say that San Jose and Livermore, not the entire Bay Area air basin or the project location, are nitric acid limited, and that no guidelines have been formed to address the ammonia induced PM10/PM2.5 problem.

This project is located in the Hayward area of Alameda County, which is outside of the area where the District has made the determination; therefore, the Districts contention that the increase in ammonia emissions from this facility would not cause any increase in PM10/PM2.5 emission impacts is not supported by the District memorandum. The District needs a site specific study to make such broad conclusions and an analysis needs to be conducted not only to evaluate the use of SCR but also to asses environmental impacts of secondary particulate and its effect on the deterioration of air quality in the BAAQMD. The projects PM 2.5 impacts may be much larger than modeled and should be subject to additional analysis.

The District needs to conduct a BACT analysis on the ammonia emission slip limit. Several Projects including the ANP Blackstone Project have 2 ppm ammonia slip limits which are designed to prevent additional particulate matter formation and limit the transportation of ammonia though the surrounding communities.

5. The statement of basis concludes that a CO limit of 4 ppm over 3 hours is BACT. (Page 32) That conclusion was determined from analyzing emissions data from the Metcalf Energy Center. The Metcalf energy center does not utilize an oxidation catalyst for CO emissions so to base the permit decision on a project that contains no CO abatement device when the proposed Russell City Project will have an oxidation catalyst is an inappropriate comparison. Several Projects have achieved a lower CO emissions rate in conjunction with a 2ppm NO_x limit. One is the Salt River Project in Arizona which meets a 2ppm NO_x limit and a 2ppm CO limit that has been verified by source testing. The Las Vegas Cogeneration facility has a 2ppm NOx limit and a 2ppm CO limit.[25] Based on available information the district should choose a 2ppm CO limit for this project to comply with BACT. [26]

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[25] See http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=25662&procnum=102130
[26] See http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=26002&Procnum=103714

6. The district reports on page 41 of the permit that the Palomar Project has reduced NO_x start up emissions by introducing ammonia earlier in the start up cycle and using the OP-Flex system. “By taking these steps, the facility was able to optimize its operating procedures and bring down its startup emissions. The facility has reported encouraging results from the first few months of operating with these new techniques.” The district then eliminates the technology because only one quarterly report from the quarterly variance reports to the SDPCD is available on the success of the new technology. “It is not possible, however, to determine based on this limited data what reductions, if any, are attributable to OpFlex and what reductions are attributable to the operational changes the facility was able to make for its specific turbines. Moreover, the facility has operated only for a relatively limited period of time with these enhancements, and so it is difficult to determine from the limited data available so far what improvements can reliably be achieved throughout the life of the facility. Included as <u>attachment 2</u> to these comments are three more Hearing Board Variance 4073; Quarterly Reports” that were acquired through a public records request. By utilizing earlier ammonia injection and utilizing the OP flex system the Russell City Power Projects start up emissions can be reduced drastically. Its must be required as BACT since it has been proved in operation for over a year and it will reduce the projects potential to violate the new California NO_2 standard and eliminate the deficient daily emission reduction credits needed for the facility as explained below.

7. Table B-12 on page 147 of the statement of basis lists the maximum daily NO_2 emissions of 1,553 pounds per day. The permit proposes to only offset 134.6 tons of NO_2 per year or 737.54 pounds per day. The ERC’s will not provide adequate mitigation for the potential 1533 pounds per day of NO_2 emitted by the project. The surrendered ERC’s only mitigate 49% of the projects daily NO_2 emission due to the excessive start up and shut down emissions. This could leave as much as 49% of the projects daily NO_2 emissions unmitigated. On days when violations of ozone standards occur the projects emissions would contribute to violations of the standard.

8. The ERC’s listed for the Russell City Energy Center have already been pledged to another Calpine Project in the BAAQMD. Certificate Number 687 for 43.8 tons of POC has

already been pledged to offset emission increases for the East Altamont Energy Center. Certificate Number 602 for 41 tons of POC was also allocated to the East Altamont Energy Center. Since these ERC's were subject to extensive scrutiny by the CEC, the SJVUAPCD and the public this transfer of ERC's should be subject to public notice and comment.

9. The BAAQMD now requires a fee for greenhouse gas emissions.[27] The license should acknowledge the green house gas fees to be paid to the BAAQMD. Greenhouse gas emissions are evaluated based on the natural gas consumption of the project. The ammonia slip will also contribute to greenhouse gas emissions from the project and should be included in the evaluation. The District should do a true BACT analysis on greenhouse gases and not just adopt the maximum allowable greenhouse gas emission per megawatt as specified by the State.

10. **Environmental Justice**[LB] ---The District state on page 65 of the statement of basis "Another important consideration that the Air District evaluated is environmental justice. The Air District is committed to implementing its permit programs in a manner that is fair and equitable to all Bay Area residents regardless of age, culture, ethnicity, gender, race, socioeconomic status, or geographic location in order to protect against the health effects of air pollution. The Air District has worked to fulfill this commitment in the current permitting action." Other than issue the public notice in Spanish on its website for comments on this permit the district has done nothing different from any other permitting actions to evaluate the specific environmental justice impacts of this project on the minority community. The District believes by conducting a health risk assessment which it does for every project or modeling criteria pollutant impacts the district believes that its met its environmental justice obligation in the permitting process. The District reasoning is that since the modeling they performed meets their requirements for the general population the minority community can't possibly be harmed by the projects emissions. The very purpose of the environmental justice evaluation is to identify the minority population's health vulnerabilities and existing pollution and hazardous materials sources and identify how the project affects the minority community not the general population. The District evaluation falls short of even the basic environmental justice analysis.

Poor health and premature death are by no means randomly distributed in Alameda County. Low-income communities and communities of color suffer from substantially worse health outcomes and die earlier. Many studies note that these differences are not adequately explained by genetics, access to health care or risk behaviors but instead are to a large extent the result of adverse environmental conditions. The Russell City Power Project is sited in a geographic area already disproportionately burdened by illness and death. The presence of a disproportionate concentration of persons with asthma, chronic lung disease, congestive heart failure and other chronic conditions that are exacerbated by air pollution must factor into the decision of where to site this power plant. Especially because these populations affected by the power plant are predominately low-income communities of color. The minorities are not distributed throughout the population randomly but instead are concentrated disproportionately in proximity to the proposed Hayward site.

As noted in the CEC staff report, Hayward is more ethnically diverse, with a significantly larger, non-white population than Alameda County. In the two zip codes near the site 94544 and 94545 residents have a high mortality rate and on average they live five years less than the county- wide expectancy rate. Death rates from air pollution-associated diseases such as coronary heart disease, chronic lower respiratory disease, are substantially and statistically significantly higher than those for the County, representing an ongoing, excess burden of mortality. The rate of death from chronic lower respiratory diseases was 43 percent higher and the rate from coronary heart disease was 16 percent higher than the County rate. Hospitalizations due to air pollution- associated diseases are substantially higher in the zip codes close to the proposed site. From 2003 to 2005 the hospitalization rates for coronary heart disease, chronic obstructive pulmonary disease, congestive heart failure and asthma in the two zip codes nearest the proposed site, 94544 and 94545, was statistically significantly higher than Alameda County rates. Which means hospitalizations due to air pollution will not occur by chance. Specifically, hospitalization rates due to coronary heart disease was 60 percent higher; chronic obstructive pulmonary disease, 20 percent higher; congestive heart failure, 35 percent higher; and asthma

Continued from the previous page
[27] See http://www.baaqmd.gov/pln/climatechange.htm#GHGFee

hospitalization rates 14 percent higher than the County rate. A disproportionate burden of the cost of these preventable hospitalizations, particularly among the uninsured, is borne by Alameda County taxpayers. The fact that rates of these illnesses are significantly higher in the proposed plant area than in the rest of the County suggests a level of vulnerability in this population that is higher than the rest of the County. A proper Environmental Justice process begins with the demographic screening analysis which the CEC staff has performed and concluded that the majority of the community surrounding the RCEC is indeed minority. There is no dispute on that fact. At that point in the analysis the public participation process should have been used to define and evaluate environmental justice concerns. Community leaders and community stakeholders should have been consulted to identify their concerns. The District should have consulted with the county health agencies to identify existing health concerns. Then the District should have examined the synergistic effects of existing pollution that already exists in the community. In this community there are multiple environmental stresses. There is a railroad which passes though the area, there are truck terminals and other heavy industries and a sewage treatment plant in the affected community. The District has not identified and examined the existing local sources of criteria pollutants and toxic emissions and evaluated their impacts in conjunction with the emissions from the RCEC.

Environmental Justice Guideline's emphasize the importance of reaching out to the community and involving them in the development of the mitigation measures and alternatives. A good example of how this process is done is the community outreach that was performed by the CCSF in the SFERP proceeding. In that proceeding over 20 community meetings were held and the community was engaged in deciding appropriate mitigation measures and alternatives. Public advocacy groups were consulted and included in the decision making. Air Quality Monitoring stations were set up in the community to examine existing air quality in the affected community.[28]

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[28] See http://www.energy.ca.qov/sitin~cases/sanfrancisco/documents/applicant/data response 1Al2004-07-08 DATA RESPONSE-PDF

The environmental justice argument against the RCEC is made even stronger by the fact that the risk assessment model may underestimate the health risk of substances that interact synergistically, as pointed out in the risk assessment guidelines. The potential for multiple and varied air and non-airborne pollutants to act synergistically, rather than additively as assumed by the risk assessment model, requires an analysis of the overall toxic burden associated with this Hayward location. Low-income, minority populations have historically been exposed to a much higher burden of environmental toxicity. The District's Environmental Justice Analysis does not accept the existing ordinate disease nor does it adequately measure the health risks associated with potential, synergistic interactions among the substances, profoundly important aspects of environmental justice.

Siting the Russell City Power plant in Hayward will disproportionately impact the geographic area, home to a comparatively high, non-white population that is already burdened by existing morbidity and mortality from disease associated with air pollution or other existing environmental factors. It is that burden that must be analyzed to truly determine if the minority population near the proposed power plant will be affected. The district is required to address environmental justice issues in the PSD process.[29] The 1998 EPA guidelines require Agencies to consider a wide range of demographic, geographic, economic, human health and risk factors. One of the three most important factors identified in the 1998 EPA guidelines is “whether communities currently suffer or have historically suffered from environmental health risks and hazards.” The 1998 EPA Guidelines require the agencies conducting an Environmental Justice Analysis to define the sensitive receptor analysis to the actual unique circumstances affecting the minority community not a generic definition of sensitive receptor that was utilized by the District and the CEC.

VI. COMMENTS AND REQUESTS FOR CLARIFICATION ON THE "AMENDED" PSD PERMIT STATEMENT OF BASIS

The Russell City Energy Center, described in detail in subsequent sections of this document, is a proposed 600 megawatt natural gas fired combined-cycle power plant, proposed to be built near the corner of Depot Road and Cabot Boulevard, in Hayward, CA. *SOB at page 3*

1 Is this the correct location or would the end of Depot road or the “southeastern shore of the San Francisco bay in the City of Hayward” be more accurate?

2. Could the site descriptions in question 1 affect public interest or informed participation?

The Energy Commission’s licensing decision is appeal able directly to the California Supreme Court. *SOB at 6*

3. Does the Energy Commission have other administrative appeal venues?

4. Could disclosure of other Energy Commission appeal venues affect public interest or informed participation?

The Air District Authority to Construct is appealable to the District’s Hearing Board and subsequently to the Superior Court of California. Federal PSD Permits are initially appealable the EPA’s Environmental Appeals Board in Washington, D.C., and subsequently to federal court. *SOB at 6*

5. Could someone appeal directly to Federal court or must they appeal to the EAB first?

6 Could disclosure of other appeal venues affect public interest or informed participation?

The proposed Russell City facility was initially licensed in 2002, but it was relocated and so its permits had to be updated. *SOB at 6*

7. Why was it relocated?

8. Could the reason for relocation affect public interest or informed participation?

The amended authority to construct (ATC) and the amended Federal PSD Permit were issued jointly in the same document, in accordance with the Air District’s administrative practice. *SOB at 6*

9. Is the PSD permit a component of the ATC or is the authority to construct valid without a PSD permit?

Continued from the previous page

[29] See http://www.epa.gov/compliance/resources/policies/ej/ej_permitting_authorities_memo_120100.pdf

The Air District's ministerial Authority to Construct permit is appealable only on the narrow issue of whether the Air District correctly incorporated the Energy Commission's conditions of certification in the Authority To Construct. That is, an error in transcribing a permit condition from the Energy Commission's license into the Authority to Construct is appealable, but an appeal cannot seek to revisit substantive issues of what permit conditions are appropriate and required, which are addressed during the CEC licensing process and on any appeals there from. *SOB footnote 2 at 6*

10. Did the District comply with CEC AQ-SC10?

11. Could the district be compelled to comply with this condition of the CEC decision?

12. Could this information affect public interest or informed participation?

AQ-SC10 In lieu of complying with AQ-SC7, AQ-SC8, and AQ-SC9, the project's combustion turbine/HRSG units shall be designed and built with equipment and control systems to minimize start-up times and emissions. These could include the Fast-Start technology with an integrated control system and a once-through Benson boiler design, appropriate system configuration and equipment to facilitate operating chemistry during starting sequences, and an auxiliary boiler. *CEC final Decision.*

All appeal avenues have therefore been exhausted, and the state-law Energy Commission license and District Authority to Construct are not subject to further review. *SOB at 7*

13. Is this statement correct?

14. Does the Authority to Construct comply with all current laws?

15. Is the Authority to Construct a document that has been published by the District?

16. Where can the public locate the Authority to Construct?

17. Please provide a copy of the Authority to Construct.

18. Could availability of the Authority to Construct affect public interest or informed participation?

The Environmental Appeals Board ruled that the Air District had not mailed notice of the proposed amended Federal PSD Permit to several parties that were entitled to it, and so it remanded the permit to the District to re-notice the proposed permit and provide the public with a further opportunity to comment. *SOB at 7*

19. Is this what the EAB remand stated?

20. Could further disclosure of details of the Remand affect public interest or informed participation?

The analysis of elements that are not being amended shows that the conditions from the initial permit that are not being changed meet current applicable legal standards for Federal PSD Permits, and that they would comply with current PSD requirements even if they were being proposed anew at this time. *SOB at 7*

21. What aspects of the PSD permit are in conflict with state law; which state law?

The Air District is not reopening the state-law permitting process that was completed under the Warren-Alquist Act (culminating with the Energy Commission's license for the project and the District's incorporation of the Energy Commission's licensing conditions into the Authority to Construct permit). Those permitting actions under state law are final and all avenues for appeal have been exhausted. The Environmental Appeals Board's remand of the Federal PSD Permit to be re-noticed does not implicate these state-law permits. They are separate legal entities and the Environmental Appeals Board has not questioned their continued validity. *SOB at 7*

22. Is this a correct statement?

23. What if prior permitting actions do not comply with present laws?

The District invites all interested parties to comment on the Draft Amended PSD Permit. The legal requirements for PSD Permits are contained in Section 52.21 of Title 40 of the Code of Federal Regulations (40 C.F.R. Section 52.21). Comments should address only the Federal PSD issues in this proceeding. The District is not considering any issues related to the state-law Authority to Construct permit or the California Energy Commission's license for the project, or any other non-PSD issues. *SOB at 7*

24. If this is the Statement of Basis for the Federal action and the District has raised issues in the statement, are all issues raised by the district part of the basis for this permit and thereby subject to comment by the public or is this merely a venue for the district to create a record without allowing public participation; i.e., is this an ad-hoc rationalization for an action the District has already taken?

25. Could this restriction of public participation affect public interest or informed participation?

The Russell City Energy Center is a proposed 600 megawatt ("MW") natural gas fired combined cycle power plant proposed to be built by Russell City Energy Company, LLC, which is owned 65% by a subsidiary of Calpine Corporation and 35% by General Electric Corporation. *SOB at 9*

26. Why was General Electric ownership not disclosed on the Public notice?

27. Could this information affect public interest or informed participation?

The proposed facility would be located at 3862 Depot Road, near the corner of Depot Road and Cabot Boulevard, in Hayward, CA. *SOB at 9*

28. Why was the address changed?

29. What is the Address identified in the Authority to Construct?

The facility was originally permitted in 2002, but was subsequently relocated approximately 1,500 feet north of the original site and required the facility's permits to be amended. *SOB at 9*

30. Exactly How far is the new site from the old site?

31. Could this information affect public interest or informed participation?

The Russell City Energy Center will consist of the following permitted equipment: S-1 Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst. *SOB at 10*

S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst. *SOB at 10*

S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst. *SOB at 10*

S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst. *SOB at 10*

S-5 Cooling Tower, 9-Cell, 141,352 gallons per minute. *SOB at 10*

S-6 Fire Pump Diesel Engine, Clarke JW6H-UF40, 300 hp, 2.02 MMBtu/hr rated heat input. *SOB at 10*

32. Please answer the following equipment questions.

Turbine Questions

a. What are the identifying or serial numbers of the proposed turbines?

b. What year were they manufactured?

c. What year did Calpine acquire them?

d. How much did Calpine pay for the turbines?

e. Has Calpine sold any similar turbines in the last 3 years? If so for how much?

f. Are the turbines used?

g. If so, Have they been refurbished?

h. Where were they originally in service?

I. Provide emission records from their use.

J. Were emission reduction credits earned when the turbines were retired?

K. Please identify more efficient turbines or alternative configurations that would result in higher efficiency or reduced emissions.

33. Calpine's attorney represented the steam turbine may be removed from a partially built plant in another state. Please answer the above "turbine questions" for this equipment.

34. Is other equipment planned to be used that has been in use in other locations? If so please answer "turbine questions" for this equipment.

35. Does Calpine have any facilities planned or in operation that are more efficient or emit comparably fewer emissions than this facility?

36. Does Calpine's partner GE manufacture any more efficient or cleaner operating equipment than that which is proposed?

37. What is the estimated CO_2 output for this facility?

38 What would the CO_2 output be from the most efficient equipment available?

39. Could the answers to questions 30-36 affect public interest or informed participation?

Load Following: Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario. *SOB at 11*

40. Does this mean that the facility can operate as a "peaker" ?

41. Could this affect the emission calculations?

EPA recently promulgated new amendments to the PSD regulations addressing PM2.5, and these amendments expressly incorporated the earlier guidance and made clear that for permit applications such as this one that were submitted and complete before July 15, 2008, permitting agencies should use the PM10 surrogate approach from the 1997 guidance. *SOB at 17 to 18*

38. When was this one submitted for public comment?

39. Is the permit subject to 40 CFR 51.166 (2) Within one year after receipt of a complete application, the reviewing authority shall (vii) Make a final determination whether construction should be approved, approved with conditions, or Disapproved?

40. What would be the effect of District compliance with 40 CFR 51.166?

See 73 Fed. Reg. 28231, 28349-50 (May 16, 2008) (to be codified at 40 C.F.R. § 52.21(i)(1)(xi)). The Air District expects shortly to be classified as "attainment" or "non-attainment" of the new PM2.5 standard by EPA. If the District is classified as "non-attainment", PM2.5 will be regulated under the District's NSR permitting program and will no longer be subject to PSD permit requirements. Permit applications such as this one that were received under the existing designation will continue to be processed under the PSD program using the surrogate approach as directed by EPA, however; *SOB footnote 7 at 18*

41. Has the District already been classified?

42. Would classification information, if already known, potentially affect public interest or informed participation?

U.S EPA lowered the 24-hour PM2.5 standard from 65 $\mu g/m^3$ to 35 m^3in 2006. EPA issued attainment status designations for the 35 m^3standard on December 22, 2008. EPA has designated the Bay Area as nonattainment for the 35 m^3 PM2.5 standard. The EPA order will be effective in April 2009, 90 days after publication of the EPA findings in the Federal Register [30]

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[30] See http://www.baaqmd.gov/pln/air_quality/ambient_air_quality.htm

43. Has the District already been classified?

44. Would classification information, if already known, potentially affect public interest or informed participation?

45. How would this process be different if the District processed this permit consistent with the new attainment status and without the surrogate approach?

Emissions rates in Table 8 are based on the emissions rates set forth in Section IV.A. above with one exception, sulfuric acid mist (H_2SO_4). Emissions of sulfuric acid mist are expected to be less than the PSD significance threshold of 7 tons per year, and the Air District is proposing an enforceable permit condition (Number 25) limiting sulfuric acid mist from the new combustion units to a level below the PSD trigger level. Compliance will be determined by use of emission factors (using fuel gas rate and sulfur content as input parameters) derived from annual compliance source tests. The annual source test will be conducted, as indicated in Condition number 34, to measure SO_2, SO_3, H_2SO_4 and ammonium sulfates. This approach is necessary because the conversion in turbines of fuel sulfur to SO_3, and then to H_2SO_4 is not well established. With this permit condition, sulfuric acid mist emissions will be less than the PSD significance threshold of 7 tons per year and the facility will not be subject to Federal PSD Permit requirements for sulfuric acid mist. *SOB footnote 9 at 18*

46. What is the Basis for “conversion” to be “not well established”?

47. What would it take to establish?

48. What Guarantee, that the emissions will not exceed the threshold limits for the other 364 day per year, exists?

49. What guarantee is there that the operator will not retest in the absence of oversight until compliance is demonstrated?

50. Can the district pre-establish an annual test dates to prevent test manipulation by retesting?

EPA has provided further guidance on how to implement this definition of “Best Available Control Technology” in its 1990 Draft New Source Review Workshop Manual (“NSR Workshop Manual”). EPA requires that the District implement the Best Available Control Technology requirement by conducting what EPA calls a “Top-Down BACT Analysis”. As described in EPA’s NSR Workshop Manual, a “Top-Down BACT Analysis” consists of five key steps... *SOB at 20*

51. It would appear that the District relied on the 1990 document for compliance how would reliance on present standards affect the permitting decision?

The majority of EPA's clarifications were proposed through a new definition of actual emissions at 40 CFR Subpart 51.166(f) and 40 CFR Subpart 52.21(f). Rather than revising the existing definition of actual emission (40 CFR 51.166(b)(21) and 52.21(b)(21)), which may continue to be used for other purposes under the PSD program, EPA's proposed new definition will only apply for determining increment consumption and providing exclusions to methods for determining increment analysis. Specifically, the proposed rule provides clarifications in the following eight areas.

> 1) Draft 1990 New Source Review Workshop Manual
> EPA clarifies that, while some of the views expressed in the draft NSR Manual may have been promulgated in other EPA regulations, the draft NSR Manual is not a binding regulation and does not by itself establish final EPA policy or authoritative interpretations of EPA regulations under the NSR program. In addition, EPA proposes to establish regulations that supersede many of the recommended approaches for conducting the increments analysis set forth in the draft NSR Manual and other EPA guidance documents.[31]
>
> The EPA's Environmental Appeals Board (``Board'') has sometimes referenced the draft NSR Manual as a reflection of our thinking on certain PSD issues, but the Board has been clear that the draft NSR Manual is not a binding Agency regulation. See, *In re: Indeck-Elwood, LLC, PSD Permit Appeal No. 03-04*, slip. op. at 10 n. 13 (EAB Sept. 27, 2006); *In re: Prairie State Generating Company, PSD Permit Appeal No. 05-05*, slip. op. at 7 n. 7 (EAB Aug 24, 2006). In these and other cases, the Board also considered briefs filed on behalf of the Office of Air and Radiation that provided more current information on the thinking of the EPA headquarters program office on specific PSD issues.[32]

NOx emissions as an ozone precursor are regulated under California law through the Energy Commission Licensing process and subsequent Air District Authority to Construct permit (discussed in more detail in Section II.A above). NO_2 is regulated under the Federal PSD program for sources in the Bay Area. *SOB footnote 11 at 21*

52. Does the intended permit comply with California's present NO_2 standard or does the District have authority to issue a permit that does not comply with California Law?

Kawasaki Heavy Industries purchased the XONON™ catalytic combustion technology from Catalytica Energy Systems in 2006. Kawasaki plans to use the XONON™ on its own turbines, but it is not known if Kawasaki will make the combustors available to other turbine manufacturers. *SOB at 24*

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[31] See http://trinityconsultants.com/air.asp?cp=133
[32] See http://www.epa.gov/EPA-AIR/2007/June/Day-06/a10459.htm

53. What is the basis for this information being "not known" and what would it take for the district to know?

The annualized SCR cost figures are based on a cost analysis conducted by ONSITE SYCOM Energy Corporation, updated and adjusted for inflation by the District. These total 1999 annualized cost for SCR was adjusted for inflation by the District using the Consumer Price Index (2008 value = 1999 value x 1.32). Emerachem provided the updated cost information for the EMx. *SOB footnote 19 at 26*

54. Does the District have some basis that the consumer price index is a valid method of guesstimating today's costs for SCR?

55 What would be a better method?

The CEC has modeled the health impacts arising from a catastrophic ammonia release and has found that the impacts would not be significant.[33] *SOB at 20*

56. Is it appropriate to use vintage data for present permitting or should the district consider potential impacts with contemporary data?

BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel, "A First Look at NOx/Ammonium Nitrate Tradeoffs, dated September 8, 1997.
SOB footnote 21at 27

57. Has the District or any others taken a second look since this 1997 Memorandum?

See Metcalf Energy Monthly BAAQMD CEM Reports, from 5/1/2005 to 1/31/2008. The Air District focused on data from days without startup or shutdown activity. When the turbines/heat recovery boilers are starting up or shutting down, Carbon Monoxide emissions are much higher than during steady-state operations as discussed in more detail in subsequent sections. By

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[33] California Energy Commission (CEC), 2002a. Final Staff Assessment (FSA) and Addendum, published on June 2002. BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel, "A First Look at NOx/Ammonium Nitrate Tradeoffs, dated September 8, 1997.

See "Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000.

looking only at data from days without startups or shutdowns, the Air District has ensured that the limit it adopts will be appropriate for steady-state operating conditions.
SOB footnote 25 at 32

58. Will the Limit be appropriate for days with start up?

59. How often can the facility start up under this permit?

60. Has the impact of startup during shoreline fumigation time periods been disclosed?

61. Is it appropriate to use vintage data for present permitting or should the district consider potential impacts with contemporary data?

GE has declined to give emissions performance guarantees for start-up operations using the OpFlex™ software, explaining that startup emissions, by nature, are highly variable and dependent on specific plant equipment and configuration. (Telephone conversations with Bob Bellis and Derrick Owen, GE Energy on November 21, 2008.)
SOB footnote 37 at 41

62. Would a higher level of diligence or verification be appropriate than “telephone conversations” be appropriate for the district to make its determinations?

For all of these reasons, the Air District has eliminated the once-through boiler alternative as an appropriate BACT technology for startup emissions for a facility such as Russell City. The Air District has concluded that the adverse impacts of requiring a single-pressure steam turbine design outweigh the additional startup benefits that can be achieved. The Air District will continue to monitor the development of once-through boiler technologies, in particular the Siemens Flex Plant 30 design using a triple-pressure steam boiler. Such future developments could change the analysis regarding the tradeoffs between overall energy efficiency and startup performance. *SOB at 44*

63. Is this monitoring for potential modification of this permit or future permits?

The relocation and apparent redesign of the 29 percent aqueous ammonia tank and the ammonia facility as a whole will result in changes in impacts to off-site receptors in the event of an accidental spill of ammonia. The project owner prepared a new Off-Site Consequence Analysis (OCA) to evaluate the potential impacts of an ammonia spill with the new configuration. Staff reviewed the results of the OCA and found that the modeling was not consistent with previous modeling using the model SLAB. Staff cannot explain the discrepancies in the OCA modeling and thus conducted its own independent modeling using the U.S. EPA’s SCREEN3 model. The results of this model show significant impacts off-site if an accidental release were to occur and fill the secondary containment area of 1,463 square feet with aqueous ammonia.[34]

64. It appears that the referenced CEC staff report states more then the SOB contemplates. Is the Screen 3 model the appropriate model for this analysis?

65. Did the District review the CEC modeling or rely purely on the staff report?

HAZ-2: The project owner shall provide a Risk Management Plan (RMP) and a Hazardous Materials Business Plan (HMBP), (that shall include the proposed building chemical inventory as per the UFC) to the City of Hayward Fire Department and the CPM for review at the time the RMP plan is first submitted to the U.S. Environmental Protection Agency (EPA). The project owner shall include all recommendations of the City of Hayward Fire Department and the CPM in the final documents. A copy of the final plans, including all comments, shall be provided to the City of Hayward and the CPM once EPA approves the RMP. [35]

66. Did the applicant complete the prerequisite of HAZ-2?

67. Shouldn't the determination of the significance of catastrophic ammonia release be completed by the district after review of the Risk Management plan?

The project was originally permitted in 2002, before Fast Start technology was developed, and the applicant purchased its equipment at that time based on the initial permits. Retrofitting that equipment now to incorporate Fast Start technology would require a complete redesign of the project and the purchase of new equipment. Furthermore, Siemens stated that emissions performance cannot be guaranteed unless the company supplies a fully integrated power plant with Fast Start technology (i.e. Flex Plant 10). (Telephone conference on November 6, 2008 with Candido Veiga, Siemens Pacific Northwest Region Vice President and Benjamin Beaver, Siemens Pacific Northwest Sales Manager.) It therefore appears that the facility would have to dispose of the equipment it has already purchased for the project and buy an entirely new integrated system. *SOB at 26*

68. How would the BACT determinations be different if Calpine did not claim to have the Equipment in stock?

69. Does Calpine or GE have Equipment available that would be cleaner?

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[34] See July 2007 CEC Final Staff Assessment (FSA) at 4.4- 2. See http://www.energy.ca.gov/2007publications/CEC-700-2007-005/CEC-700-2007-005-FSA.PDF

[35] See July 2007 CEC Final Staff Assessment (FSA) at 4.4- 6.

The facility has reported encouraging results from the first few months of operating with these new techniques.[] It is not possible, however, to determine based on this limited data what reductions, if any, are attributable to OpFlex and what reductions are attributable to the operational changes the facility was able to make for its specific turbines. Moreover, the facility has operated only for a relatively limited period of time with these enhancements, and so it is difficult to determine from the limited data available so far what improvements can reliably be achieved throughout the life of the facility. For all of these reasons, the Palomar data does not sufficiently demonstrate that there are specific, achievable emissions reductions to be gained simply from using the OpFlex technology itself. Further data will be needed to understand whether some or all of Palomar's proprietary approach for reducing emissions from its equipment can be adapted to other facilities.[36] *SOB at 41*

70. It would appear that the District has had an additional year and a half to obtain "encouraging results" from the Palomar facility. Why didn't the District update this info?

71. Could further "encouraging results affect the districts determination or public interest and informed public participation?

See Ambient Air Quality Impact Report, Colusa Generating Station, Clean Air Act PSD Permit No. SAC 06-01, EPA Region 9, May 2008. The record from that permitting action shows that EPA Region 9 considered OpFlex and the Palomar facility in response to a comment on the startup BACT issue. That comment was subsequently withdrawn and so EPA never responded to it formally on the record. But the fact that the agency determined that BACT does not require OpFlex is evident from the fact that the permit does not require it. *SOB footnote 41 at 42*

72. Please consider the referenced comments on Colusa as if incorporated here as comments for this permit and respond appropriately?

Data for the Flex Plant 10 comparison come from a permit application the Air District has received for a facility proposing to use a Flex Plant 10 design, District Application #18542. The proposed Flex Plant 10 facility will have a heat input capacity of 1857 MMBtu/hr. The District adjusted the proposed Russell City project's emissions numbers proportionally to the capacity difference between the two facilities to achieve an "apples-to-apples" comparison. Calculations assume ISO standard conditions and 59°F. Data for Russell City assume no supplemental duct burner firing, because the proposed Flex Plant 10 does not use duct burners.
SOB footnote 42 at 43

[36] Letter written by Daniel S. Baerman, Director of Electric Generation, San Diego Gas and Electric, regarding "Hearing Board Variance 4073; Quarterly Report". Submitted to Catherine Santos, Clerk of the Hearing Board for the San Diego County Air Pollution Control District, dated April 11, 2007 SOB at 41

73. Does this mean that the permit application #18542 is not using BACT; why?

California Energy Commission Decision for the Russell City Energy Center AFC, Alameda County (Sept. 11, 2002), at p. 67. *SOB footnote 65 at 62*

This determination was made based on a comparison of three individual models of combined-cycle combustion turbines using data from Gas Turbine World, an independent technical magazine that covers the gas turbine industry. See Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-4. The turbines evaluated had nominal energy efficiencies of between 55.8% and 56.5%. During review of the September 2007 amendment to that decision, CEC staff "testified that the proposed changes would not change any of the findings or conclusions in the 2002 Decision." Presiding Member's Proposed Decision, Russell City Energy Center, Amendment No. 1 (01-AFC-7C), Alameda County, August 23, 2007 (CEC-800-2007-003-PMPD), at 57. *SOB footnote 66 at 62*

See Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-4. *SOB footnote 67 at 62*

74. Again is it appropriate to use this vintage data for present permitting or should the district consider potential impacts with contemporary data?

[T]he state-law permitting process is not being reopened at this time. *SOB at 65*

75. Why is the District not opening the State-law process?

76. What would the effect on permitting be if the District did open the state law process?

77. In what ways would the existing state-law process not conform to present regulatory requirements, today's emission standards, etc?

78. If this permit is found to contribute to a violation of state law, does the District have authority to issue this permit? Please cite specific statutory authority.

[T]he increased carcinogenic risk attributed to this project is less than 1.0 in one million, and the chronic hazard index and acute hazard index attributed to the emission of non-carcinogenic air contaminants are each less than 1.0. These risk levels are less than significant for project permitting purposes. The Air District reiterates these results here because they have informed the Air District's conclusions that the control technologies chosen to comply with the Federal PSD Permit requirements will not have any significant adverse ancillary environmental impacts. Please see Appendix B for further information on the Health Risk Assessment *SOB at 65*

79. Is the modeling used for the Health risk assessment the same as it should be for the PSD permit?

The Air District has concluded that there are no significant impacts due to air emissions related to the Russell City Energy Center after all of the mitigations required by Federal and District Regulations and the California Energy Commission are implemented. There is no adverse impact on any community due to air emissions from the Russell City Energy Center and therefore there is no disparate adverse impact on an Environmental Justice community located near the facility. *SOB at 66*

80. Is there an Environmental Justice Community near the facility?

81. If so what languages are spoken in the community?

82. What languages did the district issue documents in?

83. What specific outreach did the District make in this community?

84.. Has anyone from the District visited this community?

85. What mitigations directly benefit this community or are not merely regional in nature?

86. Has anyone from the District visited the site?

To help the reader understand which requirements are part of the proposed amended Federal PSD Permit and which are based solely on state law requirements, the state-law requirements are presented in “strike-through” format below. *SOB at 67*

87. Please help the public understand which requirements are based State and Federal law and which requirements represent change of the existing state law requirements?

Within 180 days of the issuance of the Authority to Construct for the RCEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by conditions 29, 30, 32, 34, and 43. The owner/operator shall conduct all source testing and monitoring in accordance with the District approved procedures. (Regulation 1-501)
SOB at 77

88. Has the applicant performed on the above condition or any condition of the Authority to Construct?

The proposed Russell City Energy Center Power Plant will emit the toxic air contaminants summarized in Table 6, "Maximum Facility Toxic Air Contaminant (TAC) Emissions". In accordance with the requirements of CEQA, BAAQMD Regulation 2-5, and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing the air pollutant dispersion model ISCST3 and the multi-pathway cancer risk and hazard index model ACE. *SOB at 82*

89. Are District actions for other facility's PSD permits subject to CEQA?

Based upon the results given in Table B-1, the Russell City Energy Center project is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy. *SOB at 83*

90. When was the health Risk assessment completed and by whom and should it be updated? If not, why not?

SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR THE RUSSELL CITY ENERGY CENTER December 8, 2008
SOB at 85

91. There appear to be differences between the Air Quality Impact analysis completed for the State permit and the one completed for the Federal permit. Please identify the differences?

92. Which (if any) document is correct and valid for state and federal permitting? When was the new modeling completed and by whom?

The EPA guideline models AERMOD (version 07026) and SCREEN3 (version 96043) were used in the air quality impacts analysis. Because an Auer land use analysis showed that the area within 3 km is classified as rural, the AERMOD option of increased surface heating due to the urban heat island was not selected. *SOB at 87*

93. The area to the East of the site is clearly highly developed, how would consideration of this fact affect the modeling results?

94. Table 2 of the newer air quality impact analysis is mostly blank. Please complete table 2.

95. Would complete information from table 2 be of interest to the public or promote informed participation?

Meteorological data was available from the Automated Surface Observing System (ASOS) at the Oakland International Airport for the years 2003-2007. The site is located 20.8 kilometers to the northwest of the RCEC. AERSURFACE (version 08009) was used to determine surface characteristics in accordance with USEPA's January 2008 "AERMOD Implementation Guide" at both the Oakland Airport and the RCEC project site. Based upon this comparison the Oakland ASOS data was considered representative of the RCEC project location and met all EPA data completeness requirements. *SOB at 87*

The meteorological data from Oakland would not seem indicative of Hayward Data as confirmed by the transcript of district employee Glen Long emails including.

96. Please provide data from 1 year of site specific monitoring.

Air Quality Modeling Results
The maximum predicted ambient impacts of the various modeling procedures described above are summarized in Table III for the averaging periods for which AAQS and PSD increments have been set. Shown in Figure 1 are the locations of the maximum modeled impacts. *SOB at 87*

97. Please provide complete impact tables for each modeling method.

98. Figure 1 on page 89 conflicts with figure 1 on page 158 which if any is to be relied on?

Soils and Vegetation Analysis
A detailed vegetation inventory in the project and impact area is also presented in the Russell City Energy Center AFC, Vol. I, May, 2001 and Russell City Energy Center AFC Amendment No. 1 (01- AFC-7), November 2006. *SOB at 90*

99. The impact area analysis (survey) was not updated for the 2006 amendment. Is there a possibility that vegetation may have changed in this last decade?

Some project area soils (Clear Lake, Danville, and Willows) are considered prime farmland soils when found in open field or agricultural areas, but none of the project facilities cross these soils in any other context than land that is zoned and used as urban, industrial land. *SOB at 90*

100. Does this statement confirm above concerns about "rural" classification?

There are 1.68 acres of seasonal wetlands on the 14.7-acre project site. *SOB at 91*

This statement appears to describe the original site as would all documents from that era.

101. Does this statement describe the present site?

102. What other data is reused from the original site?

103. Is it appropriate to use data from the wrong site?

Much of the historic salt marsh community within 1 mile of the site has been altered or eliminated by urban development, sewage treatment facilities, salt evaporation ponds, and the construction of dikes and levees to prevent flooding and intrusion of saltwater. *SOB at 91*

104. When was this determination made?

105. Does it describe the old site, as we are aware of no present salt evaporation ponds in the area?

106. How much of the Historic salt marsh community has been altered or eliminated?

107. Have there been restoration activities in the area since this statement was made?

Special environmental areas within a 1-mile radius of the project site include Cogswell Marsh, managed by the East Bay Regional Park District, the HARD marsh restoration project and Shoreline Interpretive Center, and a small section of Mt. Eden Creek. *SOB at 91*

108. Is the Don Edwards San Francisco Bay National Wildlife Refuge within 1 mile of the project site?

The California Department of Fish and Game, the U.S. Fish and Wildlife Service, and the California Coastal Conservancy launched a four- year public process to design a restoration plan for the South Bay Salt pond restoration Project. The final plan was adopted in 2008 and the first phase of restoration started later that year.

109. Is this within 1 mile of the site?

110. Have the above agencies been notified of the proximity to the site?

111. What is the actual distance to the waters of the San Francisco Bay?

112. Is the on site waterway affected by the tides?

113. What steps has the district taken to demonstrate consistency with the Coastal Zone Management act?

114. The Clean Water Act?

115. The Endangered Species Act?

116. The Migratory Bird Treaty Act?

117. What other Federal Act(s) should this permit be consistent with?

The project maximum one-hour average NO_2, including background, is 260 μg/m^3. This concentration is below the California one-hour average NO_2 standard of 338 μg/m^3. *SOB at 92*

118. Table 9 on page 116 states that the NO_2 emissions are 370 μg/m^3. Which (if any) is correct and why is there such a large discrepancy?

The maximum annual RCEC NO_2 impact is 0.16 μg/m^3. The maximum annual NO_2 background at the Fremont monitoring station between 2005 and 2007 was in 2005 at 28.2 μg/m^3. *SOB at 92*

119. Would the Hunters Point San Francisco or Oakland monitoring stations be more indicative of Hayward air quality?

120. What would the result be using upwind monitoring like Hunters Point or Oakland?

121. Is there a provision for local monitoring?

122. If so why was Hayward not monitored?

Hayward has multiple freeways, industrial and bridge impacts that Fremont does not have and is impacted by the port of Oakland and denser uses in Oakland and San Francisco.[37]

123 Is there a possibility that newer reference material is available that may lead to a different conclusion?

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[37] (USEPA 1991, "Air Quality criteria for oxides of nitrogen").
(USEPA 1979, "Air Quality criteria for carbon monoxide").
(Zimmerman et al.1989, "Polymorphic regions in plant genomes detected by an M13 probe"
(USEPA 1979, "Air Quality criteria for carbon monoxide")
(Lerman, S.L. and E.F. Darley. 1975. Particulates, pp. 141-158. In: Responses of plants to air pollution, edited by J.B. Mudd and T.T. Kozlowski. Academic Press. New York.)
"A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," December 1980

The Department will no longer recommend comparison of modeled impacts to the 1980 sensitivity thresholds. This document is out of print (has been for at least 10 years) and appears to be no longer used by EPA. Alan Schuler, P.E., Environmental Engineer Alaska Department of Environmental Conservation

Is the District familiar with this USEPA determination[38]?

Please seek review of these materials and reference any newer data that has been used in other PSD permits or may be appropriate to validate or invalidate these reports.

124. Why does table 6 on page 93 reference a 4 hour averaging period for NO_2?

125. What would the 1 hour concentration be for start up and normal operation?

Growth Analysis

The proposed project will supply electricity to Northern California. The electricity from the new plant is expected to displace older, less efficient sources of electricity elsewhere in the region. *SOB at 93*

126. Please identify the basis for this statement and exactly which older less efficient sources this refers to and when they will be decommissioned?

There will be little or no associated industrial, commercial, or residential growth as a result of this project. *SOB at 93*

127. Is this project based upon future need based upon growth projections?

The electrical generating capacity from the project will be introduced into a regional electrical supply grid and therefore not stimulate local growth. *SOB at 93*

128. Does this logic mean that no electric generation that feeds into the "grid" contributes to growth and therefore growth analysis is unwarranted in grid connected permitting?

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[38] See http://www.dec.state.ak.us/air/ap/docs/modeling%20DEC%20Guidance%20re%20PSD%20Soil%20and%20Vegetation%20Assessments%2012-11-07.pdf

The entire permanent workforce is expected to commute from within Alameda County. *SOB at 93*

129. What are the emissions associated with temporary and permanent workers, like commuting?

The project was originally certified by the California Energy Commission in September, 2002. However, the site has been relocated approximately 1,500 feet to the north from the original location (1.24 miles east of Johnson Landing on the southeastern shore of the San Francisco Bay in the City of Hayward). *SOB at 99*

130. What is the actual distance from the original site to the new site?

131. What is the Actual distance from the site to Roberts Landing?

"Analysis of the potential adverse impacts on soils, flora and fauna should include existing vegetation types, the percent cover and biomass, spatial distribution and land use. Rare and endangered species and acidic wetlands should also be identified. Ozone concentrations and estimates of fluoride and heavy metal emissions must be supplied with pollutant baseline concentrations and pollutant contribution from all sources." [*April, 1981 PSD Guidance Document at 9.4*]

132. How has the District complied with the above quoted PSD guidance document?

The Energy Commission certified the construction and operation of the RCEC in September 2002, on 14.7 acres in the City of Hayward (the City) Industrial Corridor at the southwest corner of the intersection of Enterprise Avenue and Whitesell Street, directly south of the City's Water Pollution Control Facility (WPCF). The location is approximately two miles from the east entrance to the San Mateo-Hayward Bridge (State Route 92). Through the Petition to Amend, the project owner is now proposing to locate the facility west of the City's WPCF between Depot Road and Enterprise Avenue, approximately 1,300 feet northwest of the original location (300 feet boundary to boundary). The new location will total approximately 18.8 acres with all parcels located within the City of Hayward.
CEC FSA 1- 2 July 2007

133. Does this statement describe the present site?

134. What other data is reused from the original site?

135. Is it appropriate to use data from the wrong site?

Under the leadership of Senator, the South Bay Salt Ponds were purchased in 2003 from Cargill Inc. Funds for the purchase were provided by federal and state resource agencies and several private foundations. The 15,100 acre purchase represents the largest single acquisition in a larger campaign to restore 40,000 acres of lost tidal wetlands to San Francisco Bay.

Shortly after the property was purchased, the California Department of Fish and Game, the U.S. Fish and Wildlife Service, and the California Coastal Conservancy launched a four- year public process to design a restoration plan for the property. The final plan was adopted in 2008 and the first phase of restoration started later that year.

136. What is the distance to the South Bay Salt Pond Restoration Project?

137. Has the District informed the public, Dianne Feinstein, stakeholders and agencies associated with the National Wildlife Sanctuary and Salt Pond restoration project of the exact proximity?

138. Could this information affect their interest and informed participation?

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia.
SOB at 109

139. How "difficult to estimate" is it to estimate would it be appropriate to make the effort?

However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere.
SOB at 109

140. When this opinion made and what was its basis?

Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter within the BAAQMD. The potential impact on the formation of secondary particulate matter in the SJVAPCD is not known.
SOB at 109

141. What would it require for the above potential impact to be “known”

This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.
SOB at 109

142. What is the threshold?

Table 7 (*SOB at 116*) summarizes the offset obligation of the RCEC.

The emission reduction credits presented in Table 7 exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, “Emissions Banking”, and were subsequently issued as banking certificates by the BAAQMD under the applications cited in the table footnotes.

If the issued under any certificate exceeded 35 tons per year for any pollutant, the application was required to fulfill the public notice and public comment requirements of District Regulation 2-4-405. Accordingly, such applications were reviewed by the California Air Resources Board, U.S. EPA, and adjacent air pollution control districts to insure that all applicable federal, state, and local regulations were satisfied.

143. Please demonstrate the complete compliance history for the emission reduction credits creation and banking including any public notices.

(Information for certificate #30 is not available) SOB at 115

144. The above caption refers to an emission reduction credit for the facility. What rules apply to identification of Certificate sources?

145. Why are the emission reduction credits different in the CEC Decision?

AQ-SC11 The project owner shall surrender 12.2 tons per year of SOx or SOxequivalent emission reduction credits (ERCs) from certificate 989, 28.5 tons per year of POC ERCs, and 154.8 tons per year of NOx, or an equivalent combination of NOx and POC ERCs from certificates 602, 687, 688, and 855, prior to start of construction of the project.
CEC Final Decision at 86

146. Air Quality table 9 on page 116 appears to indicate that the facility would exceed current California NO_2 standards is this correct?

147. What Authority would allow the District to license the facility to exceed the California standard?

Pursuant to Regulation 2-2-306, a non-criteria pollutant PSD analysis is required for sulfuric acid mist emissions if the proposed facility will emit H2SO4 at rates in excess of 38 lb/day and 7 tons per year. However, RCEC has agreed to permit conditions limiting total facility H2SO4 emissions to 7 tons per year and requiring annual source testing to determine SO_2, SO_3, and H_2SO_4 emissions. If the total facility emissions ever exceed 7 tons per year, then the applicant must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions. *SOB at 115*

148. Is there some basis in the emission profile that would inform the public of the expected Sulfuric Acid emission or reason to believe from the operation profile that the facility (as planned) would emit less than 7 tons per year or 38 pounds per day?

2. Emission Offsets

General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NOx (as NO_2) emission increases from permitted sources at facilities which will emit 15 tons per year or more on a pollutant-specific basis. For facilities that will emit more than 35 tons per year of NOx (as NO_2), offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Pursuant to Regulation 2-2-302.2, POC offsets may be used to offset emission increases of NOx.
SOB at 115

149. Please demonstrate how emission trading and offsets comply with the Federal requirements of the PSD permit and how they protect air quality.

It should be noted that in the case of POC and NOx offsets, District regulations do not require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases that will be offset. Timing for Provision of Offsets
SOB at 113

150. Do Clean Air Act regulations require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases?

Pursuant to District Regulation 2-2-311, the applicant surrendered the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct on May 14, 2003. Pursuant to District Regulation 2, Rule 3, "Power Plants," the Authority to Construct was issued after the California Energy Commission issued the Certificate for the proposed power plant
SOB at 116

151. Are the emission credits contemporaneous for Federal purposes?

The District-operated Fremont-Chapel Way Monitoring Station, located 18.3 km southeast of the project, was chosen as representative of background NO_2 concentrations. Table V contains the concentrations measured at the site for the past 5 years (1996 through 2000).
SOB at 161

152. Oakland or hunters point would be more representative of Hayward air quality but the District should require 1 year of current local monitoring and consider the its reports of the effects of the port of Oakland on Hayward.

Regulation 2, Rule 1, Sections 426: CEQA-Related Information Requirements
As the lead agency under CEQA for the proposed RCEC Project, the California Energy Commission (CEC) will satisfy the CEQA requirements of Regulation 2-1-426.2.1 by producing their Final Certification which serves as an EIR-equivalent pursuant to the CEC's CEQA-certified regulatory program in accordance with CEQA Guidelines Section 15253(b) and Public Resource Code Sections 21080.5 and 25523
SOB at 117

153. How can the CEC be considered the lead agency when they have closed their administrative record so long before this permit?

(a) Any public agency which is a responsible agency for a development project that has been approved by the lead agency shall approve or disapprove the development project within whichever of the following periods of time is longer:
(1) Within 180 days from the date on which the lead agency has approved the project.
(2) Within 180 days of the date on which the completed application for the development project has been received and accepted as complete by that responsible agency.
(b) At the time a decision by a lead agency to disapprove a development project becomes final, applications for that project which are filed with responsible agencies shall be deemed withdrawn. [Government Code Section 65952]

CEQA Section 15052. Shift in Lead Agency Designation (a) Where a Responsible Agency is called on to grant an approval for a project subject to CEQA for which another public agency was the appropriate Lead Agency, the Responsible Agency shall assume the role of the Lead

Agency when any of the following conditions occur:
(1) The Lead Agency did not prepare any environmental documents for the project, and the statute of limitations has expired for a challenge to the action of the appropriate Lead Agency.
(2) The Lead Agency prepared environmental documents for the project, but the following conditions occur:
(A) A subsequent EIR is required pursuant to Section 15162,
(B) The Lead Agency has granted a final approval for the project, and
(C) The statute of limitations for challenging the Lead Agency's action under CEQA has expired.
(3) The Lead Agency prepared inadequate environmental documents without consulting with the Responsible Agency as required by Sections 15072 or 15082, and the statute of limitations has expired for a challenge to the action of the appropriate Lead Agency.
(b) When a Responsible Agency assumes the duties of a Lead Agency under this section, the time limits applicable to a Lead Agency shall apply to the actions of the agency assuming the Lead Agency duties. [Note: Authority cited: Section 21083, Public Resources Code;
Reference: Section 21165, Public Resources Code.]

Public Resources Code 25519 (h) Local and state agencies having jurisdiction or special interest in matters pertinent to the proposed site and related facilities shall provide their comments and recommendations on the project within 180 days of the date of filing of an application.

BAAQMD rules
2-3-403 Preliminary Decision: Within 180 days of accepting an AFC as complete, the APCO shall conduct a Determination of Compliance review and make a preliminary decision as to whether the proposed power plant meets the requirements of District regulations. If so, the APCO shall make a preliminary determination of conditions to Bay Area Air Quality Management District 2-3-3 be included in the Certificate, including specific BACT requirements and a description of mitigation measures to be required.

2-3-405 Determination of Compliance, Issuance: Within 240 days of the acceptance of the AFC as complete, the APCO shall issue and submit to the commission a Determination of Compliance. If the Determination of Compliance cannot be issued, the APCO shall so advise the Commission. When the AFC is approved by the Commission, the APCO shall ascertain whether the Certificate contains all applicable conditions. If so, the APCO shall grant an authority to construct.

1744.5. Air Quality Requirements; Determination of Compliance. (a) The applicant shall submit in its application all of the information required for an authority to construct under the applicable district rules, subject to the provisions of Appendix B(g)(8) of these regulations.
(b) The local air pollution control officer shall conduct, for the commission's certification process, a determination of compliance review of the application in order to determine whether the proposed facility meets the requirements of the applicable new source review rule and all other applicable district regulations. If the proposed facility complies, the determination shall specify the conditions, including BACT and other mitigation measures, that are necessary for compliance. If the proposed facility does not comply, the determination shall identify the specific regulations which would be violated and the basis for such determination. The determination

shall further identify those regulations with which the proposed facility would comply, including required BACT and mitigation measures. The determination shall be submitted to the commission within 240 days (or within 180 days for any application filed pursuant to Sections 25540 through 25540.6 of the Public Resources Code) from the date of the acceptance.
(c) The local district or the Air Resources Board shall provide a witness at the hearings held pursuant to Section 1748 to present and explain the determination of compliance.
(d) Any amendment to the applicant's proposal related to compliance with air quality laws shall be transmitted to the APCD and ARB for consideration in the determination of compliance.
[Note: Authority cited: Sections 25218(e) and 25541.5, Public Resources Code. Reference: Sections 25216.3 and 25523, Public Resources Code.]
15162. Subsequent EIRs and Negative Declarations
a(3)(C) Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative

154. The CEC approved the project on October 3, 2007 Is the District now the lead agency?

Please process this application consistent with CEQA utilizing feasible alternatives.

§ 51.166 40 CFR Ch. I (7–1–08 Edition)
(q) *Public participation.* The plan shall provide that—
(1) The reviewing authority shall notify all applicants within a specified time period as to the completeness of the application or any deficiency in the application or information submitted. In the event of such a deficiency, the date of receipt of the application shall be the date on which the reviewing authority received all required information.
(2) Within one year after receipt of a complete application, the reviewing authority shall:
(i) Make a preliminary determination whether construction should be approved, approved with conditions, or disapproved.
(ii) Make available in at least one location in each region in which the proposed source would be constructed a copy of all materials the applicant submitted, a copy of the preliminary determination, and a copy or summary of other materials, if any, considered in making the preliminary determination.
(iii) Notify the public, by advertisement in a newspaper of general circulation in each region in which the proposed source would be constructed, of the application, the preliminary determination, the degree of increment consumption that is expected from the source or modification, and of the opportunity for comment at a public hearing as well as written public comment.
(iv) Send a copy of the notice of public comment to the applicant, the Administrator and to officials and agencies having cognizance over the location where the proposed construction would occur as follows: Any other State or local air pollution control agencies, the chief executives of the city and county where the source would be located; any comprehensive regional land use planning agency, and any State, Federal Land Manager, or Indian Governing body whose lands may be affected by emissions from the source or modification.

(v) Provide opportunity for a public hearing for interested persons to appear and submit written or oral comments on the air quality impact of the source, alternatives to it, the control technology required, and other appropriate considerations.
(vi) Consider all written comments submitted within a time specified in the notice of public comment and all comments received at any public hearing(s) in making a final decision on the approvability of the application. The reviewing authority shall make all comments available for public inspection in the same locations where the reviewing authority made available preconstruction information relating to the proposed source or modification.
(vii) Make a final determination whether construction should be approved, approved with conditions, or disapproved.
(viii) Notify the applicant in writing of the final determination and make such notification available for public inspection at the same location where the reviewing authority made available preconstruction information and public comments relating to the source

155 How does this project conform with the above Federal requirement?

156. What other rules have changed or mistakes have been discovered by the District since the issuance of the FDOC or Authority to Construct?

The PSD proceedings that are the subject of this case are embedded in a larger California "certification" or licensing process for power plants conducted by the California Energy Commission ("CEC"),
Remand at 1

The PSD provisions 2 that are the subject of the instant appeal are part of the CAA's New Source Review ("NSR") program, which requires that persons planning a new major emitting facility or a new major modification to a major emitting facility obtain an air pollution permit before commencing construction. In addition to the PSD provisions, explained *infra*, the NSR program includes separate "nonattainment" provisions.
Remand at 5

As applied to the notice violation, the allegation of error is considered to be the Permit in its entirety. *See In re Chem. Waste Mgmt. of Ind.*, 6 E.A.D. 66, 76 (EAB 1995) (holding that the Board, in accordance with its review powers under 40 C.F.R. § 124.19, is "authorize[d] * * * to review any condition of a permit decision (or as here, the permit decision in its entirety.)."
Remand footnote 22 at 26

157. Is this permit being processed consistent with the EAB remand including the previous 3 statements?

AQ-SC10 In lieu of complying with **AQ-SC7**, **AQ-SC8,** and **AQ-SC9**, the project's combustion turbine/HRSG units shall be designed and built with equipment and control systems to minimize start-up times and emissions. These could include the Fast-Start technology with an integrated control system and a once-through Benson boiler design, appropriate system configuration and equipment to facilitate operating chemistry during starting sequences, and an auxiliary boiler. *CEC Final Decision at 86*

158. Had this requirement been supported by the Air District (as the concurrent El Segundo AFC) and Palomar the project would emit 48 tons or less instead of 86 tons of PM annually. Please process this application consistent with CEC AQ-SC10.

On February 19, 2008 the office of administrative law approved the new NO_2 standard of 338 $\mu g/m^3$ which went into effect on March 20, 2008.

159. Please process this permit consistent with the present NO_2 standards.

2-2-414.3 For determining whether the emission increases from the new or modified facility would cause or contribute to an air quality standard violation or an exceedance of a PSD increment, an analysis of the existing air quality in the impact area of the new or modified facility that includes one year of continuous ambient air quality monitoring data. The continuous air quality monitoring data shall have been gathered over a period of at least one year preceding the receipt of a complete application. The APCO may approve a shorter period (but not less than four months) provided that the period of monitoring includes the time frame when maximum concentrations are expected. The APCO may approve modeling in lieu of ambient air quality monitoring for pollutants for which no air quality standard exists.

160. Please complete 1 year of continuous ambient air quality monitoring data in the impact area (Hayward)

Ecosystems occurring in these areas include those commonly encountered in the foothills of the Coast Ranges, such as oak woodland and valley/foothill grassland. Biological habitats within the project area consist primarily of coastal salt marsh, brackish/freshwater marsh, salt production facilities (evaporation ponds). *SOB at 90*

161. There have not been salt production facilities in the area for many years. Please disclose when the identified salt production facilities ceased operations and utilize current information for permitting

15154. Projects Near Airports
(a) When a lead agency prepares an EIR for a project within the boundaries of a comprehensive airport land use plan or, if a comprehensive airport land use plan has not been adopted for a project within two nautical miles of a public airport or public use airport, the agency shall utilize the Airport Land Use Planning Handbook published by Caltrans' Division of Aeronautics to assist in the preparation of the EIR relative to potential airport-related safety hazards and noise problems.
(b) A lead agency shall not adopt a negative declaration or mitigated negative declaration for a project described in subdivision (a) unless the lead agency considers whether the project will result in a safety hazard or noise problem for persons using the airport or for persons residing or working in the project area.

161. Please assess the potential impact to the Hayward and Oakland Airport and air quality impact to in-flight receptors.

The following document is incorporated into these comments:

From: Schuler, Alan E (DEC)
Sent: Tuesday, December 11, 2007 1:46 PM
Subject: PSD Vegetation and Soil Assessments[39]

Also Incorporated for review by the District :

Advanced Power Plant Development and Analyses Methodologies Final Report
Reporting Period: August 1, 2000 – June 30, 2006[40]

Associated Growth
"Associated Growth" is additional commercial, residential, industrial and other growth that the project may cause or induce. This type of growth is growth in the local workforce and support infrastructure necessary to serve the proposed facility. Examples include additional residential housing, retail suppliers, and additional schools and municipal services that would be necessary to accommodate any new workers that would come to the area to work in the facility. Examples also include any additional commerce or industry necessary to provide goods and services used by the facility, maintenance facilities to serve the facility, and other similar support operations. Emissions from "associate growth" are the emissions associated with this additional human and

[39] See
http://www.dec.state.ak.us/air/ap/docs/modeling%20DEC%20Guidance%20re%20PSD%20Soil%20and%20Vegetation%20Assessments%2012-11-07.pdf
[40] See
http://www.netl.doe.gov/technologies/coalpower/fuelcells/seca/pubs/reports/UCI%20Finall%20Report%20DE-FC26-00NT40845.pdf

economic activity generated as a result of the facility under review. The Air District undertook an associated growth analysis and found that there would be no significant associated growth.4
SOB at 16

Growth Analysis
The proposed project will supply electricity to Northern California. The electricity from the new plant is expected to displace older, less efficient sources of electricity elsewhere in the region. There will be little or no associated industrial, commercial, or residential growth as a result of this project. The electrical generating capacity from the project will be introduced into a regional electrical supply grid and therefore not stimulate local growth.
SOB at 93

162. These definitions of growth ignore the growth associated with increased electrical capabilities. Please assess the associated growth possibilities from an additional 600 megawatts of capacity. Please also assess the associated negative growth in sustainable generation.

Hereby incorporated into these comments:
September 8, 1988 MEMORANDUM [41]
SUBJECT: EPA Region IX Policy on PSD Permit Extensions
FROM: Wayne Blackard, Chief New Source Section
SUBJECT: EPA Region IX Policy on PSD Permit Extensions

The project maximum one-hour average NO_2, including background, is 260 µg/m^3. This concentration is below the California one-hour average NO_2 standard of 338 µg/m^3. Nitrogen dioxide is potentially phytotoxic, but generally at exposures considerably higher than those resulting from most industrial emissions. Exposures for several weeks at concentrations of 280 to 490 µg/m^{3}can cause decreases in dry weight and leaf area, but 1-hour exposures of at least 18,000 µg/m^3 are required to cause leaf damage. The maximum annual RCEC NO_2 impact is 0.16 µg/m^3. The maximum annual NO_2 background at the Fremont monitoring station between 2005 and 2007 was in 2005 at 28.2 µg/m^3. The total annual NO_2 concentration (project plus background) of 28.4 µg/m^3 is far below these threshold limits (219.0 µg/m^3). In addition, the total predicted maximum 1-hour NO_2 concentrations of 260 µg/m3 would be significantly less than the 1-hour threshold (7,500 µg/m^3 or 3,989 ppm) for 5 percent foliar injury to sensitive vegetation (USEPA 1991, "Air Quality criteria for oxides of nitrogen"). *SOB at 92*

163. Please use current reference material like the CEC Pier nitrogen deposition report included in the EAB appeal 08-01

164. Please use correct emission data including the results of 1 year of impact area monitoring.

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[41] See http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/extnsion.pdf

Continued on the next page

165. Please also analyze the effects on the adjacent Vernal pools and protected habitats.

Permit Expiration
As provided in 40 CFR 52.21(r), this PSD Permit shall become invalid if construction:
A. is not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months after the approval takes effect;.. The stack gas volumetric flow rates.

The system shall meet EPA Performance Specifications 40 CFR 52, Appendix E.

Each CEMS shall meet the applicable requirements of 40 CFR 60 Appendix B, Performance Specifications 2, 3, and 4, and 40 CFR Part 60 Appendix F, Procedure 1, and shall be certified and tested.

Deposited ammonia also can contribute to problems of eutrophication in water bodies, and deposition of ammonium particles may effectively result in acidification of soil as ammonia is taken up by plants.

Except as provided in the grandfathering provisions that follow, these final rules go into effect and must be implemented beginning on the effective date of this rule, July 15, 2008 in all areas subject to 40 CFR 52.21, including the delegated States.

Consistent with 40 CFR 52.21(i)(1)(x), wherein EPA grandfathered sources or modifications with pending permit applications based on PM from the PM10 requirements established in 1987, EPA will allow sources or modifications who previously submitted applications in accordance with the PM10 surrogate policy to remain subject to that policy for purposes of permitting if EPA or its delegate reviewing authority subsequently determines the application was complete as submitted. This is contingent upon the completed permit application being consistent with the requirements pursuant to the EPA memorandum entitled ‘‘Interim Implementation of New Source Review Requirements for PM2.5’’ (Oct. 23, 1997) recommending the use of PM10 as a surrogate for PM2.5. Accordingly, we have added 40 CFR 52.21(i)(1)(xi) to reflect this grandfathering provision.

2. Transition With this finalization of the new PM2.5 NSR implementation requirements under 40 CFR 51.165, States now have the necessary tools to implement a NA NSR program for PM2.5. After the effective date of the amended rule (that is, July 15, 2008, States will no longer be permitted to implement a NA NSR program for PM10 as a surrogate for the PM2.5 NA NSR requirements.

Most States will then need to implement a transitional PM2.5 NA NSR program under appendix S (as amended in this rulemaking action) until EPA approves changes to a State’s SIP-approved NA NSR program to reflect the new requirements under 40 CFR 51.165. At this time, we do not believe it is appropriate to allow grandfathering of pending permits being reviewed under the

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Continued from the previous page

PM10 surrogate program in nonattainment areas, mainly because of a State's obligations to expedite attainment and the fact that we had not established a similar precedent for transitioning from PM to PM10. [Fed. Reg. 28231, 28349-50 (May 16, 2008)][42]

166. The ammonia and other toxins effects on vegetation is ignored in the analysis. Please analyze.

During recent years, in response to an increased awareness of the adverse consequences of air pollution and environmental degradation, the government has enacted legislation that is of interest to lichenologists. This paper discusses the role of lichen research in the development of this legislation or in decisions made as a result of the legislation. The major acts of interest are the National Environmental Policy Act (NEPA) of 1969 and the Clean Air Act of 1970 and its 1977 amendments. Under NEPA, the federal government announced its commitment to maintain and enhance the environmental quality of the United States. Under the Clean Air Act, the Environmental Protection Agency was authorized to establish the National Ambient Air Quality Standards; the Prevention of Significant Deterioration Class I, II and III areas; and the "adverse impact" determination for Class I areas. After review of the air pollution literature, comparison of the effects of gaseous sulfur dioxide on photosynthesis in lichens and vascular plants showed that some lichens (1) may not be as sensitive as some crops, (2) may be more sensitive than some conifers, and (3) may be about as sensitive as some native herbs and shrubs. However, it appears that visible injury symptoms occur at lower doses in crops and conifers than in lichens. Evaluation of the lichen/air pollution research (e.g. mapping, laboratory and field fumigations, and ecological baseline studies) and a computer search of environmental impact statements showed that if the efforts of lichenologists are to be of use to government decision makers, the researchers must (1) use representative concentrations of pollutants, (2) use fluctuating exposures, in addition to constant concentrations, (3) use mixtures as well as single pollutants, (4) determine the importance of peak concentrations to long-term averages on effects, (5) develop dose-response curves for single and mixed pollutants, (6) relate laboratory results to field observations, (7) document changes in lichen communities related to measured concentrations of ambient pollutants, and (8) determine the significance of lichens in the structure and function of ecosystems.[43]

167. Please analyze the effects on aquatic vegetation and lichens.

168. Please demonstrate how the project complies with NEPA

Startup and Testing of Siemens V84.3A Combustion Turbine in Peaking Service at Hawthorn Station of Kansas City Power & Light Company[44]

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[42] See http://edocket.access.gpo.gov/2008/pdf/E8-10768.pdf

[43] See http://www.jstor.org/pss/3242790

[44] See http://mydocs.epri.com/docs/public/TR-108609.pdf

ASTM fuel sulfur analysis methods were updated to correspond with NSPS Subpart GG as revised July 2004.[45]

The above linked documents are hereby incorporated into these comments

[40 CFR 124.13] (A comment period longer than 30 days may be necessary to give commenters a reasonable opportunity to comply with the requirements of this section. Additional time shall be granted under § 124.10 to the extent that a commenter who requests additional time demonstrates the need for such time.)

[40 CFR 124.8] Fact sheet (3) For a PSD permit, the degree of increment consumption expected to result from operation of the facility or activity.
(4) A brief summary of the basis for the draft permit conditions including references to applicable statutory or regulatory provisions and appropriate supporting references to the administrative record required by § 124.9 (for EPA-issued permits);
(5) Reasons why any requested variances or alternatives to required standards do or do not appear justified;
(6) A description of the procedures for reaching a final decision on the draft permit including:
(i) The beginning and ending dates of the comment period under § 124.10 and the address where comments will be received;
(ii) Procedures for requesting a hearing and the nature of that hearing; and
(iii) Any other procedures by which the public may participate in the final decision.
(7) Name and telephone number of a person to contact for additional information. and all variances that are to be included under § 124.63.

169. The District has not demonstrated compliance with the preceding laws. Please demonstrate compliance.

Under the federal Magnuson-Stevens Act and the Endangered Species Act, San Francisco Bay is considered critical habitat for certain fish species, such as Chinook salmon and Delta smelt, by the United States Fish and Wildlife Service and the National Marine Fisheries Service because

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[45] See http://www.adeq.state.ar.us/ftproot/pub/commission/p/08-007-P%20AEP%20Service%20Corp%20&%20Swepco-Hempstead%20Co%20Hunting%20Club/2008-12-03_Ex._116_Southern_Company_Calc_Method_3-03.pdf and http://www.baaqmd.gov/pmt/air_toxics/permit_modeling/psd_increment_consumption_status_report_4_16_08.pdf

the Bay plays an essential role in their life cycles. The Magnuson-Stevens Act requires that the National Marine Fisheries Service provide conservation recommendations to state agencies, such as the Commission, when a proposed project would have adverse impacts on essential fish habitat.

170. What efforts has the District taken to demonstrate consistency with the Magnuson-Stevens Act?

Dissolved oxygen is needed to support marine life and to help break down pollutants in the water. The amount of oxygen in the Bay is largely determined by the surface area of the Bay because primary sources of oxygen are: (1) churning waves that trap oxygen from the air; (2) the water surface, which absorbs oxygen from the air; and (3) the exposed mudflats, which both produce and absorb oxygen while the tide is out and transfer it to the water when the tide comes in.

171. What effect will the project have on these resources?

The Hayward Shoreline consists of marshland, bay and sloughs, and comprises of remaining natural wetlands in California. It plays an important role in providing wintering habitat for waterfowl of the Pacific Flyway. During years of drought the area becomes particularly important to waterfowl by virtue of its large expanse of aquatic habitat and the scarcity of such habitat elsewhere. The area provides critical habitat for other wildlife forms, including such endangered, rare, or unique species as the peregrine falcon, white-tailed kite, golden eagle, California clapper rail, black rail, salt-marsh harvest mouse, and Suisun shrew. The existence of this wide variety of wildlife is due to the relatively large expanse of unbroken native habitat and the diversity of vegetation and acquatic conditions that prevail in the marsh. Man is an integral part of the present marsh ecosystem and, to a significant extent, exercises control over the widespread presence of water and the abundant source of waterfowl foods. The Hayward Shoreline represents a unique and irreplaceable resource to the people of the state and nation. Future residential, commercial, and industrial developments could adversely affect the wildlife value of the area. It is the policy of the state and Nation to preserve and protect resources of this nature for the enjoyment of the current and succeeding generations.

172. How does this project protect these resources?

173. Oliver Salt Ponds is designated a “Rural Historic Landscape” How far is the project from the Oliver Salt Ponds and what has the District done to demonstrate consistency within the National Register of Historic Places.

The District must consult with the appropriate Federal, State and local land use agencies prior to issuance of a PSD permit preliminary determination. For the purposes of the Endangered Species Act (ESA), the District shall:

- Notify the appropriate Federal Land Manager (FLM) within 30 days of receipt of a PSD permit application. If the proposed project will impact a Class I area, notify the appropriate Federal Land Manager (FLM) no later than 60 days prior to issuing a public notice for the project.
- Notify the Fish and Wildlife Service (FWS) and EPA when a submitted PSD permit application has been deemed complete, in order to assist EPA in caring out its nondelegable responsibilities under Section 7 of the ESA (PL 97-304).
- Notify applicants of the potential need for consultation between EPA and FWS if an endangered species may be affected by the project.
- Refrain from issuing a final PSD permit unless FWS has determined that the proposed project will not adversely affect any endangered species
- EPA/BAAQMD PSD DELEGATION AGREEMENT

174. Please demonstrate the Districts efforts to comply with the above provision of the PSD delegation agreement. Specifically also include records of consultation with the CEC, USFWS, Alameda County, City of Hayward, Alameda county public health Department, Army Corp of Engineers California Department of Fish and Game and the Federal land manager(s) with jurisdiction over the United States waters of the San Francisco Bay and shoreline.

All Email communications from Rob Simpson and District responses are hereby incorporated into these comments by reference.

The CEC record for the Eastshore Energy Center and Russell City Energy Center are hereby incorporated by reference into these comments.

All questions posed in these comments that lead to a response that could lead to a better way to permit this facility are in effect requesting that the better way be utilized.

The District is requested to forward all applicable comments and permit information including those in the EAB appeal 08-01 to USFWS and other applicable agencies for their determinations.

(NOTE REVISED ADDRESS)
"Notice of Public Hearing and Notice Inviting Written Public Comment on" Proposed Air Quality Permit for the Russell City Energy Center, Hayward, CA

The Bay Area Air Quality Management District ("District") is proposing to issue an amended Prevention of Significant Deterioration ("PSD") Permit for the Russell City Energy Center. Before doing so, the District is providing the public with notice of its proposal and an opportunity to review and comment on the proposed permit. The District is also holding a public hearing to provide the public with an opportunity to comment in person. The proposed Russell City Energy Center is a 600-megawatt natural gas fired combined-cycle power plant to be built by Russell City Energy Company, LLC, (50 W. San Fernando Street, San Jose, CA 95113) an affiliate of Calpine Corporation.

The proposed facility would be located at 3862 Depot Road, near the corner of Depot Road and Cabot Boulevard, in Hayward, CA." *Notice*

Because the applicant address is placed first and in parenthesis and the (revised) site address is placed second and disjointed with an inaccurate reference to the sites proximity to Cabot Boulevard. The permit should be re-noticed.

A transcript of an August 18, 2008 email from Barbara Mcbride at Calpine to Weyman Lee at the District states: "Can you please change the name on the Russell City Energy Center Permit owner to Russell City Energy Company LLC and the address should be 3875 Hopyard Rd. #345 Pleasanton CA 94588. Thank you so much"

Because of the change in name and location of the applicant the permit should be re-noticed. Because the District identified Calpine but did not identify the other owner GE therefore the permit should be re-noticed. Because the notice and statement of basis do not reflect the new address identified by the applicant the permit should be re-noticed.

"The proposed power plant will consist of two combustion turbine generators, two heat recovery steam boilers, a steam turbine generator and associated equipment, a wet cooling system, and a diesel fire pump. The District initially issued a permit for the project in 2002, but it was subsequently relocated approximately 1,500 feet to the north. The permit therefore needs to be amended." *Notice*

Wet cooling systems are often associated with large outbreaks of Legionnaires' disease. Adequate consideration of the health risks of a wet cooling system has not been disclosed.

175. Please complete a Health Risk Analysis of the wet cooling system.

Because the District did not issue a PSD permit in 2002 and the relocation of the site has not been accurately disclosed the permit should be re-noticed.

"Under the proposed amended permit, the facility would be allowed to emit significant amounts of certain PSD-regulated air pollutants, including the following:

Nitrogen Oxides (as NO2): 134.6 tons per year
Carbon Monoxide (CO): 389.3 tons per year
Particulate Matter (PM): 86.8 tons per year" *Notice*

Because the pollutants disclosed do not reflect other pollutants subject to PSD limits and the disclosed pollutants are not expressed in context of their effects on air quality the permit should be re-noticed.

176. Please disclose the amount of particulate matter "spare the air days" eliminates and the cost of "spare the air days" in comparison to the cost of emission reduction credits and licensing using current BACT instead of this permit scheme.

"The project will utilize the Best Available Control Technology to minimize emissions of these air pollutants as required by 40 C.F.R. Section 52.21. The proposed project will not consume a significant degree of any PSD increment." *Notice*

Because the project does not propose to use the Best Available Control Technology the permit should be re-noticed.

Because the notice does not provide an accurate increment analysis or analysis on the effect on air quality the permit should be re-noticed.[46]

The revised public notice is not consistent with the notification that the District sent to USFWS and other agencies. They were sent only the first address and the site was incorrectly described as the corner of Depot Road and Cabot Boulevard and "industrial" with no reference to the actual shoreline location. The actual location should be disclosed to the public and involved agencies.

VII. CONCLUSIONS

The remand order from the EAB decision does not deny review of the substantive PSD issues raised by Mr. Simpson but states that permit must be re-noticed and that the appeal board refrains from opining on the substantive PSD issues raised by Mr. Simpson. The District is circumventing public participation by failing to provide access to the administrative record.

Since BACT is part of the CAA and the PDOC includes the District's BACT analysis therefore clearly the PDOC and draft PSD Permit are interdependent on the findings from the federal BACT analysis conducted by the District purportedly in 2002 and again in 2007. Therefore the District should re-notice the PDOC along with a "new" draft PSD permit consistent with the requirements of the CAA and the District's Regulations.

Because of the District's failure to carry out the USEPA EAB Remand Order to "scrupulously adhere to all relevant requirements in section [40 C.F.R. § 124.10(d)] concerning the initial notice of draft PSD permits (including development of mailing lists), as well as the proper content of such notice" therefore this also serves as a Complaint to Office of the

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[46] As in the CEC emission impacts air quality table 3 (utilizing the old PM standards)

Continued on the next page

Administrator of the U.S. Environmental Protection Agency (USEPA) and the California Air Resources Board (ARB) under 42 USC § 7604.

Respectfully submitted,

Michael E. Boyd

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Michael E. Boyd President (CARE)
CAlifornians for Renewable Energy, Inc.
Phone: (408) 891-9677
E-mail: michaelboyd@sbcglobal.net
5439 Soquel Drive
Soquel, CA 95073

Lynne Brown

____

Lynne Brown Vice-President
CAlifornians for Renewable Energy, Inc. (CARE)
24 Harbor Road
San Francisco, CA 94124
Phone: (415) 285-4628
E-mail: l_brown369@yahoo.com

cc.
A.08-09-007 CPUC electronic service list

Verification

I am an officer of the Complaining Corporation herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except matters, which are therein stated on information and belief, and as to those matters I believe them to be true.

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

Executed on this 5th day of February, 2009, at San Francisco, California.

Lynne Brown

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Lynne Brown Vice-President
CAlifornians for Renewable Energy, Inc.
(CARE)

Continued from the previous page
http://www.baaqmd.gov/pmt/air_toxics/permit_modeling/psd_increment_consumption_status_report_4_16_08.pdf

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the *CARE and Rob Simpson comments on the "amended" PSD permit for the Russell City Energy Center Application Number 15487 and Complaint to Office of the Adminstrator USEPA and ARB under 42 USC § 7604*

Executed this 5th day of February, 2009 at Soquel, California.

Carol Paramoure
5439 Soquel Drive
Soquel, California 95073
(831) 465-9809

Mary D. Nichols
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Lisa P. Jackson
Office of the Administrator
Environmental Protection Agency
Ariel Rios Building
Mail Code: 1101A
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Attachment 1

NOxOUT® ULTRA™

NOx Reduction Process

TECHNICAL BENEFITS

- Simplified process, highly efficient urea conversion
- Non-hazardous materials throughout
- Low pressure operation
- Process controls designed to follow load and provide easy shutdown
- Liquid reagent system easily modified for dry urea feedstock
- Backed by Fuel Tech's proven start-up, optimization, and service experience

Smart, safe, and simple... NOxOUT® ULTRA™ provides SCR ammonia supply without the headaches of hazardous chemical handling.

Selective catalytic reduction (SCR) has become a standard for meeting the most stringent NOx reduction requirements from power generation systems. Requiring ammonia (NH_3) as the reducing agent, operators of these systems have had little choice but to accept the handling issues, potential liability, and associated costs in using a hazardous chemical supply.

Fuel Tech's NOxOUT® ULTRA™ system is a new alternative that offers an ammonia feed from a safe urea supply. Available for new SCR systems and as a retrofit to existing applications, NOxOUT® ULTRA™ is a cost-effective solution that simplifies SCR operation.

Urea vs. NH_3

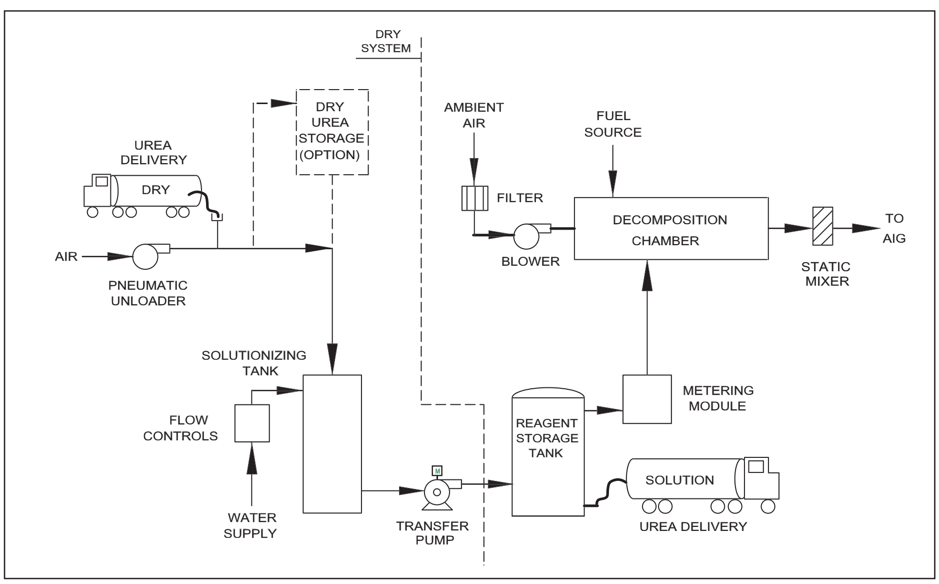
The advantages of a urea-based system over traditional anhydrous ammonia or aqueous supplies are clear. Anhydrous ammonia is classified as a hazardous chemical per CAA Section 112(r). As such, ammonia requires safety procedures to protect personnel, neighboring communities, and the environment from unforeseen chemical release. Reporting, record keeping, permitting, and emergency preparedness planning are generally all needed with on-site ammonia storage. Aqueous ammonia-based systems also require specialized equipment, including pressure vessels, a heated vaporizer, and other features, and have significantly higher operating costs than urea-based systems.

In contrast, urea products are non-hazardous sources of ammonia, so their transport, storage, and use are greatly simplified. Fuel Tech has extensive, proven experience with urea-based systems, and the NOxOUT® ULTRA™ system is built on that solid foundation.

Other urea-to-ammonia conversion systems on the market work by hydrolyzing urea on-site. These processes are complex, expensive, and include a high pressure vessel containing ammonia. NOxOUT® ULTRA™ is a more economical and easier way to generate ammonia.

Design Simplicity

The NOxOUT® ULTRA™ process provides ammonia for SCR systems by decomposing urea to feed the traditional ammonia injection grid (AIG). The process relies on post-combustion reactions in a chamber designed to



FUEL TECH™

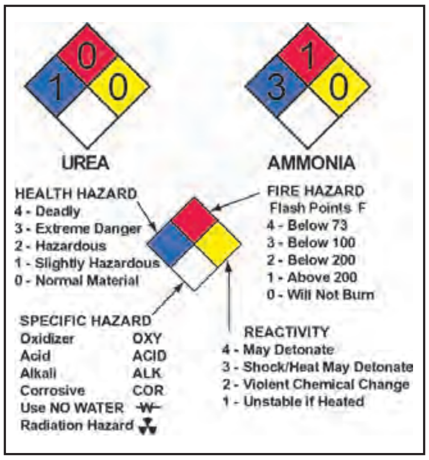
Technology for a renewed environment™

control urea decomposition in a specified temperature window (600-1000 °F). The NOxOUT® ULTRA™ system is simple, consisting of a blower, decomposition chamber, chemical pumping system, urea storage, and process controls.

Filtered ambient air is fed into the chamber through the use of a blower with automatic dampers to control discharge flow and pressure. A burner is fired downstream of the dampers, and an aqueous urea solution supplied by the storage and pumping system is sprayed into the post-combustion gases through the injectors. The urea is efficiently converted to ammonia in the decomposition chamber, and that ammonia feeds the AIG for a traditional SCR system.

System Options

The NOxOUT® ULTRA™ system can be customized for each application.



For larger systems, an in-duct gas-to-gas heat exchanger can be supplied to preheat the process air and minimize operating costs.

The liquid portion of the system can be supplied with dilution water capability to accommodate delivery of concentrated reagent solutions.

The dry urea system components can be supplied to provide flexibility for reagent selection.

New Process, Proven Technologies

The NOxOUT® ULTRA™ process incorporates commercially proven features of Fuel Tech's other NOx reduction products. Urea storage, pumping, metering, and injection are all standard to the NOxOUT® product line, first introduced in 1990. The NOxOUT CASCADE® process relies on careful duct and gas flow dynamics design. The NOxOUT SCR® system relies on the conversion of urea to ammonia for SCR reactions. So while NOxOUT® ULTRA™ is a new product to our mix of process solutions, the established technologies and know-how of Fuel Tech make it a uniquely reliable urea conversion system.

The NOxOUT® ULTRA™ system has all the benefits of direct ammonia supply for SCR without the cost, safety and environmental concerns associated with ammonia handling. More cost-effective than urea-hydrolyzing processes, NOxOUT® ULTRA™ from Fuel Tech is a smart choice for simplifying SCR operation with a urea-to-ammonia conversion process.

For more information on NOxOUT ULTRA™ programs available from Fuel Tech, call, fax, or write Fuel Tech at:

Fuel Tech, Inc. • 512 Kingsland Drive • Batavia, IL 60510
Phone 800.666.9688 • 630.845.4500 • Fax 630.845.4501
www.fueltechnv.com • webmaster@fueltechnv.com

FUEL TECH™
Technology for a renewed environment™

Attachment 2

Pack, Heidi K.

From: Hunt, Kelly [KHunt@Semprautilities.com]
Sent: Thursday, April 12, 2007 3:06 PM
To: Kellogg, Kellie; Pack, Heidi K.; Moore, Steve ; Miller, Taylor; Baerman, Daniel; Waller, Fred A.; Hardman, Charles; Blackburn, Suzanne; Annicchiarico, John; Haury, Evariste
Subject: Updated: Palomar Energy Center Variance Report - 4073 1st Quarter 2007
Attachments: Hearing Board Quarterly Report for 1st Quarter 2007.pdf

Ms. Kellogg,

Please find attached an updated copy of the 1st quarter report to the Hearing Board for 2007. This report **supersedes the submission made on 4/11/07 and** is intended for the Hearing Board meeting to be held on April 26, 2007. I apologize for any inconvenience this may have caused you. This report covers the items required by Condition F.3. of the Board's April 27, 2006 order for Variance 4073. In addition, this report covers Enforcement Condition 1 concerning compliance with required increment of progress.

If you have any questions, please feel free to call me at 760-432-2504.

Kelly Hunt
Generation Compliance Manager
San Diego Gas & Electric
2300 Harveson Place, SD1473
Escondido, CA 92029
760-432-2504 (Office)
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SDGE®
A Sempra Energy company

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dbaerman@semprautilities.com

April 11, 2007

Ms. Catherine Santos
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Santos and Members of the Board:

Set forth below is SDG&E's 2007 first quarter report to the Hearing Board. This report will cover the items required by Condition F. 3. of the Board's April 27, 2006 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

The increments of progress table attached to the Board's order is included with this letter as Attachment 1. The primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E timely filed the permit application on May 31, 2006. A rule amendment concerning Rule 69.3.1 is still under consideration by District staff and SDG&E and District staff met on February 16, 2007 to discuss the matter further.

Petitioner has timely satisfied all increments of progress within Petitioner's control. The increments of progress table also includes District staff and other third-party actions concerning rule development and permit processing. These actions were included in the increments of progress solely to describe the third-party actions necessary to resolve the regulatory issues prompting the variance. SDG&E will defer to District staff to provide an update to the Board on District's processing of SDG&E's permit application submittal, rule development and a possible revised schedule.

2. Engineering or operational alternatives [Order, Condition F.3 (1)]

Information concerning engineering or operational alternatives considered by Petitioner to ensure maximum control of emissions as recommended by District staff was included in the application for amended permit conditions submitted on May 31, 2006. SDG&E included information concerning reductions related to early ammonia injection and installation of a new software program being developed by General Electric for turbines such as those operating at Palomar ("OpFlex"). SDG&E also included information concerning seven other potential alternatives as requested by District staff.

On December 20, 2006, at District staff's request, Petitioner provided additional information regarding engineering and operational alternatives, including additional evaluation of early ammonia injection and economic impacts of several potential alternatives.

In addition, OpFlex, a General Electric turbine control system software was installed in mid-October, 2006. The turning process allows combustion turbines to minimize emissions between 20 and 60% load, by optimizing the fuel flow to the four gas stages in each combustion can. This precisely controls the flame for optimum combustion to minimize emissions. There were no equipment or hardware changes.

3. NOx Emissions Data [Order, Condition F.3 (2)]

Information concerning NOx emissions from the facility during the period of the 1 year variance to present is included in attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.3 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data

A summary how the plant has reduced NOX emissions by various controls that it has established since the inception of the variance is included as attachment 3.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

SAN DIEGO AIR POLLUTION CONTROL DISTRICT HEARING BOARD

Palomar Energy Center

PROPOSED INCREMENTS OF PROGRESS
(As of 4/11/07)

MILESTONE **DATE**

	Description	Permit Modification	Rule Change	Variance(s)
1	Variance 4068 hearing for 90-day issued			2/9/06
2	Emergency Variance 4069 for condition 21 issued to enable early ammonia injection.			2/23/06
3	*Palomar submits request for Rule Change to APCD*		*3/6/06*	
4	*APCD requests more data for rule change*		*3/14/06*	
5	*Mtg. with APCD concerning Data Requests*		*3/30/06*	
6	*Additional mtg. with APCD (Steve Moore) concerning Data Requests*		*4/4/06*	
7	*SDG&E submits requested data to APCD (Moore)*		*4/7/06*	
8	SDG&E submits summary of requested Permit Modification topics to APCD (covering matters of concern to staff beyond start up)	4/7/06		
9	Mtg. with APCD – QA/QC Plan Addendum (relating to some permit amendment topics)	4/11/06		
10	Request for Permit Modification Fee Estimate submitted to APCD by SDG&E	4/11/06		
11	*APCD (Moore) submits new data request to SDG&E (replaces 3/30 & 4/4 requests)*		*4/14/06*	
12	*Data submitted to APCD (Moore)*		*4/25/06*	
13	Variance 4073 Hearing			4/27/06
14	*Mtg. scheduled with APCD and CEC (in response to 4/7 letter from SDG&E) to discuss permit and rule amendment issues*	5/3/06 (COMPLETED 5/3/06)	*5/3/06* (COMPLETED 5/3/06)	
15	Proposed Permit Pre-application Mtg. with APCD and CEC –	5/19/06 (COMPLETED		

			5/9 & 5/23/06)		
16	Proposed Permit Application Submittal		5/31/06 (COMPLETED 5/31/06)		
17	Quarterly Progress Update (April – June) to Hearing Board				July 27, 2006 (Completed)
18	APCD Permit Application Completeness Review	Respond to APCD data requests while in process	June – July 2006 (Completed)		
19	*APCD drafts rule change*			*April – June 2006*	
20	Quarterly Progress Update (July - September)to Hearing Board				October 27, 2006 (Completed)
21	*APCD holds public workshop on rule amendment*			*July 2006*	
22	*APCD publishes draft rule for public comment*	*30-day public notice required*		*August 2006*	
23	*APCD prepares final rule adoption documents*	*Final rule and "staff report" are prepared for County Board of Supervisors review and adoption*		*September 2006*	
24	*Air Quality Advisory Committee*	*Appointed committee reviews and advises the Board*		*October 2006*	
25	*Board adoption of rule*	*Upon adoption, SDAPCD considers rule to be the version for compliance*		*October 2006*	
26	Proposed Permit Modification (ATC/PDOC) published for public comment	30-day public comment period	October 2006		
27	Final ATC/FDOC revisions	Final language that incorporates public comments is developed	November 2006		
28	Final ATC/FDOC Issued		November 2006		

29	SDG&E petitions CEC for companion amendment of Conditions of Certification (CoC)		December 2006		
30	Quarterly Progress Update (October - December) to Hearing Board				Completed January 25, 2007
31	CEC issues amendment of CoC		March 2007		
32	Quarterly Progress Update (January - March) to Hearing Board				April 26, 2007

Attachment 2

CT1 YTD Summary

	Tons	#
2Q06	9.23	18,460
3Q06	8.61	17,220
4Q06	8.63	17,260
1Q07	8.88	17,760
Total	35.35	70,700

Note: Total NOx includes startup emissions.

CT2 YTD Summary

	Tons	#
2Q06	9.28	18,560
3Q06	8.95	17,900
4Q06	9.70	19,400
1Q07	8.73	17,460
Total	36.66	73,320

Note: Total NOx includes startup emissions.

CT1 Startup YTD Summary

	Tons	#
2Q06	3.19	6,380
3Q06	1.38	2,760
4Q06	0.52	1,040
1Q07	0.38	760
Total	5.47	10,180

CT2 Startup YTD Summary

	Tons	#
2Q06	3.64	7,280
3Q06	1.10	2,200
4Q06	0.52	1,040
1Q07	0.43	860
Total	5.69	10,520

[1] Data gathered from CEMS Startup/Shutdown Incident Reports

[2] Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

OPFLEX AND EARLY AMMONIA INJECTION EFFECTS ON STARTUP EMISSIONS PALOMAR ENERGY CENTER

Subject:

This Evaluation assesses the effects of two major Palomar Energy Center efforts to reduce startup emissions.

Discussion:

Early Ammonia Injection is a SDG&E project to minimize NOx emissions during the startup process by reducing and optimizing the temperature at which ammonia is injected to the SCR's, thereby reducing NOx emissions during the startup process. The original control system allowed ammonia injection when the temperature at the SCR increased to 550 deg F during the plant startup process. This temperature was chosen to provide a safety margin above the required SCR operating temperature. If ammonia is injected at too low of a temperature, the SCR is not effective, there can be elevated ammonia slip, and there is potential for poisoning of the SCR catalyst.

Palomar personnel have analyzed the temperature requirements for the SCR and evaluated the risks associated with low temperature ammonia injection, along with the benefits of emissions reductions obtained by lowering the injection temperature. The evaluation indicated that a significant lowering of the temperature was possible, as long as close attention was paid to the environmental conditions at all locations surrounding the catalyst. The temperature set point for ammonia injection was lowered in two steps as a prudent sequence to confirm the benefits and minimize risk. The first setpoint was lowered during the summer 2006. The setpoint was lowered again to 485 deg F in October 2006.

OpFlex is a General Electric proprietary software improvement that manages the fuel splits and fuel temperature control to minimize NOx and CO emissions at part load, and significantly reduces NOx during the startup process. The turbines can now be operated down to approximately 45% load and remain in compliance with all operating emissions limitations. The NOx produced during the startup process is also minimized approximately 25% to 45%, although not to the point of compliance with the 2.0 ppmvd@15% O2 permit limit.

OpFlex was installed in mid-October, 2006. Subsequent to the installation, Palomar Operations has studied the emissions enhancements OpFlex provides, and has made adjustments to the startup process to take advantage of these enhancements to reduce startup emissions. There have been no extended startups since the installation of OpFlex, so the extended startup procedure has not yet been optimized.

Results:

OpFlex and the final adjustment to the enhanced ammonia injection setpoint were implemented at approximately the same time in mid October, so the emissions improvements attributable to each are somewhat difficult to assign. However, this analysis endeavors to separate the projects and summarize the success of each.

With the SCR at normal operating temperature, ammonia injection can lower startup-related NOx concentrations by approximately 10.0 ppm. At base load, this equates to approximately 45 lbs/hr reduction of NOx mass emissions. This mass emissions reduction remains relatively constant even at reduced operating loads if sufficient NOx is present in the exhaust stream from the turbine.
During a typical hot start following a nightly shutdown, the enhanced, lowered temperature setpoint for ammonia injection allows the ammonia to be injected approximately 60 to 90 minutes earlier than the original setpoint (550 deg F) would have allowed. This provides for a reduction of at least 45 lbs NOx produced during the hot startup. The early ammonia injection NOx reduction for an extended startup will be even greater, conservatively estimated to be 60 lbs NOx per extended start.

OpFlex lowers the NOx produced by the turbine during the startup process at all loads above approximately 25%. The NOx is lowered enough above 45% load that in conjunction with the SCR, the stack emissions are reduced below the permit limit of 2.0 ppmvd@15% O2.

Plant Operations personnel have optimized the startup process to take advantage of this reduction of NOx above 25%. When plant conditions allow, the turbine is immediately ramped to approximately 43%, so that the turbine exhaust emissions are high only for the first 20 – 30 minutes of operation, and the magnitude of these high emissions are greatly reduced above 25%.

Recent normal startups following a typical nightly shutdown have resulted in NOx emissions of 28 lbs NOx, and 10 lbs. CO. For NOx, these results are the combination of OpFlex and early ammonia injection. Prior to the OpFlex and early ammonia projects, a typical regular startup would have produced approximately 120 lbs of NOx and 35 lbs of CO. (Note: Startups early in the project life produced highly variable emissions results). All of the CO reduction for recent startups is attributable to the shorter startup allowed by OpFlex, while 45 lbs. of NOx reduction are attributable to early ammonia injection, and 47 lbs. attributable to OpFlex. See the Summary Table below:

Summary:

Early ammonia injection and OpFlex have both been highly successful in reducing emissions during normal startups. The emissions during an extended startup will also be greatly reduced, although more testing and optimization is required before the results can be quantified. The table below is illustrative of starts after an overnight shutdown of one turbine, which has been a typical mode of operation during the past year. Somewhat higher emissions could occur for longer shutdowns.

Regular Startup Summary Table:

	Startup Emissions before Opflex/Early NH3	Reduction Attributable to Early NH3 Inj.	Reduction Attributable to OpFlex	Recent Regular Startup Results – Note 1 (Nov. 2006 – Feb. 2007)
NOx (lbs.)	120	45	47	28
CO (lbs.)	35	0	25	10

Note 1: Excludes startups after lengthy shutdown (>24 hours) or after HRSG forced cool down for maintenance.

Pack, Heidi K.

From:	Hunt, Kelly [KHunt@Semprautilities.com]
Sent:	Friday, April 13, 2007 8:54 AM
To:	Waller, Fred A.; Pack, Heidi K.; Hartnett, Gary; LaBlond, Jason
Subject:	FW: Palomar Energy Exceedances Covered Under Variance 4073, March 2007 YTD
Importance:	High
Attachments:	PEC Exceedance Covered Under Variance 4073 March 2007YTD.pdf

Please see email below.

Kelly Hunt
Generation Compliance Manager
San Diego Gas & Electric
2300 Harveson Place, SD1473
Escondido, CA 92029
760-432-2504 (Office)
760-432-2510 (Fax)
khunt@semprautilities.com

From: Waller, Fred A.
Sent: Friday, April 06, 2007 5:07 PM
To: Hunt, Kelly
Subject: Palomar Energy Exceedances Covered Under Variance 4073, March 2007 YTD
Importance: High

Kelly,
Please forward this Report of Violation to APCD Compliance (Mr. Jason LaBlond, Mr. Gary Hartnett and copy Ms. Heidi Gabriel-Pack).

Mr. LaBlond,
In a previous telephone conversation we discussed the reporting requirements of APCD Rule 19.2(d)(3)-Report of Violation. You indicated that an email notification to you will suffice to meet the reporting requirements. Additionally, Ms. Heidi Gabriel-Pack, approved monthly reporting of violations which are covered under Variance 4073.

In previous months in 2006, SDG&E had provided a monthly summary report of Violations/Exceedances covered under Variance 4073 to you and copied Mr. Gary Hartnett and Ms. Heidi Gabriel-Pack. SDG&E is submitting this summary report to notify the District of one exceedance in March 2007 covered by Variance 4073 which occurred at the Palomar Energy Center, 2300 Harveson Place, Escondido, CA 92009 .

If you have any questions, please feel free to call.

Fred Waller
Environmental Specialist-Generation
Office: 760 432 2507
Cell: 619 778 6029

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
1	4/3/06	1	9:00	N/A	5 hrs 48 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
2	4/3/06	1	10:00	N/A	5 hrs 48 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
3	4/3/06	2	9:00	N/A	5 hrs 15 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
4	4/3/06	2	10:00	N/A	5 hrs 15 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
5	5/5/06	1	6:00	NOx	128.4	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
6	5/5/06	2	5:00	NOx	143.9	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
7	5/8/06	1	7:00	NOx	106.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
8	5/9/06	2	7:00	NOx	132.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
9	5/10/06	2	6:00	NOx	121.4	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
10	5/13/06	2	8:00	NOx	124.7	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
11	5/14/06	2	8:00	NOx	123.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
12	5/15/06	1	3:00	NOx	101.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
13	5/16/06	2	8:00	NOx	141.1	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
14	5/30/06	2	0:00	N/A	2 hrs 19 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	8/10/06
15	6/4/06	1	10:00	N/A	2 hr 26 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	7/9/06
16	6/13/06	1	19:00	NOx	117.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	7/9/06
17	6/13/06	1	19:00	N/A	2 hr 5 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	1/11/07

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
18	6/15/06	1	10:00	N/A	2 hr 9 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	7/9/06
19	~~6/16/06~~	~~2~~	~~6:00~~	~~N/A~~	~~2 hr 9 min~~	~~Hrs/Mins~~	~~AQ 40: 2 hour startup duration~~	~~Typical regular startup.~~	Reported in error. Was not a violation.	~~7/9/06~~
20	6/16/06	2	6:00	NOx	109.9	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	8/10/06
21	7/2/06	1	9:00	N/A	5 hrs 32 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
22	7/2/06	1	10:00	N/A	5 hrs 32 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
	Aug 2006: No events to report.									
	Sept 2006: No events to report.									
23	10/11/06	1	11:00	N/A	4 hr 45 min	Hrs/Mins	AQ 39: 4 hour startup duration	Extended startup.	Covered under Variance #4073	11/13/06
24	10/12/06	2	6:00	N/A	2 hr 20 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	11/13/06
25	10/12/06	2	6:00	NOx	223.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	11/13/06
26	10/12/06	1	3:00	NOx	127.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	11/13/06
27	November 2006: No events to report.									
28	December 2006: No events to report.									
29	January 2006: No events to report.									
30	February 2006: No events to report.									
31	03/21/07	1	15	N/A	2 hrs 2 min	Hrs/Mins	AQ 40: 2 hour startup duration	Regular startup with generator testing required by WECC.	Covered under Variance #4073	4/9/07

Events 1, 2, 3 and 4 (exceedance of Extended Startup duration limit) were not reported in April 2006 due to confusion over the Reporting requirment of Rule 19.2(d) and the existing Variance 4068.
Event 14 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
	Event 18 was not a violation of AQ 40: 2 hour Regular Startup duration limit. On 6/16/06 CTG 2 was actually started up within the 2 hour limit.									
	Event 17 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.									
	Event 19 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.									

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
There being no motion made, the Air Pollution Control District Hearing Board, unable to discuss the report due to a lack of a quorum, acknowledged the submission of the report and at the discretion of the Board, continued this item to a future date. Member Rodriguez would be provided a copy of the report to review and if she determined that there needs to be further discussion on this report, the Clerk of the Board will schedule a special meeting of the Hearing Board to address concerns.

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

____
Kellie C. Kellogg, Deputy Clerk

SDGE®

A Sempra Energy™ company

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
Escondido, CA 92029
Tel: 760-432-2501
dbaerman@semprautilities.com

July 11, 2007

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's second quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

The increments of progress table attached to the Board's order is included with this letter as Attachment 1. The primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. SDG&E was informed on July 9, 2007 that the District intends to issue the final S/A no later than July 26, 2007. A rule amendment workshop concerning Rule 69.3.1 has been scheduled for August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

No further data has been requested by the Board at this time.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

Attachment 2

CT1 Quarterly Summary

	Tons	#
Apr-07	2.17	4,340
May-07	2.48	4,960
Jun-07	2.74	5,480
Total	7.39	14,780

Note: Total NOx includes startup emissions.

CT1 Startup Summary

	Tons	#
Apr-07	0.00	0.00
May-07	0.07	143.85
Jun-07	0.03	54.35
Total	0.10	198.20

CT2 Quarterly Summary

	Tons	#
Apr-07	2.65	5,300
May-07	2.69	5,380
Jun-07	2.52	5,040
Total	7.86	15,720

Note: Total NOx includes startup emissions.

CT2 Startup Summary

	Tons	#
Apr-07	0.03	63.13
May-07	0.15	307.98
Jun-07	0.14	271.20
Total	0.32	642.31

CT1 YTD Summary

	Tons	#
3Q06	8.61	17,220
4Q06	8.63	17,260
1Q07	8.88	17,760
2Q07	7.39	14,780
Total	33.51	67,020

Note: Total NOx includes startup emissions.

CT1 Startup YTD Summary

	Tons	#
3Q06	1.38	2,760
4Q06	0.52	1,040
1Q07	0.38	760
2Q07	0.10	200
Total	2.38	4,760

CT2 YTD Summary

	Tons	#
3Q06	8.95	17,900
4Q06	9.70	19,400
1Q07	8.73	17,460
2Q07	7.86	15,720
Total	35.24	70,480

Note: Total NOx includes startup emissions.

CT2 Startup YTD Summary

	Tons	#
3Q06	1.10	2,200
4Q06	0.52	1,040
1Q07	0.43	860
2Q07	0.32	640
Total	2.37	4,740

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

Exhibit 3

SAN DIEGO AIR POLLUTION CONTROL DISTRICT HEARING BOARD

COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

Palomar Energy Center

2007 MAY 14 AM 8:35

PROPOSED INCREMENTS OF PROGRESS

(As of4/26/07)

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

MILESTONE **DATE**

	Description	Permit Modification	Rule Change	Variance(s)
1	Variance 4068 hearing for 90-day issued			2/9/06
2	Emergency Variance 4069 for condition 21 issued to enable early ammonia injection.			2/23/06
3	*Palomar submits request for Rule Change to APCD*		*3/6/06*	
4	*APCD requests more data for rule change*		*3/14/06*	
5	*Mtg. with APCD concerning Data Requests*		*3/30/06*	
6	*Additional mtg. with APCD (Steve Moore) concerning Data Requests*		*4/4/06*	
7	*SDG&E submits requested data to APCD (Moore)*		*4/7/06*	
8	SDG&E submits summary of requested Permit Modification topics to APCD (covering matters of concern to staff beyond start up)	4/7/06		
9	Mtg. with APCD – QA/QC Plan Addendum (relating to some permit amendment topics)	4/11/06		
10	Request for Permit Modification Fee Estimate submitted to APCD by SDG&E	4/11/06		
11	*APCD (Moore) submits new data request to SDG&E (replaces 3/30 & 4/4 requests)*		*4/14/06*	
12	*Data submitted to APCD (Moore)*		*4/25/06*	
13	Variance 4073 Hearing			4/27/06
14	*Mtg. scheduled with APCD and CEC (in response to 4/7 letter from SDG&E) to discuss permit and rule amendment issues*	5/3/06 (COMPLETED 5/3/06)	*5/3/06* (COMPLETED 5/3/06)	
15	Proposed Permit Pre-application Mtg. with APCD and CEC –	5/19/06 (COMPLETED		

	Description		Permit Modification	Rule Change	Variance(s)
			5/9 & 5/23/06)		
16	Proposed Permit Application Submittal		5/31/06 (COMPLETED 5/31/06)		
17	Quarterly Progress Update (April – June) to Hearing Board				July 27, 2006 (Completed)
18	APCD Permit Application Completeness Review	Respond to APCD data requests while in process	June – July 2006 (Completed)		
19	*APCD drafts rule change*			*April – June 2006*	
20	Quarterly Progress Update (July - September)to Hearing Board				October 27, 2006 (Completed)
21	*APCD holds public workshop on rule amendment*			*July 2006*	
22	*APCD publishes draft rule for public comment*	*30-day public notice required*		*August 2006*	
23	*APCD prepares final rule adoption documents*	*Final rule and "staff report" are prepared for County Board of Supervisors review and adoption*		*September 2006*	
24	*Air Quality Advisory Committee*	*Appointed committee reviews and advises the Board*		*October 2006*	
25	*Board adoption of rule*	*Upon adoption, SDAPCD considers rule to be the version for compliance*		*October 2006*	
26	Proposed Permit Modification (ATC/PDOC) published for public comment	30-day public comment period	October 2006		
27	Final ATC/FDOC revisions	Final language that incorporates public comments is developed	November 2006		
28	Final ATC/FDOC		November		

	Description	Permit Modification	Rule Change	Variance(s)
	Issued	2006		
29	SDG&E petitions CEC for companion amendment of Conditions of Certification (CoC)	December 2006		
30	Quarterly Progress Update (October - December) to Hearing Board			Completed January 25, 2007
31	CEC issues amendment of CoC	March 2007		
32	Quarterly Progress Update (January - March) to Hearing Board			April 26, 2007;completed
33	**Extension of Regular Variance Granted**			**April 26, 2007**
34	See Tentative Rule Schedule for Rule 69.3.1, Exhibit 2 to Board Order Granted April 26, 2007.	May-December, 2007		
35	Quarterly Progress Update (April – June) to Hearing Board			July 26, 2007;
36	Quarterly Progress Update (October-December) to Hearing Board			January 17, 2008

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073

ACTION:
ON MOTION of Member Rodríguez, seconded by Member Reider, the Air Pollution Control District Hearing Board accepted the quarterly report and directed San Diego Gas & Electric to provide the Board with revised Increments of Progress, reflecting the testimony of County Counsel representing the APCD. The revision to the Increments of Progress Schedule (IOPS) pertained to the accurate reflection of issuance of authority to construct or permit to operate. The revised IOPS is to be submitted to the Air Pollution Control District Hearing Board for the meeting of October 25, 2007.

AYES: Rodríguez, Tonner, Reider
ABSTAIN: Rappolt
RECUSED: Gabrielson

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

By Kellie C. Kellogg
Kellie C. Kellogg
Deputy Clerk

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric/Palomar Energy Center per Condition No. F.3, and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
ON MOTION of Member Gabrielson, seconded by Member Tonner, the Air Pollution Control District Hearing Board accepted the report from San Diego Gas & Electric.

AYES: Rappolt, Gabrielson, Tonner
ABSENT: Rodriguez

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

Kellie C. Kellogg
Kellie C. Kellogg, Deputy Clerk

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A Sempra Energy company

COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

2007 OCT 11 PM 3: 17

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
Escondido, CA 92029
Tel: 760-432-2501
dbaerman@semprautilities.com

October 11, 2007

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's third quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

Referenced below are the increments of progress table attached to the Board's order; the primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. SDG&E was updated by the District on October 8, 2007 on the progress of the issuance of the final S/A. The District intends to issue to final S/A no later than November 30, 2007. A rule amendment workshop concerning Rule 69.3.1 was held on August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

SDG&E received a letter dated September 14, 2007 from the District requesting a cold start and source test. The cold start and source test is scheduled to occur during the period of October 21, 2007 and October 26, 2007. District staff will be onsite to witness the test.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

CT1 3q07 NOx Summary

	Tons	#
Jul-07	3.01	6,011
Aug-07	3.21	6,419
Sep-07	2.97	5,932
Total	9.18	18,362

Note: Total NOx includes startup emissions.

CT1 Startup Only Summary

	Tons	#
Jul-07	0.33	658
Aug-07	0.17	341
Sep-07	0.19	386
Total	0.69	1,386

CT2 3q07 NOx Summary

	Tons	#
Jul-07	3.38	6,766
Aug-07	3.26	6,513
Sep-07	3.20	6,410
Total	9.84	19,689

Note: Total NOx includes startup emissions.

CT2 Startup Only Summary

	Tons	#
Jul-07	0.09	180
Aug-07	0.10	208
Sep-07	0.09	173
Total	0.28	561

CT1 YTD NOx Summary

	Tons	#
4Q06	8.63	17,260
1Q07	8.88	17,760
2Q07	7.39	14,780
3Q07	9.18	18,362
Total	34.08	68,162

Note: Total NOx includes startup emissions.

CT1 YTD Startup Only

	Tons	#
4Q06	0.52	1,040
1Q07	0.38	760
2Q07	0.10	200
3Q07	0.69	1,386
Total	1.69	3,386

CT2 YTD NOx Summary

	Tons	#
4Q06	9.70	19,400
1Q07	8.73	17,460
2Q07	7.86	15,720
3Q07	9.84	19,689
Total	36.13	72,269

Note: Total NOx includes startup emissions.

CT2 YTD Startup Only

	Tons	#
4Q06	0.52	1,040
1Q07	0.43	860
2Q07	0.32	640
3Q07	0.28	561
Total	1.55	3,101

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
ON MOTION of Member Gabrielson, seconded by Member Rodriguez, the Air Pollution Control District Hearing Board accepted the report.

AYES: Rappolt, Rodriguez, Gabrielson, Tonner
ABSTAIN: None

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

By Kellie C. Kellogg
Kellie C. Kellogg
Deputy Clerk

COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

2008 JAN 14 AM 8:40

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

SDG&E®

A Sempra Energy company

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
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January 13, 2008

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's fourth quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

Referenced below are the increments of progress table attached to the Board's order; the primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. The District issued the final S/A on November 6, 2007. A rule amendment workshop concerning Rule 69.3.1 was held on August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 1. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

SDG&E received a letter dated September 14, 2007 from the District requesting a cold start and source test. The cold start and source test occurred on October 22, 2007. District staff was onsite to witness the test. The District has the source test report and raw data as requested.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

CT1 4q07 NOx Summary

	Tons	#
Oct 07	2.59	5,179
Nov 07	2.92	5,831
Dec 07	3.52	7,038
Total	9.02	18,048

Note: Total NOx includes startup emissions.

CT1 Startup Only Summary

	Tons	#
Oct 07	0.18	356
Nov 07	0.13	262
Dec 07	0.03	52
Total	0.34	670

CT2 4q07 NOx Summary

	Tons	#
Oct 07	2.63	5,255
Nov 07	3.47	6,949
Dec 07	3.37	6,732
Total	9.47	18,936

Note: Total NOx includes startup emissions.

CT2 Startup Only Summary

	Tons	#
Oct 07	0.00	0
Nov 07	0.29	573
Dec 07	0.09	173
Total	0.37	747

CT1 12-Mo NOx Summary

	Tons	#
1Q07	8.88	17,760
2Q07	7.39	14,780
3Q07	9.18	18,362
4Q07	9.02	18,048
Total	34.48	68,950

Note: Total NOx includes startup emissions.

CT1 12-Mo Startup Only

	Tons	#
1Q07	0.38	760
2Q07	0.10	200
3Q07	0.69	1,386
4Q07	0.34	670
Total	1.51	3,016

CT2 12-Mo NOx Summary

	Tons	#
1Q07	8.73	17,460
2Q07	7.86	15,720
3Q07	9.84	19,689
4Q07	9.47	18,936
Total	35.90	71,805

Note: Total NOx includes startup emissions.

CT2 12-Mo Startup Only

	Tons	#
1Q07	0.43	860
2Q07	0.32	640
3Q07	0.28	561
4Q07	0.37	747
Total	1.40	2,808

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

Exhibit 24

Poloncarz, Kevin

From: Poloncarz, Kevin
Sent: Thursday, June 18, 2009 5:10 PM
To: 'Alexander Crockett'
Subject: PM10/PM2.5 Cooling Tower BACT.DOC

Attachments: PM10/PM2.5 Cooling Tower BACT.DOC; Monthly City Data.pdf; Final Clarifier_2008.pdf

Sandy:

Attached is a very brief justification for reducing the cooling tower TDS limit from 8,000 to 6,200 ppmw as BACT. Also attached are analytical data from the City of Hayward's Waste Water Treatment Plant that I previously submitted in association with the GHG BACT analysis. Additional data could be submitted to support this analysis.

Thanks.

PM10_PM2.5 ooling Tower BACT. | Monthly City Data.pdf | Final Clarifier_2008.pdf

Kevin Poloncarz
Partner
T 415.393.2870
F 415.393.2286
kevin.poloncarz@bingham.com

B I N G H A M
Bingham McCutchen LLP
Three Embarcadero Center
San Francisco, CA 94111-4067

The Air District's analysis of best available control technology ("BACT") for the cooling tower identified high-efficiency drift eliminators as the only technology available for controlling drift from the cooling tower and, as a consequence, its emissions of particulate matter ("PM"). Because the solids which form PM are contained within water droplets emitted as drift, the Air District found that imposing a direct numerical limitation on emissions of PM from the cooling tower was infeasible. Rather, based upon source test results provided by Calpine for Metcalf Energy Center, the Air District concluded that requiring Russell City Energy City ("RCEC" or the "Applicant") to equip the cooling tower with high-efficiency drift eliminators guaranteed to achieve less than 0.0005 percent drift constituted BACT.

The amount of PM emitted by the cooling tower is a function, not only of the use of high-efficiency drift eliminators, but also of (i) the concentration and type of pollutants within the cooling water (*i.e.*, the quality of the water source), (ii) the number of times such water can be cycled through the cooling system without damaging its equipment, and (iii) the manner in which the water is managed after it has been used in the system, including any restrictions on the discharge of blowdown water from the facility. In light of these considerations, the draft permit proposed a condition limiting the amount of Total Dissolved Solids ("TDS") in the facility's cooling water to 8,000 parts per million by weight ("ppmw") (milligrams per liter ("mg/l")), as measured at the base of the cooling tower or point of return to the wastewater facility. *Statement of Basis for Proposed Amended PSD Permit*, at 78, proposed condition C.44.

The proposed RCEC would reclaim and reuse up to 4 million gallons per day ("gpd") of waste water from the City of Hayward's Waste Water Treatment Plant in the power plant's cooling system. Location of the proposed project near an available supply of wastewater was one of the key project objectives identified by the California Energy Commission in its approval of RCEC.[1] By reclaiming a source of waste water and managing the resulting blowdown in a "Zero Liquid Discharge" ("ZLD") system, RCEC will eliminate the City's discharge of up to 4 million gpd of waste water to San Francisco Bay ("Bay"). This will also avoid consuming a higher-quality water source for the same purpose, as well as any of the impacts associated with "once-through cooling".

Since the time when the draft permit condition was imposed, the Applicant has received a substantial amount of additional analytical data from the City Waste Water Treatment Plant on the quality and contents of Treatment Plant effluent. Based upon the Applicant's analysis of these data and the design capacity of RCEC's waste water reclamation and ZLD systems, the Applicant has concluded that it can meet a lower TDS limit, while still achieving its primary objective of using reclaimed waste water in its cooling system. As a consequence, RCEC has proposed reducing the TDS limit from 8,000 ppmw, to 6,200 ppmw.

RCEC might meet a lower TDS limit and thereby reduce its potential emissions of PM10/PM2.5 if it were to use a higher-quality water source or discharge blowdown from the cooling tower to the Bay or the City's treatment plant. However, such alternatives would obstruct one of the

[1] The California Energy Commission determined that the objectives of the proposed RCEC were "[t]o locate near centers of demand and key infrastructure, such as transmission line interconnections, supplies of process water (preferably wastewater), and natural gas at competitive prices". *2002 California Energy Commission Decision*, at 17.

project's core objectives. As a consequence, imposition of a lower limit on cooling tower TDS would limit RCEC's use of reclaimed waste water or necessitate other significant changes to the design of its cooling, waste water reclamation and ZLD systems. The BACT standard has not historically been applied to require such fundamental changes in a proposed source's objectives or design. In light of the foregoing considerations, RCEC will meet BACT for its emissions of PM10/PM2.5 by using high-efficiency drift eliminators guaranteed to achieve less than 0.0005% drift and by meeting a TDS limit of 6,200 ppmw (as measured at the base of the cooling tower or the point of return to the facility's waste water treatment system).

City of Hayward TFSC Process Control Data

			Primary Effluent				Trickling Filter						Solids Contact										Secondary Clarifier								
Date	Temp F	Flow (Q) MGD	TSS (mg/L)	NH4 (mg/L)	CBOD (mg/L)	SCBOD (mg/L)	OLR (#/Ksf/D)	TSS (mg/L)	SCBOD (mg/L)	Efficiency (%)	NH4 (mg/L)	NO3 (mg/L)	MLSS (mg/L)	SCBOD (mg/L)	NO3 (mg/L)	DO (mg/L)	SRT Calculated	SRT Analyzer	SVI (Index)	WSS Q (gpm)	RSS TSS (mg/L)	RSS Ratio (Ratio)	TSS (mg/L)	SCBOD (mg/L)	CBOD (mg/L)	NH4 (mg/L)	NO3 (mg/L)	Blankets 1 (inches)	Blankets 2 (inches)	SOR (gal/sf/D)	SLR (#/sf/D)
1-Nov		13.5																												[illegible]	
2-Nov		13.8																												[illegible]	
3-Nov		12.6											2500																	[illegible]	[illegible]
4-Nov		13.2	118		295	182	[illegible]	291	34	[illegible]			950				[illegible]	1.3		360	3052	0.5	46		50			0	0	[illegible]	[illegible]
5-Nov		12.9																												[illegible]	
6-Nov		12.3																												[illegible]	
7-Nov		11.4																												[illegible]	
8-Nov		14.1																												[illegible]	
9-Nov		12.5																												[illegible]	
10-Nov		12.1																												[illegible]	
11-Nov		12.2																												[illegible]	
12-Nov		12.1	121		310	196	[illegible]	261	35	[illegible]			1005				[illegible]	1.5		332	3125	0.5	36		32			0	0	[illegible]	[illegible]
13-Nov		12.1	115		301	212	[illegible]	237	36	[illegible]			1100				[illegible]	1.5		332	3250	0/5	64		42			0	0	[illegible]	[illegible]
14-Nov		12.3																												[illegible]	
15-Nov		11.9																												[illegible]	
16-Nov		12.1																												[illegible]	
17-Nov		12																												[illegible]	
18-Nov		12.3	129		240	154	[illegible]	379	28	[illegible]			1206				[illegible]	2.2		332	3315	0/5	44		25			0	8	[illegible]	[illegible]
19-Nov		13.2	100					333					1256				[illegible]	2.2		332	3254	0/5	28					0	0	[illegible]	[illegible]
20-Nov		11.8	120		303	218	[illegible]	282	32	[illegible]			1260				[illegible]	2.2		332	3280	0.5	47		38			0	0	[illegible]	[illegible]
21-Nov		13.2																												[illegible]	
22-Nov		11.6																												[illegible]	
23-Nov		12.1																												[illegible]	
24-Nov		11.8																												[illegible]	
25-Nov		11.5	133		332	213	[illegible]	255	36	[illegible]			1185	8			[illegible]	1.1		360	2850	0.5	20		19			3"	3"	[illegible]	[illegible]
26-Nov		12.2	136					444					1050				[illegible]	1.1		360	2755	0.5	32					0	0	[illegible]	[illegible]
27-Nov		11.8	103		267	155	[illegible]	338	34	[illegible]	33	9	985	8	10		[illegible]	1.6		340	2940	0.5	29		23			0	0	[illegible]	[illegible]
28-Nov																															
29-Nov																															
30-Nov																															
Average	#DIV/0!	12.4	119.44	#DIV/0!	293	190	[illegible]	313	33.571	[illegible]	33	9	1250	8	10	#DIV/0!	[illegible]	1.6	#DIV/0!	342	3091	0.5	38	#DIV/0!	33	#DIV/0!	#DIV/0!	0.0	1.0	[illegible]	[illegible]
Minimum	0	11.4	100	0	240	154	[illegible]	237	28	[illegible]	33	9	950	8	10	0	[illegible]	1.1	0	332	2755	0.5	20	0	19	0	0	0	0	[illegible]	[illegible]
Maximum	0	14.1	136	0	332	218	[illegible]	444	36	[illegible]	33	9	2500	8	10	0	[illegible]	2.2	0	360	3315	0.5	64	0	50	0	0	0	8	[illegible]	[illegible]

Note:

Shading indicates a formula, as additional data is entered into the table, copy down the formulas

Formulas:

Trickling Filter Effluent OLR = Flow x Primary Effluent CBOD x 8.34 / 190

Trickling Filter Effluent Efficiency = (Primary Effluent SCBOD - Trickling Filter Effluent SCBOD) / Primary Effluent SCBOD

Secondary Clarifier SOR = Flow x 1000000 / 22608

Secondary Clarifier SLR = Flow x 8.34 x Solids Contact MLSS / 22608

Solids Contact SRT (S) = ((P x 8.34 x .8) + (W x 8.34 x .4))/ (W x 8.34) x (V/697)

City of Hayward TFSC Process Control Data				Primary Effluent				Trickling Filter						Solids Contact									Secondary Clarifier								
Date	Time	Temp F	Flow (Q) MGD	TSS (mg/L)	NH4 (mg/L)	CBOD (mg/L)	SCBOD (mg/L)	OLR (#/Ksf/D)	TSS (mg/L)	SCBOD (mg/L)	Efficiency (%)	NH4 (mg/L)	NO3 (mg/L)	MLSS (mg/L)	NO3 (mg/L)	DO (mg/L)	SRT Calculated	SRT Analyzer	SVI (Index)	WSS Q (gpm)	RSS TSS (mg/L)	RSS Ratio (Ratio)	TSS (mg/L)	SCBOD (mg/L)	CBOD (mg/L)	NH4 (mg/L)	NO3 (mg/L)	Blankets 1 (inches)	Blankets 2 (inches)	SOR (gal/sf/D)	SLR (#/sf/D)
12/2/2008		72	11.6	102					350					1240		1.1	19	1.6	83	270	3132	0.5	41					0	0	[illegible]	[illegible]
12/3/2008		72	11.6	106	36	284	186	145	353	22	88%	31	13	1090	10	1.3	17	1.6	104	335	3085	0.5	23		21		10	0	0	[illegible]	[illegible]
12/4/2008		71	11.5	109		194	140	98	299	18	87%			1148		1.2	16	1.6	92	325	3058	0.5	18		16			0	0	[illegible]	[illegible]
12/5/2008		72	8.9											1110		1.1	17	1.6		270	3230	0.5						0	0	[illegible]	[illegible]
12/6/2008		72	11.6													1.2		1.6		270		0.5						0	0	[illegible]	
12/7/2008		72	11.3													1.25		1.6		270		0.5						0	0	[illegible]	
12/8/2008		72	11.9											1250		1.28	18	1.6		270	3200	0.5						0	0	[illegible]	[illegible]
12/9/2008		71	12	101	37				249			38	10	1215		1.3	18	1.6	110	270	3235	0.5	15			36.2	10	10"	12"	[illegible]	[illegible]
12/10/2008		71	11.5	99		290	194	146	272	23	88%			1480		1.2	18	1.6	89	270	3805	0.5	14		20			4"	0	[illegible]	[illegible]
12/11/2008		71	11.4	102		249	196	125	266	23	88%			1340		1.2	18	1.6		270	3440	0.5	18	10	18			6"	0	[illegible]	[illegible]
12/12/2008		72	11.6													1.2		1.8	77	240		0.5						0	0	[illegible]	
12/13/2008		72	11.3													1.2		1.8		240		0.5						0	0	[illegible]	
12/14/2008		71	12.2													1.2		1.8		240		0.5						0	0	[illegible]	
12/15/2008		72	14.4													1.2		1.8		240		0.5						8"	8"	[illegible]	
12/16/2008		71	12.3	90	39				198			43	0.1	1300		1.2	19	1.8	95	240	3880	0.5	23			42	0	0	0	[illegible]	[illegible]
12/17/2008		72	12.1	79		191	134	101	199	18	87%			1200		1.2	20	1.8		240	3520	0.5	15		12			0	0	[illegible]	[illegible]
12/18/2008		72	9	114		264	156	104	275	32	79%					1.2		1.8		240		0.5	23	8	21			0	0	[illegible]	
12/19/2008		72	12.2													1.2		1.8		240		0.5						0	0	[illegible]	
12/20/2008		72	11.8											1300		1.2	22	2	105	200	3860	0.5						0	0	[illegible]	[illegible]
12/21/2008		71	12.1											1350		1.2	24	2	90	200	3870	0.5						0	0	[illegible]	[illegible]
12/22/2008		72	15											1370		1.2	25	2	96	200	4050	0.5						0	0	[illegible]	114
12/23/2008		71	12.8	96	39	127	82	71	127	5	94%	39	0.3	1270		1.2	22	2		200	4300	0.5	27		13	44	0.2	0	0	[illegible]	[illegible]
12/24/2008		71	12.7	77	42				313			45	0	1347		1.2	22	2		200	4450	0.5	24			44	0.1	8"	5"	[illegible]	[illegible]
12/25/2008		72	13.2	84	27	207	145	120	183	18	88%	33	0			1.2		2		200		0.5	23	3	15	29	0.5	6"	8"	[illegible]	
12/26/2008		71	12.4													1.2		2		205		0.5						12"	12"	[illegible]	
12/27/2008		70	11.9	92					416							1.2		2		210		0.5	17					8"	9"	[illegible]	
12/28/2008		70	12.2											1480		1.2	22	2		210	4550	0.5						10"	9"	[illegible]	100
12/29/2008		71	12.3											1510		1.2	22	2	95	210	4500	0.5						0	0	[illegible]	103
12/30/2008		70	12.6	86	26	236	156	131	222	18	88%	29	0	1390		1.2	22	2	94	210	4460	0.5	18		14	26	0.5	0	0	[illegible]	97
12/31/2008		70	12.9	107	26				302			31	0	1510		1.2	22	2		210	4480	0.5	22			25	0.4	10"	8"	[illegible]	[illegible]
Average		71.4	12.0	96.267	34	227	154	116	268	19.667	88%	36	3	1311	10	1.2	20	1.8	94	240	3795	0.5	21	7	17	35	3	0.0	0.0	[illegible]	[illegible]
Minimum		70	8.9	77	26	127	82	71	127	5	79%	29	0	1090	10	1.1	20	1.6	77	200	3058	0.5	14	3	12	25	0	0	0	[illegible]	[illegible]
Maximum		72	15	114	42	290	196	146	416	32	94%	45	13	1510	10	1.3	20	2	110	335	4550	0.5	41	10	21	44	10	0	0	663	114

Note:

Shading indicates a formula, as additional data is entered into the table, copy down the formulas

Formulas:

Trickling Filter Effluent OLR = Flow x Primary Effluent CBOD x 8.34 / 190

Trickling Filter Effluent Efficiency = (Primary Effluent SCBOD - Trickling Filter Effluent SCBOD) / Primary Effluent SCBOD

Secondary Clarifier SOR = Flow x 1000000 / 22608

Secondary Clarifier SLR = Flow x 8.34 x Solids Contact MLSS / 22608

Solids Contact SRT (S) = ((P x 8.34 x .8) + (W x 8.34 x .4))/ (W x 8.34) x (V/697)

Jan 09

City of Hayward TFSC Process Control Data

Date	Temp °F	Flow MGD	Primary Effluent TSS (mg/L)	Primary Effluent NH4 (mg/L)	Primary Effluent CBOD (mg/L)	Primary Effluent SCBOD (mg/L)	TFs In Service	Trickling Filter OLR (#/Ksf/D)	Trickling Filter TSS (mg/L)	Trickling Filter SCBOD (mg/L)	Trickling Filter Efficiency (%)	Trickling Filter NH4 (mg/L)	Trickling Filter NO3 (mg/L)	Solids Contact MLSS (mg/L)	Solids Contact SCBOD (mg/L)	Solids Contact NH4 (mg/L)	Solids Contact NO3 (mg/L)	Solids Contact DO (mg/L)	Solids Contact SCTs in Service	Solids Contact SRT Calculated	Solids Contact SRT Analyzer	Solids Contact SVI (Index)	Solids Contact WSS Q (gpm)	Solids Contact RSS TSS (mg/L)	Solids Contact RSS Ratio (Ratio)	Secondary Clarifier TSS (mg/L)	Secondary Clarifier SCBOD (mg/L)	Secondary Clarifier CBOD (mg/L)	Secondary Clarifier NH4 (mg/L)	Secondary Clarifier NO3 (mg/L)	Secondary Clarifier Blankets 1 (inches)	Secondary Clarifier Blankets 2 (inches)	Secondary Clarifier Clarifiers In Service	Secondary Clarifier SOR (gal/sf/D)	Secondary Clarifier SLR (#/sf/D)
1/1	69	11.4	107	26	179	113	1	90	302	24	79%	33	0	1270	5			1.2	2	2.4	2	92	200	3500	0.5	21	5	12	26	1	10	8	2	506	12.7
1/2	68	12.2					1							1260				1.2	2	2.1	2		200	4963	0.5						11	8	2	541	16.9
1/3	70	12.3	88	26			1		231			33	0	1285				1.2	2	2.1	2		200	5063	0.5	12			26	1	6	12	2	544	17.3
1/4	69	12.5		26			1					33		1278				1.2	2	2.1	2	100	200	5177	0.5				26		6	12	2	555	17.9
1/5	69	12.6					1							1310				1.2	2	2.0	2		200	6320	0.5						6	9	2	557	20.8
1/6	69	12.4	104	27			1		314			34	0.1	1325			2	1.2	2	2.1	2		200	5451	0.5	18			27	0.2	8	7	2	546	18.5
1/7	68	12.3	86	27	204	134	1	110	363	15	89%	32	0	1350			2	1.2	2	2.1	2	96	200	5600	0.5	17		15	27	2	9	11	2	544	18.8
1/8	69	12.4	50	27	206	161	1	112	301	25	84%	32	0	1480	11	26	1	1.2	2	2.1	2		200	5813	0.5	17	6	15	25	2	9	9	2	550	20.1
1/9	70	12.2					1							1580				1.2	2	2.2	2		200	5368	0.5						6	6	2	540	19.2
1/10	69	12.2					1		215					1660				1.2	2	2.3	2	95	200	5103	0.5	24					6	10	2	539	18.9
1/11	69	12.3	99	28			1					34		1668		32		1.2	2	2.3	2		200	5100	0.5				28		6	9	2	542	19.1
1/12	70	12.4					1						0	1620			0	1.2	2	2.2	2		210	5163	0.75					1	12	12	2	547	25.1
1/13	70	12.2	110	28	263	175	1	141	231	26	85%	32	0	1660		26	2	1.2	2	2.2	2		210	4950	0.75				25	1	12	14	2	539	24.2
1/14	70	12.0	107	28	244	152	1	129	228	20	87%	31	0	1655	8	27	2	1.2	2	2.2	2	103	220	4276	0.75	14		14	28	0	6	6	2	532	21.6
1/15	69	12.2	100	29			1		268			35	0	1700		29	3	1.2	2	2.0	2		257	4262	0.75	13	5	14	28	0.8	9	9	2	538	22.0
1/16	70	12.0					1							1712				1.2	2	1.9	1.9		258	4476	0.75	16					8	6	2	532	22.5
1/17	70	11.0	79	27			1		189			34	0	1810		28	1	1.2	2	1.7	1.8		288	4958	0.75				27	0.5	9	12	2	487	22.5
1/18	70	11.8					1							1799				1.2	2	1.7	1.8		302	4531	0.75	13					6	8	2	520	22.5
1/19	69	12.8					1							1796				1.2	2	1.9	1.7		275	4192	0.75						6	9	2	565	23.3
1/20	69	11.8	86	27			1		185			35	0	1847		28	3	1.2	2	1.8	1.7	88	280	4338	0.75	10			25	2	5	8	2	523	22.3
1/21	69	12.1	80	24	212	178	1	112	217	14	92%	29	0	1855		24	0	1.2	2	1.9	1.6		280	3902	0.75	17		13		0	8	10	2	534	21.3
1/22	69	14.0	123	21	222	129	1	136	272	13	90%	26	0	1839	5	27	0	1.2	2	1.9	1.7	102	270	4228	0.55	9	5	10	21	0	6	8	2	618	21.5
1/23	67	13.4					1						0	1440			0	1.2	2	1.9	1.7		270	3480	0.75					0	8	9	2	591	20.0
1/24	69	13.3	64				1		159					1381				1.2	2	2.0	1.7		262	3216	0.75	6				0	5	7	2	587	18.6
1/25	69	13.4					1							1389				1.2	2	1.9	1.6		278	3050	0.75					1	5	6	2	593	18.2
1/26	69	13.0					1							1410				1.2	2	2.2	1.8		243	3004	0.75						3	4	2	574	17.5
1/27	69	12.8	88	25			1		138			28	0	1429		20	0	1.2	2	2.2	1.8	79	240	3332	0.75	18			19	0	6	8	2	566	18.5
1/28	69	12.8	79	28	250	169	1	140	125	13	92%	30	0	1457		16	0	1.2	2	2.1	1.8		252	3159	0.75	18		13	16		6	9	2	566	18.1
1/29	69	12.7	98	27	229	148	1	128	159	11	93%	27	0	1326	6	16	0	1.3	2	2.1	1.8		251	3029	0.75	13	4	11	16		4	6	2	562	16.9
1/30	69	13.1					1							1370				1.4	2	2.5	1.8		212	3049	0.75						9	12	2	579	17.7
1/31	69	12.3					1							1428				1.6	2	2.3	1.8		222	3317	0.75						9	9	2	544	17.8
Averag	69.1	12.4	91.059	27	223	151		122	229	17.8889	88%	32	0	1529	7	25	1	1.2		2.1	1.9	94	235	4367	0.7	15	5	13	24	1	7.3	8.8		550	19.7
Minim	67	11.02	50	21	179	113		90	125	11	79%	26	0	1260	5	16	0	1.2		2.1	1.6	79	200	3004	0.5	6	4	10	16	0	3	4		487	12.7
Maxim	70	13.97	123	29	263	178		141	363	26	93%	35	0.1	1855	11	32	3	1.6		2.1	2	103	302	6320	0.75	24	6	15	28	2	12	14		618	25.1

Note:

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Formulas:

Trickling Filter Effluent OLR = Flow x Primary Effluent CBOD x 8.34 / 190

Trickling Filter Effluent Efficiency = (Primary Effluent SCBOD - Trickling Filter Effluent SCBOD) / Primary Effluent SCBOD

Secondary Clarifier SOR = Flow x 1000000 / 22608

Secondary Clarifier SLR = Flow x 8.34 x Solids Contact MLSS / 22608

Solids Contact SRT (S) = ((P x 8.34 x .8) + (W x 8.34 x .4))/ (W x 8.34) x (V/697)

City of Hayward - WPCF

February 2009

City of Hayward TFSC Process Control Data																																			
	Trickling Filter		Primary Effluent				Trickling Filter							Solids Contact												Secondary Clarifier									
Date	Temp °F	Flow MGD	TSS (mg/L)	NH4 (mg/L)	CBOD (mg/L)	SCBOD (mg/L)	TFs In Service	OLR (#/Ksf/D)	TSS (mg/L)	SCBOD (mg/L)	Efficiency (%)	NH4 (mg/L)	NO3 (mg/L)	MLSS (mg/L)	SCBOD (mg/L)	NH4 (mg/L)	NO3 (mg/L)	DO (mg/L)	SCTs In Service	SRT Calculate	SRT Analyzer	SVI (Index)	WSS Q (gpm)	RSS TSS	RSS Ratio (Ratio)	TSS (mg/L)	SCBOD (mg/L)	CBOD (mg/L)	NH4 (mg/L)	NO3 (mg/L)	Blankets 1 (inches)	Blankets 2 (inches)	Clarifiers In Service	SOR (gal/sf/D)	SLR (#/sf/D)
2/1	69	12.4	86	26			1		158			25		1461		20		2.5	2	2.4	2		212	3632	0.75	13			18		6	8	2	548	19.1
2/2	69	12.5					1							1500				2.4	2	2.3	2		227	3461	0.75						8	9	2	553	18.9
2/3	69	12.4	90	28			1		195.3			27	0	1587		20	4	1.7	2	2.3	2	83	225	3565	0.75	14.6			20	4	6	7	2	548	19.5
2/4	69	12.1	77	26	232	167	1	123	220	13	92%	30	0	1653		21	4	1.7	2	2.4	2	83	226	3495	0.75	14		14	22	4	8	10	2	535	19.1
2/5	68	12.6	111	26	281	172	1	155	350.7	20	88%	26	0	1423	10	20	0	2	2	2.4	2		212	3379	0.75	19	7	20	18	0	9	9	2	557	18.4
2/6	69	12.5					1							1418				1.5	2	2.3	2		221	3339	0.75						6	8	2	553	18.1
2/7	68	12.8	58				1		233				0	1420			0	2	2	2.3	2	92	227	3332	0.75	11				0	3	3	2	566	18.5
2/8	67	12.3					1							1418				2.8	2	2.3	2	87	228	3264	0.75						3	6	2	544	17.5
2/9	67	13.3					1							1456				1.9	2	2.3	2		225	3290	0.75						2	4	2	588	19.2
2/10	68	12.3	-			-	1		239			21	0	1432		16	0	1.4	2	2.3	2		225	3283	0.75	23			17	0	9	6	2	544	17.7
2/11	67	12.7	66	26	258	189	1	144	199.3	15	92%	20	0	1409		14	0	2	2	2.4	2	78	222	3229	0.75	19		19	14	0	8	6	2	562	17.9
2/12	69	12.1	115	25	305	192	1	162	158.7	15	92%	20	0	1310		14	0	2.1	2	2.3	2	83	211	3385	0.75	19	5	17		0	0	0	2	535	17.2
2/13	69	14.7					1							1418				3.2	2	2.4	2		212	3339	0.75						3	3	2	650	21.3
2/14	68	13.8	96	23			1		324			24	0	1207		21	0	3.1	2	2.4	2		192	3771	0.75	20			18	0	6	8	2	610	20.5
2/15	67	16.2					1							1235				4.1	2	2.3	2		197	3806	0.75						6	6	2	717	24.4
2/16	67	20.1					1							1286				3	2	2.8	2		188	2957	0.75						6	8	2	889	26.0
2/17	66	17.5	85	18			1		205			16	0	1216		12	0	3.2	2	2.5	2	78	200	3119	0.75	19			11	0	5	6	2	774	23.0
2/18	68	17.1	93	20	202	109	1	152	287	13	88%	19	0	1315		13	0	3.8	2	2.7	2	87	186	3289	0.75	19		15	11	0	8	10	2	756	23.9
2/19	68	12.9	104	22	276	166	2	78	256	24	86%	24	0	1444	11	20	0	1.6	2	2.5	2		200	3612	0.75	22	9	20	18	0	4	2	2	571	19.8
2/20	69	11.7					2							1407				1.2	2	2.2	2		217	4107	0.7						3	3	2	518	18.5
2/21	68	12.1	99	24			2		270			19	0	1422		17	1	1.2	2	2.3	2		210	3956	0.7	19			16	1	4	6	2	535	18.7
2/22	68	14.0					2							1435				2.1	2	2.5	2		194	3786	0.7						6	8	2	619	21.1
2/23	68	13.3					2							1484				2	2	2.2	2		216	4372	0.7						5	12	2	588	22.3
2/24	68	13.3	101	22			2		367			21	0	1511		16	1	1.6	2	2.1	2		224	4303	0.7	37			15	1	4	9	2	588	22.2
2/25	68	13.3	88	20	185	70	2	54	233	38	46%	20	0	1536		15	2	1.2	2	2.1	2		220	4594	0.7	26		15	17	2	4	6	2	588	23.3
2/26	68	13.0	105		102	75	2	29	313	10	87%		0	1904	4		2	1.2	2	2.2	2		228	4867	0.7	29	4	15		1	6	6	2	575	25.5
2/27	68	13.9					2							1937				1.3	2	2.0	2		250	4858	0.7						9	11	2	615	27.4
2/28	68	13.6	90				2		362				0	1785			0	1.4	2	1.9	1.8		260	4622	0.7	17				0	4	6	2	602	25.2
Average	68	13.6	91	24	230	143		112	257	19	1	22	0	1465	8	17	1	2		2	2	84	216	3715	1	20	6	17	17	1	5	7		601	21
Minimum	66	11.7	58	18	102	70		29	158	10	0	16	0	1207	4	12	0	1		2	2	78	186	2957	1	11	4	14	11	0	0	0		518	17
Maximum	69	20.1	115	28	305	192		162	367	38	1	30	0	1937	11	21	4	4		2	2	92	260	4867	1	37	9	20	22	4	9	12		889	27

Note:

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Formulas:

Trickling Filter Effluent OLR = Flow x Primary Effluent CBOD x 8.34 / 190

Trickling Filter Effluent Efficiency = (Primary Effluent SCBOD - Trickling Filter Effluent SCBOD) / Primary Effluent SCBOD

Secondary Clarifier SOR = Flow x 1000000 / 22608

Secondary Clarifier SLR = Flow x 8.34 x Solids Contact MLSS / 22608

Solids Contact SRT (S) = ((P x 8.34 x .8) + (W x 8.34 x .4))/ (W x 8.34) x (V/697)

City of Hayward - WPCF

March ~~February~~ 2009

City of Hayward TFSC Process Control Data

	Trickling Filter		Primary Effluent				Trickling Filter							Solids Contact												Secondary Clarifier									
Date	Temp °F	Flow MGD	TSS (mg/L)	NH4 (mg/L)	CBOD (mg/L)	SCBOD (mg/L)	TFs in Service	OLR (#/Ksf/D)	TSS (mg/L)	SCBOD (mg/L)	Efficiency (%)	NH4 (mg/L)	NO3 (mg/L)	MLSS (mg/L)	SCBOD (mg/L)	NH4 (mg/L)	NO3 (mg/L)	DO (mg/L)	SCTs in Service	SRT Calculated	SRT Analyzer	SVI (Index)	WSS Q (gpm)	RSS TSS	RSS Ratio (Ratio)	TSS (mg/L)	SCBOD (mg/L)	CBOD (mg/L)	NH4 (mg/L)	NO3 (mg/L)	Blankets 1 (Inches)	Blankets 2 (Inches)	Clarifiers In Service	SOR (gal/sf/D)	SLR (#/sf/D)
3/1	68	13.8					2							1617				1.8	2	1.7	1.5		298	4178	0.7						6	6	2	610	23.1
3/2	68	15.1					2							1430				1.3	2	1.8	1.6	90	269	3915	0.7						6	12	2	668	23.2
3/3	69	15.9	113	23			2		105			26	0.5	1420		19	0.3	3	2	2.0	1.6		246	3524	0.7	19			13	0.2	4	4	2	703	22.8
3/4	68	17.1	83	23	281	89	2	105	174	42	53%	18	0.0	1170		11	0.0	2.1	2	1.5	1.6	92	296	3963	0.7	15		13	14	0.0	9	12	2	756	24.9
3/5	69	15.8	92	22	258	171	2	89	275	16	91%	20	0.0	1464	6	9	0.0	2.2	2	2.2	1.8		237	3385	0.7	15	< 3	14	11	0.3	9	12	2	699	22.3
3/6	70	14.9					2							1700				1.1	2	2.1	1.8		253	3826	0.7						4	9	2	659	24.1
3/7	68	14.3	101	23			2		312			19	0.0	1778		8	0.3	1.1	2	2.0	1.8		259	4268	0.7	6			8	0.5	6	3	2	633	25.1
3/8	69	13.2					2							1856				1.1	2	1.8	1.8		269	4813	0.7						4	3	2	584	25.4
3/9	68	13.9					2							1892				1.2	2	1.9	1.6	87	263	4856	0.7						8	9	2	615	27.1
3/10	70	13.6	100	23			2		267			26	0.0	1848		9	0.6	1.2	2	1.4	1.6		352	4915	0.75	18			11	0.6	6	6	2	602	27.8
3/11	68	13.4	97	24	279	179	2	82	284	15	92%	19	0.0	1938		5	0.0	1.1	2	1.5	1.4	85	350	4607	0.75	15		15	7	0.0	3	6	2	593	26.7
3/12	68	13.1	133	25	181	138	2	52	201	20	86%	22	0.0	1921	8	8	0.0	1.2	2	1.5	1.4		374	4064	0.75	16	5	34	8	0.0	9	3	2	579	24.0
3/13	69	12.9					2							1774				1.4	2	1.4	1.2		382	3969	0.75						9	3	2	571	22.6
3/14	69	12.7	96	25			2		434			23	0.0	1760		11	0.0	1.2	2	1.4	1.2		375	4023	0.75	7			12	0.0	3	3	2	562	22.4
3/15	68	12.7					2							1565				2.3	2	1.4	1.2		380	3297	0.75						3	3	2	562	18.9
3/16	68	12.7					2							1374				1.3	2	1.8	1.6		293	2955	0.75						3	2	2	562	16.8
3/17	70	12.9	107				2		217				0.0	1454			0.0	1.3	2	1.7	1.6		300	3331	0.75	15				0.0	12	4	2	571	18.8
3/18	69	12.6	97				2		202				0.0	1465			0.0	1.6	2	1.8	1.6		294	3172	0.75	16				0.0	5	2	2	557	17.9
3/19	70	12.9					2							1520				2.3	2	1.6	1.5		331	3344	0.7						3	6	2	571	18.4
3/20	69						2							1401				2.7	2	1.7	1.5		310	3119	0.7										
3/21																																			
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3/26																																			
3/27																																			
3/28																																			
3/29																																			
3/30																																			
3/31																																			
Average	69	13.9	102	23	250	144		82	145	23	1	21	0.1	1617	7	9	0	2		2	2	89	307	3876	1	14	5	19	10	0.2	6	6		613	23
Minimur	68	12.6	83	22	181	89		52	0	15	1	18	0.0	1170	6	5	0	1		2	1	85	237	2955	1	6	5	13	7	0.0	3	2		557	17
Maximu	70	17.1	133	25	281	179		105	434	42	1	26	0.5	1938	8	13	1	3		2	2	92	382	4915	1	19	5	34	14	0.6	12	12		756	28

Note:

Shading indicates a formula, as additional data is entered into the table, copy down the formulas

Formulas:

Trickling Filter Effluent OLR = Flow x Primary Effluent CBOD x 8.34 / 190

Trickling Filter Effluent Efficiency = (Primary Effluent SCBOD - Trickling Filter Effluent SCBOD) / Primary Effluent SCBOD

Secondary Clarifier SOR = Flow x 1000000 / 22608

Secondary Clarifier SLR = Flow x 8.34 x Solids Contact MLSS / 22608

Solids Contact SRT (S) = ((P x 8.34 x .8) + (W x 8.34 x .4))/ (W x 8.34) x (V/697)

Reclaimed Water Project - 2008
Final Clarifier

Sample Date	4/16/2008	Matix: Water
Prep Date:	4/16-18, 21-24/08	
Analyze Date	4/17, 21-24/08	

ANALYTE	RESULT	UNITS
Turbidity	5.2	NTU
Iron	0.24	mg/l
Magnesium	11	mg/l
Potassium	13	mg/l
Sodium	83	mg/l
Strontium	0.17	mg/l
Titanium	< 0.050	mg/l
Tin	< 0.050	mg/l
Boron	0.30	mg/l
Calcium	23	mg/l
Cobalt	< 0.50	ug/l
Copper	12	ug/l
Lead	< 0.50	ug/l
Manganese	48	ug/l
Nickel	5.2	ug/l
Selenium	< 2.0	ug/l
Antimony	< 0.50	ug/l
Silver	< 0.50	ug/l
Thallium	< 1.0	ug/l
Vanadium	< 2.0	ug/l
Zinc	39	ug/l
Arsenic	< 1.0	ug/l
Barium	9.4	ug/l
Beryllium	< 0.50	ug/l
Cadmium	< 0.25	ug/l
Chromium	0.99	ug/l
Mercury	< 0.0010	mg/l
Nitrate as NO3	< 1.0	mg/l
Phosphate	8.7	mg/l
Chloride	88	mg/l
Fluoride	1.4	mg/l
Nitrite as NO2	< 1.0	mg/l
Sulfate as SO4	32	mg/l
Bicarbonate Alkalinity as CaCO3	250	mg/l
Carbonate Alkalinity as CaCO3	< 5.0	mg/l
Hydroxide Alkalinity as CaCO3	< 5.0	mg/l
Total Alkalinity as CaCO3	250	mg/l
Hardness, Total	103	mg/l
Total Dissolved Solids	430	mg/l
Total Suspended Solids	3.0	mg/l
Cyanide (total)	< 0.020	mg/l
pH	7.6	pH Units
Total Nitrogen	33	mg/l
Ammonia as NH3	35	mg/l
Total Kjeldahl Nitrogen	32	mg/l
Silica	13	mg/l
Biochemical Oxygen Demand	12	mg/l
Chemical Oxygen Demand	83	mg/l
Total Organic Carbon	15.3	mg/l

Exhibit 25

From: Rob Simpson
Sent: Wednesday, September 16, 2009 11:43 PM
To: Weyman Lee;
Subject: Comments RCEC

Attachments: rcec sept 09 asob comment final.pdf
Attached please find my comments for application 15487 Calpine/GE Hayward plan

Thank you all.

Rob Simpson
510-909-1800

Thank you for this opportunity to submit comments on the Revised Amended/Not-amended Corrected Additional Statement of Basis for the Proposed Draft Federal “Prevention of Significant Deterioration” Permit for application Number 15487 Russel City Energy Center in the City of Hayward

The last (undated) Notice of public Hearing identifies "Russell City Energy Company," as "an affiliate of Calpine Corporation." Are they merely an affiliate or is the company wholly owned by the Calpine corporation and or General Electric? I have found no disclosure of General Electric (GE) ownership of this project. Is GE an owner of the project ? If so how did the District satisfy the notice requirements of 40 C.F.R 124. if GE is an owner and the District did not satisfy the notice disclosure requirements please disclose this information in a public notice and recirculate the Draft permit.

The Notice states "Comments submitted during the previous comment period **do not** need to be resubmitted at this time" Does this include all comment periods? Are the comments that were received by the District and placed in the Eastshore Energy Center proceeding included? Are the comments received between comment periods included? Is the submittal to the District appeals board and both EAB appeals considered comments? Have the people, whose comments were included in the Easthsore Proceeding provided Notice of this proceeding? Have the people who signed petitions against the permit that were submitted to the District, been provided Notice of this proceeding? Have the people who participated in the proceeding before the CEC or District since 2001 been provided Notice of the proceeding? Have the Comments received by The CEC regarding Air Quality Been included? Please provide the District mailing list for this proceeding. Please incorporate all comments questioned above into my comments of today. I also incorporate by reference into my comments all comments by Bob Sarvey,
Government and Public Officials:
Supervisor Gail Steele, District II
Congressman Pete Stark
Chabot-Los Positas Community College District
Hayward Area Park and Recreation District, (HARD)

Community Organzations:
Hayward Area Shoreline Planning Agency, Citizens Advisory Committee, (HASPA CAC)
San Lorenzo Heritage Society
Hayward Democratic Club
Hayward Area Planning Association (HAPA)
Skywest Town House Homeowners Association
California State Audubon Society
Sierra Club, Southern Alameda County Chapter
Sierra Club, State of California
California Native Plant Society, East Bay Chapter
Healthy 880 Communities
Green Action
Students for Social Justice, Chabot College
Pacific Environment,
CARE CAlifornians for Renewable Energy
Citizens to Complete the Refuge
California Pilots Association

Golden Gate University Environmental Law and Justice Clinic
Earthjustice, and Communities for a Better Environment

Mike Toth, Ernie Pacheco and Andrew Wilson.

It appears from the index posted by the District that application 15487 was received by the District in May of 2001. What are the statutory time periods for processing an application? This process has made it impossible for informed public participation. There is no other indication of when the application was received or considered complete. When was it received? When was it considered considered complete? The PSD and ATC permits were apparently first integrated, then disintegrated through District failures, A Draft PSD permit was circulated as an amendment then determined to never have been issued, now partially recirculated with partial responses to select comments without identifying commenter's and bifurcated with the intent to subsequently reintegrate with an ATC permit that was based upon the PSD permit that is now disclosed to not have been issued. Supporting determinations are stale and scattered over the last decade. The District documents do not even disclose the most basic information that should be in a public notice, a simple chart detailing the National Air Quality standards, our attainment status and the projects effect on air quality or PSD increment. The District has gone to such great lengths to evade its responsibility to process a compliant ATC and PSD permit that it can not even keep its story straight. The District should rescind the Delegation agreement and let the EPA process this permit.

The Public notices, when the District claimed that the permit was an amendment gave great weight to the idea that it was an amendment. Now that the district admits it is not an amendment. There is nothing in the public notice identifying this truth. The "Project fact sheet" which I believe is the 4th iteration, has not been changed to reflect this information. How many "fact sheets" have been issued? It still states that it is an "Amended Federal Prevention of Significant Deterioration (“PSD”) Permit" The District does not disclose that it is not an amendment until page 5 of the Amended Statement Of Basis (ASOB). Incorrect information that serves to legitimize the action can mislead the public. The Draft permit is riding the coattails of a non existent permit. The District appears to acknowledge this fact in the following statement, "To the extent that there were any issues involving the District’s proposal that any members of the public refrained from commenting on during the initial comment period because they understood the proposed permit to be an amendment and not a new permit, the Air District invites the public to submit any such comments for the District’s consideration at this time." ASOB 6 The problem is that the District did not include this information in the notice or correct the Fact sheet.

Please re-notice the draft permit and disclose in the notice the correction and chart identified above. Also please issue another Fact sheet, this time limited to facts. It is notable that the District consumed considerable resources of the EAB to futilely defend the previously issued permit which included concerns of Endangered species act consultation and only now discloses that "the District did not issue a final Federal PSD Permit along with its state-law Authority to Construct, as is the District’s normal practice. The record indicates that the District did not finalize the Federal PSD Permit at the time it issued the Authority to Construct because EPA Region 9 had not completed its Endangered Species Act consultation with the US Fish & Wildlife Service." ASOB 5 Is an Authority to Construct (ATC) for this facility valid without a PSD permit or should the District have understood that when the PSD permit was remanded, it invalidated the ATC?

The District stated "Redesigning the project to incorporate a solar system like Victorville’s would therefore require the facility to be moved to another location, making it impossible to achieve the project objectives served by the current location" ASOB 12. The City recently put out an RFP for a solar facility next to the project site there is nothing on this record beyond a baseless statement to support the "impossible" contention. Does the District have any basis for this statement?
The District stated "if the underlying estimates turn out to be inaccurate and actual emissions exceed

the estimates as they have been incorporated into the permit limits, the facility will be in violation of its permit and will have to shut down or curtail operations unless it can fix whatever problems are causing the increased emissions" ASOB 13 This is not the procedure that we saw in Calpines Metcalf and Sutter plants or PG&Es Gateway. What we saw in Metcalf and Sutter with similar plants is that When they changed operations to function like peakers because there is not demand for additional baseload generation they simply quietly amended their permits to pollute more. Gateway has not been required to "shut down or curtail" despite no permit. Would the District include an enforceable permit condition that the facility will not be permitted to modify its permit or obtain a new permit to increase its emissions? If not the statement is misleading.

Does the District have evidence that the "intermediate-to-Baseload capacity.. for which the facility has been proposed and designed" ASOB page 13 is consistent with the intended operations contained in the facilities power purchase agreement?

The District stated "the District also received some comments asking for detailed information about the combustion turbines the applicant intends to use at the facility, such as turbine serial numbers, dates of manufacture, cost, *etc*. But specific details such as these are not relevant to determining the Best Available Control Technology" ASOB 13

I still contend that these are likely used or re-manufactured turbines from a turbine repair company that Calpine bought in Las Vegas (where they claim that the turbines are stored). This is important because as they District stated;

"The original equipment manufacturer's degradation curves only account for anticipated degradation within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, because the projected 5.2% degradation rate represents the *average*, and not the maximum or guaranteed, rate of degradation for the gas turbines, the Air District has determined that, for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate." ASOB 31

"For the gas turbines, the Air District is basing its analysis on a 48,000-operating-hour degradation curve provided by Siemens, which reflects anticipated recoverable and non-recoverable degradation in heat rate between major maintenance overhauls of approximately 5.2% According to combustion turbine manufacturers, anticipated degradation in heat rate of the gas turbines alone can be expected to increase non-linearly over time." ASOB 32

(ii) "a reasonable performance degradation margin of 6% to reflect reduced efficiency from normal wear and tear on the equipment between major maintenance overhauls" ASOB 28

An enforceable BACT limitation must be set at a level that the facility can achieve for the life of the facility, including as its equipment ages and incurs anticipated degradation.
ASOB 28

The turbines' Design Base Heat Rate is 6,852 Btu/kWhr (HHV), based on operation of both combustion turbines with no duct firing, corrected to ISO conditions.48 (For comparison with a pounds-per-megawatt-hour efficiency rating, this is between 792.9 and 815.5 lbs/MWhr, depending upon which CO_2 emissions factor is applied.49) This represents what the plant (at the design stage) is expected to achieve when it is new and clean; it does not represent what it will achieve over time as the equipment incurs degradation between major maintenance overhauls." ASOB 29

So, if the turbines are used or overhauled, their pollution characteristics may be different than the original manufacturer specifications.

The District stated "The facility's contribution was based on modeling using the facility's emissions, and the background contribution was based on the Fremont-Chapel Way monitoring data as discussed above. For the contribution from other nearby sources, the Air District undertook a search of its database of PM2.5 sources within a radius of six miles (9.7 km) around the facility location that have been permitted since January 1, 2007, and located a total of 29 such sources (21 of which are diesel backup generators). The Air District also evaluated non-point sources within this area that could cause a significant concentration gradient at any of the areas where the facility's impact was above the SIL. The Air District identified a portion of Highway 92 that is located approximately 1 km south of the facility as such a non-point source, and included it in the analysis. The cumulative impact from all of these contributions (the facility, the 29 point sources, and Highway 92) was then modeled for each receptor location within the impact area where the facility's impact was above the SIL.
ASOB 87

I contend that Fremont is not the right monitoring station if the District used the Hunters point or Oakland stations it would be more representative and comparable distance. I witness from my house that smog comes from Oakland and S.F. and is lesser in Fremont. second the District recognized highway 92 in their analysis but ignored within the same 6 mile radius many miles of highways including 11.7 miles of 880, 10.5 miles of 92, 4.85 miles 580, 8.6 miles of 238, 10 miles of route 185 plus major arterial Roads.

What would the results be if Oakland or San Francisco monitoring stations were used?

The District stated "With respect to the new electrical generating capacity that the project will provide, it is speculative whether this new capacity will be a cause or any significant growth in the region. Some of it may be used to take the place of older generating capacity that is being taken off-line, and even if it does provide some overall expansion of the region's total electric generating capacity there is no indication that this would cause any new development. It is unlikely that any new growth or development will occur simply because of the existence of excess electrical generating capacity, as opposed to some other independent reason." ASOB 91 This which comes first chicken or egg speculation seems to have no basis in the facts on the record. If accepted the same argument could be used to dismiss any growth analysis. It is clear that areas without electricity do not tend to grow, inversely areas with excess capacity could tend to grow. Please complete a Growth analysis based upon facts on the record.

Can the District identify any other Plant that presently affects Hayward's Air quality?
Please identify older plants that would be "taken off-line" as a result of this development and the benefit to Hayward Air Quality.

The District stated "The proposed facility has been designed to handle wastewater from the treatment plant and use it as cooling water, not the other way around – the wastewater treatment plant was not built to handle wastewater from the proposed facility. This will be an environmentally beneficial aspect of the facility in that it will obviate the need for the City of Hayward to discharge its wastewater into the Bay." ASOB 92 I have found no evidence on this record to indicate any environmental benefit from discharging wastewater into the air instead of into the bay. Discontinuance of water deliveries to the bay may cause an undisclosed negative effect that should be studied and disclosed. Emissions of 4 million gallons of effluent into the air could have public health risks that have not adequately been studied. "The project will require a new tertiary treatment plant to treat the wastewater from the wastewater treatment plant in order to make it clean enough to use in the facility's cooling system, but it will not involve any expansion to the capacity of the wastewater treatment plant." 92 ASOB There has been no disclosure of the energy usage or pollutants associated with this water treatment for the facility. please disclose this information.

The District stated "Commenters suggested that the wet cooling system could involve a risk of causing Legionnaire's disease, and claimed that this potential health risk should be investigated further as part of the Health Risk Analysis. The Air District notes that its expertise as a public health agency is primarily in the area of chemical air pollutant and the health problems they can cause, not in medical pathogens. For this reason, the Air District does not address medical concerns such as issues related to Legionnaire's disease in its Health Risk Assessment. To the extent that the proposed project may raise concerns about Legionnaire's disease, those concerns should appropriately be addressed in the broader environmental review context through the Energy Commission's CEQA-equivalent process." If the District is requiring that the CEC consider this comment prior to issuance of the PSD permit then this response would be sufficient. If not this analysis is deficient because it does not analyze the health risks associated with dispersion of 4 million gallons of "effluent" per day into the air. If the District does not have the expertise please hire someone who does and provide a health risk analysis for the "effluent" dispersal.

They State in Footnote 164 "As noted in the December 2008 Statement of Basis, the state-law permitting process has been completed and is now final. Avenues for reviewing state-law conditions have therefore been exhausted" ASOB 98 Is this a true statement?

"Reopening the comment period under 40 C.F.R. section 124.10 to give interested persons an opportunity to comment on the new information and the District's proposed treatment of it; and to give interested persons an opportunity to submit any further comments that they could not reasonably have submitted during the initial comment period." ASOB 2. It is unclear from the code cited to what extent this partial reopening of the comment period complies with 40C.F.R. 124.10. Please identify the specific authority that permits this piecemeal method to limit public participation and what thresholds will be used to determine which comments could or "could not reasonably" have been submitted. Even if all comments are accepted this statement by the District may have precluded public participation.

The District stated "it [is] appropriate for the permitting authority to distinguish between electric generating stations designed to function as 'base load' facilities and those designed to function as 'peaking' facilities, and that this distinction affects how the facility is designed and the pollutant emissions control equipment that can be effectively used by the facility"). This issue is moot here, however, as the Air District has concluded that there are no superior alternatives even if such an analysis were required. ASOB Footnote 5 page 10 Why would an analysis be necessary if the District can reach its conclusions without analysis?

"A solar alternative to duct burning would not be feasible for the Russell City facility, however, because there is far less available area at the project than in the Mojave Desert, and the compact site would not provide adequate space for installation of a solar collectors. To construct a solar thermal plant to replace some of the peak capacity from duct burning would need 275 acres of To construct a solar thermal plant to replace some of the peak capacity from duct burning would need 275 acres of land,13 which would not be feasible given the space-constrained project site on the edge of the San Francisco Bay.14 " This statement seems to rely on the application For certification from 2001. Has solar technology changed at all this decade which may lead to a different conclusion if a contemporary analysis were completed? Please complete an alternative analysis based upon current technology. The San Francisco Bay, industrial areas of Hayward and City streets are well over 275 acres. What consideration has been given to utilizing adjacent acreage for solar. Is 275 acres a fixed size for a solar installation or would 1/2 the acreage or twice the acreage , for instance, produce "some of the peak capacity"? The City of Hayward recently published a request for proposals for an adjacent solar facility. Has that been considered in this proceeding?

The footnote for the above states, 14 The project site for the Russell City Energy Center is a 14.7-acre area located in the West Industrial District of Hayward, California, adjacent to the City of Hayward Water Pollution Control Facility and near existing transmission facilities. *See* Calpine, *Application for Certification*, *Russell City Energy Center* (May 2001) (hereinafter, "RCEC Application for Certification"), at 9-3 – 9-4; available at: www.energy.ca.gov/sitingcases/russellcity/documents/applicant_files/afc/vol-1/.

This refers to the previous site. Please conduct an analysis of the present site using current data. Although, I believe that I informed the District of the new site location in previous comments, the Districts confusion is understandable. The public is also likely confused. Many probably still do not understand that the plant named Russell City is actually in the city of Hayward. The District also never disclosed the actual location before misleading name in public notices. Readers of the notice may stop reading when reading the name of another city. The District should first figure out where the project is, analyze it in context to its location and then if it intends to issue a permit provide Notice of the location prior to the misleading name. The site location, description and address Continue to change. Is the site "on the edge of the San Francisco Bay" as described above? Is it 14.7 acres as described above? Is it near the corner of Depot Road and Cabot Boulevard as identified in the latest public notice? How many different addresses and site descriptions has the District published for this project and what are they? Is it in the "West industrial District" as identified above. What is the zoning? Have there been nearby land use changes since the original application that could effect determinations? for instance any protected habitats, Federal wildlife sanctuaries, wetland restorations.

The District also received comments noting that the facility would be operated to meet contractual load and spot sale demand, and may not operate on a full-time, base-loaded basis. These comments questioned the anticipated operating mode of the proposed Russell City Energy Center, suggesting that if it were intended for load-following or other duty that would involve frequent startup and shutdown events, the Applicant should be required to construct a fast-start-capable, peaking-to-intermediate duty plant instead.
The Air District has considered this issue further in light of these comments. The Air District notes that the Federal PSD Permit process is designed to ensure that a proposed facility will be as low-emitting as possible (among other requirements). It is not designed to require an applicant to propose a different type of project of a different fundamental scope and design, for example to substitute a simple-cycle peaking plant instead of a combined-cycle intermediate-to-baseload project as the commenters suggest here.17 Moreover, it would not make any sense from an emissions standpoint to require a simple-cycle facility for the purpose that this facility is intended to be used for, which is to serve intermediate-to-baseload capacity. Simple-cycle facilities are less efficient than combined-cycle facilities, which recover the heat from the turbine exhaust (which would simply be emitted and wasted in a simple-cycle facility) and use it to generate additional electricity. Simple-cycle facilities are therefore generally

inferior to combined-cycle facilities, except for applications where the generating capacity must come on-line in a very short time frame, which is not the case with the uses for which this facility has been proposed and designed. The Air District therefore disagrees that it should require the applicant to redesign the facility as a simple-cycle peaking facility."
ASOB 12 Like all the District responses it is impossible to identify which comments they are responding to. Is a fast starting or solar augmented facility necessarily a simple Cycle facility? Could these technologies be considered control technologies and not a "different type of project"?

"Of the comments the Air District has received so far, none has disagreed with the Air District's assessment that the only feasible control technology for reducing greenhouse gas emissions from fossil-fuel burning power generating facilities is to use the most efficient electrical generating technology,25 and that at present there are no feasible post-combustion add-on controls for such facilities." ASOB 18 Allow me to disagree; Carbon Sequestration is a feasible control technology that has not been adequately studied for this project. Subterranean sequestration may be a viable alternative as well as bio-sequestration of pollutants in algae producing ponds. There are extensive ponds adjacent to the site that could accommodate this. After sequestration the water/ algae could be utilized for reforestation or irrigation to create a buffer between the the developed and natural areas of the shoreline or in other locations further sequestering Carbon. Please study this plan.

The Air District did receive comments stating that the Air District should have evaluated alternative energy production methods that do not rely on fossil fuel combustion, however. These comments suggested that the District should not focus simply on turbine efficiency, as opposed to looking at more efficient ways of making electricity without using combustion turbines.
The Air District has considered these comments and is in agreement that the development of non-fossil-fuel electrical generating sources is of critical importance in meeting California's energy needs while at the same time furthering its air quality goals, especially in light of recent advances in the understanding of the problems posed by global climate change. The Air District recognizes, however, that alternative generating technologies are not currently capable of meeting the state's electrical power demand at all times and under all circumstances, and that some fossil-fuel generating capacity is still needed.26 Determining the most appropriate mix of electrical generation sources under these circumstances is a highly complex engineering and policy exercise that is most appropriately undertaken by the California Energy Commission, the state's expert agency on energy policy matters. The Air District obviously has a supporting role to play in helping the Energy Commission to understand the air quality impacts of its siting decisions and to include appropriate air quality conditions in its licenses. But as an agency, the Air District does not have the expertise nor the authority to determine what type of generation sources are needed, of what capacity, and where. The Air District must therefore necessarily defer to the Energy Commission's decision that the proposed natural-gas fired, combined-cycle facility is the most appropriate alternative for this project. If it would be more appropriate to use wind or solar power to serve the function intended for the proposed Russell City project, the Energy Commission is the agency best suited – and specifically tasked by the California legislature – to make that determination. ASOB 18
Because The CEC determinations are stale for the purposes of this PSD permit the District should require current determinations regarding this vital issue.

"The Energy Commission ultimately rejected those alternatives as not feasible because "they do not fulfill a basic objective of the plant: to provide power from a baseload facility to meet the growing demands for reliable power in the San Francisco Bay Area."27 .. 27 2002 Energy Commission Decision, *supra* note 15, at p. 19. The Energy Commission made a further finding in its 2007 Amendment decision that no renewable alternatives would be able to meet the project's objectives. *See*

California Energy Commission, *Final Commission Decision, Russell City Energy Center* (October 2007) (hereinafter, “2007 Energy Commission Decision”),p.21,finding3(availableatwww.energy.ca.gov/2007publications/CEC-800-2007-003/CEC-800-2007-003-CMF.PDF). In making this finding, the Commission relied in part upon the detailed analyses that were undertaken in connection with the original licensing proceeding in 2002. *See id*. at pp. 20-21." ASOB 19 Is demand growing? if so is it growing through increased per capita usage or population growth? Will this facility facilitate growth? If it is not built will it restrict growth? Is it better from an air quality standpoint to increase supply or decrease demand? If the facility is not built may demand be met through conservation or cleaner sources? Would the District collect the same fees for a cleaner plant?

● *Data Showing Achievable Emissions ~800 lb/MW-hr:* The commenters stated that emissions data from new turbines show that current equipment should be able to achieve emissions as low as 800 lb/MW-hr. Commenters also stated that the District should look at the best achievable performance level of all turbines, including new turbines, and not limit its review to turbines that were built several years ago. Commenters also claimed that the District considered emissions data from only one year of operation from only two facilities, and should conduct a broader review. ASOB 25 What year were the turbines built? Was it "several years ago" or several decades ago?

"105 In addition, it is worth noting that any Appendix S requirements would be applicable through a Non-Attainment NSR permit, not through the PSD Permit. There may be reasons to address both types of requirements in an integrated permit proceeding, but technically they are separate permitting programs applicable under different sections of the Clean Air Act." ASOB 55 Wasn't this an integrated permit proceeding? will it be reintegrated? Is it now disintegrated or what is it called? What would the "reasons to address both types of requirements" be?

"These comments stated that a Flex-Plant 10 system is appropriate for peaking-to-intermediate duty operations, whereas the Flex-Plant 30 system is the appropriate technology for intermediate-to-baseload operations. These comments were based on the observation that there is an energy efficiency penalty when using the single-pressure steam boilers system, compared with the more efficient triple-pressure system that is being proposed here. The Air District agrees with the latter comments. Flex-Plant 10 is an excellent technology to allow peaking-to-intermediate plants – which have to be able to start up and come on line very quickly – to gain the benefits from using combined-cycle technology (as opposed to less efficient simple-cycle turbines). But it is not appropriate for intermediate-to-baseload facilities where quick startup times are less important because of the energy efficiency penalty associated with using a single-pressure steam turbine. For intermediate-to-baseload facilities, it is preferable to obtain the better overall emissions performance achievable through the use of a triple-pressure system instead of using a less efficient single-pressure system like the Flex-Plant 10. (Note that when Flex-Plant 30 technology becomes available it will allow suitable triple-pressure systems to achieve faster startups as well, but this technology is not yet available for this project.)" ASOB 70 An analysis of the Power Purchase agreement and current need assessment should be needed to make these conclusions

"The Air District also received comments that disagreed with the District’s assertion that EPA Region IX does not require OpFlex as BACT, based on the permit Region IX issued for the Colusa Project. The comments noted that a commenter in the Colusa proceeding brought the issue to the Region's attention in a comment, but that the comment was withdrawn and so Region IX did not consider it. The comments requested that the District consider the comments that were submitted and subsequently withdrawn in the Colusa proceeding here. The District agrees that that EPA Region IX did not formally respond to the withdrawn comments on the record. But once EPA was aware of the issue, it would not (and legally could not) fail to require OpFlex technology if that technology were BACT. The agency has an independent responsibility to impose BACT based on all of the information available to it, even if the specific comment that brought the issue to light was withdrawn. For this reason, the District stated in the initial Statement of Basis that EPA Region IX did not require OpFlex as BACT.132

Finally, as for considering the Colusa comments that were withdrawn, they were submitted in the Colusa proceeding and were not submitted on the record as comments in this proceeding, so the District is not obligated to respond to them. If the commenters believe that the Air District should consider them on the record in this proceeding, they have an obligation to submit them into the record for the Air District to review, but they did not do so here. Nevertheless, the Air District obtained a copy of the comments from EPA Region IX to ensure that it had researched all information that could have bearing on this issue, and found nothing whatsoever in those comments to suggest that OpFlex should be required here. The comment letter cited several of the same points about the Palomar Energy Center that have been raised in this proceeding, to which the Air District is responding in detail in this section." ASOB 73 Since the District admits that it has the comments I will consider them "on the record" and state that they do not appear to be adequately analyzed. It is also notable that the Colusa permit has been reopened for modification. Opflex should be required here.

"Another comment claimed that, based upon telephone conversations with Siemens representatives, a low-load "turn-down" technology product is currently available for Siemens turbines. The Air District investigated this issue further, and reviewed communications from Siemens confirming in writing that it does not have a low-load product that is commercially available for F-class turbines. Siemens' LLOF product, known as "Low Load Carbon Monoxide" (LLCO), has been validated for G-class turbines as noted in the documentation the Air District relied on in the initial Statement of Basis. (*See* Statement of Basis at p. 41 and n. 33.) The Air District confirmed this with Siemens in response to this comment. Siemens reports that "LLCO validation for F-class turbine began in December 2008 and [is] currently in process [but] the validation for the F-class turbine has not been concluded." ASOB 73 There is not likely a pressing need for Siemens to develop this technology for the antiquated turbines proposed for this facility. If BACT for one pollutant is not the same technology as BACT for another the District should consider both before making a decision that coincidently selects the outdated turbines that the developer happens to have in stock.

As explained in the initial Statement of Basis, Air District has estimated sulfuric acid mist emissions as accurately as it can, and believes that emissions will be below 7 tons per year. The Air District is not aware of any data or analysis suggesting that emissions will be over 7 tons per year, and none of the comments on this issue cited any, and so the Air District continues to believe that this is an accurate assessment. ASOB 76 How much Sulfuric acid would the facility emit?

Class I Areas Analysis

Finally, EPA also requires an analysis of the potential for impacts to any Class I areas within 100 km of the proposed facility. Point Reyes National Seashore is located approximately 62 km from the project, so the Air District conducted a Class I area impact analysis for PM2.5" ASOB 88 Is the Adjacent Don

Edwards National Wildlife Sanctuary a Class on Area? Should it be considered one?

The District stated "The proposed project will have two stacks each having a height of 150 feet above the ground level." ASOB 95 The CEC decision states Each HRSG unit will have a 145-foot exhaust stack CEC decision 10 which is correct?

"The Air District received comments citing recent developments in the understanding of the health impacts of fine particulate matter. These comments suggested that the Air District should consider fine particulate matter in its Health Risk Assessment.
The District has considered adding fine particulate matter in our permitting procedures...
These guidelines have not been developed at this stage, however, and so the Air District does not have the appropriate tools to include fine particulate matter in its formal Health Risk Assessment" ASOB 95
If the "District does not have the appropriate tools" they should get them and use them prior to approval or the application should be rejected or someone else with the proper tool should process the application.

#602 Del Monte Corp Oakland 6/6/84 #30

#855 PG&E San Francisco 9/30/85 #14
FDOC

Calpine/GE propose to mitigate polluting in Hayward with Emission Reduction Credits some from a plant that closed in San Francisco in 1985 some from Del Monte in Oakland in 1984. How do these credits help Hayward?

Page 19 of the FDOC indicates regarding the Emission reduction credits
(Information for certificate #30 is not available

Is information regarding certificates required for compliance with the Clean Air Act?
Are the credits planned contemporaneous?

If after the plant is built the asthma rates increase for children in Hayward or the respiratory rate increases for Seniors in Hayward what will the District do?

Some estimates are that we are already overbuilt for electricity generation by as much as 30%, including a new 550 megawatt plant that came on line in Antioch 6 months ago. Calpine also curtailed operations at its San Jose plant based upon the reduced need. Plants like these operate through contracts with PG&E and so get paid by PG&E ratepayers whether they operate or not. With a finite need for electricity, overbuilding fossil fuel fired generation prevents the need for renewable resources and the potential redistribution of wealth from PG&E, Calpine and GE to communities like ours.
If Calpine/GE builds this 600 megawatt fossil fuel fired plant in Hayward Does that prevent 600 megawatts of renewable energy from being developed?

Some estimates suggest that renewable energy projects would create 10 times the number of jobs.
Would renewable energy projects create more jobs?

This plant was originally planned in response to the turn of the century energy crisis. The crisis has since been proved a scam by companies like Enron. Calpine was subsequently fined $6,000,000 by the

California Attorney Generals office for manipulating the energy market, then Calpine went bankrupt. Is the electricity from this plant needed?

It appears that the Turbines planned for this facility are antiquated models perhaps retired from another facility and other equipment will be removed from a plant that was never completely constructed in another state.
Modern comparable sized plants like the one planned in Carlsbad would emit less than 1/2 of some of the worst pollutants. Calpine/GE intend to emit 12.2 tons per year of Sulfur Dioxide into Hayward's air, Carlsbad will emit 5.6 tons. Calpine/GE would emit 71.8 tons of particulate matter (small enough to go straight through the lungs into the bloodstream) Carlsbad will emit 39 tons. Calpine/GE plan to emit 127 tons of Oxides of Nitrogen compared to Carlsbad 72.8 tons.
Can the District explain why, if this is the best available Control Technology other plants emit less?

There appears to be limited wastewater storage available.
Does the District have any information about how much time elapses between the time we flush and when they would vaporize the effluent?

At any time in the last 10 years has the Air District monitored the Air in Hayward to provide a basis for its air quality claims? If not why not?

As a local Real Estate Broker I contend that development of this plant at the San Mateo Bridge gateway to the City will harm property values throughout the city.
Has the District conducted any studies to demonstrate the effects on property values from their plan?

Rob Simpson
27126 Grandview Avenue
Hayward CA. 94542
510-909-1800
rob@redwoodrob.com

Exhibit 26

Poloncarz, Kevin

From: Gregory Darvin [darvin@atmosphericdynamics.com]

Sent: Monday, February 22, 2010 10:02 AM

To: Poloncarz, Kevin

Subject: FW: Request for Records Relied On: RCEC applica. 15487

Give me a call when you get this.

Gregory Darvin

Atmospheric Dynamics, Inc.

2925 Puesta del Sol

Santa Barbara, CA 93105

darvin@atmosphericdynamics.com

805.569.6555 (p)

805.569.6558 (f)

From: Glen Long [mailto:Glong@baaqmd.gov]
Sent: Monday, February 22, 2010 9:29 AM
To: Gregory Darvin
Subject: FW: Request for Records Relied On: RCEC applica. 15487

From: Jewell Hargleroad [mailto:jewellhargleroad@mac.com]
Sent: Friday, February 19, 2010 4:17 PM
To: Alexander Crockett
Cc: Weyman Lee; Public Records; Glen Long
Subject: Re: Request for Records Relied On: RCEC applica. 15487

Sandy, as described below:

1. Please promptly provide all modeling files (***input and output***) of both AERMOD and SCREEN3 that you relied on for PM2.5 project only 24-hour;

2. Please promptly provide what documentation, including any communications, the District relies on to make this assertion, including the identification of what

inputs were incorrect. As reflected below, the assertion refers to: "The February 4, 2010 response to comments at p. 161 claims: "The Air District used the same publicly-available AERMOD program as the commenters did, and the discrepancy in the commenters' results comes from the fact that they used incorrect inputs, . . "

3. Please promptly provide a copy of that summary referred to in footnote 333: Summary of CALPUFF Class I Modeling Analysis Results, prepared by Greg Darvin, Atmospheric Dynamics, October 14, 2009."

4. Please also promptly provide all modeling files (***input and output***) of the CALPUFF modeling upon which the District relied and refers to in the February 4, 2010 response, pp. 167-168. Page 168, the February 4, 2010 response to comments states "the applicant provided an updated CALPUFF modeling analysis for the impact of the project's emission on Point Reyes National Seashore."

5, [P]lease provide a copy of the Memorandum from G. Darvin (Atmospheric Dynamics) to G. Long (Bay Area Air Quality Management District), September 28, 2009 identified in footnote 322.

Note too my earlier email to you today confirming the three attachments which Public Records forwarded to me on Wednesday, February 17, 2010, concerning CALPUFF, one of which is an undated and unidentified one page pdf and two zip files on CALPUFF. It's the memorandums and the CD we have been discussing that I am still waiting for, unless there is more CALPUFF info. NOT included in what Public Records already sent. Thanks.

Jewell J. Hargleroad, Esq.
Ph: 510-331-2975
Hayward, California 94541
jewellhargleroad@mac.com

On Feb 19, 2010, at 3:40 PM, Alexander Crockett wrote:

Also, let me make sure that I understand exactly what documents you are requesting and the current status:
1. All AERMOD and SCREEN3 modeling files the District used in its source impact analysis, including input and output data. Also including the final PM2.5 modeling runs that used the revised emissions rate.
2. Documentation supporting the assertion in the Response to Comments document that the discrepancy between our modeling results and yours comes from the fact that you used a higher emissions rate and we used a lower emissions rate.
3. Summary of CALPUFF Class I Modeling Analysis Results, Greg Darvin, Atmospheric Dynamics, 10/14/09, cited in fn. 333 of the Response to Comments document.
4. Modeling files, including input and output data, for the CALPUFF modeling upon which the District relied.
5. Memorandum from G. Darvin to G. Long, 9/28/09, cited in fn. 322 of the Response to Comments document.
Is this correct? Did I miss anything?
Sandy Crockett

From: Alexander Crockett
Sent: Friday, February 19, 2010 3:30 PM
To: 'Jewell Hargleroad'
Cc: Weyman Lee; Public Records

Subject: RE: Request for Records Relied On: RCEC applica. 15487
Hmmm. I will get the files from Glen on Monday and have them put on a CD for you. As I mentioned, Glen is out today.

From: Jewell Hargleroad [mailto:jewellhargleroad@mac.com]
Sent: Friday, February 19, 2010 3:26 PM
To: Alexander Crockett
Cc: Weyman Lee; Public Records
Subject: Re: Request for Records Relied On: RCEC applica. 15487

Sandy, this confirms that the CD we received does not contain a folder labeled "PM25' with a date of 10/29/09." Please ask to have the CD which includes this folder described copied. If you can drop that copy in today's mail so that it is picked up today or tomorrow, that would be great.

Also, please let me know when I can expect to receive the remaining memoranda requested below. Thanks.

Jewell J. Hargleroad, Esq.
Ph: 510-331-2975
Hayward, California 94541
jewellhargleroad@mac.com

On Feb 19, 2010, at 2:53 PM, Alexander Crockett wrote:

Jewell:

To clarify, Glen Long, our modeling staff person, believed that you were looking under a folder on the CD entitled “NO2, CO, and PM10” where there were some previous PM2.5 runs made using the higher emissions rate. He said that the final runs made for PM2.5, using the revised emission rate, are contained in the first main folder labeled “PM25” with a date of 10/29/09. You should have been given this explanation in our initial response to your request -- I apologize if you did not get it. I hope that this now makes sense. I’m not directly familiar myself with what files are on that CD, so unfortunately I can’t help you more than just passing on what he said. Glen is out today, but I can ask him about this further on Monday if you still can’t find it on your CD. Perhaps we could get on the phone together and he can walk you though how to find it if need be. If you can’t find it (or if it is not in fact on your CD) the obviously we will of course provide you with the information on another CD ASAP.

Sandy Crockett

____

Alexander G. Crockett, Esq.
Assistant Counsel
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109
Phone: (415) 749-4732
Fax: (415) 749-5103
www.baaqmd.gov

From: Jewell Hargleroad [mailto:jewellhargleroad@mac.com]
Sent: Friday, February 19, 2010 1:48 PM
To: Alexander Crockett
Cc: Weyman Lee; Public Records
Subject: Re: Request for Records Relied On: RCEC applica. 15487

Sandy,

Perhaps you could identify what "different section" or "correct folder" staff is referring to including the date the run was made? I think another copy of the CD of the run which BAAQMD asserts it relied on in the February 4, 2010 response to comments is in order as I requested below on February 12, 2010. The CD can be mailed to me if available today or I

can arrange for a pick up on Monday.
Thanks for checking on the remaining documents yet to be provided.

Jewell J. Hargleroad, Esq.
Ph: 510-331-2975
Hayward, California 94541
jewellhargleroad@mac.com

On Feb 19, 2010, at 1:22 PM, Alexander Crockett wrote:

According to our staff, the PM2.5 runs with the lower emissions rate were on the CD, but in a different section. Are you certain that you have been looking in the correct folder?
I will check on the status of the remaining items in your request.
Sandy Crockett

Alexander G. Crockett, Esq.
Assistant Counsel
Bay Area Air Quality Management District
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Phone: (415) 749-4732
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From: Jewell Hargleroad [mailto:jewellhargleroad@mac.com]
Sent: Friday, February 19, 2010 12:05 PM
To: Alexander Crockett
Cc: Weyman Lee; Public Records
Subject: Fwd: Request for Records Relied On: RCEC applica. 15487

Sandy,
First, I would just like to clarify that on September 1, 2009 we did receive the output files for the 24-hour project only PM 2.5 runs with the emissions rate of 1.134 g/s. To date we have not received any files, however, with any 24 hour project only PM2.5 runs utilizing any other emission rates which BAAQMD's February 4, 2010 responses to comments states it relied on.
This also confirms that your public records department did provide me with the following CALPUFF files entitled as follows: 1. a one page untitled document identified as "Cal-Puff Letter-1.pdf; 2. a zip file entitled "PTREYES_CALPUFF.zip"; and 3. a zip file entitled "PINNACLES_CALPUFF.zip"
Other than these attachments described above, to date I have not received any of the other requested memoranda listed below. I appreciate it that our request was made on Friday, February 12, 2010, however, as you are aware, time is of the essence and I would appreciate learning when BAAQMD intends to provide these requested documents. I look forward to your prompt response. Thanks

Jewell J. Hargleroad, Esq.
Ph: 510-331-2975
Hayward, California 94541
jewellhargleroad@mac.com

Begin forwarded message:

From: Jewell Hargleroad <jewellhargleroad@mac.com>
Date: February 12, 2010 5:02:58 PM PST
To: Weyman Lee <weyman@baaqmd.gov>
Cc: Alexander Crockett <ACrockett@baaqmd.gov>, Public Records <publicrecords@baaqmd.gov>
Subject: Request for Records Relied On: RCEC applica. 15487

Weyman:

On September 1, 2009, I made the following request on behalf of Chabot-Las Positas Community College District:

This confirms our telephone conversation this morning concerning obtaining the AERMOD/SCREEN3 modeling files for the Russell City Energy Center application.

As we discussed, we would like all modeling files (***input and output***) of both AERMOD and SCREEN3. For AERMOD, please also provide all meteorological input data, including the 2003-2007 meteorological input data.

As I mentioned, once these files are placed on a CD, we can either have the CD picked up from your offices or you can overnight the CD to me, whatever works easiest for you and enables us to obtain the files sooner rather than later. As we discussed, we would like to have them as soon as possible so that we have adequate time to review them to incorporate any comments by September 16, 2009.

Thanks very much for assisting us on this. So that we have some idea on scheduling, please let me know when your office anticipates having these available.

Emphasis added. That same day, Sandy Crockett emailed the following message-

According to our modeling folks, all of the files you are interested in are already on a CD that is included with the publicly available permitting record documents open for public review here in our Communications and Outreach Division offices. I will have a copy of the CD made and sent to you

They were copied that same day and I had a messenger pick up the CD. Sandy also confirmed on September 1, 2009 the following: "Public Records coordinator know that you had requested information, just to keep her in the loop. She assigned your request a District PRA tracking number, for District administrative purposes. It is:

09-09-02_Hargleroad. [P]This will confirm that the District has fulfilled this request for Public Records."

The February 4, 2010 response to comments at p. 160 states the following:

The commenters stated that they used an emission rate of 1.134 grams per second (g/s),

which they note is higher than the rate of 0.945 g/s specified by the applicant's Source Impact Analysis. Apparently, the commenters selected the wrong emissions rate because the commenters had relied upon an outdated modeling report generated by the Air District, which used the combustion turbine/HRSG emissions rate proposed in the December 2008 Draft Permit (9 lbs/hr), rather than the reduced emissions rate (7.5 lb/hr) proposed in the August 2009 Draft Permit and in the modeling reports referenced in the Additional Statement of Basis. (The higher emission rate of 9 lb/hr equals 1.134 g/s.)

This confirms that the emissions rate in the air modeling files your District provided to us in response to your public records request on September 1, 2009 used an emission rate of 1.134 g/s, which is the same rate that our modeling used. Now you contend that rate is incorrect and you did not use that emissions rate. Please promptly provide all modeling files (***input and output***) of both AERMOD and SCREEN3 that you relied on; in this regard, this confirms that the September 1, 2009 files did NOT include your output data. Please include that output data as well this time.

The February 4, 2010 response to comments at p. 161 claims: "The Air District used the same publicly-available AERMOD program as the commenters did, and the discrepancy in the commenters' results comes from the fact that they used incorrect inputs, . . "

No citation to any document is provided to support this assertion. As we informed you, our modeling used the identical inputs and emission rates the District provided in the air modeling files provided on September 1, 2009. Please promptly provide what documentation, including any communications, the District relies on

to make this assertion, including the identification of what inputs were incorrect. At page 168, the February 4, 2010 response to comments states "the applicant provided an updated CALPUFF modeling analysis for
the impact of the project's emission on Point Reyes National Seashore." Also on that page footnote 333 refers to the following: Summary of CALPUFF Class I Modeling Analysis Results, prepared by Greg Darvin, Atmospheric Dynamics, October 14, 2009."
Please promptly provide a copy of that summary referred to in footnote 333. Please also promptly provide all modeling files (***input and output***) of the CALPUFF modeling upon which the District relied and refers to in the February 4, 2010 response, pp. 167-168.
Lastly, please provide a copy of the Memorandum from G. Darvin (Atmospheric Dynamics) to G. Long (Bay Area Air Quality Management District), September 28, 2009 identified in footnote 322.

Please let me know when these documents and air modeling files will be available for pick-up. Of course, we are willing to accept anything that can be transmitted via email to make satisfying this request easier. As you know, time is of the essence. If you have any questions, please advise.

Thank you for your prompt attention in this matter.

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