Responses to Data Requests Dated October 4, 2007

Application for Certification (07-AFC-3)

for

CPV Sentinel Energy Project

Riverside County, California

November 5, 2007

Prepared for:

CPV Sentinel, LLC

Prepared by:

URS

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LIST OF ACRONYMS AND ABBREVIATIONS USED IN RESPONSES

AB	Assembly Bill
ACM	asbestos-containing materials
AFC	Application for Certification
BACT	Best Available Control Technology
Btu/kwh	British thermal units per kilowatt hour
California ISO	California Independent System Operator
CARB	California Air Resources Board
CCR	California Code of Regulations
CEC	California Energy Commission
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
CPVS	CPV Sentinel Energy Project
CTG	Combustion Turbine Generator
CVWD	Central Valley Water District
°F	degrees Fahrenheit
DESCP	Drainage Erosion and Sediment Control Plan
dscf	dry standard cubic feet
DWA	Desert Water Agency
DWR	California Department of Water Resources
ECP	Erosion Control Plan
EGF	Electrical Generating Facility
E-I	Energy Industrial
ERC	emission reduction credit
ESA	Environmental Site Assessment
ETo	evapotranspiration
g/s	grams per second
GHG	greenhouse gases
gpm	gallons per minute
gr/100 scf	grains per hundred standard cubic feet
GWP	global warming potential
ISO	Independent System Operator
kV	kilovolt
kw	kilowatt
lb/hr	pounds per hour
lb/MW-hr	pounds per megawatt-hour
lb/yr	pounds per year
LBP	lead-based paint
LGIA	Large Generator Interconnection Agreement
LHV	lower heating value
MGD	million gallons per day
μg/L	micrograms per cubic liter
MMBtu/hr	million British thermal units per hour
MSWD	Mission Springs Water District
MW	megawatt
MWD	Metropolitan Water District
NA	not applicable
NO_2	nitrogen dioxide
NO_X	nitrogen oxides

OAL	Office of Administrative Law
PCBs	polychlorinated biphenyls
PM_{10}	particulate matter less than 10 microns
PUP	Public Use Permit
RH	relative humidity
RTCs	RECLAIM Trading Credits
RWQCB	Regional Water Quality Control Board
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
scf	standard cubic feet
SCGC	Southern California Gas Company
SF	Sulfur hexafluoride
SO_2	sulfur dioxide
SO_X	sulfur oxides
SWP	State Water Project
SWPPP	Storm Water Pollution Prevention Plan
SWRCB	State Water Resources Control Board
ton/hr	ton per hour
UWMP	Urban Water Management Plan
VOC	volatile organic compounds
WWTP	Wastewater Treatment Plant

AIR QUALITY

Technical Area: Air Quality
Author: Joe Loyer

BACKGROUND: EMISSION REDUCTION CREDITS

The applicant proposes to rely on the District's nitrogen oxides (NO_x) RECLAIM program to acquire emission reduction credits to offset the project's NO_x emission impacts. The applicant also proposes to purchase volatile organic compounds (VOC) emission reduction credits (ERC) from the District's ERC banks. Finally, the applicant proposes to purchase PM_{10} and sulfur dioxide (SO_2) ERCs as part of the due diligence requirements in District Rule 1309.1 (Priority Reserve). However, the applicant has not provided any information on how they intend to meet their RECLAIM and ERC obligations.

DATA REQUEST

1. Please provide a list of NO_x RECLAIM trading credits (RTCs) that the applicant owns or has under option contract.

RESPONSE

Pursuant to South Coast Air Quality Management District (SCAQMD) Rule 2001(i)(2)(M), the CPV Sentinel Energy Project (CPVS) is not automatically included in the nitrogen oxides (NO_X) RECLAIM program, but may elect to enter into the program pursuant to Rule 2001(f). While it is likely to do so, CPV Sentinel, LLC has not yet determined whether it will elect to enter the NO_X RECLAIM program, and therefore has not yet acquired any NO_X RECLAIM Trading Credits (RTCs), or any options to acquire NO_X RTCs. The decision about whether or not to enter the NO_X RECLAIM program will be made at a later time based on conditions in the NO_X RTC and NO_X emission reduction credit (ERC) markets.

DATA REQUEST

2. Please update staff as to the status of securing the NO_x RTCs, VOC, PM_{10} and SO_2 ERCs as part of the monthly status reports that are filed with the CEC.

RESPONSE

CPV Sentinel, LLC has not acquired any RTCs or ERCs at this time. CPV Sentinel updates staff regarding credit acquisitions in its status reports.

BACKGROUND: NATURAL GAS SULFUR CONTENT

The Application For Certification (AFC) indicates that the facility would use natural gas with a maximum sulfur content of 0.25 grain per 100 standard cubic feet (gr/100 scf). Staff has seen in previous siting cases that the delivered natural gas can contain as much as 1 gr sulfur/100 scf. If higher sulfur content natural gas fuel is used at the facility, SO_X and PM emissions may be underestimated, the project impacts may be underestimated and insufficient offsets may be provided. Thus staff needs additional information to assure that the sulfur content of the fuel does not exceed the levels stated in the AFC.

DATA REQUEST

3. Please provide specific documentation from Southern California Gas Company that the sulfur content of supplied natural gas would not exceed 0.25 gr/100 scf.

RESPONSE

Southern California Gas Company (SCGC) gas quality is regulated by Rule No. 30, Transportation of Customer-Owned Gas. Rule No. 30, Section I(e), specifies that gas shall not contain more than 0.75 grain of sulfur per 100 standard cubic feet (scf). In practice, the gas supplier, based on historical fuel analysis data, delivers gas to its customers with fuel sulfur contents well below 0.25 grain per 100 scf. Appendix A-1 provides the Rule No. 30 sheet specifying sulfur content.

Application for Certification (AFC) Table 5.2-2 accurately summarizes the relevant data pertaining to sulfur in the natural gas supply during 2006 received from SCGC. Appendix A-1 also provides correspondence from SCGC indicating that the Blythe receipt point (B1 and B2) is the most representative sample for the CPVS location. As shown on Table 5.2-2 in the AFC, sulfur at B1 and B2 ranged from 0.051 to 0.119 grain of sulfur per 100 scf, with an average of 0.071 at B1 and 0.079 at B2.

The background statement raises concerns regarding the potential to underestimate impacts if natural gas fuel with a higher sulfur content is used at CPVS. To address these concerns, additional air quality modeling was conducted. The purpose of the modeling was to determine whether compliance with the ambient air quality standards would be maintained even in the unlikely event that the sulfur content of the natural gas received at CPVS reached a level as high as 0.75 grain of sulfur per 100 scf of natural gas.

Accordingly, a new AERMOD dispersion modeling analysis was conducted to estimate the potential impacts from a short-term higher sulfur natural gas event. The sulfur content of the natural gas was set to 0.75 grain per 100 scf. The short-term full load emission rate from each turbine was estimated on this basis and is presented in Table 3-1. Annual impacts were not analyzed, as the delivery of higher sulfur natural gas might only occur for brief periods. The same stack parameters, meteorological input data, and receptor reported in the AFC were used for the additional modeling.

The results of the new analysis with the assumed higher sulfur content natural gas are presented in Table 3-2. The 1-hour and 3-hour peak concentrations do not change from the previous analysis, because the diesel blackstart engine contributes the most to the peak concentration. The modeling predicts the 24-hour concentration to be approximately three times higher due to the higher sulfur content natural gas, the turbines contribute the most to the peak concentration. The maximum predicted sulfur dioxide (SO_2) concentrations for all averaging times, including background, are well below the National Ambient Air Quality Standards and California Ambient Air Quality Standards. Therefore, no significant impacts are expected to occur in the hypothetical event of higher sulfur natural gas fuel deliveries to CPVS.

The air dispersion model input and output files supporting this analysis are included on a CD attached to this data response.

Table 3-1
Sulfur Dioxide Emission Rate from Each CPVS in the Event of High Sulfur Natural Gas (0.75 grain sulfur/100 dscf)

Averaging Time	SO_2 Emission Rate (g/s) per Turbine
Short-term (1-hour, 3-hour and 24-hour)	0.232

Notes:
dscf = dry standard cubic feet
g/s = grams per second
SO_2 = sulfur dioxide

Table 3-2
Maximum Predicted Sulfur Dioxide Concentrations Due to Hypothetical High Sulfur Natural Gas Usage at CPVS

Pollutant	Averaging Period	Maximum Predicted Impact Lower Natural Gas Sulfur (0.25 gr/100 scf) (µg/m^3)	Maximum Predicted Impact Higher Natural Gas Sulfur (0.75 gr/100 scf) (µg/m^3)	SCAQMD Significant Change (µg/m^3)	Background Concentration (µg/m^3) [1]	Total Concentration (Higher Sulfur Scenario) (µg/m^3)	NAAQS (µg/m^3)	CAAQS (µg/m^3)
SO_2	1-hour	44.3	44.3	NA	62.9	107.2	NA	655
	3-hour	38.3	38.3	NA	41.6	79.9	1,300	NA
	24-hour	1.06	3.27	NA	39.4	42.7	365	105

Notes:
[1] Background represents the maximum values measured at the monitoring stations presented in the AFC.
gr/100 scf = grains per hundred standard cubic feet
NA = not applicable
µg/L = micrograms per cubic liter
SO_2 = sulfur dioxide

DATA REQUEST

4. Please provide documentation from Southern California Gas Company of the up-stream supply points for the natural gas that is proposed to be delivered to the project site.

RESPONSE

According to SCGC (Appendix A-1), the Blythe receipt point (B1 and B2) is the most representative sample for the CPVS location. AFC Table 5.2-1, Natural Gas Chemistry Analysis; and Table 5.2-2, Natural Gas Sulfur Analysis; are based on SCGC data for Blythe.

As discussed in Data Request 3, additional air modeling results also demonstrate that no significant impacts would occur in the unlikely event that high sulfur natural gas was delivered to the CPVS.

DATA REQUEST

5. Please provide the steps the applicant would take to ensure that the natural gas that has higher than 0.25 gr/100 scf of sulfur would not be used at the facility.

RESPONSE

As discussed in the response to Data Request 3, SCGC gas quality is regulated by Rule No. 30, Transportation of Customer-Owned Gas. Rule No. 30, Section I(e), specifies that gas shall not contain more than 0.75 grain of sulfur per 100 scf. In practice, the gas supplier, based on historical fuel analysis data, delivers gas to its customers with fuel sulfur contents well below 0.25 grain per 100 scf. Appendix A-1 provides the Rule No. 30 sheet specifying sulfur content. Also, the response to Data Request 3 presents additional air modeling results that demonstrate that no significant impacts would occur in the unlikely event that high sulfur natural gas was delivered to the CPVS.

DATA REQUEST

6. Please provide the method for ensuring continuous compliance with the sulfur content limits specified for the supplied natural gas fuel.

RESPONSE

See the response to Data Request 3.

CUMULATIVE ASSESSMENT

BACKGROUND: CUMULATIVE ASSESSMENT

The applicant indicates on page 7.1-25 in the AFC that the required cumulative assessment will be completed and submitted after further information from the District is received and evaluated.

DATA REQUEST

7. Please provide the documentation of new sources within six miles of the proposed CPV Sentinel Energy Project site.

RESPONSE

As required by California Energy Commission (CEC) policy, a dispersion modeling analysis is necessary to evaluate the maximum cumulative air quality effects of the CPVS along with other new sources within 6 miles of the CPVS site that are either under construction, newly permitted in 2006–2007, or currently in the permitting process. In order to facilitate the cumulative analysis, the SCAQMD was contacted to obtain a list of permitted emission sources within 6 miles of the CPVS facility. The list that was obtained from the SCAQMD is included as Appendix A-2. Note that this list includes *all* permitted sources within this 6-mile radius and not just new sources. After review of the source list and discussions with SCAQMD permit engineers, there were no new sources identified within 6 miles of the CPVS site that needed to be included in any cumulative modeling analysis. The reasons why individual sources were excluded from the cumulative modeling analysis are indicated in the table provided in Appendix A-2.

DATA REQUEST

8. Please provide the completed cumulative assessment or the date it will be provided.

RESPONSE

No new sources were identified within 6 miles of the CPVS site that needed to be included in any cumulative modeling analysis. Thus, no cumulative dispersion modeling was performed. The modeling results associated with the operation of the facility provided in the AFC were added to the maximum background air quality concentrations to incorporate the impacts from the other existing sources in the area.

BACKGROUND: GREENHOUSE GAS EMISSIONS

The AFC does not discuss the potential sulfur hexafluoride (SF_6) emissions from proposed electricity transmission systems that may exist at the proposed CPV Sentinel Energy Project site. Such systems are referred to on page 4-1 ("CPVS Switchyard") and figure 2.4-1 and appear to be part of the proposed project.

DATA REQUEST

9. Please provide the estimated SF_6 emissions (in units of equivalent tons of CO_2) from any equipment on the proposed CPV Sentinel Energy Project site.

RESPONSE

New transmission facilities associated with the CPVS will be limited to a single-circuit 220-kilovolt (kV) line to deliver the project's electrical output to the Southern California Edison (SCE) transmission grid at a connection point in the switchyard within the Devers substation. The length of this line is estimated to be 3,250 feet, approximately 1,800 feet of which would be outside of the power plant or Devers substation boundaries. Sulfur hexafluoride (SF_6) will be present only at three new circuit breakers in amounts estimated at between 22 and 126 pounds each. Emissions of SF_6 were estimated based on vendor information on typical SF_6 amounts and leakage rates for a 230-kV breaker and main circuit breaker, as summarized in Table 9-1.

Table 9-1
Typical SF_6 Amounts and Leakage Rates for 230-kV Breaker and Main Circuit Breaker

Breaker	Qty	Typical Make	Typical Model	SF_6, lbs/brkr	Leakage Rate (%)	Leakage, lb/yr (per breaker)	Leakage, lb/yr (all breakers)
230-kV Main Breaker (3000A)	1	Mitsubishi	200 SFMT	126	1.0	1.26	1.26
230-kV Unit Breakers (1200A)	8	Mitsubishi	200 SFMT	126	1.0	1.26	10.08
Generator Main Circuit Brkr	4	Mitsubishi/ ABB	To Be Determined	22	1.0	0.22	0.88
						Total	**12.22**

Appendix A-3 includes emails exchanged with a Mitsubishi representative and brochures for the two following typical breakers:

- Typical 230-kV Breaker
- Typical Generator Main Circuit Breaker

BACKGROUND: ADDITIONAL LORS COMPLIANCE

The South Coast Air Quality Management District (AQMD) has amended their Rule 1309.1 (Priority Reserve) which grants the applicant access to the priority reserve credits for PM_{10} and SO_x. The applicant has been asked by the AQMD to submit further information regarding project compliance with the new requirements of Rule 1309.1. The Rule may require that the applicant perform new modeling analysis, revise emission calculations, or in some way modify the project operations.

DATA REQUEST

10. Please provide any additional information submitted to the AQMD regarding the project's compliance with Rule 1309.1, including new modeling analyses.

RESPONSE

The Applicant provided two letters to the SCAQMD dated September 17, 2007, and October 11, 2007, regarding Rule 1309.1 requirements. These letters are provided in Appendices A-4 and A-5, respectively.

ALTERNATIVES

Technical Area: Alternatives
Author: Suzanne Phinney

BACKGROUND

AFC page 8-4 discusses land to the north, west, south and east of Southern California Edison's (SCE) Devers substation. With the exception of land to the east of the substation, the discussion is vague as to exact locations of the areas that were considered. The area north of the substation is identified as consisting of multiple 5-10 acres lots owned by multiple private land owners. The area west is described as being undeveloped with wind farm development further west. The area south of the substation is identified as the location of the previously-proposed Ocotillo Power Plant (01-AFC-8), now rezoned and the location of wind turbines. Staff is not able to determine if the analysis of alternatives encompasses all possible sites.

DATA REQUEST

11. a) Please provide a map showing the aerial extent of the land evaluated as potential site alternatives to the Sentinel project.

b) Identify the location of the multiple 5- to 10-acre lots, showing the individual parcels.

c) Identify the geographic boundaries of existing and proposed wind energy facilities in the vicinity of the project.

RESPONSE

a) Figure 11-1 shows the aerial extent of the land evaluated as potential site alternatives for the proposed project. As discussed in Section 8.4 of the AFC, the alternative sites evaluated for the project focused on areas near the Devers substation.

b) Figure 11-1 shows the 5- to 10-acre lots located north of the Devers substation.

c) Figure 11-1 shows the existing and proposed wind energy facilities in the vicinity of the proposed project.

DATA REQUEST

12. Please identify the City of Palm Springs' current zoning for the land previously considered for the Ocotillo Power Plant and describe why this zoning would preclude development and whether zoning variances are an option at this location.

RESPONSE

The land previously considered for the Ocotillo Power Plant is currently zoned Energy Industrial (E-I) by the City of Palm Springs. This zoning designation does not allow for a power plant. As indicated by the CEC's 2001 Draft Staff Assessment for the Ocotillo Power Plant, the power plant would be inconsistent with the current E-I zoning.

In 2001, the City of Palm Springs Planning Commission considered an amendment to the Palm Springs Zoning Ordinance to make provisions for Natural-Gas–Fueled Electrical Generation Facilities in the E-I zoning district subject to a Conditional Use Permit. The City of Palm Springs Planning Commission voted to recommend amending the ordinance and sent the item to the City Council for final action. Although the City Council never issued final approval for this action, a variance to the zoning code may be an option at this alternative site location. However, since 2001, this site has been developed with wind turbines, which would preclude development of a power plant (see Figure 11-1). Furthermore, since the proposed CPVS site is currently consistent with Riverside County's Zoning Code and would not require a zoning variance, the proposed site is still considered the environmentally superior alternative when compared to the former Ocotillo Power Plant site alternative.

BACKGROUND

AFC page 8-4 states that the area directly west of the Devers substation has just been approved by the Riverside County Planning Commission for further wind farm development and that the EIR for the Dillon Wind Farm project was certified by the Riverside County Planning Commission in May 2007. The EIR likely includes possible site alternatives to the wind farm project. Given that the wind farm would need to connect with the Devers substation, similar to Sentinel, the Dillon Wind Farm alternatives discussion may identify additional locations that could serve as alternative sites for the Sentinel project.

DATA REQUEST

13. Please identify the alternatives considered in the Dillon Wind Farm EIR and discuss whether those alternatives could serve as alternatives to the Sentinel project.

RESPONSE

The site boundaries proposed in the Dillon Wind Project EIR are depicted in Figure 11-1.

According to the Draft EIR for the Dillon Wind Farm Project, this project would connect to a new substation located at the intersection of Diablo Road and Tiffany Way (south of "Area 1" and west of "Area 5," shown on Figure 11-1). The wind farm would not connect to the Devers substation. Therefore, the alternatives evaluated in the Dillon Wind Farm EIR would not necessarily be applicable to the proposed project. However, an evaluation of the alternatives discussed for the Dillon Wind Farm project is provided below.

The four alternatives considered in the Dillon Wind Project EIR include:

- Alternative 1: No Project.
- Alternative 2: Relocation or Elimination of Certain Turbines in Area 1.
- Alternative 3: Relocation or Elimination of Certain Turbines in Area 3.
- Alternative 4: Buildout of Estate Density Residential Area with Elimination of Certain Turbines in Area 3.

Alternatives 2, 3, and 4 relocate and/or remove planned wind turbines within Area 1 or 3.

These alternatives are discussed below in relation to the CPVS:

Dillon Wind Farm Alternative 1: The No Project alternative was evaluated for the CPVS project in Section 8.3 of the AFC.

Dillon Wind Farm Alternative 2: "Area 1" is located directly west of the Devers substation (Figure 11-1). This area has already been evaluated for the CPVS site, as discussed in Section 8.4 of the AFC. This area was eliminated as a potential site for the CPVS due to current and future planned wind farm development.

Dillon Wind Farm Alternative 3: "Area 3" is located approximately 3,400 feet east of the Devers substation (Figure 11-1). The proposed CPVS site is located approximately 700 feet east of the Devers substation. Area 3 is located farther from the Devers substation and would require a longer transmission interconnection than from the proposed CPVS site. Furthermore, Area 3 is visually more separated from the Devers substation than the proposed site. Therefore, constructing a power plant in Area 3 would likely have more visual impacts than a

power plant on the proposed site. Based on these factors, Area 3 was eliminated as a potential site for the CPVS.

Dillon Wind Farm Alternative 4: This alternative assumes the buildout of a residential area at a density consistent with an Estate Density Residential designation (2-acre minimum with single family detached housing). This alternative was evaluated to reduce visual impacts from the wind turbines in Area 3 from viewpoints along Indian Avenue and the exit from Two Springs RV Resort. Area 3 has already been eliminated as a potential site alternative, as discussed above, and therefore the Dillon Wind Farm Alternative 4 is also eliminated as a potential alternative.

CULTURAL RESOURCES

Technical Area: Cultural Resources
Author: Dorothy Torres

Any information that identifies the location of archaeological sites needs to be submitted under confidential cover.

BACKGROUND

The Water Resources Section, page 7.14, discusses five ground water wells that may be constructed on or near the proposed project site. To assess potential impacts to cultural resources caused by construction of the wells, staff needs information regarding the proposed locations of the wells.

DATA REQUESTS

14. a) Please identify the proposed well locations and conduct a cultural resources survey of well locations if the areas were not previously surveyed for the CPV Sentinel Project.

b) Please provide an updated Figure 7.3-5 that identifies the well locations and cultural resources survey boundaries.

RESPONSE

a) The proposed well locations are expected to be within the 37-acre proposed CPVS site. Figure 2.5-2 provided in the AFC depicts the locations of these five wells. The field cultural resources survey that was conducted from March 5 through 7, 2007, covered the 37-acre proposed project site. Therefore, no additional surveys are required.

b) A revised Figure 7.3-5 is included, showing the proposed well locations as well as the surveyed areas.

DATA REQUEST

15. Please provide a discussion of the survey methodology, procedures, resumes of survey personnel, and findings.

RESPONSE

Please see the response to Data Request 14. No additional surveys were conducted because the proposed wells will be within the previously surveyed areas.

BACKGROUND

The discussion of survey coverage, by project component, on page 2-3 of the Confidential Technical Report identifies locations that were not surveyed because there were issues regarding access. Figure 7.3-5 identifies those locations. Staff needs additional information about incomplete surveys at buffer areas to ensure that all cultural resources have been identified.

DATA REQUEST

16. a) Please provide a discussion of why each area was not surveyed. Please include a description of the environment that could be observed at the each location that was not surveyed, but could be observed from fence lines or roadways.

b) Please explain how the above observations substantiate the Technical Report conclusion that no cultural resources were identified.

RESPONSE

a) As indicated, Figure 7.3-5 in the AFC shows areas that were not surveyed due to inaccessibility. Access to these areas was prevented by fences which we did not have permission to cross. URS staff visually inspected these areas from the fence lines. Please see Table 3 of the Confidential Technical Report, which provides a description of the environmental setting at each location that could not be surveyed.

b) Although small portions of the search radii were not physically surveyed, it was determined that were no cultural resources within those areas, based on visual observations, the nature of the soils and environment immediately adjacent to these areas (e.g., if an area was highly disturbed), and knowledge of the surrounding areas obtained through the records search and the field survey.

LAND USE

Technical Area: Land Use
Author: Amanda Stennick

INTRODUCTION

Prior to making findings for its license, the Energy Commission needs to know whether Riverside County would normally require the CPV Sentinel Energy Project (Sentinel) to obtain a conditional use permit and height variance (and what conditions the County would attach to these entitlements) but for the exclusive jurisdiction and permit authority of the Energy Commission. Also, the Energy Commission needs to know the County's timeline for granting the proposed parcel merger and any conditions the County would place on the parcel merger. On September 13, 2007, staff sent a letter to the Riverside County requesting that the County provide this information.

For the Sun Valley Energy Project (05-AFC-3) proposed in western Riverside County, Energy Commission staff did not receive a written response from the County to a similar letter without the project applicant initiating a formal request to the County regarding the project's conformity and consistence with its general plan and zoning designations. To ensure Riverside County's timely review of the project's local LORS compliance, the Sun Valley project applicant submitted an application and associated fees to Riverside County for an advisory Conditional Use Permit (CUP). The County was aware that their CUP was advisory and their actions in this matter represented a review of the project that the County would normally undergo but for the Energy Commission's exclusive jurisdiction and permit authority. In addition to zoning development standards, the advisory CUP addressed and conditioned the project in the areas of biological resources, visual resources, drainage and flood control, health, waste, socioeconomic resources, and traffic and transportation. Similar to the Sun Valley case, staff encourages CPV Sentinel to work with Riverside County to resolve these issues, all of which are discussed in detail below.

Also, because portions of the proposed construction laydown area and gas line would lie within Palm Springs city limits, staff sent a letter to the City of Palm Springs requesting they provide similar information where a use permit would normally be required but for the Energy Commission's exclusive jurisdiction and permit authority. Staff also encourages CPV Sentinel to work with the City of Palm Springs to determine the type of use permits and any associated conditions that the City would normally place on the project but for the Energy Commission's exclusive jurisdiction and permit authority.

BACKGROUND

As stated in the AFC, the Riverside County General Plan land use designation for the site and proposed transmission line is Public Facilities (PF); the site is zoned W-2 (Controlled Development Area). According to the AFC, allowed uses in this land use designation include electric generating stations; permitted uses in this zoning district include structures and the pertinent facilities necessary and incidental to the development and transmission of electrical power and gas. Portions of the construction laydown area are designated by Riverside County as Rural Desert (RD) and zoned as W-E (Wind Energy Resource). The storage of vehicles, machinery and materials would be a proposed use in the construction laydown area.

Prior to making findings for its license, the Energy Commission needs to know whether the project would normally require a conditional use permit but for the exclusive authority of the Energy Commission and what conditions Riverside County would attach to this project, were it

the permitting agency. As part of the County's discussion of the conditional use permit, we are also interested in understanding the County's position on the proposed project's consistency with its General Plan and Zoning Ordinance.

DATA REQUEST

17. Please provide written confirmation from Riverside County as to whether the project would need a conditional use permit or any other land use entitlement from Riverside County but for the exclusive authority of the Energy Commission.

RESPONSE

A letter was sent to Riverside County on October 26, 2007, requesting the County's input on Data Requests 17 through 20 (Appendix B). The County has requested that the Applicant submit a Public Use Permit (PUP) application and associated deposit to fund their evaluation of the project on an advisory basis. The Applicant will be submitting the PUP Application to the County by November 9, 2007. The Applicant is also scheduled to meet with the County on November 14, 2007, to discuss the project and the estimated timeline for the County's evaluation. As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will submit the County's written confirmation upon receipt.

DATA REQUEST

18. If the project would need a conditional use permit, please provide the conditions, if known, that Riverside County would place on the project or provide a timeline as to when these conditions would become available to staff.

RESPONSE

Please see the response to Data Request 17.

DATA REQUEST

19. Please provide Riverside County's position on the proposed project's consistency with its General Plan and Zoning Ordinance.

RESPONSE

Please see the response to Data Request 17.

BACKGROUND

The project's stacks would exceed the County's height limit of 75 feet (Riverside County Zoning Ordinance, Article XV W-2 Zone) and the project would normally need a variance from Riverside County, but for the Energy Commission's exclusive licensing jurisdiction.

DATA REQUEST

20. Please provide written confirmation from Riverside County whether, in the County's opinion, a variance could be granted and if so, what conditions Riverside County would require were it the permitting agency.

RESPONSE

Please see the response to Data Request 17. It should also be noted that upon further review of the zoning code, it appears that a height variance would not be required for the project's stacks (90 feet each), but may be required for the proposed transmission poles (85 to 115 feet tall). The 37-acre project site and proposed transmission corridor are both in areas zoned W-2 (Controlled Development Area). Development standards for W-2 state the following:

> A. One-family residences shall not exceed forty (40) feet in height. No other building or structure shall exceed fifty (50) feet in height, unless a greater height is approved pursuant to Section 17.172.230. In no event, however, shall a building exceed seventy-five (75) feet in height or any other structure exceed one hundred five (105) feet in height, unless a variance is approved pursuant to Chapter 17.196.

"Building" is defined as a structure having a roof supported by columns or walls.

"Structure" is defined as anything constructed or erected and the use of which requires more or less permanent location on the ground or attachment to something having a permanent location on the ground, such as awnings and patio covers, but not including walls and fences 6 feet or less in height.

The stacks and transmission towers would not qualify as buildings as defined, but would qualify as structures. Therefore, the 105-foot height restriction is applicable rather than the 75-foot height restriction. The Applicant will obtain written confirmation from the County regarding this issue, as discussed in the response to Data Request 17.

DATA REQUEST

21. Please cite the section of the zoning or other code that states the findings the County would make for a variance, were it the permitting agency.

RESPONSE

The Riverside County Municipal Code, Title 17 (Zoning), Chapter 17.144.020 W-2, Controlled Development Areas Zone Development Standards, states that "In no event, however, shall a building exceed seventy-five (75) feet in height or any other structure exceed one hundred five (105) feet in height, unless a variance is approved pursuant to Chapter 17.196." Chapter 17.196 is the zoning code chapter that describes the basis, application, public hearing, conditions, uses, and revocation of variances.

Variances from the terms of Title 17 Zoning may be granted when, because of special circumstances applicable to a parcel of property, including size, shape, topography, location, or surroundings, the strict application of this title deprives such property of privileges enjoyed by other property in the vicinity that is under the same zoning classification.

BACKGROUND

As stated in the AFC, the 37-acre power plant site consists of three separate Assessor's Parcel Numbers (APNs): 668-130-005, 668-130-007, and 668-140-001, which CPV Sentinel anticipates merging through an application for a Certificate of Parcel Merger with the Riverside County Planning Department.

DATA REQUEST

22. Please provide the County's timeline for granting the parcel merger and what conditions (if any) Riverside County would place on the parcel merger. Please cite the section of the zoning or other code that states the findings the County would make for the merger.

RESPONSE

The Riverside County Planning Department has indicated that a parcel merger is a ministerial process that is typically approved within approximately 1 month after an application is filed. It is not anticipated that the County would impose any conditions of approval in connection with a merger. Riverside County Land Division Ordinance No. 460.139, Section 18.7, Merging of Contiguous Parcels, provides as follows:

A. Notwithstanding the preceding sections, four or fewer contiguous parcels under common ownership may be merged without reverting to acreage, provided that the merger is approved by the Planning Director and an instrument evidencing such merger is recorded with the County Recorder.

B. Applications to merge contiguous parcels shall be made to the Planning Director on forms provided by the Planning Department.

C. The Planning Director shall transmit a completed application (available at http://www.tlma.co.riverside.ca.us/planning/content/devproc/apps/ 295_1016_cpm.pdf) to the County Surveyor for review and recommendation and shall grant approval of the request for merger if:

1. The parcels to be merged are, at the time of merger, under common ownership; and written consent has been obtained from all record owners.
2. The parcel as merged will be consistent with the zoning of the property.
3. The parcel as merged will not conflict with the location of any existing structures on the property.
4. The parcel as merged will not be deprived access as a result of the merger.
5. Access to the adjoining parcels will not be restricted by the merger.
6. No new lot lines are created through the merger.
7. The existing right-of-way shall not be altered. Any alteration shall be accomplished through a separate vacation process.

D. The Planning Director shall submit to the County Recorder for recordation the new legal description and exhibit within 20 days after it has been approved by the Planning Director.

SOCIOECONOMICS

Technical Area: Socioeconomics
Author: Hedy Born

BACKGROUND

Sections 7.8.2.2 through 7.8.2.4 (see AFC pages 7.8-8 to 7.8-10) state the economic impacts and fiscal resources of the proposed project. In order to know the time value of money, please provide the following.

DATA REQUEST

23. Please indicate the year for all economic dollar estimates (e.g., construction costs, construction and operation payroll, sales taxes, property taxes, school impacts fees, etc.).

RESPONSE

All economic dollar estimates were provided in current (2007) dollars.

TRANSMISSION SYSTEM ENGINEERING

Technical Area: Transmission System Engineering
Author: Ajoy Guha, P.E., and Mark Hesters

INTRODUCTION

Staff needs to determine the system reliability impacts of the project and to identify the interconnection facilities, including downstream facilities needed to support the reliable interconnection of the proposed CPV Sentinel Energy Project (CPV Sentinel). The interconnection must comply with Laws, Ordinances, Regulations and Standards (LORS) such as Utility Reliability and Planning Criteria, North American Electric Reliability Council (NERC) Planning Standards, NERC/Western Electricity Coordinating Council (WECC) Planning Standards, and California Independent System Operator (California ISO) Planning Standards. In addition the California Environmental Quality Act (CEQA) requires the identification and description of the "direct and indirect significant effects of the project on the environment."

For the compliance with planning and reliability standards and the identification of indirect or downstream transmission impacts, staff relies on the System Impact Study (SIS) and Facilities Study (FS) as well as review of these studies by the agencies responsible for insuring the interconnecting grid meets reliability standards, in this case, Southern California Edison (SCE) and California ISO. The studies analyze the effect of the proposed project on the ability of the transmission network to meet reliability standards. When the studies determine the project will cause the transmission to violate reliability requirements, the potential mitigation or upgrades required to bring the system into compliance are identified. The mitigation measures often include modification and construction of downstream transmission facilities. CEQA requires environmental analysis of any downstream facilities for potential indirect impacts of the proposed project.

BACKGROUND

The submitted Application for Certification (AFC) indicates the interconnection on-line date for the proposed CPV Sentinel generation plant units would be between March, 2010 and May, 2010. The April 6, 2005 SIS and the January 6, 2006 FS analyzed the interconnection of the project with 2008 summer peak and spring system conditions based on a May 1, 2008 on-line date. Therefore, for demonstration of conformance or non-conformance with the NERC/WECC, California ISO and/or Utility Planning Standards and reliability criteria, staff requires a report or letter from the CA ISO and /or from the SCE confirming the validity of the above SIS and FS reports with regard to the proposed on-line date in 2010 or a new SIS/FS analyzing the proposed project under 2010 system conditions.

According to the California ISO letter of August 8, 2007, the California ISO will shortly complete a Large Generator Interconnection Agreement (LGIA) with CPV Sentinel and also pursuant to Section 12.2.4 of the Large Generator Interconnection Procedures (LGIP) an Operational study examining the impacts of the proposed project on the grid as of the 2010 in-service date. Staff, therefore, concludes that the Operational study would substitute for the requirement of the SIS based on the on-line date.

Also under Article 14 of the LGIA, a LGIA is required to comply with all regulatory requirements and LORS, and under Article 3 of the LGIA, the transmission provider is required to provide a copy of the signed LGIA (with any amendments) with Government agencies when asked for.

DATA REQUESTS

24. Please provide a copy of the final executed Large Generator Interconnection Agreement (LGIA) between the CPV Sentinel owner and the California ISO.

RESPONSE

The Large Generator Interconnection Agreement (LGIA) has not yet been executed. As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will submit the LGIA to the CEC when it is available.

25. Provide SCE's Operational study report based on CPV Sentinel's net 850 MW generation output under 2010 system conditions to assess potential impacts on the grid with a selected mitigation plan.

RESPONSE

The Applicant will not be able to provide this report at this time, since it has not yet been prepared. The California Independent System Operator (California ISO) submitted a letter to the CEC dated August 8, 2007, which has been filed in the docket for this proceeding and which addresses completion of the Operational Study. In that letter, the California ISO explains: "The CAISO routinely requires an operational study examining the impact of adding the proposed project as of the in-service date; the LGIA for the Project will require such a study."

The letter further indicates that SCE "has indicated it expects to commence the operational study for the Project roughly 60 days after the LGIA is signed and that it will take roughly sixty days to complete. Consequently, the operational study should be concluded by some time early next year. In short, projected system conditions as of the June 2010 in-service date will be studied prior to interconnection of the Project."

As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will provide the operational study to the CEC when it is available.

VISUAL RESOURCES

Technical Area: Visual Resources
Author: William Kanemoto

BACKGROUND

In order to review potential cumulative impacts of project vapor plumes, setting information on other existing or foreseeable vapor plume sources is necessary.

DATA REQUEST

26. Please identify any other existing or foreseeable vapor plume sources within a 5-mile radius of the project site, if any.

RESPONSE

Based on our review of existing sources located within 5 miles of the proposed facility, there is only one facility—the Indigo Energy Facility—that could possibly release visible plumes. The Indigo Energy Facility is a peaking power plant located approximately 2 miles southeast of the proposed CPVS facility. The Indigo facility has three natural gas-fired LM6000 turbines that could potentially emit short visible moisture plumes under certain specific ambient conditions.

However, the Indigo gas turbines are simple cycle units that have high stack exit temperatures (usually greater than 750°F) and high stack exit velocities. Such peaking units are almost exclusively operated during the warmest months, when demand for electricity in Southern California is greatest.

The ambient temperature in the vicinity of the Palm Springs area from May through September is generally high (60 degrees Fahrenheit [°F] average minimum and 108°F average maximum temperatures), and the relative humidity (RH) is very low (40 percent highest monthly average for morning readings and 15 percent lowest monthly average for afternoon readings). Exhaust moisture plumes are most visible when exit velocities are low, RH is high, and ambient temperatures is low compared with the corresponding properties of the plumes exiting the stacks. The typical summertime conditions in the Palm Springs area when the Indigo peaking plant is expected to operate are not conducive to the creation of visible plumes due to the low ambient RH and high ambient temperature. Thus, significant visible vapor plumes from the Indigo Energy Facility are not expected to add appreciably to the moisture plumes from the CPVS, which will also be very limited by all the same factors mentioned above for the Indigo plumes.

WASTE MANAGEMENT

Technical Area: Waste Management
Author: Christopher Dennis, P.G.

BACKGROUND

The October 2006 report, "Phase I Environmental Assessment, Assessor's Parcel Numbers (APNs) 668-130-005 and 668-140-001, Riverside County, California," states that the environmental assessment (ESA) was conducted according to the scope and limitations of "Standard Environmental Site Assessment: Phase I Environmental Site Assessment Process," (ASTM E 1527-00, ASTM International). ASTM E 1527-05, Standard Practice for Environmental Site Assessments: Phase I Environmental Site Assessment Process," contains the following requirements:

> 12.13 *Environmental Professional Statement* – As required by 40 CFR 312.21(d), the report shall include the following statements of the *environmental professional(s)* responsible for conducting the *Phase I Environmental Site Assessment* and preparation of the *report*.
>
> 12.13.1 "[I, We] declare that, to the best of [my, our] professional knowledge and belief, [I, we] meet the definition of *Environmental professional* as defined in §312.10 of 40m CFR 213" and
>
> 12.13.2 "[I, We] have the specific qualifications based on education, training, and experience to assess a *property* of the nature, history, and setting of the subject *property*. [I, We] have developed and performed the all appropriate inquiries in conformance with the standards and practices set forth in 40 CFR Part 312."

DATA REQUEST

27. For the Phase I report, please provide this statement in accordance with ASTM E 1527-05.

RESPONSE

Appendix C-1 provides a supplemental letter certifying that the Phase I Environmental Site Assessment (ESA) was prepared by an *Environmental professional* as defined by §312.10 of 40 CFR 213.

BACKGROUND

A Phase II environmental assessment was conducted for the project and was documented in a February 2007 report, "Phase II Baseline Investigation – CPV Ocotillo Site, Assessor's Parcel Numbers (APNs) 668-130-005 and 668-140-001, Riverside County, California." While the report is signed, there is no indication that the environmental assessment or report was overseen and signed by a California licensed Professional Engineer or Geologist. Sections 7835 and 7835.1 of the California Business and Professions Code requires all geological and geophysical reports to be signed or stamped by a licensed engineer or geologist, indicating his or her responsibility for the assessment and report.

DATA REQUEST

28. Please provide the name and license of the Professional Engineer or Geologist overseeing the Phase II baseline investigation and report.

RESPONSE

William J. O'Braitis of URS oversaw the Phase II Baseline Investigation. He is a Professional Geologist, License #6062, Expiration 7/31/09. Appendix C-2 provides a supplemental letter certifying that the Phase II Baseline Investigation was overseen by a Professional Geologist.

BACKGROUND

In a letter dated August 8, 2007, the California Department of Toxic Substances Control (DTSC) reviewed the Application for Certification (AFC), including the Phase II baseline investigation report, and had the following comments applicable to this data request:

Item 5: All environmental investigations, sampling and/or remediation should be conducted under a Workplan approved and overseen by a regulatory agency that has jurisdiction to oversee hazardous waste cleanup. The findings and sampling results from the subsequent report should be clearly summarized in the EIR.

Item 6: Proper investigation, sampling and remedial actions, if necessary, should be conducted at the site prior to the new development or any construction, and overseen by a regulatory agency.

Item 8: Human health and the environment of sensitive receptors should be protected during construction or demolition activities. A study of the site overseen by the appropriate government agency might have to be conducted to determine if there are, have been, or will be, any releases of hazardous materials that may pose a risk to human health or the environment.

Item 9: If it is determined that hazardous wastes are, or will be, generated by the proposed operations, the wastes must be managed in accordance with the California Hazardous Waste Control Law (California Health and Safety code, Division 20, Chapter 6.5) and the Hazardous Waste Control Regulations (California Code of Regulations, Title 22, Division 4.54). If so, the facility should obtain a United States Environmental Protection Agency (U.S. EPA) Identification Number by contacting (800) 618-6942.

Item 10: If hazardous wastes are (a) stored in tanks or containers for more than 90 days, (b) disposed of onsite, then a permit from DTSC may be required. If so, that facility should contact DTSC at (818) 551-2171 to initiate pre-application discussions and determine the permitting process applicable to the facility.

Item 11: Certain hazardous waste treatment processes may require authorization from the local Certified Unified Program Agency (CUPA). Information about the requirement for authorization can be obtained by contacting your local CUPA.

Item 13: If during construction/demolition of the project, soil and/or groundwater contamination is suspected, construction/demolition in the area should cease and appropriate health and safety procedures should be implemented. If it is determined that contaminated soil and/or groundwater exist, the AFC should identify how any required investigation and/or remediation will be conducted, and the appropriate government agency to provide regulatory oversight.

Item 14: If structures in the Project Site contain potentially hazardous materials, such as: asbestos-containing material (ACM), lead-based paint (LBP), and mercury- or PCB-containing material, such materials should be removed properly prior to demolition, and disposed of at appropriate landfills or recycled, in accordance with regulatory guidance provided in California Code of Regulations (CCR) and following the requirements of the Universal Waste Rule (40 CFR part 9).

DATA REQUEST

29. In accordance with the August 8, 2007, DTSC letter, please provide evidence that Items numbers 5, 6, 8, and 14 were addressed during the Phase II baseline investigation for the potential LBP and ACM in the building material of the onsite

structures. This includes the structures in the construction area and in the laydown area.

RESPONSE

Response to individual comments:

DTSC Item 5 – The Phase I and II ESAs were performed voluntarily for property transaction purposes and not under any requirement, order, or oversight by a regulatory agency; therefore, a workplan was not submitted to any agency.

DTSC Item 6 – Investigation at the site consisted of the Phase I and II ESAs. No contamination was detected; therefore, no remediation is required or planned. The *potential* lead-based paint (LBP) and asbestos in the structure are discussed below.

DTSC Item 8 – No hazardous materials were detected at the site, with the exception of the potential LBP and asbestos-containing materials (ACM) discussed below. No study of potential impacts to human health or sensitive receptors appears warranted since no hazardous materials were detected.

DTSC Item 14 – The structures present at the project site were not entered due to access limitations during the ESAs. As a conservative measure, URS identified the potential presence of LBP and ACM in the structures. The landowner of the 37-acre project site has planned to demolish the onsite structures, regardless of whether the proposed project is constructed or not. It is possible that the landowner may demolish the onsite structures as part of long-term plans not associated with the proposed project. In the event that the structures are demolished as part of the project, the structures will be fully surveyed for the presence of hazardous materials such as ACM, LBP, mercury, or polychlorinated biphenyls (PCBs), and the results will be submitted to the CEC. Any such materials identified will be disposed of in accordance with hazardous waste or universal waste regulations.

There is one small existing structure in the construction laydown area which is currently used by the wind farm for equipment storage. This structure will remain and will not be demolished. There is also one small structure located along the proposed access road corridor (just north of the construction laydown area), which will also remain and be used for equipment storage.

BACKGROUND

Items 9, 10, 11, 13, and 14 in the August 8, 2007 DTSC letter, need to be addressed. All wastes need to be properly documented and handled in accordance with state and federal regulations. If contaminated material is encountered, work must stop and all proper health and safety procedures implemented until such material is properly characterized and removed or remediated by other means. All such activity must be conducted with the oversight by the appropriate regulatory agency.

DATA REQUEST

30. Please discuss a plan and schedule for responding to DTSC items 9, 10, 11, 13, and 14.

RESPONSE

Response to individual comments:

DTSC Item 9 – If future operations generate hazardous wastes, these wastes will be stored, managed, and disposed of in accordance with California and federal hazardous waste regulations. The facility will obtain a hazardous waste generator identification number from the U.S. EPA prior to beginning operations.

DTSC Item 10 – The proposed project does not anticipate onsite treatment or disposal of hazardous wastes, or storage in excess of the deadlines prescribed in the hazardous waste generator regulations. As a result, the project will not require DTSC permitting as a transfer, storage, and disposal facility.

DTSC Item 11 – It is anticipated that the facility will operate under oversight of the local Certified Unified Program Agency (Riverside County Department of Environmental Health), that a Hazardous Materials Business Plan will be submitted, and permits will be obtained from this agency.

DTSC Item 13 – A Phase I ESA and a Phase II ESA conducted at the site show that no surface or subsurface contamination was detected or is suspected. In the unlikely event that contamination is detected at the site during demolition, excavation, or construction, appropriate health and safety procedures will be implemented and the contamination will be further characterized. Depending on the nature of the contamination detected, it is anticipated that either the Riverside County Department of Environmental Health, the Regional Water Quality Control Board, or the Cal-EPA DTSC will be advised of the contamination and will become the lead oversight agency for any further characterization and remediation at the site.

DTSC Item 14 – See the individual response to DTSC Item 14 in the response to Data Request 29.

BACKGROUND

The October 2006 report, "Phase I Environmental Assessment, Assessor's Parcel Numbers (APNs) 668-130-005 and 668-140-001, Riverside County, California," states that LBP and/or ACM may be present in the building materials of the structures on the subject property. The February 2007 report, "Phase II Baseline Investigation, Assessor's Parcel Numbers (APNs) 668-130-005 and 668-140-001, Riverside County, California," states that LBP and/or ACM may be present in the building materials of the structures on the subject property. However, no LBP or ACM sampling and analysis were conducted on the structures on the building materials of the subject property. In addition, based on the aerial photographs, there is another building in the project laydown area. No mention of this building was made in the Phase I or Phase II reports.

DATA REQUEST

31. Please provide the report documenting the LBP and ACM sampling, analytical results, and recommendations.

RESPONSE

The structures present at the project site were not entered due to access limitations during the environmental assessments. As discussed in the response to Data Request 29, the landowner of the 37-acre project site has planned to demolish the onsite structures, regardless of whether the proposed project is constructed. It is possible that the landowner may demolish the onsite structures as part of long-term plans not associated with the proposed project. In the event that the structures are demolished as part of the project, they will be fully surveyed for the presence of hazardous materials such as ACM, LBP, mercury, or PCBs, and the results will be submitted to the CEC. Any such materials identified will be disposed of in accordance with hazardous waste or universal waste regulations.

In the construction laydown area, there is one small existing structure which is currently used by the wind farm for equipment storage. This structure will remain and will not be demolished. There is also one small structure located along the proposed access road corridor (just north of the construction laydown area), which will also remain and be used for equipment storage.

DATA REQUEST

32. Please provide evidence that a copy of the Phase I report was provided to the appropriate oversight regulatory agency(s).

RESPONSE

The Phase I and II reports were prepared for internal property transaction and baseline purposes, not under order or oversight by a regulatory agency; therefore, they were not submitted to any agency.

DATA REQUEST

33. Please determine whether LBP or ACM are present in the building within the project laydown area and provide a copy of a related report containing the determination to the appropriate oversight agency and the California Energy Commission.

RESPONSE

In the construction laydown area, there is one small existing structure that is currently used by the wind farm for equipment storage. This structure will remain during and after project construction and will not be demolished.

WATER AND SOIL RESOURCES

Technical Area: Water and Soil Resources
Author: Christopher Dennis, P.G.

BACKGROUND

Construction and operation of the Sentinel Power Plant Project (the Project) may induce water and wind erosion in the construction area, transmission and pipeline corridors, and laydown and parking areas. The entire project area is currently undeveloped, except for an uninhabited residential building and associated garage and groundwater well within the construction area and a building and possible building materials within the laydown area. The residential building and garage are to be removed by the existing property owner. The groundwater well will apparently remain. Wells partially destroyed and later lost during construction can provide a direct route of contamination to aquifers. The status of the building and possible building materials in the laydown area is unknown. Also, in the project laydown area and pipeline corridor area are windmills that are part of a wind farm.

To determine the potential erosion impacts to water and soil resources from construction of the Project, the California Energy Commission (CEC) requires a draft Drainage Erosion and Sediment Control Plan (DESCP). The draft DESCP is to be updated and revised as the project moves from the preliminary to final design phases and is to be a separate document from the construction Storm Water Pollution Prevention Plan (SWPPP). The DESCP, submitted prior to site mobilization, must be developed and signed by a professional engineer/erosion control specialist. Please note that Section 7.14.4.2 of the AFC mentions that an approved Erosion Control Plan is discussed in Section 7.9.2 of the AFC. However, no such plan is referenced in Section 7.9.2 or is part of the AFC.

DATA REQUEST

34. Please discuss:

a) Will the groundwater well be properly abandoned in accordance with the California Department of Water Resources (DWR) Bulletin 74-90, California Well Standards, and Riverside County requirements prior to construction?

b) If not, please provide a written plan outlining the procedures that will be followed for the protection of this well.

RESPONSE

a) The proposed project does not intend to abandon the existing onsite well. The intent is to have the well available as a potential source of construction water supply and as a potential monitoring well. The well is currently located near the proposed access road. The internal road at the southeast portion of the site has been reconfigured to avoid the existing well (see revised Figure 2.5-2).

However, in the event that the well is abandoned in the future, then it will be properly abandoned in accordance with the California Department of Water Resources (DWR) Bulletin 74-90, California Well Standards; and Riverside County requirements.

b) Based on DWR Bulletin 74-90, California Well Standards, a concrete base or pad would be constructed at the ground surface around the top of the well casing, contacting the

annular seal. The concrete base or pad would be sloped away from the well casing by at least 2 feet in each direction (4 feet square), and would be a minimum of 4 inches thick. In addition, bollards would be placed around the well.

DATA REQUEST

35. Please provide a copy of the Erosion Control Plan referenced in Section 7.14.4.2 of the AFC.

RESPONSE

As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Erosion Control Plan (ECP) has not been developed, but the Applicant will develop and submit the ECP prior to construction, as required by applicable regulations.

DATA REQUEST

36. Please provide a draft DESCP containing elements A through I listed below. These elements will outline site management activities and erosion/sediment control Best Management Practices (BMPs) to be implemented during site mobilization, excavation, construction, and post-construction activities. The level of detail in the draft DESCP should correspond to the current level of planning for site construction and corresponding site grading and drainage. Please provide all conceptual erosion control information for those phases of construction and post-construction that have been developed or provide a statement when such information will be available.

a) Vicinity Map: A map(s) at a minimum scale 1" = 100' shall be provided indicating the location of all Project elements and depictions of all significant geographic features including swales, storm drains, and sensitive areas.

b) Site Delineation: All areas subject to soil disturbance, such as the construction area, laydown area, parking area, all linear facilities, and landscaping areas shall be delineated showing boundary lines and the location of all existing and proposed structures, pipelines, roads, and drainage facilities.

c) Watercourses and Critical Areas: The DESCP shall show the location of all nearby watercourses including swales, storm drains, and drainage ditches. Indicate the proximity of those features to the Project construction, laydown, and landscape areas and all transmission and pipeline construction corridors.

d) Drainage Map: The DESCP shall provide a topographic site map(s) at a minimum scale 1" = 100' showing existing, interim, and proposed drainage systems and drainage area boundaries. On the map, spot elevations are required where relatively flat conditions exist. The spot elevations and contours shall be extended off-site for a minimum distance of 100 feet in flat terrain.

e) Drainage of Project Site Narrative: The DESCP shall include a narrative of the drainage measures to be taken to protect soil and water resources onsite and downstream. The narrative shall include a summary of the hydraulic analysis prepared by a professional engineer/erosion control specialist. The narrative shall state the watershed size in acres that was used in the calculation of drainage measures. The hydraulic analysis should be used to support the selection of BMPs and structural controls to divert off-site and on-site drainage around or through the construction and laydown areas.

f) Clearing and Grading Plans: The DESCP shall provide a delineation of all areas to be cleared of vegetation and areas to be preserved. The plan shall provide elevations, slopes, locations, and extent of all proposed grading as shown by contours, cross-sections, or other means. The locations of any disposal areas, fills, or other special features shall also be shown. Illustrate existing and proposed topography tying in proposed contours with existing topography.

g) Clearing and Grading Narrative: The DESCP shall include a table with the quantities of material excavated or filled during construction in all area such as the construction area, laydown area, and transmission and pipeline corridors. This table shall identify whether the materials removed and brought in were temporarily or permanently added or removed and the amount of such material brought in or removed.

h) Best Management Practices Plan: The DESCP shall identify on the topographic site map(s) the location of the site specific Best Management Practices (BMPs) to be employed during each phase of construction, initial grading, project element excavation and construction, and final grading/stabilization. BMPs shall include measures designed to prevent wind and water erosion. Treatment control BMPs used during construction should enable testing of groundwater and/or stormwater runoff prior to discharge.

i) Best Management Practices Narrative: The DESCP shall show the location (as identified in H above), timing, and a maintenance schedule of all erosion and sediment control BMPs to be used prior to initial grading, during Project excavation and construction, final grading/stabilization, and post-construction. Separate BMP implementation schedules shall be provided for each phase of construction. The maintenance schedule should include post-construction maintenance of structural control BMPs or a statement provided when such information will be available.

RESPONSE

Due to the site surveys and level of detail required to complete the Drainage Erosion and Sediment Control Plan (DESCP), the Applicant seeks additional time to prepare the draft. As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will submit the draft DESCP no later than January 4, 2008.

BACKGROUND

Potentially significant impacts to soil by wind and water erosion could be mitigated through the preparation of construction and operation SWPPPs and the use of appropriate BMPs.

DATA REQUEST

37. Please provide a copy of the final construction SWPPP.

RESPONSE

The Applicant prepared a draft Storm Water Pollution Prevention Plan (SWPPP) and included it in the AFC. As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will prepare and submit the final SWPPP prior to construction, as required by applicable regulations.

BACKGROUND

The State Water Resource Control Board's (SWRCB) policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling (SWRCB Resolution 75-58) states fresh inland water should only be used for power plant cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound. The SWRCB policy requires that power plant cooling water should come from, in order of priority: wastewater being discharged to the ocean; ocean water; brackish water from natural sources or irrigation return flow; inland waste waters of low total dissolved solids; and other inland waters. Additionally, Water Code Section 13550 finds the use of potable water for industrial and irrigation uses is a waste or an unreasonable use of potable water within the meaning of Section 2 of Article X of the California Constitution if recycled water is available and meets certain conditions. The Energy Commission adopted a similar policy in the 2003 Integrated Energy Policy Report (CEC, 2003).

The Project proposes using groundwater for cooling operations for the power plant. The Mission Creek sub-basin groundwater will be accessed using onsite wells. The peak water usage is stated to be 1,100 acre-feet per year (AFY) with an average use of 550 AFY. According to the 2007 Desert Water Agency Engineer's Report: *Ground Water Replenishment and Assessment Program for the Mission Creek Subbasin*, the sub-basin is already in a state of overdraft by 9,000 to 10,000 AF. If the sub-basin aquifers come to a state of extreme overdraft, the soil matrix can irreversibly collapse leading to land subsidence and lose of available aquifer volume. Comparing the existing groundwater overdraft to the expected yearly average and peak groundwater requirements of the project, an average of 5.5 to 6.1 percent and maximum 11 to 12.2 percent of the total overdraft volume annually is proposed to be used for plant cooling operations. In other words, the project is proposing to use annually between 5.5 to 12.5 percent of the water needed to recharge the over-drafted groundwater sub-basin.

The project, if approved, would require a number of complex water transfers and exchanges for groundwater replenishment. Each of these transfers or exchanges require either a will-serve letter or a letter of intent indicating: (1) that the purveyor is willing to serve the project; (2) that the purveyor has adequate water supplies available for the life of the project; and (3) any conditions or restrictions that apply to the provision of the water. Agencies and districts involved include the Mission Springs Water District (MSWD), Desert Water Agency (DWA), Metropolitan Water District (MWD), and the California Department of Water Resources (DWR).

DATA REQUEST

38. Please provide a detailed discussion and analysis, and the supporting economic and environmental factors for the proposed use of groundwater for power plant cooling compared to other options/alternatives including air-cooled systems and inlet chiller systems. This discussion and analysis should include:

a) An explanation with supporting data of why the use of air-cooled systems are not considered economically feasible.

b) An analysis of the groundwater water supply for power plant cooling with an explanation of why it is considered technically/environmentally feasible in a over-drafted sub-basin with a limited and unreliable supply of recharge water.

c) A breakdown of estimated capital and operating costs for the use of water-cooled and air-cooled systems for the project.

d) Specific contact responses and other data that support the detailed evaluation and conclusions that water-cooling is the most feasible cooling method available.

RESPONSE

Please refer to the response to Data Request 46 for a detailed discussion of the CEC's policy regarding use of fresh water for power plant cooling.

The statement above that CPVS "proposes using groundwater for cooling operations" is incomplete. It fails to take into consideration the fact that CPVS will acquire and bank treated wastewater in the Mission Creek Subbasin, from which water will be extracted for power plant cooling. CPVS readily concedes that the water molecules withdrawn at the plant site are not likely to be the precise water molecules that are percolated at the Horton Wastewater Treatment Plant (WWTP). This is almost never the case when water is banked in a natural aquifer, as has been done in connection with other CEC-approved projects. Any discussion about how much water the project "is proposing to use annually" must also point out that the project will be replenishing the basin with an equal or greater amount of water in order to be complete.

a) Use of air-cooled systems to reject heat from the LMS100 intercoolers would increase the cost of developing the project by $275 million and is clearly not economically feasible. The increased costs would result primarily from: 1) offsetting severe adverse performance impacts; 2) acquiring a substantially larger parcel of land for the project (assuming it was available); and 3) acquiring additional emission offsets.

Performance Impacts

To illustrate the adverse performance impacts associated with rejecting the LMS100 intercooler duty to dry coolers, CPVS has generated performance runs at the conditions analyzed in the AFC (17°F, 72°F, and 107°F), as well as additional high temperature conditions (83°F and 90°F to 120°F in 10°F increments). Table 38-1 summarizes key plant performance results. Copies of the GE combustion turbine performance modeling results are also attached as Appendix D-1.

Net Power Impact

Dry cooling would reduce CPVS plant net power by 13 percent at SCE test conditions and by 25 percent at 120°F ambient, which is below the extreme high for project area.

The adverse impact related to dry cooling is much more severe with LMS100 based peaker technology, than with an F-class combined cycle plant, for example. This is due, in part, to unique benefits of the LMS100 intercooler and other cycle differences. With a combined cycle plant, use of dry cooling only adversely affects the steam turbine output, which is typically about one third of the plant output. With a LMS100 based peaker, use of dry cooling directly adversely affects the combustion turbine performance, which is 100 percent of the gross output. By comparison, a typical 3 × 1 combined cycle with dry air-cooled condenser would suffer a 4 percent drop at 107°F (approximately 30 percent of the impact on an LMS peaker) and 5 percent drop at 120°F (approximately 20 percent of the impact on an LMS peaker). Furthermore, with a combined cycle plant, duct-firing can be used to offset the dry-cooling related high ambient power decrease, which results in higher heat rate (fuel consumption approximately 7 to 9 percent higher, with corresponding increases in emissions). Duct-firing is not an option for any peaker.

Table 38-1
Wet- Versus Dry Cooling Comparison-Expected Performance

Ambient, °F	**17**	**72**	**83**	**90**	**100**	**107**	**110**	**120**
Cooling Tower Based LMS100 Intercooler Heat Rejection (8 Units)								
Expected Plant Performance (8 units)								
Net Power, kw	791,028	779,996	761,916	747,980	736,908	727,244	724,028	712,972
Net Heat Rate, Btu/kwh (LHV)	7,978	8,120	8,163	8,206	8,241	8,273	8,284	8,321
Fuel Use, MMBtu/hr (LHV)	6,311	6,334	6,219	6,138	6,073	6,016	5,998	5,933
Water Use, gpm	1,683	1,966	1,974	1,982	2,014	2,030	2,035	2,065
Water Use, gpm per net MW	2.1	2.5	2.6	2.6	2.7	2.8	2.8	2.9
Expected Emissions (per LMS)								
CO_2, lb/hr	102,680	103,099	101,260	99,931	98,876	97,957	97,649	96,596
NO_X as NO_2, lb/hr	7.9	7.9	7.8	7.7	7.6	7.5	7.5	7.4
CO, lb/hr	11.6	11.6	11.4	11.2	11.1	11.0	11.0	10.9
SO_X as SO_2, lb/hr	1.3	1.3	1.3	1.3	1.2	1.2	1.2	1.2
VOC as CH_4, lb/hr	2.2	2.2	2.2	2.1	2.1	2.1	2.1	2.1
PM_{10}, lb/hr	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Ammonia Slip, lb/hr	5.9	5.9	5.8	5.7	5.6	5.6	5.6	5.5
Dry Cooler Based LMS100 Intercooler Heat Rejection (8 Units)								
Expected Plant Performance (8 units)								
Net Power, kw	783,073	772,041	753,961	724,241	679,593	633,577	615,809	535,185
Net Heat Rate, Btu/kwh (LHV)	8,059	8,204	8,249	8,312	8,419	8,548	8,605	8,931
Fuel Use, MMBtu/hr (LHV)	6,311	6,334	6,219	6,020	5,722	5,416	5,299	4,780

Table 38-1
Wet- Versus Dry Cooling Comparison-Expected Performance (Continued)

Ambient, °F	**17**	**72**	**83**	**90**	**100**	**107**	**110**	**120**
Water Use, gpm	551	582	572	564	565	547	542	506
Water Use, gpm per net MW	0.7	0.8	0.8	0.8	0.8	0.9	0.9	0.9
Expected Emissions (per LMS, not equalized for constant power production)								
CO_2, lb/hr	102,680	103,099	101,260	98,028	93,164	88,179	86,258	77,798
NO_X as NO_2, lb/hr	7.9	7.9	7.8	7.5	7.2	6.8	6.6	6.0
CO, lb/hr	11.6	11.6	11.4	11.0	10.5	9.9	9.7	8.8
SO_X as SO_2, lb/hr	1.3	1.3	1.3	1.2	1.2	1.1	1.1	1.0
VOC as CH_4, lb/hr	2.2	2.2	2.2	2.1	2.0	1.9	1.9	1.7
PM_{10}, lb/hr	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Ammonia Slip, lb/hr	5.9	5.9	5.8	5.6	5.3	5.0	4.9	4.4
Compare Dry Performance to Wet Performance (8 LMS Units)								
Net Power, kw	-1.0%	-1.0%	-1.0%	-3.2%	-7.8%	-12.9%	-14.9%	-24.9%
Net Heat Rate, Btu/kwh (LHV)	1.0%	1.0%	1.1%	1.3%	2.2%	3.3%	3.9%	7.3%
Water Use, gpm	-67.3%	-70.4%	-71.0%	-71.5%	-71.9%	-73.1%	-73.4%	-75.5%
Water Use, gpm per net MW	-66.9%	-70.1%	-70.7%	-70.6%	-69.6%	-69.1%	-68.7%	-67.3%
Calculate Number of Dry-Cooled Units Required to Match Wet-Cooled Net Output								
Theoretical Number of Units	8.1	8.1	8.1	8.3	8.7	9.2	9.4	10.7
Actual Number of Units	9	9	9	9	9	10	10	11
Resulting Load Factor	90%	90%	90%	92%	96%	92%	94%	97%
Aprx. Part Load Heat Rate Impact (dry v dry)	2.2%	2.0%	2.1%	1.7%	0.8%	2.0%	1.5%	1.0%
Resulting Total Heat Rate Impact (dry v wet)	3.3%	3.0%	3.1%	3.1%	3.0%	5.4%	5.4%	8.4%

Table 38-1
Wet- Versus Dry Cooling Comparison-Expected Performance (Continued)

Ambient, °F	17	72	83	90	100	107	110	120
Typical 3×1 F-Based Combined Cycle with Cooling Tower								
Net Power, kw	826,546	782,788	---	---	---	731,342	---	718,436
Net Heat Rate, Btu/kwh (LHV)	6,291	6,247	---	---	---	6,341	---	6,360
Fuel Use, MMBtu/hr (LHV)	5,200	4,890	---	---	---	4,637	---	4,569
Water Use, gpm	2,053	2,792	---	---	---	3,206	---	3,333
Water Use, gpm per net MW	2.5	3.6	---	---	---	4.4	---	4.6
Typical 3×1 F-Based Combined Cycle with Dry Air-Cooled Condenser								
Net Power, kw	828,069	764,522	---	---	---	704,854	---	683,432
Net Heat Rate, Btu/kwh (LHV)	6,280	6,396	---	---	---	6,579	---	6,685
Fuel Use, MMBtu/hr (LHV)	5,200	4,890	---	---	---	4,637	---	4,569
Water Use, gpm	39	96	---	---	---	166	---	198
Water Use, gpm per net MW	0.0	0.1	---	---	---	0.2	---	0.3
Compare Dry Performance to Wet Performance for Typical 3×1 F-Based Combined Cycle								
Net Power, kw	0.2%	-2.3%	---	---	---	-3.6%	---	-4.9%
Net Heat Rate, Btu/kwh (LHV)	-0.2%	2.4%	---	---	---	3.8%	---	5.1%
Water Use, gpm	0.0%	0.0%	---	---	---	0.0%	---	0.0%
Water Use, gpm per net MW	-98.1%	-96.6%	---	---	---	-94.8%	---	-94.1%

Notes:

Btu/kwh = British thermal units per kilowatt hour
CH_4 = methane
CO = carbon monoxide
CO_2 = carbon dioxide
gpm = gallons per minute
kw = kilowatt
lb/hr = pounds per hour
LHV = lower heating value
MMBtu/hr = million British thermal units per hour
MW = megawatt
NO_2 = nitrogen dioxide
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns
SO_2 = sulfur dioxide
SO_X = sulfur oxides
VOC =volatile organic compounds

To maintain plant output, additional units would have to be added. CPV Sentinel would have to install ten dry-cooled LMS100s to maintain the wet-cooled output from eight LMS100s at the SCE 107°F test condition (with the ten engines operating at a nominal 92 percent load to match net power), and it would take eleven dry-cooled engines to maintain the net output from eight wet cooled LMS100s at 120°F (with the eleven engines operating at a nominal 97 percent load to match net power).

Heat Rate

Dry cooling would increase plant heat rate (i.e., decrease efficiency) by 3.3 percent at SCE test conditions and 7.3 percent at 120°F ambient.

Physical Size

The dry cooler for each LMS100 is essentially the same size as a cooling tower that will serve five LMS100s. The site does not have room to accommodate the larger footprint with dry coolers. Based on vendor quotations, the dry cooler to serve each LMS100 will be 204 feet long and 56 feet wide, whereas a cooling tower structure to serve five LMS100s would be 211 feet long and 56 feet wide. In order to maintain the proposed output of the eight-unit configuration, the footprint of the project would double in size.

Emissions Increases

Emissions impacts are summarized in Tables 38-2, 38-3, and 38-4. As reflected therein, dry cooling increases maximum hourly emissions, typical summer daily emissions, and expected annual emissions.

Table 38-2
Maximum Hourly Operating Emissions (Per Unit)

Constituent	Wet-Cooled 8×	Dry Cooled 11×	Difference (per unit)	Difference (per unit)
CO_2, metric ton/hr	46.8	47.2	0.5	1.0%
NO_X as NO_2, lb/hr	7.9	8.0	0.08	1.0%
CO, lb/hr	11.6	11.7	0.12	1.0%
SO_X as SO_2, lb/hr	0.6	0.7	0.01	1.0%
VOC as CH_4, lb/hr	2.2	2.2	0.02	1.0%
PM_{10}, lb/hr	6.0	6.0	0.00	0.0%

Notes:

1. The wet-cooled data is comparable to Table 7.1-13 in the AFC. The same methodology was used for dry-cooled data.
2. Factoring in additional units required with dry-cooling, maximum hourly dry-cooled emissions will be an additional 37.5 percent higher.
3. Small differences are due to the updated GE performance model and rounding. However, these do not influence the comparison.

CO_2 = carbon dioxide
ton/hr = ton per hour
NO_X = nitrogen oxides
NO_2 = nitrogen dioxide
lb/hr = pounds per hour
CO = carbon monoxide
SO_X = sulfur oxides
SO_2 = sulfur dioxide
VOC =volatile organic compounds
CH_4 = methane
PM_{10} = particulate matter less than 10 microns

Table 38-3
Typical Summer Emissions (All Operating Units)

Constituent	Wet-Cooled 8×	Dry Cooled 11×[3]	Difference	Difference
CO_2, metric ton/hr	6,993	7,316	323	4.6%
NO_X as NO_2, lb/hr	1,614	1,775	161	10.0%
CO, lb/hr	2,451	2,710	259	10.6%
SO_X as SO_2, lb/hr	94.3	98.2	3.86	4.1%
VOC as CH_4, lb/hr	429	469	39.8	9.3%
PM_{10}, lb/hr	904	1,130	226	25.0%

Notes:

1. The start/stop/run hour scenario for each combustion turbine is as defined in Table 7.1-28 in the AFC.
2. Small differences are due to the updated GE performance model and rounding. However, these do not influence the comparison.
3. The dry-cooled data reflects additional combustion turbine(s) to maintain wet-cooled net power. See Table 38-1 for number and load.

CO_2 = carbon dioxide
ton/hr = ton per hour
NO_X = nitrogen oxides
NO_2 = nitrogen dioxide
lb/hr = pounds per hour
CO = carbon monoxide
SO_X = sulfur oxides
SO_2 = sulfur dioxide
VOC =volatile organic compounds
CH_4 = methane
PM_{10} = particulate matter less than 10 microns

Table 38-4
Expected Annual Emissions (All Operating Units)

Constituent	Wet-Cooled 8×	Dry Cooled 11×[3]	Difference	Difference
CO_2, metric ton/hr	1,126,997	1,178,943	51,946	4.6%
NO_X as NO_2, lb/hr	129.6	142.5	12.9	9.9%
CO, lb/hr	196.8	217.5	20.7	10.5%
SO_X as SO_2, lb/hr	7.6	7.9	0.31	4.1%
VOC as CH_4, lb/hr	34.5	37.7	3.18	9.2%
PM_{10}, lb/hr	72.8	91.0	18.20	25.0%

Notes:

1. The wet-cooled data is comparable to Table 7.1-17 in the AFC. Consistent methodology was used for dry-cooled data.
2. Small differences are due to the updated GE performance model and rounding. However, these do not influence the comparison.
3. The dry-cooled data reflects additional combustion turbine(s) to maintain wet-cooled net power. See Table 38-1 for number and load.

CO_2 = carbon dioxide
ton/hr = ton per hour
NO_X = nitrogen oxides
NO_2 = nitrogen dioxide
lb/hr = pounds per hour
CO = carbon monoxide
SO_X = sulfur oxides
SO_2 = sulfur dioxide
VOC =volatile organic compounds
CH_4 = methane
PM_{10} = particulate matter less than 10 microns

With eleven dry-cooled units necessary to maintain the wet-cooled net power output, the maximum hourly emissions for a dry-cooled plant will be an additional 37.5 percent higher. Maximum potential greenhouse gas (GHG) emissions (CO_2) on an hourly basis will be 39 percent higher for the plant. See Table 38-2 for details.

Typical daily summer emissions will be higher with dry cooling as compared to wet cooling. See Table 38-3 for details. Emissions of particulate matter less than 10 microns (PM_{10}) will be 25 percent higher; NO_X, carbon monoxide (CO), and volatile organic compound (VOC) emissions will be approximately 10 percent higher, and sulfur oxides (SO_X) emissions will be approximately 4 percent higher. Typical daily summer GHG emissions (CO_2) will be approximately 5 percent higher for the plant.

Expected annual emissions will be higher with dry cooling as compared to wet cooling. See Table 38-4 for details. PM_{10} emissions will be 25 percent higher; NO_X, CO, and VOC emissions will be approximately 10 percent higher, and SO_X emissions will be approximately 4 percent higher. Expected annual GHG emissions (CO_2) will be approximately 5 percent higher for the plant.

Resulting Increases in Cost

Changing from wet, cooling tower-based intercooler heat rejection to dry coolers will significantly increase the capital costs for the project. We estimate the capital cost increase associated with switching to dry cooling will be $3.8 million dollars per unit (i.e., per LMS100). The single largest component in this increase is the equipment cost differential. Based on budgetary vendor quotations, bare equipment cost for a dry cooler to serve a single LMS100 is $2.8 million, whereas cost for a cooling tower to serve five LMS100s, including delivery and erection, is $2.2 million. This results in a $2.4 million increase per LMS100. Other increases include site work and concrete (due to size of dry coolers); and upsizing of electrical infrastructure for the expected 42 fans per dry cooler. The significant downsizing of the water treatment/zero liquid discharge system (estimated 75 percent cost reduction) and downsizing of the raw water storage tanks (estimated 50 percent cost reduction) partially offset the increases.

A more significant capital cost increase is the cost associated with adding additional units to maintain the net output if the plant is switched from wet to dry cooling. As discussed above, to maintain the plant output at 107°F, which is the SCE Test/Guarantee condition in the Power Purchase Agreement for the first five units; it would be necessary to install ten units instead of eight. At 120°F ambient temperature, it would be necessary to install 11 units. Incremental costs associated with adding each additional unit will exceed $60 million per unit. The ancillary balance of plant equipment, construction, financing, risk fees, and permitting sales taxes would go up as well, and would result in an estimated total capital cost increase of $225 million, not including the cost of additional land and emission offsets.

Assuming that sufficient land were available to double the size of the project footprint, which it is not, the increased cost associated with such additional land would be between approximately $3 million and $5 million dollars.

Emission offsets for the project are estimated to cost the following:

- PM_{10}: $92,000 per pound (the cost per pound of any new units at Sentinel would be based on the current 1309.1 amended rate)

- SO_X: $34,400 per pound (the cost per pound of any new units at Sentinel would be based on the current 1309.1 amended rate)
- NO_X: $100 per pound for RECLAIM perpetuities
- VOC: $10,000 per pound

Based on the increased emissions associated with dry cooling technology, the increased costs for emission offsets would be approximately $45 million, assuming eleven units are required to meet the same capacity requirements under the arid, hot conditions in which the plant is expected to operate.

Based on the foregoing, the increased capital cost of switching to dry cooling technology would be approximately $275 million. Operating cost differentials have not yet been determined.

In evaluating these costs, it is important to keep in mind that CPV Sentinel has already entered into a Power Purchase Agreement with SCE, which requires it to deliver the output from the first five units at the site at an agreed upon price. The pricing in the Power Purchase Agreement was based upon a certain set of assumptions regarding the cost of producing the power. This included assumptions regarding the base technology, including the proposed cooling system. This is the reason that CPV Sentinel previewed the proposed cooling system and cooling water supply with the CEC Siting Office staff on January 23, 2007. A copy of the presentation that was made to the staff, which included a detailed graphic explaining the water supply proposal, is attached as Appendix D-4. No concerns were expressed regarding the proposal at that time. The ability of the project to absorb increased capital and operating costs at this stage is extremely limited, and certainly does not encompass cost increases of the magnitude described above.

b) Because the proposed project would offset the project's water supply demand by replenishment (via percolation at the Horton WWTP and the Mission Creek Recharge Basin), the project would not negatively affect water levels or supply in the Mission Creek Subbasin. As described below, CPV Sentinel would be paying a replenishment fee to address the subbasin's overdraft.

As part of the proposed project's water supply plan, 1,500 AFY of tertiary treated wastewater would be purchased at the Horton WWTP, to be percolated at the Horton WWTP percolation ponds. The proposed project would then extract up to 1,100 AFY of this banked water supply via the onsite wells on an as-needed basis. The amount of water extracted by the proposed project would be less than the amount percolated; therefore, there would be a net inflow to the aquifer. Assuming the maximum annual use of 1,100 AFY by the CPVS, the net inflow to the subbasin would be 400 AFY. Assuming the expected long-term average annual use of 550 AFY, the net long-term average inflow to the subbasin would be 950 AFY.

These amounts do not include the amount of water that would be percolated at the Mission Creek Recharge Basin. As part of the water supply agreement with MSWD, the proposed project would be required to pay a replenishment fee for the water it extracts, which would be collected by the MSWD and paid to the Desert Water Agency (DWA). The DWA is then responsible for replenishment at the Mission Creek recharge basin. The annual fees, and thus the amount of water that is percolated at the recharge basin, are based on the actual amount of water extracted from the Mission Creek Subbasin for

the previous year. Therefore, the amount of water that is percolated at the Mission Creek Subbasin would offset the same amount of water that was extracted on a one-to-one basis. It should be noted that while the amount of water that is used to recharge the basin can be curtailed (e.g., during dry years), there also are provisions in the agreement between DWA and MSWD to allow for surplus water deliveries in wet years (2005 is an example of such a case).

c) Capital cost impacts are discussed in the response to Item a of this Data Request response. Operating cost differentials have not been determined.

d) Specific contact responses and other data that support the detailed evaluation and the conclusion that water-cooling is the most feasible cooling method available are discussed in Item a of this Data Request response and attached in Appendix D-1.

DATA REQUEST

39. Please provide a will-serve letter or letter of intent for each transfer and exchange of water associated with this project.

RESPONSE

As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant expects to obtain the will-serve letter from the MSWD by January 4, 2008, and will submit the letter to staff upon receipt.

DATA REQUEST

40. For transfer and exchange of water associated with this project, please provide the status of all public agency approvals, the contracts or agreements involved, and describe the contractual relationships between the agencies.

RESPONSE

The proposed project only requires approval from MSWD. CPV Sentinel, LLC (CPV Sentinel) and MSWD are negotiating a water supply agreement under which MSWD will own the groundwater wells supplying CPV Sentinel and charge CPV Sentinel a rate for delivered water that includes the current replenishment assessment in effect between MSWD and DWA. The agreement will also include MSWD's obligations to percolate tertiary treated wastewater at the Horton WWTP percolation ponds on behalf of the proposed project.

MSWD is the retail water district. DWA is the wholesale water agency for the MSWD service area and is also a State Water Project (SWP) contractor.

DWA's Ground Water Replenishment and Assessment Program was established to augment groundwater supplies and arrest or retard declining water table conditions within the Upper Coachella Valley, specifically within the Mission Creek Subbasin. Each year, DWA issues an Engineer's Report that details the history and status of water supply in the subbasin and presents related cost data supporting the proposed "replenishment assessment" for the coming year. The Engineer's Report and proposed new annual replenishment assessment are publicly noticed, and after the statutory period and process, the new replenishment assessment goes into effect. As a retailer of water, MSWD includes the replenishment assessment in the rates charged for water delivered to customers like CPVS. MSWD collects the replenishment assessment from its retail customers and, pursuant to in-place agreements with DWA, transfers the collected replenishment assessments to DWA.

DWA's Engineer's Report is provided in Appendix D-2.

DATA REQUEST

41. Please describe the rules and regulations with citations that are applicable to SWP/CRA water importation by DWA, and provide either a Webpage link to each rule and regulation or a hard copy.

RESPONSE

Responding to this data request requires gathering old documents, such as water agency planning documents and historical deliveries data, which are available only in hard copy at the DWA. DWA has been requested to provide this information. As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will submit the response to this data request after receiving information from DWA.

BACKGROUND

According to the MSWD Urban Water Management Plan dated February 2006, the capacity to reduce overdraft conditions by continuing groundwater recharge of the sub-basin depends on the availability of future water from the Colorado River Aqueduct (CRA) water and the on MWD's exchange agreements with DWA. This water supply is a fixed amount set by the DWR. In addition, according to the DWA's April 2007 Engineer's Report, the sub-basin overdraft will continue until increased maximum SWP water allocations are obtained. The U.S. Ninth Circuit Court, on August 31, 2007, ruled that surface water pumping, for the SWP and federal Central Valley Project, be reduced to protect the Delta Smelt, a small, endangered delta fish. This could result in a reduction of the water available to recharge the sub-basin by as much as 30%. In addition, in drought years or as other circumstances warrant, the DWR could substantially reduce the volume of SWP water available to the DWA.

DATA REQUEST

42. Please discuss in detail the reliability for recharging the water supply to the sub-basin from sources including CRA water, SWP water, and recycled water. This detailed discussion should include:

a) The amount of SWP water required for exchange of CRA water.

b) The amount of CRA water, SWP water, and recycled water that can obtained reliably on a month-to-month and year-to-year basis.

c) Citations from the CRA, SWP, and other water agency planning documents to support the Item "b" conclusions.

d) The DWA's estimated annual delivery over the life of the project, based on the DWR's 2005 Final State Water Project Delivery Reliability Report.

e) Data documenting all of the historical deliveries to the sub-basin over the last 10 years.

f) The effect of the following on the available water supply over the life of the project: (1) the recent Ninth Circuit Court ruling; (2) single dry and multiple dry years; and (3) increased water supply demand as the regions population and economy grow.

RESPONSE

Responding to this data request requires gathering old documents, such as water agency planning documents and historical deliveries data, which are available only in hard copy at the DWA. DWA has been requested to provide this information. As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will submit the response to this data request after receiving information from DWA.

DATA REQUEST

43. Please discuss in detail the supply of water available to the MSWD and the project. This detailed discussion should include:

a) The amount of water needed for the project.

b) The amount of recycled water that will be used in conjunction with the project and its source.

c) The monthly and annual deliveries representative of normal and critically dry single and multiple water years for MSWD's existing customers.

d) Since the project has only one source of water with no backup supply, please discuss the dependability of the water source.

e) The available historical data for any interruptions to the proposed water supply over the last 10 years.

f) A summary of MSWD's water supply rights, entitlements, and service contracts and commitments of its water supply to existing and planned customers, noting the: (1) priority for service; (2) maximum supply rate; (3) maximum annual volume; (4) maximum contractual deliveries for all months; and (5) the term of the agreements.

RESPONSE

a) During the 18-month construction period, the proposed project would use approximately 42 acre-feet of water (see AFC Table 2.4-4). Construction water would be supplied by the existing onsite well, the future groundwater wells, or water trucks that import water to the site.

Plant operations will require up to 1,100 afy of water, with an expected flow range of 1,626 gallons per minute (gpm) to 2,059 gpm with all eight units operating. The proposed project is expected to be dispatched, on a lifetime average basis, approximately half of the maximum annual permitted capacity, resulting in an expected lifetime average demand of 550 afy.

The proposed project will require approximately 1,975 gpm of raw water makeup when operating at full plant load during average summer ambient conditions 90°F, 30.2 percent RH. Maximum water requirements on a peak ambient summer day (120°F, 12.7 percent RH) will be 2,059 gpm. Key plant raw water uses will include makeup to the cooling tower systems, makeup to the mobile demineralizer system, and makeup to the service water system.

Potable water will be supplied by MSWD. Potable water requirements are expected to average 2 afy.

b) CPV Sentinel will purchase from MSWD, at the Horton WWTP, 1,500 afy of reclaimed water. The reclaimed water will be percolated at the Horton WWTP into the Mission Creek Subbasin for storage. The proposed project will then access this banked water via onsite wells. The project is expected to extract approximately 550 afy on an average

lifetime basis and up to 1,100 afy in any calendar year. Therefore, the project would percolate and bank more water than it would use at the plant.

c) MSWD's 2005 Urban Water Management Plan (UWMP) provides projections for water supply and water demands during normal water years, single dry water years and multiple water years through 2030. Estimates are provided on an annual basis, and no monthly information is provided. Normal and Dry Water Year deliveries from this UWMP are summarized in Table 43-1.

Projected deliveries for the multiple dry year scenario are summarized in Table 43-2.

d) The project would include redundant water wells to serve as backup in the event of a well failure or pump outage. The onsite storage tanks have the capacity for approximately 24 hours of operation. In addition, one of the raw water storage tanks contains a fire water reserve, accessible only to the fire water pumps, equal to 2 hours of fire system flow.

The reclaimed water will be discharged at a rate of 1,500 AFY to existing percolation ponds adjacent to the Horton WWTP. The water will percolate into the underlying Mission Creek subbasin, which is part of the Coachella Valley Groundwater Basin and be banked for later use by the proposed project. This storage within the subbasin would enable the project to procure the banked reclaimed water for later use. This stored water would be pumped to supply the project as needed.

e) The proposed water supply is banked reclaimed water stored in the Mission Creek Subbasin. The only anticipated interruptions of the Horton WWTP would be pumps that could go out of service. The Applicant does not have information on historical interruption of service at the Horton WWTP. The Applicant has requested this information from MSWD and will provide it to CEC when received. However, as discussed in (d) above, the redundant water wells provide redundant backup to the Project in the event of a single well failure. The size of the subbasin storage capacity (1.4 million acre feet) precludes any impact due to a temporary interruption of flow of reclaimed water from the Horton WWTP.

f) The Applicant has requested this information from MSWD and will provide it to CEC when received.

Table 43-1
Estimates of Normal and Dry Water Year Deliveries

Year	Normal Water Year Water Deliveries – AFY	Dry Water Year Water Deliveries – AFY
2010	14,400	14,540
2015	19,800	20,080
2020	22,500	22,940
2025	25,200	25,690
2030	27,900	28,450

Source: MSWD 2005 UWMP, Tables 4.2-2 and 4.2-3 (PSOMAS, 2006b)

Table 43-2
Projected Deliveries for the Multiple Dry Year Scenario

Year	Type of Year	Water Deliveries – AFY
2006	Normal	10240
2007	Normal	11280
2008	Dry	12440
2009	Dry	13490
2010	Dry	14,540
2011	Normal	15,480
2012	Normal	16,560
2013	Dry	17,820
2014	Dry	18,971
2015	Dry	20,080
2016	Normal	20,340
2017	Normal	20,880
2018	Dry	21,790
2019	Dry	22,270
2020	Dry	22,940
2021	Normal	23,040
2022	Normal	23,580
2023	Dry	24,590
2024	Dry	25,020
2025	Dry	25,690
2026	Normal	25,740
2027	Normal	26,280
2028	Dry	27,340
2029	Dry	27,770
2030	Dry	28,450

Source: MSWD 2005 UWMP, Tables 4.2-4 through 4.2-8 (PSOMAS, 2006b)

DATA REQUEST

44. Please provide a detailed discussion of the project's potential impact to other users of the groundwater supply currently and over the life of the project. This detailed discussion should include:

a) The quality of imported water used for recharge compared to the quality of groundwater existing in the sub-basin. Laboratory analytical data should be used in this discussion, if available.

b) The effect on the sub-basin's groundwater quality of importing water for recharge, including the degree of groundwater quality degradation and the spatial extent of the degradation.

c) The impact from the Project's planned 550 AFY average groundwater use and 1,100 AFY peak groundwater use to the supply of other users of the sub-basin's groundwater resource.

RESPONSE

In order to provide the exceptional level of detail required for this discussion, the Applicant will need to conduct additional modeling. As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will submit its responses to these requests no later than February 4, 2008.

BACKGROUND

All water supplied to the sub-basin (surface and reclaimed water) is limited in volume and is currently being used for groundwater recharge of the over-drafted sub-basin.

DATA REQUEST

45. Please support the statement that extracting groundwater from the sub-basin can lead to a net overall gain to the sub-basin water supply relative to current conditions.

RESPONSE

As described in the response to Data Request 38, the proposed project would put more water into the subbasin than it would extract over the life of the project. The proposed project would also pay a replenishment fee to offset the amount of water the project would extract from the aquifer.

DATA REQUEST

46. a) Please discuss how using groundwater for turbine cooling and then offsetting the groundwater use with reclaimed water and surface water would impact the aquifer, in that the reclaimed and surface waters are currently providing recharge to an over-drafted sub-basin.

b) Discuss how these methods are consistent with the SWRCB and Energy Commission water policies (see Background statement preceding Data Request No. 38 for a summary of the SWRCB policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling and the Energy Commission's water policy).

RESPONSE

a) While the Mission Creek Subbasin has historically been in overdraft conditions (i.e., outflow exceeds inflow), since the commencement of replenishment at the Mission Creek Recharge Basin, particularly in 2005 and 2006, groundwater levels within the Mission Creek Subbasin have been relatively stable and slightly increasing (see Figure 58-1).

The MSWD water supplies are from groundwater and are expected to include recycled water in the future. The District's average demand in 2005 was approximately 9,200 AFY and is anticipated to increase to approximately 27,900 AFY by 2030. Analyses of water demand and supply projections for the District, as presented in the 2005 UWMP (PSOMAS, 2007), demonstrate that projected supplies (i.e., combination of groundwater and reclaimed water) exceed demand through the water year 2030.

The proposed project would purchase reclaimed water from the Horton WWTP, which would be percolated into the basin via percolation ponds. On average, the amount of water to be percolated on an annual basis would be approximately 1,500 AFY. The basin has adequate storage capacity available to store the banked water. The proposed project would then access its banked water supply via onsite wells. Since the average annual amount of percolation at the Horton WWTP would be more than the amount of water used by the proposed project, there would be a net inflow to the basin. Assuming the maximum annual use of 1,100 AFY by the CPVS, the net inflow to the aquifer would be 400 AFY. Assuming the expected long-term average annual use of 550 AFY, the net long-term average inflow to the basin would be 950 AFY.

While reclaimed water from the Horton WWTP is currently being percolated at the plant's percolation ponds, there is no assurance that this water would continue to be percolated. In fact, MSWD's long-term plans are to discontinue percolation of the Horton WWTP wastewater into the subbasin and instead sell it to irrigation customers. CPVS' water supply plan ensures that 1,500 AFY continues to percolate into the sub-basin. Moreover, MSWD has plans to expand the capacity of the Horton WWTP and increase the supply of reclaimed water in the future. The proposed CPVS would be purchasing and securing a portion of this future reclaimed water supply to offset the proposed project's extraction from the subbasin. Excess reclaimed water would still be available to other users.

In addition, the proposed project would pay a replenishment fee for the water it extracts, which would be collected by the MSWD and paid to the DWA. This assessment is used by DWA to fund the costs of artificial replenishment operations in the basin aimed at

arresting the historic overdraft conditions. These operations include recharge with Colorado River water under the terms of various exchange agreements in which DWA delivers purchased water from the SWP to Metropolitan in exchange for the Colorado River water deliveries from Metropolitan. Since the project both offsets its groundwater use with reclaimed water and pays for replenishment water to correct potential overdraft caused by the cumulative effects from all groundwater pumping, potential impacts to groundwater supplies are considered less than significant, and would actually be beneficial to the basin.

Overall, the District's strategy to meet its water supply demands through 2030 provides adequate water supply for District water users as well as the proposed project. The reliability of the groundwater supply, future recycled water supply, imported water connections, and reservoirs ensures availability of supplies for the proposed project and the rest of the District's service area.

b) CPV Sentinel is familiar with the 2003 Integrated Energy Policy Report (CEC, 2003), in which the Commission stated that it "will approve the use of fresh water for cooling purposes by power plants which it licenses only where alternative water supply sources and alternative cooling technologies are shown to be 'environmentally undesirable' or 'economically unsound'" (CEC, 2003, at 41).

As we understand it, the Commission interprets "environmentally undesirable" to mean having a significant adverse environmental impact and "economically unsound" to mean economically or otherwise infeasible (CEC, 2003, at 41). The Commission defines "feasible" as the term is used in CEQA: "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors" (14 California Code of Regulations [CCR] § 15364 (CEC, 2003 at 41 n. 64). CEQA defines "significant effect on the environment" as "a substantial, or potentially substantial, adverse change in the environment" (California Public Resources Code § 21068). Therefore, for the Commission to approve the use of fresh water for cooling, an applicant must show that both alternative water supply sources and alternative cooling technologies cause a substantial, or potentially substantial, adverse change in the environment or are not capable of being accomplished in a successful manner within a reasonable period of time, taking into account the listed factors.

As we understand it, the CEC's policy with respect to the use of fresh water for power plant cooling is based on several key sources, all of which dictate a case-by-case analysis, taking into consideration all of the factors involved in the particular situation.

First, CEC (2003) states that it must "apply state water policy," as reflected in the California Constitution, to "minimize the use of fresh water" by power plants, as "power plants have the potential to use substantial amounts of water for [wet cooling]" (CEC, 2003 at 40). The California Constitution states:

> It is hereby declared that because of the conditions prevailing in this State the general welfare requires that the water resources of the State be put to beneficial use to the fullest extent of which they are capable, and that the waste or unreasonable use or unreasonable method of use of water be prevented, and that the conservation of such waters is to be exercised with a view to the reasonable and beneficial use thereof in the interest of the people and for the public welfare.
> *California Constitution, article X, § 2*

In *Joslin v. Marin Municipal Water District,* the California Supreme Court held that, under Article X, § 2, "[w]hat is reasonable use or method of use of water is a question of fact to be determined according to the circumstances in each particular case" (*Joslin v. Marin Municipal Water Dist.,* 67 Cal2d 132, 138 [Sup. Ct. 1967] [citing *Gin S. Chow v. City of Santa Barbara*, 217 Cal. 673]). Furthermore, contrary to the statement contained in the background section preceding Data Request 38, that the use of water for power plant cooling is "wasteful," the state of California recognizes that the use of water for cooling water supply is a "beneficial use." (See California Water Code 13050(f) [defining beneficial uses of water that may be protected against quality degradation, including industrial supply and power generation]. See also Colorado River Basin Regional Water Quality Control Board, 2005, Table 2-5 [designating "Industrial Service Supply," a category that includes "cooling water supply," as a beneficial use for certain waters within the Coachella Valley]; and State Water Resources Control Board Cases, 136 Cal. App. 4th 674, 778 (2006) [stating that all beneficial uses – including industrial uses – should be considered]).

Second, the Commission relies on a resolution adopted more than 30 years ago, in 1975, by the State Water Resources Control Board (see State Board, Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Powerplant Cooling, Resolution No. 75-58 [June 19, 1975] [SWRCB, 1975]). Recognizing that "[t]here is a limited supply of inland water resources in California," the State Board states:

> Where the Board has jurisdiction, use of fresh inland waters for power plant cooling will be approved by the Board only when it is demonstrated that the use of other water supply sources or other methods of cooling would be environmentally undesirable or economically unsound.
> *SWRCB, 1975 at 3, 4*

The SWRCB also states that "every reasonable effort [should] be made to conserve energy supplies and reduce energy demands to minimize adverse effects on water supply and water quality and at the same time satisfy the State's energy requirements." Thus, the SWRCB recognized the need to conserve both water and energy supplies.

Finally, the Commission cites state water policy found in the Warren-Alquist Act (California Public Resources Code 25000 et seq.): "It is further the policy of the state and the intent of the Legislature to promote all feasible means of energy and water conservation and all feasible uses of alternative energy and water supply sources" (California Public Resources Code § 25008) (CEC, 2003 at 41). This provision also requires a careful balancing of both water and energy conservation.

Thus, the bases upon which the CEC's policy rest make it clear that the policy must be applied on a case-by-case basis, taking into consideration all of the relevant factors, to determine whether or not alternative water supplies and alternative methods of cooling are environmentally undesirable or economically unsound. Energy conservation (i.e., efficiency) must specifically be taken into consideration.

As detailed in the response to Data Request 38, dry cooling, in the context of this proposed project, results in dramatic losses in performance and efficiency with consequent impacts on the cost of the project and the environment. These impacts make dry cooling for this project both environmentally undesirable and economically unsound. The increases in air emissions that would result from a change to dry cooling are outlined in the response to Data Request 38, but one issue in particular deserves

further elaboration in the context of this policy discussion—the increased emissions of GHGs that would result from producing the same amount of power using a dry cooling alternative.

As illustrated by the following summary of recent legislative and policy initiatives, reduction of GHG has become the State of California's number one environmental policy objective:

1. Assembly Bill 32 (Sept. 2006)

Signed into law by Governor Schwarzenegger on September 27, 2006, Assembly Bill (AB) 32 (or the California Global Warming Solutions Act of 2006, California Health and Safety Code § 38500 *et seq.*) directs the California Air Resources Board (CARB) to design measures to reduce GHG emissions to 1990 emissions levels by 2020. CARB must begin emissions monitoring and annual reporting by January 1, 2008, starting first with those emissions sources that contribute the most to statewide emissions.

2. Executive Order S-3-05 (June 2005)

Governor Schwarzenegger's Executive Order S-3-05, signed on June 1, 2005, set GHG emission reduction targets for California to reduce greenhouse gas emissions to 2000 levels by 2010; to 1990 levels by 2020; and to 80 percent below 1990 levels by 2050. The Order directs the California Environmental Protection Agency to coordinate efforts to meet those targets, report the impacts to California of global warming, prepare and report on mitigation plans, and monitor progress toward meeting the GHG emission targets.

3. Senate Bill 1368 (September 2006)

Effective January 1, 2007, Senate Bill (SB) 1368 added Sections 8340 and 8341 to the California Public Utilities Code to prevent long-term investments in power plants with GHG emissions in excess of those produced by a combined-cycle natural gas power plant. This bill provides a mechanism for reducing the emissions of in-state and out-of-state electricity providers, thereby helping CARB meet its mandate under AB 32. SB 1368 required the California Public Utilities Commission (CPUC) to establish, by February 1, 2007, a GHG emission performance standard for all electricity providers under its jurisdiction, including the state's three largest privately-owned utilities. In addition, SB 1368 directed the CEC to adopt a performance standard "consistent with" the CPUC performance standard and apply it to local publicly-owned utilities by June 30, 2007.

4. Western Regional Climate Action Initiative (February 2007)

At the National Governor's Association conference in Washington, D.C., the governors of Arizona, California, New Mexico, Oregon, and Washington created the Western Regional Climate Action Initiative. The Governors committed their states to:

1. by August 26, 2007, set a regional goal to reduce emissions from the states collectively, consistent with state-by-state goals;

2. by August 26, 2008, develop "a design for a regional market-based multi-sector mechanism, such as a load-based cap and trade program, to achieve the regional GHG reduction goal;" and

3. participate in a multi-state GHG registry.

5. Joint Action Framework on Climate Change (December 2006)

On December 1, 2006, the heads of the public utility commissions of California, Oregon, New Mexico, and Washington signed an agreement to collaborate on combating global climate change. The Joint Action Framework grew out of a 2003 agreement among the Governors of California, Oregon, and Washington to reduce GHG emissions along the West Coast. Although each commission is governed by its respective state laws and regulations, the Joint Action Framework commits the four states to a set of shared principles, including regional cooperation to address climate change, development and use of low-carbon technologies in the energy sector, a continued commitment to renewable energy resources, and reliance upon Integrated Resource Plans to inform utility and commission decisions. The Joint Action Framework identified several areas for cooperative action, such as developing best practices for energy efficiency and demand response, development of low-carbon energy and corresponding sequestration of CO_2 emissions, and advancing policies to develop transmission capabilities to transport renewable energy across state lines.

6. California and United Kingdom Agreement, July 31, 2006

On July 31, 2006, California Governor Schwarzenegger and Prime Minister Tony Blair announced an agreement to collaborate on reducing GHG emissions and promoting low carbon technologies. The agreement committed the parties to evaluate and implement market-based mechanisms to spur innovation, quantify the economic impacts of climate change, collaborate on technological research, and enhance linkages between the parties' scientific communities.

7. Climate Action Registry

California SBs 1771 and 527 created the structure of the California Climate Action Registry (the "Registry"), and former Governor Gray Davis signed the Registry's enabling legislation into law on October 13, 2001. These bills establish the Registry as a non-profit entity to help companies and organizations establish GHG emissions baselines against which future GHG emission reduction requirements can be applied. Using any year from 1990 forward as a base year, participants can record their annual GHG emissions with the Registry. In return for this voluntary action, the State of California offers its "best efforts" to ensure that participants receive consideration for their early action if they are subject to any future state, federal, or international emissions regulatory scheme. A state-certified third party must approve a participant's baseline emissions and subsequent emission reports.

In accordance with legislative directives, the CEC has an active role in climate change and GHG emissions initiatives. To implement AB 32, the CEC and CPUC are conducting joint workshops on topics related to the 1990 electricity sector baseline development, current entity-specific GHG emissions levels, and policy

issues related to entity-specific allowance allocation. The first workshop was held on June 22, 2007, and a second workshop is scheduled for November 5, 2007.

On October 30, 2006, the CEC instituted a proceeding in Docket No. 06-OIR-1 to implement SB 1368 by establishing a GHG emission performance standard for all baseload generation of local publicly owned electric utilities. On June 29, 2007, the Office of Administrative Law (OAL) disapproved the rulemaking action. The OAL cited a number of reasons for its disapproval, including ambiguities relating to certain exemptions. The CEC revised its proposed regulations and held a public hearing on August 29, 2007.

In addition to its role in implementing AB 32 and SB 1368, the CEC recently has issued several reports on studies climate change and GHG emissions, including:

- Carbon Sequestration Options for the West Coast States (Phase 1, Report to the United States Department of Energy) (January 2007);
- Inventory of California Greenhouse Gas Emissions and Sinks: 1990 – 2004 (December 2006);
- Assessing Impacts of Rangeland Management and Reforestation of Rangelands on Greenhouse Gas Emissions: A Pilot Study for Shasta County (December 2006);
- Refining Estimates of Water-Related Energy Use in California (December 2006);
- The Economic Cost of Climate Change Impact on California Water: A Scenario Analysis (July 2006);
- Public Interest Energy Research, Economic Impacts of Delta Levee Failure Due to Climate Change: A Scenario Analysis (July 2006);
- Public Interest Energy Research, Estimated Impacts of Climate Warming on California Water Availability Under Twelve Future Climate Scenarios (April 2006); and
- Climate Change and Electricity Demand in California (February 2006).

Taking into consideration the unique factors associated with this project, and in light of the importance that the state, including the CEC, has placed on reducing GHG emissions, any proposal that would increase GHG emissions, without a corresponding benefit, must be deemed environmentally undesirable.

BACKGROUND

The applicant discussed in the AFC the feasibility of installing wells at the property under existing property rights, negotiating conditions with the MSWD for extraction of groundwater, and paying a replenishment fee to the DWA. The applicant also discussed in the AFC the feasibility of buying approximately 1,500 AFY of secondary or tertiary treated water from the MSWD Horton Wastewater Treatment Plant (WWTP) for groundwater recharge while also using groundwater via onsite wells.

DATA REQUEST

47. If the Applicant were to purchase treated water for groundwater recharge, discuss the legal status of the applicant to act as a groundwater replenisher in the basin with an existing 2004 Settlement Agreement between the MSWD, DWA, and Coachella Valley Water District. Also, discuss the Applicant's need for regulatory or statutory authority to act as a recharger in the sub-basin.

RESPONSE

CPV's purchase of the wastewater from MSWD to be used for percolation would be governed by the contract negotiated between CPV and MSWD. MSWD would be responsible for percolating the purchased wastewater at the Horton WWTP. CPV does not need, nor would it acquire by virtue of the agreement with MSWD, any special status as a groundwater "replenisher" or "recharger."

DATA REQUEST

48. Please describe and explain any legal requirements, including citations, that govern the use of groundwater in the basin, reclaimed water from the Horton WWTP, and SWP water.

RESPONSE

California water law recognizes several kinds of water rights, including riparian, appropriative, overlying, and prescriptive rights. The nature, extent, and permanent exercise of a water right depends in large part on the source of the water and the location and purpose of its use. In 1914, the California Legislature adopted the Water Commission Act, which provides the statutory procedure for the allocation of rights to unappropriated surface waters but specifically excludes percolating groundwater from its provisions. With certain exceptions, no statewide system of statutory regulation yet exists in California to allocate rights to the use or management of percolating groundwater. Rather, the development of the law of percolating groundwater has been left to the courts. In general, no discretionary permit is required to pump percolating groundwater, even in overdrafted basins. A landowner may simply obtain a county well permit, drill a well, and pump the water.

The rights of overlying users are paramount to the rights of appropriators, which include those who take water for use outside the basin or watershed. The overlying right extends only to the quantity of water that is necessary for reasonable and beneficial use on the overlying land. As between overlying users, all have equal rights to the water and all must share in water shortages. Thus, in times of shortage, overlying users may be required to engage in pro rata cutbacks. In addition, if one overlying user's exercise of its right unreasonably interferes with another overlying user's rights, the overlying user whose rights are impacted may have a cause of action against the other overlying user.

An appropriator may take any surplus (*Katz v. Walkinshaw* [1903] 141 Cal.116, 135-136). As between appropriators of percolating groundwater—that is, those who use the water for non-overlying purposes—the first in time of use has priority over those that use the water later, but all appropriators are limited to water which is surplus beyond that which is needed for use on the overlying lands (*Pasadena v. Alhambra* [1949] 33 Cal.2d 908, 926). An appropriator may be enjoined from use by an overlying owner if there is no surplus water (*Corona Foothill Lemon Company v. Lillibridge* [1937] 8 Cal.2d 522, 531).

In an overdrafted basin, unchallenged pumping by an appropriator can lead to the establishment of prescriptive rights (i.e., rights arising out of adverse possession) against private pumpers in the basin (*Los Angeles v. San Fernando* [1975[14 Cal.3d 199, 294). Prescriptive rights are acquired when the essential elements for adverse use are met. To acquire prescriptive rights, the use must be for a reasonable and beneficial purpose, open and notorious, adverse and hostile, continuous and uninterrupted for a period of 5 years, exclusive and under a claim of right (*Saxon v. DuBois* [1962] 209 Cal.App.2d 713, 719). In a groundwater basin, the hostility element of prescription is present only if the basin is in overdraft. If prescriptive rights are obtained, they may become paramount to the overlying rights of the private pumpers in a basin.

The ownership of wastewater is addressed in Water Code Section 1210, et al. This section provides that "[t]the owner of a waste water treatment plant operated for the purpose of treating waste from a sanitary sewer system shall hold the exclusive right to the treated waste water as against anyone who has supplied the water discharge into the waste water collection and treatment system, including a person using water under a water service contract, unless otherwise provide by agreement." This Water Code section does not, however, apply to the

rights of the owner of a wastewater treatment plant vis a vis a downstream purchaser of treated wastewater and such rights are freely transferable by contract provisions.

CCR Title 22 governs the use of recycled water in California. Under the current regulations, water used for industrial or commercial cooling involving a cooling tower, evaporative condenser, or spraying that creates a mist must be treated to a tertiary level. The treatment standards for groundwater recharge are not currently addressed in Title 22 but are instead governed by permits issued by the Regional Water Quality Control Board (RWQCB).

The DWR operates the SWP and provides water to 29 contracting agencies. DWA contracted with the DWR in 1962 for the delivery of State Project Water and has amended its contract several times. A conforming copy of the current contract is available at http://www.swpao.water.ca.gov/wsc/index.cfm#D . Since signing its SWP Contract, DWA has repeatedly increased the quantities of water it is entitled to receive. The SWP has not been completed and the DWR is unable in many years to deliver the full amount of DWA's entitlements. Recent court actions have further limited the ability of DWR to deliver the full entitlements. DWA has purchased excess entitlements from other State Water Contractors and has purchased surplus water during wet years to ensure that its total supply of water is adequate to meet its regional obligations for water delivery. As noted above, the Applicant is in the process of assembling all of the applicable contracts relevant to DWA's ability and obligations to supply recharge water to the Mission Creek subbasin.

DWA is the wholesale water agency for the MSWD's service area (PSOMAS, 2006b). According to MSWD's 2005 UWMP, the primary source of water supply for MSWD is groundwater obtained through at least eleven production wells, although two additional wells were under construction at the time of publication of the UWMP (PSOMAS, 2006b). The Central Valley Water District (CVWD) provides a secondary emergency source of water through two inter-connections, but only on a limited basis (PSOMAS, 2006b). Finally, DWA and Metropolitan Water District (MWD) of Southern California provide a third source of water through a number of agreements that enable the exchange of Colorado River water for SWP water (PSOMAS, 2006b). DWA maintains a turnout from the Colorado River Aqueduct and manages a recharge facility close to the turnout that enables the water to percolate into the subbasin (PSOMAS, 2006b).

There are a number of exchange agreements between DWA and MWD that establish the terms for exchange of SWP water for Colorado River water, which is delivered to DWA from MWD's Colorado River Aqueduct. The Applicant is endeavoring to obtain copies of all these agreements.

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DATA REQUEST

49. Describe any legal requirements governing a non-governmental entity's ability to bank reclaimed or surface water in the ground, and provide either a Webpage link to each rule and regulation or a hard copy.

RESPONSE

CPV's rights to the wastewater would be governed by contract, as opposed to common law principles. As such, CPV's rights to the water are more easily defined and are less likely to be curtailed, eliminated, or challenged in an adjudication or other legal action. The contractual rights are not governed by the same priority system as are common law rights. Instead, contractual rights to water are generally treated separately and are governed by contract law. Even if contractually owned water is commingled with the native groundwater supply, ownership of that water is typically retained by the contractual owner, i.e., that water does not become part of the native supply.

DATA REQUEST

50. Please provide a description of the site-specific hydrologic and geologic conditions of the Horton WWTP percolation site. The purpose of this request is to obtain information necessary to assess the hydrologic effect of the percolation. Please include the following information:

a) Describe the MSWD and DWA recharge projects using SWP/CRA and reclaimed water. Include any available assessments of the recharge performance of these projects

b) Outline the current and future service area of the WWTP on an appropriately scaled map.

c) Describe the source of wastewater treated at the Horton WWTP.

d) Discuss the legal authority of the MSWD to sell wastewater on a retail basis and for the project.

e) Include a surface map of an appropriate scale of the site(s) location and a description of current recharge rate, recharge capacity, hydrology, and hydrogeology.

f) Identify the underlying aquifer formations using geologic cross-section(s).

g) Describe layering and subsurface features that would affect groundwater recharge, for example, hardpans, lakebed deposits or faults.

h) Please describe the following: (1) Aquifer parameters including hydraulic conductivity and specific yield; (2) Depth to groundwater over the last 10 years, if available, and (3) descriptions and results of percolation tests or studies.

i) Total acreage of irrigation or percolation site.

j) Historical monthly irrigation records and/or average monthly irrigation rates (provide monthly breakdown of supply sources if reclaimed water is not sole source).

k) Please discuss the volume of wastewater expected to be produced during 2007 and 2008 and how much of that water will be used for groundwater recharge through percolation.

l) Average monthly potential evapotranspiration, along with evapotranspiration balance.

m) Please discuss how much freshwater use is required to make 1,500 AF of wastewater?

RESPONSE

a) **DWA's Mission Creek Recharge Basin**

As described in DWA's Engineer's Report dated April 2007, artificial recharge at the Mission Creek Recharge Basin commenced in 2002. The basin is recharged using Colorado River water exchanged for available SWP water. See the response to Data Request 57 for a summary of historical quantities of water recharged at the basin. Through 2006, the total amount of Colorado River water used to recharge the basin was approximately 55,000 acre-feet. Due to these replenishment efforts, groundwater levels within the Mission Creek Subbasin have, on average, been relatively stable or have risen slightly during 2005 and 2006 (Krieger & Stewart, 2007) (also see the response to Data Request 58 and Figure 58-1).

The recharge basin receives Colorado River water from a 48-inch turnout located just south of Indian Avenue and west of Worsley Road. The recharge facility consists of 60 acres of recharge basins. The number of recharge basins in operation depends upon the availability of water. In 2005, about two-thirds (40 acres) of the facility were being used at one time. The recharge rate at the facility is estimated to be on the order of about 4 feet per day (URS, 2005).

DWA installed a monitoring well to monitor the flow of underground water downstream of the recharge facility. Historical water levels as recorded at this monitoring well are shown on Figure 58-1 (see the response to Data Request 58). The data show that water levels respond quickly to the water recharged at the facility.

MSWD's Horton WWTP Percolation Ponds

The Applicant has requested information regarding the Horton WWTP recharge from MSWD and will forward this information when available.

b) The Applicant has requested this information from MSWD and will forward it to CEC once it has been received.

c) The Horton WWTP currently provides secondary treatment to the sewerage generated by customers of the MSWD sanitary collection system, which serves approximately 6,000 developed parcels (URS, 2005) or approximately 8,000 people within the MSWD service area (PSOMAS, 2007a).

d) The Applicant has requested this information from MSWD and will forward it to CEC once it has been received.

e) The Applicant has requested this information from MSWD and will forward it to CEC once it has been received.

f) The Applicant has requested this information from MSWD and will forward it to CEC once it has been received.

g) Subsurface conditions in the vicinity of the Horton WWTP are described in RWQCB Order No. 01-020, as outlined in Table 50-1.

Table 50-1
Subsurface Conditions at Horton Wastewater Treatment Plant

Depth Interval	Description
Ground surface to 25 feet bgs	Coarse, clean, whitish gray, dry sand
25 feet to 28 feet bgs	Soil is sandy silt, light brown in color and slightly porous
Below 28 feet bgs	Soil is similar to that in the first 25 feet, except it is much finer and has traces of silt in it.

Note:
bgs = below ground surface

h) Information is as follows:

1) Tyley (1974) provides figures that show transmissivities and specific yields throughout the Mission Creek Subbasin. In the vicinity of the Horton WWTP, the transmissivity is approximately 50,000 gallons per day per foot. Assuming an aquifer thickness of 1,000 feet, the hydraulic conductivity would be approximately 6.7 feet per day. The specific yield in the vicinity of the Horton WWTP is approximately 0.15.

2) In the vicinity of the Horton WWTP, groundwater is located approximately 300 feet below ground surface (RWQCB, 2001). Groundwater contour maps developed by PSOMAS (2004) indicate that the groundwater elevation in the vicinity of the Horton WWTP was at about elevation 710 feet in 2004 and was at about elevation 724 feet in 1991.

3) The infiltration rate at the Horton WWTP percolation ponds is estimated to be 0.67 foot per day (RWQCB, 2001). The Applicant has requested additional information from MSWD and will forward it to CEC once it has been received.

i) The acreage of the existing Horton WWTP percolation ponds is approximately 5 acres, based on aerial photos.

j) The Applicant has requested this information from MSWD and will forward it to CEC once it has been received.

k) The Applicant has requested this information from MSWD and will forward it to CEC once it has been received.

l) Average monthly potential evapotranspiration (ETo) rates and potential losses from 5 acres of irrigated land surface are summarized in Table 50-2.

However, because the percolation ponds are open water bodies, not vegetated landscaped surfaces, evaporation instead of evapotranspiration (which also includes the transpiration from soils by plants) would be more appropriate to estimate losses from the ponds. In PSOMAS' Preliminary Water Balance for the Mission Creek Groundwater subbasin (PSOMAS, 2004), evaporation is reported to average approximately 75 inches per year from free water surfaces. The monthly estimates of evaporation presented below are based on the monthly distribution of the evapotranspiration rates. Potential loss due to evaporation from 5 acres of pond area is summarized in Table 50-2.

Table 50-2
Potential Loss Due to Evaporation by Month

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ETo (inches)[1]	2.8	4.7	6.6	9.4	11.3	13.2	13.2	10.3	9.4	6.6	3.8	2.8	93.9
Potential loss from 5 acres of irrigated landscape (AF)	1.2	2.0	2.8	4.0	4.7	5.5	5.5	4.3	3.9	2.8	1.6	1.2	39.1
Evaporation (inches) [2]	2.2	3.8	5.3	7.5	9.0	10.5	10.5	8.2	7.5	5.3	3.0	2.2	75
Potential loss from a 5-acre pond surface (AF)	0.9	1.6	2.2	3.1	3.8	4.4	4.4	3.4	3.1	2.2	1.3	0.9	31.3

Sources:

a. PSOMAS, 2007b
b. Annual evaporation from PSOMAS, 2004. Monthly distribution is based on monthly distribution for ETo.

Notes:

AF = acre-feet
ETo = evapotranspiration

m) As presented in the Water Supply Assessment and Verification Report for the Palmwood Project (PSOMAS, 2006a, included in this report as Appendix D-3), approximately 35 percent of water supplied to customers is returned as wastewater. Therefore, to produce 1,500 AFY of wastewater requires approximately 4,300 AFY of water supply.

BACKGROUND

The groundwater use was modeled in the AFC. The groundwater was modeled assuming that only the wells on the project site would be extracting groundwater, and did not account for potential impacts on other users of groundwater (i.e., other wells) or the loss of recharge water through absorption and evaporation while settling in percolation ponds at the Horton WWTP.

DATA REQUEST

51. The rate of evapotranspiration in the project area is approximately 72 to 94 inches per year. Please determine the volume of water loss through evapotranspiration, and revise the groundwater model to include this loss of water available for recharge of the sub-basin.

RESPONSE

PSOMAS' Preliminary Water Balance for the Mission Creek Groundwater Subbasin (PSOMAS, 2004) refers to DWR (1964), reporting evaporation averaging 75 inches per year from free water surfaces. Therefore, the estimated amount of evaporation from the percolation ponds at the Horton WWTP would be on the order of approximately 30 AFY, based on approximately 5 acres of pond area. In comparison, the estimated amount of water loss through evapotranspiration for a 5-acre area would be approximately 30 to 39 AFY, assuming an evapotranspiration rate of approximately 72 to 94 inches per year. (Also see the responses to Data Request 50, Item L, and Data Request 53.)

Evaporation from an open water body instead of evapotranspiration (which also includes the transpiration from soils by plants) will be used in the revised groundwater model to be developed and submitted to CEC at a later date. Evaporation losses at the two recharge basins (i.e., the Horton WWTP percolation ponds and the Mission Creek Recharge Basin) will be incorporated into the revised model.

Although the potential evapotranspiration rate is high, the groundwater table is so deep in most of the model domain area (several hundred feet) that the actual evapotranspiration from groundwater would be considered negligible.

The amount of water extracted from the subbasin due to evapotranspiration from plants (Specifically phreatophytes) along faults is estimated to be approximately 1,460 AFY, based on a total plant area of approximately 1,123 acres (PSOMAS, 2004).

DATA REQUEST

52. Please determine and incorporate into the model the volume of water lost due to absorption by the soil during percolation.

RESPONSE

Typically, water is lost in the vadose zone to absorption when initially recharged into the aquifer. Since water would be recharged into existing DWA and Horton WWTP percolation ponds, we would not expect water loss due to absorption to be significant. This is consistent with the approach and assumptions used by PSOMAS for the groundwater model developed for MSWD (PSOMAS, 2007a).

DATA REQUEST

53. The AFC stated that the Project would purchase 1,500 AFY of treated water from the MSWD Horton WWTP for groundwater recharge at the WWTP. Incorporating loss of water to soil absorption and evapotranspiration, please provide support for the conclusion that 1,500 AFY is a sufficient volume of water to more than equate to the maximum volume of water proposed to be used by the Project (i.e., 1,100 AFY).

RESPONSE

The amount of water lost to evaporation can be estimated based on approximately 5 acres of percolation ponds at Horton and assuming that the evaporation rate is approximately 75 inches per year (see the responses to Data Request 50, Item L, and Data Request 51). This would result in approximately 31 AFY lost to evaporation at the percolation ponds. If 1,500 AFY is applied at the percolation ponds, then 1,469 AFY or approximately 98 percent of the amount applied would percolate to the subsurface. This would still exceed the amount of water to be extracted from the subbasin by the proposed project.

54. Please discuss the cumulative effect of groundwater extraction from all groundwater users on the overdraft of the sub-basin over the life of the project (including the project's use of groundwater).

RESPONSE

As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will submit its responses to this request no later than February 4, 2008.

DATA REQUEST

55. Using existing well data (well location and known pumping rates) please revise the model to assess the net affect of all groundwater extraction from the sub-basin over the life of the project.

RESPONSE

In order to provide the exceptional level of detail required for this discussion, the Applicant will need to conduct additional modeling. As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will submit its responses to this request no later than February 4, 2008.

DATA REQUEST

56. Please describe and quantify the annual groundwater production rates in the sub-basin for the last 10 years.

RESPONSE

The MSWD was established in 1953. The service area consists of 135 square miles including the City of Desert Hot Springs, ten smaller communities in Riverside County, and communities in the City of Palm Springs. The water source for the MSWD service area is groundwater from the Mission Creek Subbasin. In 2005, MSWD provided service to approximately 23,000 people (PSOMAS, 2007a).

Annual water production for the past 10 years is listed in Table 56-1, for MSWD pumping and total production (including MSWD, CVWD and private well pumping).

Table 56-1
Annual Water Production for Past 10 Years

Year	MSWD Annual Production (AFY)[1]	Total Pumping from Mission Creek Subbasin (AFY)[2]
1997	7,297	10,673
1998	7,382	10,944
1999	7,763	12,084
2000	8,010	12,427
2001	7,979	11,756
2002	8,283	12,938
2003	8,736	13,316
2004	10,197	14,624
2005	NA	15,686
2006	NA	16,547

Sources:

1. Data for MSWD annual production (1997-2004) from URS, 2005.
2. Data for total pumping from subbasin from PSOMAS, 2007a. Pumping includes MSWD wells as well as pumping by CVWD and private well pumping.

DATA REQUEST

57. Please describe and quantify changes in recharge that have occurred in the sub-basin during the last 10 years. Include information on water importation, reclamation of wastewater, and new recharge programs.

RESPONSE

In 2001, the Horton WWTP had a design treatment capacity of 1.0 million gallons per day (MGD) (RWQCB, 2001) and discharged approximately 0.856 MGD of treated wastewater effluent into five infiltration basins located at the facility. Current plant permitted capacity is 2.0 MGD (URS, 2005). PSOMAS (2004) estimated the average amount of percolation at the Horton WWTP to be approximately 1,013 AFY.

Mission Creek Recharge Basin was completed in June 2002 and recharge activities commenced in November 2002. Annual recharge is summarized in Table 57-1. In addition, the table provides the last 10 years of recharge at the Whitewater Recharge Basin. DWA and CVWD have been recharging at the Whitewater Recharge Basin since 1973, using Colorado River water in exchange for SWP water. The total amount of water recharged at the Whitewater facility for the period 1973 through 2006 is 1,983,276 acre-feet.

Table 57-1
Historical Recharge Volumes

Year	Mission Creek Recharge Volume (AFY)	Whitewater Recharge Volume (AFY)
1997	0	113,677
1998	0	132,455
1999	0	90,601
2000	0	45,477
2001	0	707
2002	4,733	33,435
2003	0	961
2004	5,564	13,224
2005	24,723	66,885
2006	19,901	151,199
Total	**54,921**	**648,621**

Source: Krieger & Stewart, 2007

Other sources of inflow to the subbasin include surface water inflow, subsurface inflow, and return flows from wastewater systems and irrigation.

Natural inflow to the Mission Creek Subbasin includes infiltration and percolation of natural runoff from Mission Creek, Big Morongo Creek, and Little Morongo Creek. Natural inflow from surface runoff is estimated to range from approximately 3,500 AFY to approximately 6,000 AFY, as estimated by various agencies including DWA (1980), the United States Geological Survey

(Tyley, 1974), and DWR (1964) (Krieger & Stewart, 2007). PSOMAS (2004) estimated the inflow to the subbasin from surface runoff to be approximately 6,834 AFY.

Natural subsurface inflow includes groundwater flux from the Desert Hot Springs Subbasin. This inflow is estimated to be approximately 3,080 AFY (PSOMAS, 2004). In addition, PSOMAS (2004) estimated approximately 3,979 AFY due to inflow from Mission Creek alluvium.

Additional recharge to the subbasin is attributed to the approximately 5,500 un-sewered private disposal systems. PSOMAS (2004) estimates the amount of recharge from these domestic disposal systems to be approximately 341 AFY.

Return flow from golf courses, resort landscape watering, and agricultural irrigation practices is estimated to be approximately 302 AFY, assuming a total application of 1,510 AFY and that 20 percent of the water consumed would be returned to groundwater (PSOMAS, 2004).

DATA REQUEST

58. Please describe and quantify the changes in groundwater levels that have occurred in the sub-basin over the last 10 years. Include hydrographs and groundwater contour maps to describe these changes.

RESPONSE

As stated above in the response to Data Request 57, the Mission Creek Recharge Basin was completed in 2002 and recharge began in 2004. Prior to recharge, water levels within the Mission Creek Subbasin for the period 1993 through 2003 had declined at least 10 feet and a much as 26 feet as the result of pumpage (Krieger & Stewart, 2007). Due to groundwater replenishment efforts, groundwater levels within the Mission Creek Subbasin have risen and, on average, have been relatively stable during 2005 and 2006. Figure 58-1 provides a water well hydrograph that illustrates water levels from December 1, 1996 through February 2, 2007.

Figure 58-2 shows the changes in groundwater elevations within the Mission Creek Subbasin between 1991 and 2004, represented as a contour map (PSOMAS, 2004). The figure does not include 2005 and 2006, which had significant volumes of recharge at the Mission Creek Recharge Basin (see Table 57-1).

DATA REQUEST

59. Please provide a 10-year balance of water outflows and water inflows for the sub-basin and discuss the status and future of overdraft of the sub-basin

RESPONSE

As discussed in the response to Data Request 57, natural inflow to the Mission Creek Subbasin includes surface water inflow and subsurface inflow. The net natural inflow into the subbasin is estimated to be approximately 9,163 AFY (PSOMAS, 2004). The amount of natural inflow is estimated to be approximately 13,893 AFY (PSOMAS, 2004).

Natural outflow includes surface water outflow, subsurface outflow, and evapotranspiration. PSOMAS (2004) estimated the average amount of surface water inflow that would leave the subbasin to be approximately 70 AFY. Natural subsurface outflow occurs as groundwater flows across the Banning Fault to the Garnet Hill Subbasin. This subsurface outflow has been estimated to range from approximately 2,000 AFY (Tyley, 1974) to approximately 5,470 AFY (PSOMAS, 2004). PSOMAS (2004) selected a midrange value of 3,200 AFY for subsurface flow across the Banning Fault for purposes of its preliminary water balance evaluation. As mentioned in the response to Data Request 51, PSOMAS (2004) also accounted for approximately 1,460 AFY of water loss from evapotranspiration from plants (specifically phreatophytes) along faults. Therefore, the total estimated average annual natural outflow is approximately 4,730 AFY.

Table 59-1 provides a groundwater budget for 1997 through 2006 based on historical pumping information from PSOMAS (2007), natural inflow, recharge at the Mission Creek Recharge Basin, and natural outflow.

Historically, the Mission Creek Subbasin has been in overdraft conditions (i.e., outflow exceeds inflow). As shown in Table 59-1, inflows to the subbasin have exceeded outflows since replenishment at the Mission Creek Recharge Basin commenced in 2002. With replenishment, groundwater levels within the Mission Creek Subbasin have been relatively stable and have slightly increased during 2005 and 2006 (see Figure 58-1).

Due to the programs and agreements in place, replenishment at the Mission Creek Recharge Basin will continue into the future. During years when SWP/Colorado River water may be curtailed, outflow may exceed inflow. However, during years when there may be surplus water available, (e.g., wet years such as 2005), DWA/CVWD would request additional water for replenishment to make up for the curtailed supply years, as it did in 2005.

Table 59-1
Groundwater Budget (1997-2006)

Year	Subbasin Inflow (AFY)[1]	Mission Creek Recharge Basin (AFY)[2]	Total Inflow (AFY)	Natural Outflow (AFY)[3]	Pumping from Mission Creek Subbasin (AFY)[4]	Total Outflow (AFY)	Storage Change (AFY)
1997	15,549	0	15,549	4,730	10,673	15,403	146
1998	15,549	0	15,549	4,730	10,944	15,674	-125
1999	15,549	0	15,549	4,730	12,084	16,814	-1,265
2000	15,549	0	15,549	4,730	12,427	17,157	-1,608
2001	15,549	0	15,549	4,730	11,756	16,486	-937
2002	15,549	4,732	20,282	4,730	12,938	17,668	2,614
2003	15,549	0	15,549	4,730	13,316	18,046	-2,497
2004	15,549	5,564	21,113	4,730	14,624	19,354	1,759
2005	15,549	24,723	40,272	4,730	15,686	20,416	19,856
2006	15,549	19,901	35,450	4,730	16,547	21,277	14,173

Sources:

PSOMAS, 2004; PSOMAS, 2007a; and Krieger & Stewart, 2007.

Notes:

1. Subbasin inflow includes natural inflow (13,893 AFY), recharge from wastewater systems (341 AFY), irrigation return flows (302 AFY), and estimated Horton WWTP inflow (1,013 AFY).
2. Mission Creek Recharge Basin amounts are from the DWA's Engineer's Report (Krieger & Stewart, 2007).
3. Outflow includes flow across the Banning Fault (assumed to be approximately 3,200 AFY), evapotranspiration from phreatophytes (1,460 AFY), and surface water outflow (see the response to Data Request 57).
4. Historical pumping rates from PSOMAS, 2007a.

DATA REQUEST

60. Please discuss the safe yield of the sub-basin at the Project location, and include all assumptions and calculations for this estimation.

RESPONSE

MSWD has estimated that the safe yield of the Mission Creek Subbasin is approximately 40,000 AFY (PSOMAS, 2006a and 2006b). In comparison, the amount of groundwater in storage in the Mission Creek Subbasin is approximately 1.4 MAF (PSOMAS, 2007a). As such, the 40,000 AFY represents less than 3 percent of the total amount of groundwater in the subbasin.

DATA REQUEST

61. Given the reliability issues of imported water (e.g., SWP and CRA supplies) for recharge of the sub-basin, please revise the model using two separate conditions: (1) a conservative baseline of guaranteed water supply for groundwater recharge, and all assumptions included; and (2) a reasonably foreseeable water supply available for groundwater recharge, including all assumptions used. In other words, in the model, please provide a worst-case scenario and a most-likely scenario for recharge water supply and how this affects the sub-basin's overdraft condition.

RESPONSE

In order to provide the level of detail required for this discussion, the Applicant will need to conduct additional modeling. As stated in the "Objections to CEC Staff Data Requests, Set One" letter dated October 24, 2007, the Applicant will the Applicant will submit its responses to this request no later than February 4, 2008.

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