650 Town Center Drive, 20th Floor
Costa Mesa, California 92626-1925
Tel: (714) 540-1235 Fax: (714) 755-8290
www.lw.com

LATHAM&WATKINS LLP

July 2, 2007

File No. 039810-0001

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DATE JUL 0 2 2007
RECD. JUL 0 2 2007

VIA FEDEX

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 07-AFC-1
1516 Ninth Street, MS-4
Sacramento, California 95814-5512

Re: Victorville 2 Hybrid Power Project: Docket No. 07-AFC-1

Dear Sir/Madam:

Pursuant to California Code of Regulations, title 20, sections 1209, 1209.5, and 1210, enclosed herewith for filing please find a copy of a letter from Sara Head to Ed Pike re Supplement to Application for Prevention of Significant Deterioration Permit.

Please note that the enclosed submittal was filed today via electronic mail to your attention and to all parties on the CEC's current electronic proof of service list.

Very truly yours,

Paul E. Kihm
Senior Paralegal

Enclosure

cc: CEC 07-AFC-1 Proof of Service List (w/ encl. via e-mail)
Michael J. Carroll, Esq. (w/ encl.)

OC\898748.1

ENSR | AECOM

ENSR
1220 Avenida Acaso, Camarillo, CA 93012
T 805.388.3775 F 805.388.3577 www.ensr.aecom.com

June 25, 2007

Mr. Ed Pike
U.S. Environmental Protection Agency
75 Hawthorne Street
San Francisco, CA 94105

Subject: Supplement to Application for Prevention of Significant Deterioration Permit for Victorville 2 Hybrid Power Project (VV2)

Dear Ed,

The purpose of this letter is to provide additional information regarding PM2.5 emissions that was requested to supplement the VV2 PSD Application submitted on May 2, 2007. The PSD Application previously submitted indicated that while PM2.5 is an attainment pollutant within the MDAQMD, that it was not explicitly addressed because EPA has not yet finalized the PM2.5 implementation rule for New Source Review. However, EPA has determined the City of Victorville needs to also request that the EPA issue a PSD permit for PM2.5 emissions, and provide all of the information EPA needs to process this request. Therefore, to this purpose, the following information is provided herein:

- BACT Analysis for PM2.5,
- Class II PM2.5 Air Quality Impact Analysis (information that was provided in the AFC Application), and
- Modeled PM2.5 air concentrations at the Class I areas.

BACT Analysis for PM2.5

<u>Combustion Turbines and Heat Recovery Steam Generators</u>

Like PM10, PM2.5 will be emitted by the combined-cycle generating systems due to sulfur, inert trace contaminants in pipeline natural gas, dust drawn in from the ambient air, particulate carbon and metals worn from the equipment while in operation, and hydrocarbons resulting from incomplete combustion. It was conservatively assumed that all PM10 is emitted as PM2.5.

Top-down Ranking of Achievable Control Levels

There are no additional controls for PM2.5 emissions. Neither the EPA BACT Clearinghouse nor SCAQMD[1] BACT Guidelines list any emission levels for PM2.5 for combined-cycle turbines. The only available emissions control for PM2.5 is the use of pipeline natural gas.

PM2.5 BACT Determination for Normal Operation

The most stringent particulate matter control method for gas turbines is the use of low-ash fuels such as natural gas, and all known combined-cycle units employ inlet air filters. No add-on control technologies are listed in the EPA BACT Clearinghouse. Inlet air filtration, combustion control and the use of low or zero-ash

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[1] MDAQMD does not have source-specific BACT Guideline, so SCAQMD Guidelines were reviewed.

fuel (such as natural gas) are the only control methods listed for turbines with PM10 limits. It was conservatively assumed that all PM10 is emitted as PM2.5 at the VV2 plant. Therefore, the same BACT emission limits are proposed: 12.0 lb/hr with duct burners off, 18.0 lb/hr with duct burners on, and the exclusive use of pipeline quality natural gas.

Note, these values are below the typical GE guarantee of 18.0 lbs/hr for the combustion turbines without duct burners. However, source test data for PM10 shows that these proposed values are achievable in practice.

PM2.5 BACT Determination for Startup and Shutdown

Since PM2.5 emissions result from impurities in the natural gas burned and do not depend on an emissions control system, the proposed BACT mass limits that govern normal operation also represent BACT for emissions during startup and shutdown.

Auxiliary Boiler and HTF Heater

PM2.5 emissions for both the auxiliary boiler and the HTF heater will be limited through the use of low sulfur pipeline quality natural gas. It was conservatively assumed that all PM10 is emitted as PM2.5. Therefore, the same emission limit is proposed for PM2.5 as PM10: 0.007 lb/MMBtu at full load for both the auxiliary boiler and the HTF heater. BACT will be achieved by the exclusive use of low sulfur pipeline quality natural gas during normal operations.

Emergency Diesel Generator and Fire-Water Pump Engine

It was conservatively assumed that all PM10 is emitted as PM2.5. Therefore, the PM10 emission rates from 40 CFR 60 Subpart IIII apply for PM2.5. The emergency generator and the fire-water pump engine will be limited to 0.20 g/kW-hr of PM2.5. The engines will only be tested or maintained up to 50 hours per year. Use of a Tier 2 engine and compliance with federal limits constitutes BACT/LAER for PM2.5 emissions for both the emergency generator and the fire-water pump engine.

Evaporative Mechanical Draft Cooling Tower

The VV2 Project will utilize reclaimed water from the nearby VVWRA wastewater treatment facility for steam turbine condenser cooling and will employ a ten cell evaporative (wet) cooling tower. Cooling towers emit trace amounts of solid particulate matter due to release of the dissolved solids (salts) in droplets that escape the mist eliminator at the top of the tower, referred to as cooling tower drift. In theory, these droplets may evaporate (rather than falling back to earth as liquid droplets) to form solid particulate matter. PM10 and PM2.5 are the only criteria pollutants of concern from wet cooling towers.

Often it is assumed that only a portion (e.g., 50%) of the total dissolved solids (TDS) in the water will form PM10 and only a portion of the PM10 emissions will be in the PM2.5 size range. However, for this analysis, it was very conservatively assumed that all (100%) TDS will form PM2.5.

Furthermore, there are differences in opinion whether a BACT review should include alternative technologies that would significantly alter the design of the plant. However, at the request of EPA, this BACT analysis evaluates alternative cooling technologies. Three types of cooling technology approaches are available – wet cooling, dry cooling, and wet-dry hybrid cooling.

Wet Cooling Description. Wet cooling uses circulating water to condense turbine-generator exhaust steam in a shell and tube heat exchanger (condenser). Cool circulating water enters the tube side of the condenser where it is warmed by the shell-side steam, causing the steam to condense such that condensate pumps may return it to the boiler feed water system. The warm circulating water then travels to a wet mechanical draft cooling tower. The cooling tower dissipates heat through circulating water evaporation and contact with ambient air. Once cooled, the circulating water is returned to the condenser to complete the cooling circuit.

Dry Cooling Description. Dry cooling technology uses an air cooled condenser (ACC) that cools the steam turbine-generator exhaust steam using a large array of fans that force air over finned tube heat exchangers. The exhaust from the steam turbine flows through a large diameter duct to the ACC where it is condensed inside the tubes through indirect contact with the ambient air. The heat is then rejected directly to the atmosphere.

Wet-Dry Hybrid Cooling Description. The wet-dry hybrid cooling approach involves the use of a combination of both wet and dry cooling technologies in parallel, and uses all of the equipment involved in both wet and dry cooling. As in a purely wet cooling system, cool water is circulated in a shell and tube heat exchanger to condense the turbine exhaust steam, and then a cooling tower is used to dissipate the heat in the warmed water. As in a purely dry cooling system, an air-cooled condenser uses a large array of fans to force air over finned tube heat exchangers, and the steam is condensed through indirect contact with the ambient air. Hybrid cooling technology divides the cooling function between the wet and dry systems depending on the capabilities of each system under different environmental and operational conditions.

Wet cooling systems have direct emissions of PM2.5 due to drift emissions. Because exhaust passing through the tower comes into direct contact with the cooling tower water, some water is entrained. These droplets contain dissolved solids that evaporate and form fine particles. It is estimated that a wet cooling system at the VV2 plant will emit up to 7.2 tpy of particulates, which are all conservatively assumed to be PM2.5. Dry cooling systems have no direct PM2.5 emissions. However, dry cooling systems increase the back pressure on the steam turbines, and also increase the parasitic load on the power plant. It is estimated by Bibb (the VV2 engineer) that installing a dry cooling system would reduce the efficiency of the VV2 plant by about 6.5%, which would increase stack PM2.5 emissions by 7.6 tpy[2], as well as increasing NOx and CO by similar amounts, to achieve the same net power output. Because the mechanical draft wet cooling tower emissions of PM2.5 are at most 7.2 tpy[3], a dry cooling tower would not result in a net emission decrease on an equal power output basis.

A wet-dry hybrid cooling system would have the same performance as a dry-cooled plant because the ACC portion forces the wet cooling tower portion of the hybrid would have to operate at the same steam turbine backpressure. A hybrid system would have additional PM2.5 drift emissions when the wet portion of the tower is operating.

Table 1 compares the economics of operating wet and dry cooling towers. The capital costs for an ACC are almost $1 million more for the ACC than for the wet tower, not including the cost of a redesigned steam turbine that would be able to withstand the higher back pressures caused by the ACC. As shown in Table 1, the annual cost to operate the wet cooling tower would be about $9,300,000/year, including capital recovery as well as the cost of water, chemicals, and power needs. Due to the high penalty cost of increasing the steam turbine backpressure, the cost to operate a dry cooling system was estimated to be about $56,800,000/year.

[2] Maximum annual PM10 emissions from the combustion turbines estimated to be 117 tpy, 6.5% of this total is 7.6 tpy
[3] Based on assuming 100% of TDS is emitted as PM2.5, a very conservative assumption

Table 1 Comparison of operating costs for wet and dry cooling

	Wet Cooling Tower	Dry Cooling
Required Power		
Fan Power(e)	1,700 kW	3,000 kW
Circulating Pump Power	2,400 kW	0 kW
Power Loss Due to High Steam Turbine Backpressure	0 kW	38,700 kW
Water Treatment Power Consumption (Zero Liquid Discharge)	850 kW	<200 kW
Total Net Power Loss	4,950 kW	41,900 kW
Costs		
Direct Capital Cost	$20,600,000	$21,500,000[e]
Water Pipeline Installation	$1,100,000	$0
Annualized Costs		
Capital Recovery[a]	$1,748,000	$1,733,000
Net Power Loss Cost[b]	$6,504,000	$55,056,000
Treatment Chemical Addition[c]	$20,000	$0
Make-up Cooling Water[d]	$1,050,000	$0
Total $/year	$9,323,000	$56,789,000

Notes:
(a) Assumes a 30-year lifetime with a 7% interest rate.
(b) Assumes the facility operates 8,760 hr/year and a power cost of 0.15 $/kWh.
(c) Assumes that water treatment chemicals would be needed in a wet tower to prevent corrosion, bio-fouling, etc.
(d) Estimated at $200/acre-foot.
(e) Does not include additional costs required for a steam turbine that can be operated at high back pressure.

The capital cost of a wet-dry hybrid system for the VV2 facility would be about $41,000,000, about twice the cost of a wet or dry cooling system. The operating costs would depend on the amount of time that the system operates in wet or dry modes. However, because the hybrid cooling system includes the backpressure penalty, the operating costs will be similar to the dry cooling system.

As noted above, dry cooling could actually increase emissions of all pollutant for an equivalent amount of power produced. However, putting that aside, based on the annualized cost difference between the two options shown in Table 1 of $47,466,000, the cost effectiveness of reducing 7.2 tpy of emissions would be $6.2 million per ton. If the size of the dry cooling tower was increased, the power loss would decrease, and the overall annual cost would be expected to decrease. However, the performance of the largest possible dry cooling tower cannot approach the performance of a wet cooling tower. Even if the net power loss costs for ACC could be decreased to only 20% of those shown in Table 1, which is not a realistic scenario, the cost effectiveness would still be $449,000 per ton. These values are not considered to be cost effective for reducing the small amount of PM2.5 emissions that would be released by a wet cooling tower, and hence an ACC is not considered to be BACT for this project. An ACC would also have other environmental impacts, including being more visually intrusive and noisy.

BACT for PM2.5 from evaporative cooling towers is the use of high efficiency drift eliminators. No other control technology has been identified that could reduce emissions of PM2.5 from an evaporative cooling tower beyond levels that can be achieved with state-of-the-art drift eliminators. The project will install a ten-cell cooling tower with a circulation rate of approximately 123,000 gallons per minute. Drift eliminators will be used to restrict the drift rate to 0.0005 percent. This technology represents BACT for control of PM2.5 from the proposed evaporative cooling tower.

Class II PM2.5 Air Quality Impacts

As documented in the PSD Application and the Application for Certification (AFC) submitted to the California Energy Commission, dispersion modeling was conducted with the AERMOD model to assess air quality impacts for the VV2 project. As discussed in the BACT analysis above, PM2.5 emissions have been assumed equivalent to PM10. These results are summarized below in Table 2 and compared to the NAAQS. In Table 2, the maximum modeled PM2.5 concentrations on a daily and annual basis are summed with an ambient background component. The wet cooling tower, even with the very conservative assumption that 100% of the particulate emissions are PM2.5, contributes only 0.8 $\mu g/m^3$ on a 24-hour basis and 0.07 $\mu g/m^3$ on an annual basis to the maximum concentrations. As described in the AFC, the 24-hour background value represents the average of the 98th percentile values measured at the Victorville monitor over three recent years (2003-2005). The annual background value is the highest concentration measured at the Victorville monitor over the same three year period. As shown in the table, total concentrations are below the NAAQS.

Table 2 NAAQS Analysis for Project Normal Operations

Pollutant	Averaging Period	Concentrations ($\mu g/m^3$)			
		AERMOD Result	Ambient Background	Total [a]	NAAQS
PM2.5	24-hr	6.1	26	32	35
	Annual	0.3	11	11	15
(a) Modeled concentration plus background.					

As noted above, EPA has not yet finalized the implementation rule for the PM2.5 PSD analyses. Therefore, there are as yet no PSD increments defined for PM2.5. However, the project-only impacts (AERMOD Result) given in Table 2 are well below the PSD Class II increments for PM10 of 30 $\mu g/m^3$ on a 24-hour basis and 17 $\mu g/m^3$ on an annual basis.

Modeled PM2.5 air concentrations at the Class I areas

An estimate of maximum PM2.5 concentrations was developed for the Class I areas that were addressed in the PSD permit application. The areas include: Cucamonga WA, Joshua Tree NP, San Gorgonio WA, San Gabriel WA, and San Jacinto WA. The Class I area impact analysis conducted to support the VV2 PSD application utilized the CALPUFF model to estimate air increment and regional haze impacts for each of the Class I areas.

In support of regional haze computations CALPUFF computes the transformation of secondary particulate (PM2.5) using a pseudo first-order parameterization, referred to as the MESPOPUFF II chemical mechanism. The rate of transformation from SO_2 to ammonium sulfate is determined from solar radiation, background ozone, atmospheric stability class and relative humidity. The rate of transformation of NO_X to nitrate depends on the ozone concentration, NO_X concentration and atmospheric stability. Although the transformation rate for nitrate is generally faster than sulfate, not all of the nitrate formed is in particulate form. The direct result of the nitrate reaction is nitric acid, which is an invisible vapor. The nitric acid will then combine with available ammonia in the atmosphere to form ammonium nitrate aerosol. The model first allocates the background ammonia to ammonium sulfate and the balance is then available to form nitrate aerosol.

The computed sulfate and nitrate concentrations already available from the CALPUFF regional haze runs that were conducted for PSD application were used to estimate the concentrations of ammonium sulfate and ammonium nitrate; i.e., the secondary PM2.5. That is, the sulfate and nitrate concentrations were scaled by the ratio of their respective molecular weights (MW) to ammonium sulfate and ammonium nitrate using CALPUFF's post-processing package, POSTUTIL. The scaling factors used were as follows:

- For ammonium sulfate: The MWs are $[NH_4]_2SO_4$ = 132 and SO_4 = 96. The scaling factor is 132/96 = 1.38 to estimate ammonium sulfate from the sulfate concentration.
- For ammonium nitrate: The MWs are NH_4NO_3 = 80 and NO_3 = 62. The scaling factor is 80/62 = 1.29 to estimate ammonium nitrate from the nitrate concentration.

The ammonium sulfate and ammonium nitrate concentrations were then summed together with the primary PM2.5 concentration (i.e., same as the PM10 concentration) to estimate the total PM2.5 concentration at the receptors in each Class I area.

Table 3 summarizes the 24-hour and annual average PM2.5 concentrations associated with the VV2 project at each Class I area determined from this method. There are no applicable PM2.5 increments for Class I areas to compare to these results. However, these values are all well below the PM10 Class I increments of 10 μg/m^3 on a 24-hour basis and 5 μg/m^3 on an annual basis.

Table 3 Modeled PM2.5 Concentrations at the Class I Areas

Pollutant	Class I Area	Averaging Period	Maximum Modeled Concentrations (μg/m^3)		
			2001	2002	2003
PM2.5	Cucamonga WA	24-hour	0.1773	0.1110	0.1465
		Annual	0.0072	0.0069	0.0055
	Joshua Tree NP	24-hour	0.0456	0.0541	0.0442
		Annual	0.0041	0.0043	0.0038
	San Gorgonio WA	24-hour	0.1070	0.0850	0.1657
		Annual	0.0063	0.0053	0.0064
	San Gabriel WA	24-hour	0.0501	0.0327	0.0899
		Annual	0.0026	0.0021	0.0020
	San Jacinto WA	24-hour	0.0259	0.0258	0.0337
		Annual	0.0016	0.0016	0.0014

In summary, this PSD Application supplemental analyses demonstrates that there would be no significant impact from the VV2 Project's PM2.5 emissions.

Please contact me at 805-388-3775 if you have any questions regarding this information or require additional information to complete your review. We appreciate your attention to this important project.

Sincerely,

Sara J. Head
Vice President

cc: Ms. Dee Morse, National Park Service
Mr. Mike McCorison, U.S. Forest Service
Mr. John Kessler, California Energy Commission
Mr. Alan De Salvio, Mojave Desert Air Quality Management District
Mr. Jon B. Roberts, City Manager, Victorville
Mr. Tom Barnett, Inland Energy, Inc.
Mr. Tony Penna, Inland Energy, Inc.
Mr. Mike Carroll, Latham & Watkins
Ms. Kim McCormick, Law Offices of Kim McCormick

STATE OF CALIFORNIA
ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of:	)	Docket No. 07-AFC-1
	)	
Application for Certification,	)	**ELECTRONIC PROOF OF SERVICE**
for the VICTORVILLE 2	)	**LIST**
HYBRID POWER PROJECT	)	
	)	**(revised June 14, 2007)**
	)	
	)	

☒ Transmission via electronic mail and by depositing one original signed document with FedEx overnight mail delivery service at Costa Mesa, California with delivery fees thereon fully prepaid and addressed to the following:

DOCKET UNIT

CALIFORNIA ENERGY COMMISSION
Attn: DOCKET NO. 07-AFC-1
1516 Ninth Street, MS-4
Sacramento, California 95814-5512
docket@energy.state.ca.us

☒ Transmission via electronic mail addressed to the following:

APPLICANT

Jon B. Roberts
City Manager
City of Victorville
14343 Civic Drive
P.O. Box 5001
Victorville, CA 92393-5001
JRoberts@ci.victorville.ca.us

APPLICANT'S CONSULTANTS

Thomas M. Barnett
Inland Energy, Inc.
South Tower, Suite 606
3501 Jamboree Road
Newport Beach, CA 92660
TBarnett@inlandenergy.com

Sara Head
Environmental Manager
ENSR
1220 Avenida Acaso
Camarillo, CA 90012
SHead@ensr.aecom.com

INTERESTED AGENCIES

Electricity Oversight Board
770 L Street, Suite 1250
Sacramento, CA 95814
esaltmarsh@eob.ca.gov

INTERVENORS

California Unions for Reliable Energy (CURE)
c/o Marc D. Joseph
Adams Broadwell Joseph & Cardozo
601 Gateway Boulevard, Suite 1000
South San Francisco, CA 94080
mdjoseph@adamsbroadwell.com

ENERGY COMMISSION

James Boyd
Presiding Committee Member
jboyd@energy.state.ca.us

Jackalyne Pfannenstiel
Associate Committee Member
JPfannen@energy.state.ca.us

Gary Fay
Hearing Officer
gfay@energy.state.ca.us

John Kessler
Project Manager
JKessler@energy.state.ca.us

Caryn Holmes
Staff Counsel
CHolmes@energy.state.ca.us

Mike Monasmith
Public Adviser
pao@energy.state.ca.us

DECLARATION OF SERVICE

I, Paul Kihm, declare that on July 2, 2007, I deposited the required original signed copy of the attached:

LETTER FROM SARA HEAD TO ED PIKE RE SUPPLEMENT TO APPLICATION FOR PREVENTION OF SIGNIFICANT DETERIORATION PERMIT

with FedEx overnight mail delivery service at Costa Mesa, California with delivery fees thereon fully prepaid and addressed to the California Energy Commission. I further declare that transmission via electronic mail was consistent with the requirements of California Code of Regulations, title 20, sections 1209, 1209.5, and 1210. All electronic copies were sent to all those identified on the Proof of Service List above.

I declare under penalty of perjury that the foregoing is true and correct. Executed on July 2, 2007, at Costa Mesa, California.

Paul Kihm