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

DATE: November 9, 2001

TO: Interested Parties

FROM: Nancy Tronaas, Compliance Project Manager

SUBJECT: **Sunrise Power Project (98-AFC-4C)**
Staff Analyses of Proposed Project Modification
Conversion to Combined-Cycle Operations

On May 14, 2001 the California Energy Commission (Energy Commission) received a petition from the Sunrise Power Company (SPC) to amend the December 2000 Energy Commission Decision for the Sunrise Power Project (SPP). SPP is a 320MW simple-cycle natural gas power plant that commenced commercial operation on June 27, 2001. SPP is located approximately 35 miles southwest of Bakersfield, and one mile southwest of the intersection of State Route 33 and Shale Road in Kern County, California.

The proposed modifications will add approximately 265 MW of generating capacity, resulting in a nominal 585 MW combined cycle power plant (aka "Sunrise II") that is expected to be operational by summer 2003. This 265 MW increase is being processed by the Energy Commission as an amendment, rather than a new application for certification, under the express authority of Executive Order D-25-01 of the Governor of the State of California, dated February 8, 2001.

The primary new project features for combined-cycle operations include:

- two heat recovery steam generators,
- a steam turbine generator,
- new equipment for the existing SPP and La Paloma switchyards,
- a wet cooling tower system,
- an anhydrous ammonia selective catalytic reduction system,
- a 15.5 mile water supply line,
- expanded power plant /construction laydown areas, and
- four deep injection wells for wastewater disposal

Also, the Energy Commission recently approved two project modifications for the simple-cycle power plant that included the construction of a recycling wastewater discharge system to TCI's station 2-22, and the construction of a 2.5 mile underground pipeline and two deep injection wells as a wastewater disposal option to support the simple cycle operations. If Sunrise II is approved by the Energy Commission, both of these wastewater disposal options also will be used for the combined-cycle operations.

Energy Commission staff reviewed the Sunrise II modifications to assess the impacts of this proposal on environmental quality, public health and safety. Staff prepared new

and/or revisions to existing conditions of certification for biological and cultural resources, facility design, air quality, land use, hazardous materials handling, worker safety, and soil and water resources. It is the Energy Commission staff's opinion that with the implementation of these conditions, the project will remain in compliance with applicable laws, ordinances, regulations, and standards and that the proposed project modification will not result in a significant effect upon the environment (*Title 20, California Code of Regulations, Section 1769).*

These staff analyses are attached for your information and review. Energy Commission staff intends to recommend approval of the petition at the November 19, 2001 Business Meeting of the Energy Commission.

If you have comments on this proposed project change, please submit them to the me at the address above prior to November 19, 2001. If you have any questions, please call me at (916) 654-3864 or e-mail at ntronaas@energy.state.ca.us.

Attachments

CALIFORNIA ENERGY COMMISSION
STAFF ANALYSIS
FOR THE
PETITION TO CONVERT TO COMBINED CYCLE OPERATIONS
SUNRISE POWER PROJECT (98-AFC-4C)
November 2001

TABLE OF CONTENTS

Technical Area	Page
Summary, Conclusion, and Staff Recommendation	ii
Air Quality	1
Biology	25
Cultural Resources	31
Facility Design	34
Hazardous Materials Management	38
Land Use	39
Worker Safety and Fire Protection	47
Soil and Water Resources	49

PETITION TO CONVERT TO COMBINED CYCLE OPERATIONS
SUNRISE POWER PROJECT (98-AFC-4C)
SUMMARY, CONCLUSION, and STAFF RECOMMENDATION
November 2001

Location

The Sunrise Power Project is a 320MW simple-cycle natural gas power plant that is located approximately 35 miles southwest of Bakersfield, and one mile southwest of the intersection of State Route 33 and Shale Road in Kern County, California.

History

The original Sunrise Cogeneration and Power Project application for certification was filed in 1998 for a cogeneration facility that would generate electricity for sale and produce steam for use in the adjacent oilfields in thermally-enhanced oil recovery processes. After evidentiary hearings and issuance of the Presiding Member's Proposed Decision, the project was modified to a simple-cycle peaking power plant to deliver power for the peak demand of summer 2001. The simple-cycle project was certified on December 6, 2000, construction began on December 7, and commercial operations commenced on June 26, 2001.

Pursuant to Condition of Certification AQ-41, the December 2000 Commission Decision will expire on December 31, 2002, unless the project owner files an application for certification or an amendment petition to the existing Conditions of Certification for a modification to the project to a combined cycle or cogeneration project. In accordance with Executive Order D-25-01 of the Governor of the State of California, dated February 8, 2001, the proposed project change petition has been processed by the Energy Commission as an amendment, rather than a new application for certification.

Since certification in December 2000, the Commission approved earlier project amendments for the Sunrise power plant, including a one-mile long recycle water discharge line to TCI Station 2-22, and a 2.5 mile wastewater discharge line and two deep injection wells to be used as a wastewater disposal option. These facilities were originally part of the May 11, 2001 petition described below; however, at the request of the project owner, they were processed separately to support simple cycle operations.

Proposed Amendment

The Sunrise Power Company filed a petition on May 11, 2001 to convert from a simple-cycle to a combined-cycle power plant. This conversion will add approximately 265 MW of generating capacity, resulting in a nominal 585 MW combined-cycle power plant that is expected to be operational by summer 2003. The conversion to combined-cycle operations will require the addition of two duct-fired heat recovery steam generators (HRSG), one 265 MW steam turbine generator (STG), new equipment for the existing SPP and La Paloma switchyards, an evaporative condenser cooling tower system that

will use approximately 3,900 acre-feet of water annually, an anhydrous ammonia selective catalytic reduction system, a 15.5 mile water supply line to connect to the West Kern Water District well fields northeast of the project site, a 4.8 acre expansion of the existing power plant site, a seven acre expansion of the construction laydown area, and four additional deep injection wells for wastewater disposal located approximately 1.5 miles southeast of the existing power plant.

The conversion to combined-cycle operations will provide baseload and peaking power up to 24 hours per day, seven days per week. Both generating and fuel efficiencies will be substantially improved through combined-cycle operations by more complete utilization of the combustion turbine generator's hot gases to generate steam in the HRSGs for added steam cycles and increased electrical output from the new STG.

Staff Analysis

The petition was reviewed by Energy Commission technical staff for potential environmental effects and consistency with applicable laws, ordinances, regulations, and standards (LORS). Many of the proposed combined-cycle project features and potential environmental effects were previously analyzed by staff during their review of the original Sunrise Cogeneration and Power Project AFC. Where applicable, staff referred to those previous environmental assessments in the attached analyses of the combined-cycle petition. Staff determined that the following technical or environmental areas will be affected by the proposed project change to combined-cycle operations, and staff has proposed new and revised conditions of certification (noted in parentheses) in order to assure compliance with LORS and to reduce potential environmental impacts to a level of insignificance:

- Air Quality—projected increases in PM_{10} due to construction activities will be mitigated with implementation of oxidizing soot filters or/and or use of alternative fuels on construction equipment and fugitive dust control (AQ-C3); operational emissions will be mitigated by using emission control equipment and providing emission offsets (AQ-14—18, AQ-44—59).

- Biological Resources—temporary and permanent impacts to 154.7 acres sensitive species habitat will be mitigated through the purchase of at least 211.5 acres of compensation habitat (BIO-15), and installation of bird flight diverters on the transmission line will facilitate protection of the California Condor (BIO-16).

- Cultural resources—mitigation is proposed to ensure that adequate processes are in place to avoid or minimize impacts to cultural resource finds in the vicinity of the new water line and injection wells (CUL-19).

- Facility design—changes to existing an condition of certification will ensure continued compliance with construction regulations (GEN-2).

- Hazardous Materials Management—potential impacts from the use of anhydrous ammonia will be mitigated by compliance with local, state, and federal requirements for its use and transport (HAZ-2).

- Land Use—potential land use impacts will be mitigated through implementation of compliance with the Kern County Zoning Ordinance and General Plan (LAND USE-1), and restoration of 14.3 acres of disturbed land due to water line construction (LAND USE-3).

- Worker Safety and Fire Protection—although the proposed project will not cause a significant impact to safety or fire protection, additional fire hydrants along the new water line will be provided by the project owner in response to a request from the Kern County Fire Department to improve fire response actions in the vicinity of the power plant. An optional condition of certification has been proposed (SAFETY-4).

- Soil and Water Resources—the combined-cycle project may contribute to cumulative impacts on water resources. This potential significant impact will be mitigated to a less-than-significant level by limiting the project to 3,900 acre-feet of water per year (SOIL & WATER-4), implementing a groundwater monitoring plan (SOIL & WATER-5), and preparing a "Water Conservation Plan" (SOIL & WATER-6) that will define technological options that will be implemented by the project owner if groundwater monitoring results indicate that the threshold groundwater level has been reached. Some water-conservation methods will be required to be implemented by the second year of operation in order to improve water use efficiency.

Staff Conclusion And Recommendation

Staff concludes that the following required findings mandated by Title 20, section 1769(a)(3) of the California Code of Regulations can be made and will recommend approval of the petition to the Energy Commission:

A. There will be no new or additional unmitigated significant environmental impacts associated with the proposed changes,

B. The facility will remain in compliance with all applicable laws, ordinances, regulations, and standards,

C. The change will be beneficial to the public, applicant, or intervenors. In this case, the amendment will be of benefit to the project owner by improving thermal and operational efficiency, and

D. Filing the petition was a post-certification business decision in response to the Energy Commission's requirement that the December 2000 Decision expires on December 31, 2002 unless a new application for certification or amendment petition to convert to combined-cycle or cogeneration is filed prior to that date.

Sunrise Power Project (98-AFC-4C)
Petition to Convert to Combined Cycle Operations
Air Quality Staff Analysis
Prepared by Joseph M. Loyer

AMENDMENT REQUEST

The Sunrise Power Company, LLC (Sunrise) submitted a petition on May 11, 2001 to amend its current Conditions of Certification to prepare for Phase II for their project. Phase II will convert the Sunrise Power Project (SPP) from a simple-cycle peaking operation to a combined-cycle operation.

Sunrise is also requesting to update the construction mitigation condition AQ-C2 to allow the use of ultra-low sulfur diesel fuel instead of oxidizing soot filters on construction equipment.

BACKGROUND

SPP was licensed by the California Energy Commission on December 6, 2000 as a 320 megawatt (MW) peaking facility with the condition that the facility be converted into a combined cycle or cogeneration facility within two years of the license being granted (AQ-41). This amendment request is the applicant's compliance with Condition of Certification AQ-41. It is the applicant's stated intention to begin construction of the combined cycle portion of the facility by November of 2001 and increase the available capacity to 585 MW (a difference of 265 MW). To do this, Sunrise will add a heat recovery steam generator (HRSG) to each turbine train, a 265 MW steam turbine and a cooling tower in addition to other ancillary equipment. Since this is an amendment of a recently licensed power plant, staff will rely by reference to the extent reasonable on the Final Staff Assessment of the Sunrise Power Project (CEC 2000), dated October 26, 2000.

There have been no significant changes in the San Joaquin Valley Unified Air Pollution Control District (District) rules or regulations since the SPP facility was granted a license in December of 2000. Therefore, for the LORS and Environmental Setting sections, staff intends to rely completely by reference on the FSA.

The applicant has chosen to characterize their construction emissions by equating them to the construction emissions estimated to build the simple cycle facility. The construction of the simple cycle facility included the construction of turbines, pipelines, transmission lines and ancillary facilities, and was completed on June 19, 2001. This is significantly more construction activity than Sunrise is proposing for the combine cycle upgrade, that include the HRSG, steam turbine, cooling towers and minor ancillary facilities. It is therefore staff's opinion that the construction emission estimates will exceed the actual potential emissions of the proposed combined cycle upgrade by a large margin.

The simple cycle facility was licensed prior to staff incorporating environmental justice (EJ) issues into each subject area. Therefore, staff will produce an EJ analysis with this amendment request.

Staff's analysis will focus on the project emissions, impacts (including EJ) and the proposed offsets, in addition to the recommended new and modified Conditions of Certification.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

There are no additional laws, ordinances, rules or statues that apply to the combined cycle SPP other than those identified in the FSA (CEC 2000).

ANALYSIS

Project Description

Sunrise proposes to install the following components at the current simple cycle SPP facility to convert it into a combined cycle facility.

- Two duct-fired heat recovery steam generators (HRSG), gas fired only. Each HRSG is to have a selective catalytic reduction device (for NOx control) and an oxidation catalyst (for CO and VOC control).
- One 265 MW steam turbine generator.
- New 230 kV equipment for the existing Sunrise and La Paloma switchyards.
- A 9-cell wet cooling tower with 0.0006% drift eliminators.
- An anhydrous ammonia storage and handling system.
- Water treatment equipment.
- A 15 mile long water supply line from Western Kern Water District.

Project Emissions

Construction

Sunrise proposes to use the construction emission estimates that were provided for the simple cycle SPP in the Application for Certification. The simple cycle SPP included two GE frame 7F turbine, natural gas pipeline, electrical connection equipment and water/waste water pipelines. The original construction estimates also included a significant amount of cut and fill requirements (moving dirt). All of this construction has been completed for the simple cycle SPP.

The foundations for the HRSG were completed with the simple cycle SPP (as a requirement for installing the gas turbines). Therefore the only major equipment to be constructed for the combined cycle SPP is the HRSG, the cooling towers and the steam generator, in addition to the identified ancillary equipment. There is expected to be no, or very little cut and fill activities necessary for the construction of the combine cycle SPP. It is staff's opinion that the construction of the combine cycle components of the SPP will result in significantly fewer emissions that the construction of the simple cycle SPP. Staff estimates that the construction emissions for the combine cycle SPP will be approximately 1/3 of the simple cycle SPP, based on the footprints of the identified equipment to be constructed.

Air Quality Table 1
Maximum Expected Daily Construction Emissions (lbs/day)

	NOx	VOC	CO	PM10	SOx	Fugitive PM10
Project Site & 230kV substation	221	37	314	24	21	154[a]
Transmission line	132	15	55	15	12	Negligible
Emission estimates assume an 8-hour workday. a – Fugitive dust emission estimate assumes no controls.						

(CEC 2000)

Operation

In the following tables, staff presents the expected hourly, daily and annual emissions as a result of the proposed amendment. It should also be noted that the basic operation of the SPP is proposed to change from a peak load operation to a base load or load following operation. This essentially means that the SPP will operate long hours, but at a reduced emission rate for some pollutants (NOx, CO and VOC). PM10 and SOx emissions typically increase as the facility operational hours increase due to the additional amount of fuel burned over time and are not controlled through a post combustion process.

Air Quality Table 2 shows the expected maximum hourly emission rates from the proposed modifications. In most cases, the expected maximum hourly emission rates for a combustion turbine occur during startup or shutdown. In this case Sunrise has some additional information because the combustion turbines have already been built and have been running. The information the applicant is able to give us is more accurate on startup emissions than would normally be expected. Air Quality Table 2 shows that the maximum emission for each pollutant is dependent on what type of startup (hot, warm or cold) is being considered. For NOx emissions, the worst case 1-hour emission is during a cold startup of the SPP facility. This means that the facility has been shut down for an extended period of time and all components are cold (relative to their normal operational temperatures). Total duration for a cold startup of a combined cycle facility is approximately 3 hours. For VOC, CO and PM10, the worst case 1-hour emissions occur during a warm startup. This means that the facility would have been running at maximum capacity for several hours prior to being shut down for several hours. The duration of a warm startup can be very short (approximately 1 hour), but can also last as long as 2 hours. The reason these emissions experience higher rates during the warm startup is that more fuel is being burned in a shorter time frame (as compared to a cold startup) and the oxidation catalyst is not operating at peak efficiency yet. The maximum SOx emissions occur during maximum load operations. This is because the SOx emissions are a direct result of the sulfur content of the fuel being burned, therefore the more fuel burned, the higher the emissions.

Air Quality Table 2
Expected Maximum Hourly Emission Rates

Pollutant	Emission Rate (lbs/hr)	Operational State
NOx	350	Cold Startup
CO	790	Warm Startup
VOC	40	Warm Startup
PM10	40	Warm Startup
SOx	1.55	Full Load with duct burn

Air Quality Table 3 shows the expected maximum daily emissions from the proposed modifications at the SPP. As is indicated in the Sunrise amendment request, the project emissions are at their maximum (excluding startup or shut down) when the turbines are at full load and the duct firing is on. Therefore, staff expects the maximum daily emissions to occur on days when the SPP facility has a cold startup followed by 100% loading and the duct firing on. Operational emissions are maximum for all criteria pollutants when the facility is at full load with the duct firing on, and the ambient air temperature is 15 ^{o}F, except for PM10. PM10 is at its maximum when the ambient air temperature is 115 ^{o}F. The maximum daily emissions for each pollutant do not need to incorporate the same assumptions. All that is required is that the maximum potential for each pollutant is identified and mitigated.

Air Quality Table 3
Expected Maximum Daily Emissions

Pollutant	Maximum hourly emissions during normal operation (lbs/hr)	Maximum total emissions expected during startup (lbs)	Worst Case daily emissions for both Turbines (lbs/day)[c]	Normal Operational daily emissions for both Turbines (lbs/day)[d]
NOx	15.96[a]	350	3525.1	766.1
CO	28.85[a]	775	7697.6	1384.8
VOC	5.51[a]	22	439.9	264.5
PM10	17.80[b]	22	921	854.4
SOx	1.55[a]	1.55	74.4	74.4

a – Turbine at 100% load with the duct firing on at 15 ^{o}F.
b – Turbine at 100% load with the duct firing on at 115 ^{o}F.
c – Total daily emissions include 230 minutes of cold startup, 1 hour of shutdown, and the turbines operating at 100% load with the duct firing on for the balance of time.
d – Total daily emissions include 100% load with duct firing for the 24-hour period.

Air Quality Table 4 shows the expected maximum annual emissions from the proposed modifications at the SPP. Sunrise has proposed two different numbers of startups; 100 startups (30 hot, 50 warm and 20 cold starts) which corresponds to a dispatch capacity factor of 86% (7,537 hour of turbine operation with 5,669 hours of duct burner operation) and 33 startups (10 hot, 16 warm and 7 cold starts) corresponding to a dispatch capacity factor of 95% (8,324 hour of turbine operation with 6,228 hours of

duct burner operation). NOx and CO emissions were worst in the 86% capacity factor case, while PM10, SOx and VOC were worse in the 95% capacity factor case.

Air Quality Table 4
Expected Maximum Annual Emissions

Pollutant	Annual Emissions (tons/year)[a]
NOx	152.9[b]
CO	315.8[b]
VOC	43.0[c]
PM10	138.0[c,d]
SOx	11.8[c]

a – Emissions include both turbines and the cooling tower.
b – Emissions include 100 startups, 100 shutdowns and 7,537 of turbine operation with 5,669 hour of duct burner operation.
c – Emissions include 33 startups, 33 shutdowns 8,324 hours of turbine operation with 6,228 hours of duct burner operation.
d – Includes PM10 emissions from the cooling tower.

(Sunrise 2001a)

Ammonia Emissions

Due to the large combustion turbines used in this project and the need to control NO_x emissions, significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia mixes in the flue gases to reduce NOx; a portion of the ammonia passes through the SCR and is emitted unaltered, out the stack. These ammonia emissions are known as ammonia slip. Sunrise has committed to an ammonia slip no greater than 10 ppm, which is the current ammonia slip level being permitted throughout California. On a daily basis, the ammonia slip of 10 ppm is equivalent to approximately 703 lbs/day of ammonia emitted into the atmosphere.

It should be noted that an ammonia slip of 10 ppm is usually associated with the degradation of the SCR catalyst, usually in a time frame of five years or more after initial operation. At that point, the SCR catalysts are removed and replaced with new catalysts. During most of the operation of the SCR system, ammonia slip emissions are usually in the range of 1 to 2 ppm, corresponding to a mass emissions in the SPP case to approximately 100 to 250 pounds per day. The implications of these ammonia emissions are discussed later in this analysis.

Project Impacts

Construction

SPP performed air dispersion modeling analyses of the potential construction impacts at the project site. The analyses included fugitive dust generated from the construction activity (modeled as an area source) and combustion emissions from the equipment (modeled as point sources). The emissions used in the analysis were the highest emissions of a particular pollutant during a one month period, converted to a gram per second emission rate for the model. Most of the highest emissions occurred in the initial months of the 15-month construction period. The results of this modeling effort are shown in Air Quality Table 5. They show that the construction activities would cause a violation of the state 24-hour and annual average PM10 standards. In reviewing the modeling output files, staff determined that the project's construction

impacts are not occasional or isolated events, and occur over an area within a few hundred meters of the project site. These predicted impacts are of a high magnitude for a number of reasons.

AIR QUALITY Table 5
Maximum Construction Impacts

Pollutant	Averaging Time	Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hour	298[a]	97	395	470	84%
	Annual	9.6[b]	20.6	30.2	100	30%
CO	1-hour	1,486	2,941	4,427	23,000	19%
	8-hour	680	2,222	2,902	10,000	29%
SO_2	1-hour	99	104	203	655	31%
	3-hour	67.9	68	135.9	1300	10%
	24-hour	23.3	38	61.3	130	47%
	Annual	1.2	1.8	3	80	3.75%
PM10	24-hour	137	118	255	50	510%
	Annual	9.3	42.6	51.9	30	173%

a – Results obtained using the Ozone Limiting Method (OLM).

b – Results obtained using the Ambient Ratio Method (ARM) default value 0.75.

First, the model itself calculates impacts that are conservative, usually exceeding actual impact levels. Second, some of the sources of combustion emissions (the bulldozers and trucks) are mobile sources, not stationary sources, as assumed in the input to the model. As mobile sources, the air quality impacts would not always be at the same locations. Third, it was assumed that all the equipment identified for the modeling evaluation would be running simultaneously. It is doubtful that all the major equipment would all be operating at one time. Finally, the emissions inputs to the model were from the highest monthly emissions assumed during the 15-month construction period. The levels of emissions used reflect a period of activity of approximately 4 months, not the entire 15-month construction. During the other months of construction work, considerably fewer pieces of emission generating equipment will be used and thus the impacts will be lower.

Although the modeling results for the construction of the SPP project predict an impact on the PM10 ambient air quality standards, it is not possible to determine to what extent the modeling results are over estimating the SPP construction emission impacts. Therefore, staff concludes that the emissions from the construction of SPP have the potential to cause unavoidable short-term significant PM10 impacts if left unmitigated.

Operation

FUMIGATION

During the early morning hours before sunrise, the air is usually very stable. During such stable meteorological conditions, emissions from elevated stacks rise through this stable layer and are dispersed. When the sun first rises, the air at ground level is heated, resulting in a vertical (both rising and sinking air) mixing of air for a few hundred feet or so. Emissions from a stack that enter this vertically mixed layer of air will also be vertically mixed, bringing some of those emissions down to ground level. Later in the day, as the sun continues to heat the ground, this vertical mixing layer becomes higher and higher, and the emissions plume becomes better dispersed. The early morning air pollution event, called fumigation, usually lasts approximately 30 to 90 minutes. Since fumigation impacts will not typically occur much beyond a 1-hour period, only impacts on 1-hour standards are addressed. Air Quality Table 6 shows the results of the fumigation modeling that Sunrise performed. These results demonstrate that the 1-hour standards for NO_2, SO_2 and CO are not exceeded under fumigation conditions for proposed modifications to SPP. Therefore, staff concludes that under fumigation conditions, the Sunrise project emissions have no potential to cause a significant impact on the ambient air quality.

AIR QUALITY Table 6
1-hour Fumigation Modeling Results

Pollutant	Averaging Time	Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hour	56.7	97	153.7	470	33%
CO	1-hour	128.0	2,941	3,069	23,000	13%
SO_2	1-hour	0.51	104	104	655	16%
(Sunrise 2001a)						

REFINED MODELING

Sunrise provided a refined modeling analysis, using the ISCST3 model to quantify the potential impacts of the proposed changes to SPP both during normal steady state operation and during startup or shutdown conditions. This modeling reflects the expected maximum emissions identified in the **Project Emissions – Operations** section of this assessment. These modeling results are shown in Air Quality Table 7. The only pollutant to cause or contribute to an exceedance of the ambient air quality standards is PM10, exceeding both the 24-hour and Annual California Ambient Air Quality Standards. If left unmitigated, this could constitute a significant impact.

Air Quality Table 7
Refined Modeling of the Sunrise Proposed Amendment

Pollutant	Averaging Period	Modeled Impact (ug/m^3)	Background (ug/m^3)[a]	Total predicted Impact (ug/m^3)	Limiting Standard (ug/m^3)	Percent of Standard (%)
CO	1-hour	1,743.5	2,941	4,685	23,000	20
	8-hour	307.6	2,222	2,530	10,000	25
NO_2	1-hour	243.5[b]	97	340	470	72
	Annual	0.17[c]	20.6	21	100	21
PM10	**24-hour**	**4.01**	**118**	**122**	**50**	**244**
	Annual	**0.22**	**42.6**	**43**	**30**	**143**
SO_2	1-hour	3.42	104	107	655	16
	3-hour	1.61	68	70	1,300	5
	24-hour	0.26	38	38	105	36
	Annual	0.03	1.8	2	80	3

a - Background data from the Fellows monitoring station 1992-1995
b - Results obtained using ozone limiting method
c - Results obtained using ambient ration method with a default ratio of .75

(Sunrise 2000a)

Cumulative Impacts

Sunrise provided a cumulative impact analysis, which includes the La Paloma, Elk Hills and Western Midway Sunset power plant projects recently licensed through the California Energy Commission. The results of the cumulative analysis are presented in Air Quality Table 8. The results of that analysis show that, other than the expected impacts on PM10, the proposed Sunrise amendment will not cause a significant cumulative impact. The PM10 impacts shown could constitute a significant impact if left unmitigated.

Air Quality Table 8
Cumulative Impacts Analysis for the Sunrise Proposed Amendment

Pollutant	Averaging Period	Modeled Impact (ug/m^3)	Background (ug/m^3)[a]	Total predicted Impact (ug/m^3)	Limiting Standard (ug/m^3)	Percent of Standard (%)
CO	1-hour	1,748	2,441	4,189	23,000	18
	8-hour	307.7	2,222	2,530	10,000	25
NO_2	1-hour	243.5[b]	97	340.5	470	72
	Annual	4.18	20.6	24.8	100	25
PM10	**24-hour**	**6.51**	**118**	**124.5**	**50**	**249**
	Annual	**0.96**	**42.6**	**43.6**	**30**	**145**
SO_2	1-hour	16.87	104	121	655	18
	3-hour	10.13	68	78	1,300	6
	24-hour	1.47	38	39.5	105	38
	Annual	0.21	1.8	2.0	80	3

a - Background data from the Fellows monitoring station 1992-1995
b - Results obtained using ozone limiting method

(Sunrise 2000a)

SECONDARY PM10

Concerning secondary PM10 (primarily ammonium nitrate but also ammonium sulfate) formation, the applicant for the La Paloma Project (LPPP 1999a) submitted a study by Sonoma Technology, Inc. which concludes that the San Joaquin Valley is generally ammonia rich during the winter season when ambient PM10 levels are highest. This means that under such conditions, adding more ammonia to the ambient air will not automatically result in more ammonium nitrate PM10 formation. Unfortunately, there is currently no accepted model that predict the impact on ammonium nitrate formation from a single ammonia emission source.

Sunrise has committed to an ammonia slip level no greater than 10 ppm, which is the current ammonia slip level being permitted throughout California. On a daily basis, the ammonia slip of 10 ppm is equivalent to approximately 1,166 lb./day of ammonia emitted into the atmosphere. However, the assumption that the ammonia slip is routinely at 10 ppm is incorrect. That level of ammonia emission is usually associated with the degradation of the SCR catalyst, usually in a time frame of five years or more after initial operation. At that point, the SCR catalysts are removed and replaced with new catalysts. Through most of the operation of the SCR system, ammonia slip emissions are usually in the range of 1 to 2 ppm, corresponding to mass emissions of approximately 100 to 250 pounds per day. Given the Sonoma Technology Study as well as the fact that ammonia emissions tend to be well below 10 ppm, staff concludes that there is very little potential for any ambient air impacts from the SPP project ammonia emissions.

However, the NO_x and SO_x emissions from SPP could add to ammonium nitrate and ammonium sulfate (PM10) formation, since there is more than sufficient ambient ammonia available for the NO_x or SO_x to react with and form PM10. The process of gas-to-particulate conversion is complex and depends on many factors, including local humidity and the presence of other compounds. Currently, there are no agency (EPA or CARB) recommended models or procedures for estimating nitrate or sulfate formation from single source emissions. Nevertheless, studies during the past two decades have provided data on the oxidation rates of SO_2 and NO_x. The data from these studies can be used to approximate the conversion of SO_2 and NO_x to particulate. This can be done by using an aggregate conversion factor (typically about 0.01 to 1 percent per hour) with Gaussian dispersion models such as ISCST3. The model is run with and without chemical conversion (decay factor) and the difference corresponds to the amount of SO_2 and NO_2 that is converted to particulate. This approach is an over-simplification of a complex process; nevertheless, given the stringency of the PM10 standards, staff believes this issue needs to be addressed.

Staff, as part of their cumulative modeling analysis, quantified the potential secondary PM10 impacts from the three power projects in the area currently before the Commission for licensing: La Paloma, Sunrise and Elk Hills. For NO_x to nitrate formation, staff assumed a conversion rate of 33% over a time span of 18 to 24 hours. For oxides of sulfur to sulfate formation, staff assumed a conversion rate of 50% over 8 hours. These conversion rates can be input into the ISCST3 model to predict possible nitrate and sulfate PM10 impacts. The combined three-project nitrate impact was predicted to be approximately 1$\mu g/m^3$, located about 50 miles to the northeast of the

projects' sites. The combined sulfate impacts would be approximately 0.1$\mu g/m^3$, located about 30 miles to the northeast. Based on these results Staff concludes that the Sunrise project NO_x and SO_x emissions do have the potential to contribute to secondary PM10 levels in the region if left unmitigated.

Environmental Justice Impacts

In this section staff will discuss the potential impacts regarding air quality related environmental justice issues. This section is not intended to provide a definitive analysis on environmental justice impacts in general, but only addresses those concerns related to air quality. Conclusions reached here are limited in scope to air quality impacts only.

Environmental Justice impacts are determined based in principle on the idea that low income and minority populations may be exposed to a higher portion of pollution due to their proximity to light or heavy industry as compared to affluent or non-minority populations. In determining if there is such an impact, staff must first determine where, if anywhere, low income or minority population exist and at what demographic concentrations. Concentrations of low income or minority populations at greater than 50% within a contiguous community would designate that community as an Environmental Justice Population (EJ-Population). Once an EJ-Population has been identified within six miles of the proposed site, then the direct air quality impact (excluding ozone and secondary PM10 impacts) on that EJ-Population must be compared with the impacts on non-Environmental Population (NEJ-Population) that is within six miles. If the impact on the EJ-Population is significant (by itself) and significantly higher than that on the NEJ-Population, then staff must conclude that there is a potential for an Environmental Justice Impact (EJ-Impact) if the emissions are left unmitigated.

The census data that the staff relies on to analyze minority and low-income population concentrations in the Sunrise area are inconclusive. Specifically, the citizens of the nearby town of Derby Acres did not respond in sufficient numbers to the census inquiry to enable staff to determination if they are an EJ-Population. Staff therefore drove through Derby Acres to do an informal survey. From this survey staff concluded that there was a potential for Derby Acres to meet the definition of an EJ-Population. Therefore, staff finds it reasonable to conservatively presume that Derby Acres is an EJ-Population.

Derby Acres is located approximately 1.5 miles due north of the project site. The modeling analysis provided by the applicant indicates that the PM10 24-hour and annual impacts will be almost exclusively west and south of the project site (See Figure 8.1-6 and -7). The maximum PM10 impacts, as determined by ISCST3 modeling, are 4.01 ug/m^3 for the 24-hour averaging period and 0.22 ug/m^3 for the annual. The points of maximum impact are predicted to occur approximately 3 miles south of Derby Acres. Derby Acres is expected to receive PM10 concentrations of less than 0.5 ug/m^3 (24-hour) and 0.01 ug/m^3 (annual) from the Sunrise facility. This is compared with a background of 118 ug/m^3 and 42 ug/m^3 respectively.

From the modeling provided, it is staff's expectation that there is little or no potential that Derby Acres will be significantly impacted from primary PM10 emissions at the Sunrise facility. Therefore, staff concludes that there is no EJ-Impact on the Derby Acres community.

Mitigation Measures

Construction Mitigation

There are a series of District rules under Regulation 8 that limit fugitive dust during the construction phase of a project. Those rules require the use of chemical stabilizing agents and dust suppressants on gravel areas on site, and the wetting or covering of stored earth materials on site. They also encourage, although do not require, the use of paved access aprons, gravel strips, wheel washing or other means to limit mud or dirt carryout onto paved public roads. Because they are required by District rules, Sunrise will employ appropriate fugitive dust mitigation measures to limit their construction related PM10 emissions.

The simple cycle SPP included a construction condition that required the applicant to install and use oxidizing soot filters on suitable construction equipment. This is a fairly new requirement implemented by Staff to mitigate construction related PM10 emissions. This condition has been refined from one power plant project to the next as more information becomes available on soot filters and alternative fuels. The staff now incorporates an option for the applicant to use either oxidizing soot filters or 1996 CARB/EPA certified engines in conjunction with ultra-low sulfur diesel fuel. Sunrise has requested the latest version of this latter condition for Condition of Certification AQ-C2.

Operational Mitigation

SPP's air pollutant emissions impacts will be reduced by using emission control equipment on the project and by providing emission offsets. To reduce NO_x emissions, Sunrise proposes to use dry-low NO_x combustors in the CTGs. In addition, an ammonia injection grid will be used in conjunction with a Selective Catalytic Reduction system.

To reduce CO and VOC emissions, Sunrise proposes to use good combustion and maintenance practices. PM10 emissions will be limited by the use of a clean burning fuel (natural gas) and the efficient combustion process of the CTGs. The use of natural gas as the only fuel will limit SO_2 emissions.

Dry Low-NO_x Combustors

Over the last 20 years, combustion turbine manufacturers have focused their attention on limiting the NO_x formed during combustion. Because of the expense and efficiency losses due to steam or water injection in the combustor cans to reduce combustion temperatures and the formation of NO_x, CTG manufacturers are presently choosing to limit NO_x formation through the use of dry low-NO_x technologies. The GE version of the dry low-NO_x combustor is a four-stage ignition system. Initially the fuel/air mixture is ignited in two independent combustors (0% to 35% load). Then the startup sequence moves to a lean-lean operation (35% to 70% load) where the center burner is engaged as well. Then second stage burning is begun and all the fuel is directed to the center burner. The second stage burning is a transient event while proceeding to the premixed phase. Premixed operation (70% and 100% load) has fuel being pumped to all burners, but ignition only in the center burner.

In this process, firing temperatures remain somewhat low, thus minimizing NO_x formation, while thermal efficiencies remain high. At steady state CTG loads greater than 40 percent, NO_x concentrations entering the HRSG are 25 ppm corrected to 15 percent O_2. CO concentrations are more variable, with concentrations greater than 100 ppm at 50 percent load, dropping to 5 ppm at 100 percent load.

Selective Catalytic Reduction (SCR)

Sunrise is proposing to use selective catalytic reduction to control NO_x emissions from the HRSG. Selective catalytic reduction refers to a process that chemically reduces NO_x by injecting ammonia into the flue gas stream over a catalyst in the presence of oxygen. The process is termed selective because the ammonia reducing agent preferentially reacts with NO_x rather than oxygen, producing inert nitrogen and water vapor. The performance and effectiveness of SCR systems are related to operating temperatures, which may vary with catalyst designs.

Flue gas temperatures from a combustion turbine typically range from 950 to 1100°F. Catalysts generally operate between 600 to 750°F (ARB 1992), and are normally placed inside the HRSG where the flue gas temperature has cooled. At temperatures lower than 600°F, the ammonia reaction rate may start to decline, resulting in increasing ammonia emissions, called ammonia slip. At temperatures above about 800°F, depending on the type of material used in the catalyst, damage to some catalysts can occur. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or a noble metal are also used. These newer catalysts (versus the older alumina-based catalysts) are resistant to fuel sulfur fouling at temperatures below 770°F (EPRI 1990).

Regardless of the type of catalyst used, efficient conversion of NO_x to nitrogen and water vapor requires uniform mixing of ammonia into the exhaust gas stream. Also, the catalyst surface has to be large enough to ensure sufficient time for the reaction to take place.

Offsets

District Rule 2102, Section 4.2, requires that SCPC provide emission offsets, in the form of banked Emission Reduction Credits (ERC), for the project's emissions increases of NO_x, SO_2, VOC and PM10. Offsets for the project's CO emissions are not required since the project will not cause any violations of any CO standard and the area currently does not experience any violations of any CO standard.

AIR QUALITY Table 9
Offset Liability and Emission Reduction Credit Balance

	Offset Liability (tons/yr)	Emission Reduction Credits (ton/yr)[a]	Project Emissions not Offset (tons/yr)	Project Daily Emissions (lbs/day)	ERC Average Daily Offset[b] (lbs/day)	Daily Project Emission Exceedances (lbs/day)
NO_x	152.9	202.4	-49.5	766.1	1109.1	-343
SO_2	11.8	28.5	-16.7	74.4	156.4	-82
VOC	43.0	40.6	2.4	264.5	222.5	42
PM10	138.0	188.9	-50.8	854.4	1034.8	-180.4

[a] The annual ERC value is calculated by summing the ERC without considering the distance ratio normally applied by the District.
[B] The ERC Average Daily Offsets are calculated by summing the annual ERCs without considering the distance ratio normal apply by the District, then dividing by 365.

As AIR QUALITY Table 9 shows VOC emission reduction credits are exceeded on both an annual and daily basis. However, these exceedances are more than compensated for by the excess emission reductions for NOx on both an annual and daily basis. Since NOx and VOC are precursors to ozone formation and there are no exceedances of the NOx ambient air quality standards, it is staff's opinion that the excess VOC emissions are more reasonably compensated for.

CONCLUSIONS

Based on this analysis, we conclude that there are no significant air quality impacts associated with the proposed amendment changes. These changes are based on information not available during the siting proceedings. The proposed language retains the intent of the original Commission Decision and Conditions of Certification.

RECOMMENDED CHANGES TO THE CONDITIONS OF CERTIFICATION

AQ-C2 The Project owner shall require as a condition of its construction contracts that its contractors/subcontractors ensure that all heavy earthmoving equipment, that includes but is not limited to bulldozers, backhoes, compactors, loaders, motor graders and trenchers, and cranes, dump trucks and other heavy duty construction related trucks, have been properly maintained and the engines tuned to the engine manufacturer's specifications. ~~The Project owner shall further require as a condition of its construction contracts that all heavy construction equipment to the extent practical shall shut down during times of non-use that are expected to exceed 20 minutes.~~

Verification: The Project owner shall submit to the CPM, via the Monthly Compliance Report, documentation which demonstrates that the contractor's/subcontractor's heavy earthmoving equipment is properly maintained and that the engines are tuned to the manufacturer's specifications. The Project owner shall maintain construction contracts on the site for six months following the start of commercial operation.

~~**AQ-C3** The Project owner shall install oxidizing soot filters on all suitable construction equipment used either on the power plant construction site or on associated linear construction sites. Where the oxidizing soot filter is determined to be unsuitable, the owner shall install and use an oxidation catalyst. Suitability is to be determined by an independent California Licensed Mechanical Engineer who will stamp and submit for approval an initial and all subsequent Suitability Reports as necessary containing at a minimum the following:~~

~~**Initial Suitability Report**~~

~~A list of all fuel burning, construction related equipment used,~~
~~A determination of the suitability of each piece of equipment to firstly work~~
~~with an oxidizing soot filter,~~
~~A determination of the suitability of each piece of equipment to secondly work with an oxidation catalyst,~~
~~If a piece of equipment is determined to be unsuitable for an oxidizing soot~~
~~filter, an explanation by the independent California Licensed Mechanical Engineer as to the cause of this determination,~~
~~If a piece of equipment is determined to be unsuitable for both an oxidizing~~
~~soot filter and an oxidizing catalyst, an explanation by the independent California Licensed Mechanical Engineer as to the cause of this determination.~~

~~*Installation Report*~~

~~Following the installation of either the oxidizing soot filter or oxidizing catalyst as prescribed in the Initial Suitability Report, a California Licensed Mechanical Engineer will issue an Installation Report that either confirms that the installed device is functioning properly or that installation was not possible and the cause. The owner/operator shall attach to this report a~~

~~copy of receipts of purchase for the appropriate equipment and payment for labor to install, if applicable.~~

~~**Subsequent Suitability Reports**~~
~~If a piece of construction equipment is subsequently determined to be unsuitable for an oxidizing soot filter or oxidizing catalyst after such installation has occurred, the filter or catalyst may be removed immediately. However, notification must be sent to the CPM for approval containing an explanation for the change in suitability within 10 days. Changes in suitability are restricted to the following three explanations that must be identified in any subsequent suitability report. Changes in suitability may not be based on the use of high-pressure fuel injectors, timing retardation and/or reduced idle time.~~

~~1.The filter or catalyst is reducing normal availability of the construction equipment due to increased downtime, and/or power output due to increased back pressure by 20% or more.~~
~~2.The filter or catalyst is causing or reasonably expected to cause significant damage to the construction equipment engine.~~
~~3.The filter or catalyst is causing or reasonably expected to cause a significant risk to nearby workers or the public.~~

~~**Verification:** The Project owner will submit to the CPM for approval, the initial suitability report stamped by an independent California Licensed Mechanical Engineer, 15 days prior to breaking ground on the Project site. The Project owner will submit to the CPM for approval, the installation report, stamped by an independent California Licensed Mechanical Engineer prior to the use of the identified construction equipment. The Project owner will submit to the CPM for approval, subsequent suitability reports as required, stamped by an independent California Licensed Mechanical Engineer no later than 10 working days following a change in the suitability status of any construction equipment.~~

AQ-C3 The project owner shall mitigate, to the extent practical, construction related emission impacts from off-road, diesel-fired construction equipment. Available measures which may be used to mitigate construction impacts include the following:

- Catalyzed Diesel Particulate Filters (CDPF);
- Ultra-Low-Sulfur Diesel fuel, with a sulfur content of 15 ppm or less (ULSD);
- Diesel engines certified to EPA and CARB 1996 or newer off-road equipment emission standards.

Additionally, the project owner shall restrict idle time, to the extent practical, to no more than 10 minutes.

The use of each mitigation measure is to be determined in advance by a Construction Mitigation Manager (CMM), who will be available at the project site(s). The CMM must be approved by the CPM prior to the submission of any reports.

The CMM shall submit the following reports to the CPM for approval:

- Construction Mitigation Plan
- Reports of Change and Mitigation Implementation
- Reports of Emergency Termination of Mitigation, as necessary

Diesel Construction Equipment Mitigation Plan:

The Construction Mitigation Plan shall be submitted to the CPM for approval prior to rough grading on the project site, and must include the following:

1. A list of all diesel fueled, off-road, stationary or portable construction-related equipment to be used either on the project construction site or the construction sites of the related linear facilities. Equipment used less than a total of 10 consecutive days need not be included in this list.
2. Each piece of construction equipment listed under item (1) must demonstrate compliance with the following mitigation requirements:

Engine Size (BHP)	1996 CARB or EPA Certified Engine	Required Mitigation
< or =100	Yes or No	ULSD
>100	Yes	ULSD
>100	No	ULSD and CDPF, if suitable as determined by the CMM

3. If compliance can not be demonstrated as specified under item (2), then the project owner may appeal for relief to the CPM. However, the owner must demonstrate that they have made a good faith effort to comply as specified under item (2).

Report of Change and Mitigation Implementation

Following the initiation of construction activities, and if changes to mitigation measures are necessary, the CMM shall submit a Report of Change and Mitigation Implementation to the CPM for approval. This report must contain at a minimum the cause of any deviation from the Construction Mitigation Plan, and verification of any Construction Mitigation Plan measures that were implemented.

The following is acceptable proof of compliance, other methods of proof of compliance must be approved by the CPM.

1. EPA or CARB 1996 off-road equipment emission standards:
   a. A copy of the certificate from EPA or CARB.
2. Purchase and use of ultra-low-sulfur fuel (15 ppm or less).
   a. Receipt or other documentation indicating type and amount of fuel purchased, from whom, where delivered and on what date; and
   b. A copy of the text included in the contract agreement with all contractors and sub-contractors for use of the ultra-low-sulfur fuel in diesel burning construction equipment as identified in the Construction Mitigation Plan.
3. Installation of CDPF:
   a. The suitability of the use of CDPFs is to be determined by a qualified mechanic or engineer who must submit a report to the CPM for approval.
   b. Installation is to be verified by a qualified mechanic or engineer.
4. Construction equipment engine idle time:
   a. A copy of the text included in the contract agreement with all contractors and sub-contractors to keep engine idle time to 10 minutes or less to the extent practical.

Report of Emergency Termination of Mitigation

If a specific mitigation measure is determined to be detrimental to a piece of construction equipment or is determined to be causing significant delays in the construction schedule of the project or the associated linear facilities, the mitigation measure may be terminated immediately. However, notification containing an explanation for the cause of the termination must be sent to the CPM for approval. All such causes are restricted to one of the following justifications and must be identified in any Report of Emergency Termination of Mitigation.

1. The measure is excessively reducing normal availability of the construction equipment due to increased downtime for maintenance, and/or power output due to an excessive increase in back pressure.
2. The measure is causing or is reasonably expected to cause significant engine damage.
3. The measure is causing or is reasonably expected to cause a significant risk to nearby workers or the public.
4. Any other seriously detrimental cause which has approval by the CPM prior to the change being implemented.

Verification: The project owner will submit to the CPM for approval the qualifications of the CMM at least 15 days prior to the due date for the Diesel Construction Equipment Mitigation Plan. The project owner will submit the Diesel Construction Equipment Mitigation Plan to the CPM for

approval 30 calendar days prior to rough grading on the project site or start of construction on any associated linear facilities. The project owner will submit the Report of Change and Mitigation Implementation to the CPM for approval no later than 10 working days following the use of the specific construction equipment on either the project site or the associated linear facilities. The project owner will submit a Report of Emergency Termination of Mitigation to the CPM for approval, as required, no later than 10 working days following the termination of the identified mitigation measure. The CPM will monitor the approval of all reports submitted by the project owner in consultation with CARB, limiting the review time for any one report to no more than 20 working days.

SJVUAPCD Permit No. S-3746-1-~~0: 165 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-Nox COMBUSTORS~~ GENERAL ELECTRIC FRAME 7, MODEL PG724FA, NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRIC GENERATOR WITH DRY LOW NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION, OXIDATION CATALYST, AND STEAM TURBINE LISTED WITH S-3746-2 (585 MW TOTAL PLANT NOMINAL RATING).

SJVUAPCD Permit No. S-3746-2-~~0: 165 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATION SYSTEM #2 CONSISTING OF GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NoXCOMBUSTORS~~ GENERAL ELECTRIC FRAME 7, MODEL PG724FA, NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRIC GENERATOR WITH DRY LOW NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION, OXIDATION CATALYST, AND STEAM TURBINE LISTED WITH S-3746-2 (585 MW TOTAL PLANT NOMINAL RATING).

AQ-14 During startup or shutdown of any combustion turbine generator(s), combined emissions from the two CTGs (S-3746-1 and '-2) shall not exceed the following: Nox– ~~145.24~~700 lbs and CO – ~~364.86~~1580 lbs in any one-hour. [CEQA]

Verification: The Project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-15 Emission rates from each CTG, except during startup and shutdown events, shall not exceed any of the following:

PM10:	~~9.0~~17.8 lbs/hr
SOx (as So2):	~~3.85~~1.55 lbs/hr
NOx (as No2):	~~60.93~~15.96 lbs/hr and ~~9.0~~2.0 ppmvd @ 15% O2
VOC:	~~2.81~~5.51 lbs/hr and ~~1.3~~2.0 ppmvd @ 15% O2
CO:	~~29.14~~19.22 lbs/hr and ~~7.5~~4.0 ppmvd @ 15% O2

Ammonia: 10 ppmvd @ 15% O_2
NOx (as NO2) emission concentration limit is a one-hour rolling average. Ammonia emission concentration limit is a 24-hour rolling average. All other emission concentration limits are three-hour rolling averages [District Rules 2201, 4001, and 4703]

Protocol: Each one-hour period in a one-hour rolling average will commence on the hour. Each one-hour period in a 3-hour rolling average will commence on the hour. The 3-hour average will be compiled from the three most recent 1-hour periods. 24-hour average emissions will be compiled for a 24-hour period starting and ending at twelve-midnight. [District Rule 2201]

Verification: The Project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31.**

AQ-16 Emission rates from each CTG shall not exceed the following:

PM10:	~~158~~ 461.2 lbs/day
SOx (as So2):	~~64.17~~37.2 lbs/day
NOx (as No2):	~~1038.88~~1,170.9 lbs/day
VOC:	~~78.96~~220.6 lbs/day
CO:	~~792.24~~2,443.4 lbs/day

[District Rule 2201]

Protocol: Daily emissions will be compiled for a 24-hour period starting and ending at twelve-midnight. [District Rule 2201]

Verification: The Project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-17 Annual emissions from the CTG calculated on a twelve consecutive month rolling basis shall not exceed any of the following:

PM10:	~~34,292~~269,651 lbs/year
SOx (as So2):	~~13,222~~24,259 lbs/year
NOx (as No2):	~~215,060~~311,337 lbs/year
VOC:	~~16,718~~87,674 lbs/year
CO:	~~166,721~~507,978 lbs/year

[District Rule 2201]

Protocol: Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions total to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201]

Verification: The Project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-18 Prior to or upon startup of either S-3476-1~~-0~~ or '2~~-0~~, emission offsets shall be surrendered for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) in the following table at least 30 days prior to the commencement of construction.

	Quarter 1	Quarter 2	Quarter 3	Quarter 4
PM10	3,964	7,584	18,780	3,964
NOx (as NO2)	21,036	41,894	111,094	21,036

[District Rule 2201]

Prior to or upon startup of either S-3746-1~~-0~~ or '2~~-0~~, the following emissions offsets shall be provided to the District to provide additional environmental benefits during the initial phase of this Project and shall be used towards the offset requirements, if needed, when the next phase of this Project is implemented:

	Quarter 1	Quarter 2	Quarter 3	Quarter 4
PM10	67,364	64,647	51,763	69,001
SOx (as SO2)	14,075	14,231	14,387	14,387
NOx (as NO2)	67,207	0	18,105	26,538
VOC	13,949	14,104	14,259	14,259

Prior to or upon startup of either S-3746-1, '2 and '3, the following emissions offsets shall be provided to the District to provide additional environmental benefits during the initial phase of phase II of the Sunrise Project and shall be used towards the offset requirements:

	Quarter 1	Quarter 2	Quarter 3	Quarter 4
PM10	10,541	8,266	20,637	16,404
NOx (as NO2)	9,157	4,195	0	6,571
VOC	4,983	3,111	5,791	6,648

Verification: The Project owner shall provide copies of all the necessary ERC certificates to the CPM no later than 30 days prior to the commencement of construction.

AQ-44 The project owner shall submit selective catalytic reduction, oxidation catalyst and continuous emission monitor design details to the District and the CPM prior to commencement of construction. [District Rule 4102]

Verification: The Project owner shall provide the information identified in this condition no later than 30 prior to the commencement of construction of permanent structures on the project site.

AQ-45 The project owner shall equip the ammonia injection grid with an operational ammonia flowmeter and injection pressure indicator. [District Rule 2201]

Verification: The Project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-46 The project owner shall design the heat recovery steam generator to provide space for additional SCR and oxidation catalyst if required to meet NOx and CO emission limits. [District Rule 2201]

Verification: The Project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-47 The project owner shall monitor and record the exhaust gas temperature at the SCR and oxidation catalyst inlets. [District Rule 2201]

Verification: The Project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-48 The project owner shall inject ammonia into the SCR when the inlet temperature of the SCR exceeds 500 ^{o}F. The project owner shall monitor and record the SCR temperature during periods of startup. [District Rule 2201]

Verification: The Project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-49 No more than two hours after turbine initial firing, CTG exhaust emissions shall ot exceed any of the following:

NOx (as NO2): 10.3 ppmv @ 15% O_2
CO: 25. ppmv @ 15% O_2
[District Rule 4703]

Verification: The Project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-50 Emission rates from BOTH CTGs (S-3746-1 and '2), on days when a startup or shutdown occurs for either or both turbines, shall not exceed any of the following:

PM10:	922.3 lbs/day
SOx (as SO2):	74.4 lbs/day
NOx (as NO2):	2,341.8 lbs/day
VOC:	441.2 lbs/day
CO:	4,886.8 lbs/day

[District Rule 2201]

Verification: The Project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-51 The project owner shall demonstrate compliance with the ammonia slip level by using the following calculation procedure:

Ammonia Slip ppmv @ 15% O^2 = ((a-(bc/1,000,000)) x (1,000,000/b) x d

Where:

a = ammonia injection rate (lbs/hr)/17 (lb/lb mole)

b = dry exaust gas flow rate (lbs/hr)/29 (lb/lb mole)

c = change in measured NOx concentration ppmv @ 15% O^2 across the catalyst

d = correction factor.

Protocol: The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, the project owner may utilize a continuous in-stack ammonia monitor, acceptable to the District, to monitor for compliance.

[District Rule 4102]

Verification: If the project owner must submit a monitoring plan for District and CPM review at least 60 days prior to its use, if the owner chooses to utilize a continuous in-stack ammonia monitor. The Project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

S-3746-3: 137,000 GALLON/MINUTE COOLING TOWER WITH UP TO 10 CELLS AND HIGH EFFICIENCY DRIFT ELIMINATORS

AQ-52 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-53 The project owner shall submit drift eliminator design details and vendor specific emission justification for the correction factor to be used to correlate

blowdown TDS to drift TDS and the amount of drift that stays suspended in the atmosphere in the equation in **Condition AQ-58** to the District. [District Rule 2201]

Verification: 30 days prior to commencement of construction of the cooling towers, the project owner shall submit the information required above to the District and the CPM.

AQ-54 The project owner shall submit cooling tower design details including the cooling tower type and materials of construction to the District at least 30 days prior to commencement of construction, and at least 90 days before the tower is operated. [District Rule 7012]

Verification: 30 days prior to commencement of construction of the cooling towers, the project owner shall submit the information required above to the District and the CPM.

AQ-55 No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-56 Drift eliminator drift rate shall not exceed 0.0006%. [District Rule 2201]

Verification: The project owner shall submit documentation from the selected cooling tower vendor that verifies the drift efficiency to the CPM 30 days prior to commencement of construction of the cooling towers.

AQ-57 PM10 emission rate shall not exceed 15.78 lb/day. [District Rule 2201]

Verification: Please refer to **Condition AQ-58**.

AQ-58 Compliance with the PM10 daily emission limit shall demonstrated as follows: PM10 lb/day = circulating water recirculation rate * total dissolved solids concentration in the blowdown water * design drift rate * correction factor. [District Rule 2201]

Verification: The project owner shall compile the required daily PM10 emissions data and maintain the data for a period of five years. The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-59 Compliance with PM10 emission limit shall be determined by circulating water sample analysis by independent laboratory within 90 days of initial operation and weekly thereafter. [District Rule 1081]

Verification: The project owner shall compile the required daily PM10 emissions data and maintain the data for a period of five years. The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

Sunrise Power Project (98-AFC-4C)
Petition to Convert to Combined Cycle Operations
Biological Resources Staff Analysis
Prepared by Rick York

SETTING

Sunrise Power Company, LLC, (SPC) filed a petition on May 11, 2001 to convert of the existing Sunrise Power Project simple cycle peaking facility to combined cycle operation (aka "Sunrise II"). The existing Sunrise power plant is located in western Kern County approximately 35 miles southwest of Bakersfield, California.

In addition to expanding the power plant site, the proposed Sunrise II project includes the construction of a 15.5-mile water supply line from the West Kern Water District. Along the westernmost 2.5 miles of the water supply pipeline, a wastewater discharge line (approved under a separate amendment petition) and four of six deep injection wells (the first two were approved under a separate amendment petition) also will be constructed for wastewater disposal. These linear facilities are expected to cross approximately 30 unnamed "blue line" intermittent drainages. In addition, the project will also require the addition of two new transmission line towers and conductors for an additional 800 feet of new transmission line. Parts of the proposed project have the potential to affect several state and federally protected species and their habitats.

APPLICABLE LAWS, ORDINANCES, REGULATIONS, and STANDARDS (LORS)

The LORS referenced in the Final Staff Assessments (October 1999; October 2000) and the Commission Decision (December 2000) are applicable to this proposed amendment, and there are no additional LORS.

ANALYSIS

As with the Sunrise simple-cycle power plant, the Sunrise II project will be located in an area with a wide variety of sensitive biological resources, i.e. state and federally-protected species, that will need to be avoided as much as possible during project construction. In addition, temporary and permanent habitat impacts will require habitat compensation mitigation.

The following two tables identify the sensitive species found in the project area during spring 2001, biological resource field surveys.

Sensitive Plants	**Status***
Hoover's woolly star (*Eriastrum hooveri*)	FT, CNPS List 1B
Oil neststraw (*Stylocline citroleum*)	CNPS List 1B
Cottony buckwheat (*Eriogonum gossypinum*)	CNPS List 1B

* **Status legend**: **FT** = Federal Threatened, **CNPS List 1B** = California Native Plant Society (CNPS) Inventory of Rare and Endangered Vascular Plants of California – Plants Rare and Endangered in California and Elsewhere.

Sensitive Wildlife	**Status***
San Joaquin kit fox (*Vulpes macrotis mutica*)	FE/ST
Blunt-nosed leopard lizard (*Gambelia sila*)	FE/SE/SFP
Giant kangaroo rat (*Dipodomys ingens*)	FE/SE
Potential listed fairy shrimp (*Branchinecta* & *Lepidurus*)	FE/FT
San Joaquin antelope squirrel (*Ammospermophilus nelsoni*)	ST
American badger (*Taxidea taxus*)	SSC
Burrowing owl (*Athene cunicularia*)	SSC
Loggerhead shrike (*Lanius ludovicianus*)	SSC
LeConte's thrasher (*Toxostoma lecontei macmillanorum*)	SSC
Short-nosed kangaroo rat (*Dipodomys nitratoides brevinanus*)	SSC
Potential San Joaquin pocket mouse (*Perognathus inornatus*)	SSC

*** Status legend:** **FE** = Federal Endangered, **FT** = Federal Threatened, **SE** = State Endangered, **ST** = State Threatened, **SFP** = State Fully Protected, **SSC** = State Species of Special Concern.

The existing Sunrise simple-cycle power plant has already received a federal (USFWS) Biological Opinion, a state Incidental Take Permit and Streambed Alteration Agreement from the California Department of Fish and Game (CDFG), and developed and implemented a Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP). In addition, Sunrise Power Company has already provided the required habitat compensation funding to compensate for permanent and temporary impacts to sensitive species habitat.

The Sunrise II project will add a new 15.5-mile water supply pipeline and four new deep injection wells (in addition to the wastewater discharge pipeline and two injection wells that were previously analyzed in a previous amendment), all of which have the potential to affect state and federally protected species and their habitat. Therefore, the Sunrise II project owner will be required to acquire a new or amended:

- *Biological Opinion* from the USFWS;
- *Streambed Alteration Agreement* and *Incidental Take Permit* from CDFG; and
- *Nationwide Permit 12* from the U. S. Army Corps of Engineers.

In addition, the Sunrise II project will also be required to revise the existing Sunrise BRMIMP to address construction of the project's additional facilities so sensitive species and their habitats are avoided as much as possible. The Sunrise II project owner will also need to provide additional habitat compensation to address the Sunrise II project's temporary and permanent habitat impacts, as the project is expected to have temporary and permanent acreage impacts to state and federal sensitive species habitat. Some acreage impacts will occur on private lands, while other impacts will occur on federal lands managed by the Bureau of Land Management and the Department of Energy. The lands managed by the federal government are considered to be conserved lands since the federal government manages federal lands for resource development (e.g. oil development) as well as endangered species habitat that needs protection. Conserved lands (e. g. federal, state or privately owned protected areas) require a higher compensation ratio when temporarily and permanently impacted.

The following table identifies the Sunrise II project temporary and permanent, conserved, and private acreage impacts:

Facility	Private Permanent acres	Private Temporary acres	Conserved Permanent acres	Conserved Temporary acres
Power plant	4.8	7.0	0.0	0.0
15.5 mile water line	0.0	109.1	0.0	31.8
Four Injection wells	0.2	1.8	0.0	0.0
Totals	**5.0 acres**	**117.9 acres**	**0.0 acres**	**31.8 acres**

Compensation ratios are used to calculate the amount of compensation habitat that will be needed to compensate for the temporary and permanent loss of sensitive species habitat. The compensation ratio changes based upon the ownership (private, federal, or state) and whether the impacts are expected to be temporary or permanent. The California Department of Fish and Game and the U. S. Fish and Wildlife Service establish these compensation ratios, and they are consistent with the ratios used for past energy projects.

In the following table, compensation ratios are used to multiply the expected temporary and permanent acreage impacts to sensitive species habitat on private and conserved lands in western Kern County.

Duration of Impact/Ownership	Acreage Impacts	X	Compensation Ratio	=	Compensation Acreage
Permanent/conserved	0.0		4:1		0.0
Permanent/private	5.0		3:1		15.0
Temporary/conserved	31.8		2:1		66.8
Temporary/private	117.9		1.1:1		129.7
Totals	**154.7 acres**				**211.5 acres**

To be consistent with the habitat compensation strategy for the Sunrise simple-cycle project, the Sunrise Power Company shall provide the required habitat compensation funds to the Center for Natural Lands Management (CNLM), and CNLM will assume the responsibility of purchasing the habitat and establishing an endowment for perpetual care and management. The compensation acreage will be added to the existing Lokern Preserve located within the Lokern Natural Area of western Kern County.

The project owner will be required to contact CNLM to ascertain the final compensation funding in order for CNLM to assume the responsibility for purchasing the compensation habitat and establishing the perpetual endowment. The agreed-upon habitat compensation funds shall be provided to CNLM prior to the start of any ground disturbance activities related to the Sunrise II project.

CONCLUSIONS AND RECOMMENDATIONS

If the project owner agrees to abide by staff's recommended new and amended Conditions of Certification, then staff concludes that the proposed Sunrise II project will

be in compliance with all state, federal, and local laws, ordinances, regulations, and standards, and staff recommends approval of the proposed amendment.

The Sunrise II project shall abide by the current Conditions of Certification for the Sunrise project. Staff recommends that the following amended and new Conditions of Certification be required for the Sunrise II project. The condition numbering is consistent with the Decision for the Sunrise Power Project. **BIO-14** is included to correct a typographical error in Commission Order 01-0808-02 that approved the 2.5 mile wastewater discharge pipeline and two injection wells to serve the existing simple-cycle power plant and, if approved by the Commission, the combined-cycle plant. The Sunrise II project will require minor additions to the existing transmission line at the power plant site; therefore, the new transmission lines will be fitted with bird flight diverters as has been done for the Sunrise and La Paloma transmission lines; proposed **BIO-16** requires the installation of the bird flight diverters.

REVISIONS TO EXISTING CONDITIONS AND PROPOSED NEW CONDITIONS OF CERTIFICATION

Deleted text is shown in ~~strikethrough~~, added text is underlined.

Habitat Compensation for the 2.5 mile Wastewater Pipeline and Two Injection Wells

~~BIO 1~~ **BIO-14** To compensate for temporary and permanent impacts to sensitive wildlife habitat for the additional wastewater pipeline and injection well-related impacts, the project owner will contact the Center for Natural Lands Management (CNLM) so CNLM can calculate the amount of compensation funds that will be required for CNLM to assume responsibility for acquiring and protecting no less an additional 29.1 acres of compensation habitat as part of the Lokern Preserve.

Verification: Within ~~one (1) week~~ 60 (sixty) days of approval of the wastewater pipeline and injection well amendment, the project owner must provide written verification to the CPM that the required compensation funds have been provided to CNLM.

> Within 180 days after completion of project construction, the project owner shall provide the CPM aerial photographs taken after construction and an analysis of the amount of any additional habitat disturbance beyond that identified in the Energy Commission Final Staff Assessment. The CPM will notify the project owner of any additional funds required to compensate for any additional habitat disturbances at the adjusted market value at the time of construction to acquire and manage habitat.

Habitat Compensation for the Sunrise II 15.5 mile Water Supply Line and Four Injection Wells

BIO-15 To compensate for additional, Sunrise II-related temporary and permanent impacts to sensitive wildlife habitat, the project owner will consult the Center for Natural Lands Management (CNLM) so CNLM can calculate the amount of additional compensation funds that will be required from the Sunrise II project owner for CNLM to assume responsibility for acquiring and protecting no less than 211.5 acres of compensation habitat as part of the Lokern Preserve.

Verification: Within one (1) week of the Sunrise II project amendment approval , the project owner must provide written verification to the CPM that the required compensation funds have been provided to CNLM.

Within 180 days after completion of project construction, the project owner shall provide the CPM aerial photographs taken after construction and an analysis of the amount of any additional habitat disturbance beyond that identified in the Energy Commission Final Staff Assessment. The CPM will notify the project owner of any additional funds required to compensate for any additional habitat disturbances at the adjusted market value at the time of construction to acquire and manage habitat.

California Condor

BIO-16 During construction of the new Sunrise II and Sunrise Power Project transmission lines, the power plant owner will install USFWS-approved bird flight diverters on the new transmission line ground wire(s), including the new La Paloma transmission line ground wires if Sunrise links directly to that line at the La Paloma Generating project power plant. Bird flight diverters must be:

- installed per manufacturer's specifications;
- replaced when damaged or deemed defective; and
- maintained for the full length of the transmission line for the life of the facility.

Verification: No later than 10 days prior to energizing the new Sunrise transmission line (including the La Paloma transmission line if Sunrise links to that new transmission line), the project owner will provide photographic verification to the Energy Commission CPM that all required bird flight diverters have been installed, according to manufacturer's specifications, for the full length of the new transmission line.

No later than 10 days prior to energizing the new Sunrise II transmission line, the Sunrise II project owner will provide photographic verification to the CPM that all required bird flight diverters have been installed, according to manufacturer's specifications, for the Sunrise II project transmission line.

The project's final Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) will provide complete guidance regarding bird flight diverter installation and maintenance.

Federal Nationwide Permit #12

BIO-17 The Sunrise II project owner will acquire and implement the terms and conditions of an Army Corp of Engineers Nationwide Permit #12.

Verification: Fifteen (15) days prior to the start of any Sunrise II project-related ground disturbance activities, or a lesser time as mutually agreed upon by the project owner and the CPM, the project owner shall submit to the CPM a copy of the federal Nationwide Permit #12 from the U. S. Army Corp of Engineers. The terms and conditions of the Nationwide Permit #12 will be incorporated into the revised Biological Resources Mitigation Implementation and Monitoring Plan. See Condition of Certification **BIO-9**.

Sunrise Power Project (98-AFC-4C)
Petition to Convert to Combined Cycle Operations
Cultural Resources Staff Analysis
Prepared by Gary Reinoehl

BACKGROUND

The Sunrise Power Company is proposing to amend its existing project, a 320MW simple-cycle power plant in western Kern County approximately 35 miles southwest of Bakersfield, California. The new proposal is to add approximately 265 MW of nominal generating capacity to the existing simple-cycle Sunrise Power Project, resulting in a nominal 585 MW combined-cycle facility. New project features include an expansion of the project site and laydown areas, a 15.5 mile water supply line, and four new deep injection wells for wastewater disposal (these wells are in addition to the two injection wells previously approved by the Energy Commission as a separate project amendment).

APPLICABLE LAWS, ORDINANCES AND REGULATIONS AND STANDARDS (LORS)

The LORS listed in the Final Staff Assessment (October 2000) and the Energy Commission Decision (December 2000) are applicable to this amendment. There are no additional LORS.

ANALYSIS

Plant Site Area

The expansion of the power plant site was included within previously surveyed areas, and no cultural resources were identified within this area during the survey. Several isolated finds were reported during the grading of the plant site area during construction. None of the finds were considered to be eligible for the California Register of Historical Resources.

Water Supply Pipeline (Routes C, C', and E)

A cultural resource survey was conducted for the entire 15.5-mile water supply line and the alternate routes for the supply line (C, C' and E). Avoidance of cultural resources is the preferred mitigation. However, five cultural resources were identified for which avoidance does not appear to be a feasible alternative (four of the five resources are outside of the area of the injection wells).

Wastewater Injection Wells

A cultural resource survey was conducted for the four deep injection wells. Avoidance of cultural resources is the preferred mitigation. However, of the six cultural resources identified in the area of the injection wells, avoidance may not be possible a feasible alternative for two of the resources (one of the two resources are outside of the area of the water supply pipeline).

A new condition of certification (**CUL-19**) is proposed to ensure that the impact to these resources will be reduced to a less than significant level by requiring a series of actions. The first is to determine if the resource can be avoided and, if so, to identify the mitigation measures necessary to ensure the avoidance, such as fencing. If the resource can not be avoided, then the resource has to be evaluated to determine if it is eligible for the California Register of Historical Resources or for the National Register of Historic Places. If the resources are eligible for either of these lists, then mitigation measures will be implemented, such as data recovery, to reduce the impact to less than significant. Revisions to the Sunrise Power Project Cultural Resources Monitoring and Mitigation Plan (CRMMP) will be required to identify all the areas where avoidance measures and other mitigation measures will be necessary along the water supply pipeline and in the area of the injection wells. Proposed Condition of Certification **CUL-19** requires evaluation of cultural resources that can not be avoided, and the identification of mitigation measures to reduce the impact to a less than significant level. The existing Sunrise Power Project CRMMP (**CUL-3)**, shall be revised to include the new mitigation measure.

Existing Conditions of Certification **CUL-10** and **CUL-11** require that the project owner will comply with the permitting requirements of the Bureau of Land Management as the lead agency for the U.S. Department of Energy.

CONCLUSIONS AND RECOMMENDATIONS

The proposed combined-cycle amendment, along with the cultural resources supplemental information, describe the procedures that will be followed in order to reduce environmental impacts to cultural resources to a less than significant level. Identification of all cultural resources was not completed prior to filing the amendment petition; consequently, a new condition establishing a specific process, **CUL-19**, is proposed. Staff recommends that the amendment petition be approved with the addition of **CUL-19**.

PROPOSED NEW CONDITION OF CERTIFICATION

New text is underlined.

CUL-19 Prior to any ground disturbance along the water supply pipeline within 200 feet of P-15-006488, W-16, W-21, W-23, or W-26 or in the area of the deep injection wells within 200 feet of P-15-006488 or P-15-006327, the project owner shall complete the following:

If any of the aforementioned cultural resources can be avoided, then mitigation measures shall be implemented, if required, to assure the avoidance of the resources. If any of the aforementioned cultural resources can not be avoided, then an evaluation program shall be initiated by the Cultural Resource Specialist (CRS) and a report documenting the findings including recommendations as to the eligibility of the resource for the California Register of Historical Resources (CRHR) and the National Register of Historic Places (NRHP) shall be provided to the CPM and the Lead Federal Agency. The determination of eligibility to the CRHR will be made by the CPM and eligibility for

the NRHP will be made by the Lead Federal Agency. The evaluation report shall contain recommendations for mitigation measures.

If a resource is determined to be eligible for the CRHR by the Compliance Project Manager (CPM), then approved mitigation measures shall be implemented to lessen the impact to less than significant. If a resource is determined to be eligible for the NRHP by the Lead Federal Agency, then mitigation measures approved by the CPM and the lead federal agency shall be implemented that take into account impacts of the activity to historical properties.

A Native American monitor shall be retained when any ground disturbance activity conducted in the vicinity of a sensitive prehistoric cultural resource or during any archeological testing and data recovery efforts, should such activities be undertaken.

An addendum to the CRMMP shall be prepared that identifies all mitigation measures that will be utilized. All monitoring and mitigation measures and associated technical reports shall be incorporated into the CRR.

Verification: At least 30 days prior to ground disturbance along the water supply pipeline, the project owner shall provide to the CPM for review and approval, an addendum to the CRMMP that identifies all avoidance and monitoring measures being implemented to assure the protection of resources that can be avoided. At least 30 days prior to ground disturbance within 200 feet of P-15-006488, W-16, W-21, W-23, W-26 or P-15-006327, the project owner shall provide the CPM and BLM with a report for review and approval that evaluates any cultural resources that can not be avoided and recommends mitigation measures, and an addendum to the CRMMP that identifies any cultural resources within the impact area and incorporates all mitigation measures necessary to ensure that the impacts to cultural resources will be less than significant. All technical reports not previously submitted to the CHRIS and SHPO shall be incorporated into the CRR.

Sunrise Power Project (98-AFC-4C)
Petition to Convert to Combined Cycle Operations
Facility Design Staff Analysis
Prepared by Shahab Khoshmashrab

BACKGROUND

On May 11, 2001, the California Energy Commission (Energy Commission) received an amendment to the Application for Certification (98-AFC-4C) from the Sunrise Power Company. This post certification amendment proposes to modify the previously licensed 320 MW simple-cycle Sunrise Power Project (SPP) to a nominally-rated 585 MW combined-cycle project (aka "Sunrise II").

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

If the modification to this project from a simple cycle to a combined cycle project is approved, no changes to the applicable LORS will result and the project will remain in compliance with all the applicable LORS.

ANALYSIS

The analysis associated with the original application has not changed as a result of the proposed modification from a simple cycle project to a combined cycle project except that some components have been added. These additional components are listed below:

- Two (2) duct-fired heat recovery steam generators (HRSGs);
- One (nominal) 265 MW steam turbine generator;
- New 230 kV equipment for the existing Sunrise and La Paloma switchyards;
- A wet cooling tower system;
- An anhydrous ammonia-type selective catalytic reduction (SCR) system;
- An oxidation catalyst system; and
- An anhydrous ammonia storage and handling system.

Additional changes resulting from the proposed modification involve the inclusion of the following:

- An approximately 15.5 mile water supply line from West Kern Water District (WKWD);
- An expanded construction laydown, and borrow area totaling approximately 7 acres within the previously surveyed area;
- Potential upgrades to the existing WKWD system to accommodate the additional combined-cycle water demand, and

- An additional four deep injection wells to be used as a wastewater disposal option.

As a result of the added project components, a revised list of major structures and equipment, Table 1, is provided in Condition of Certification **GEN-2**, below, that designates these new components and their associated structures.

Sunrise II, as a modification of the existing project, will be constructed on the same project site and will result in a minor expansion of the existing facility footprint to accommodate new facility components.

In addition, Sunrise II will utilize existing 230 kV Sunrise-La Paloma and La Paloma-Midway Transmission lines being constructed as part of the simple cycle project.

The above changes do not necessitate additional analysis or re-analysis of the project from an engineering perspective.

CONCLUSIONS AND RECOMMENDATIONS

The proposed modification from a simple-cycle to a combined-cycle power plant will not result in impacts on facility design. Staff recommends approval of this request and proposes the following changes to the existing Conditions of Certification.

PROPOSED CHANGES TO EXISTING CONDITIONS OF CERTIFICATION

Proposed changes include the addition of the new major structures and equipment to the list in Condition of Certification **GEN-2**, Table 1, below. Added text is underlined, deleted text is shown in ~~strikethrough~~.

GEN-2 The project owner shall furnish to the Energy Commission CPM and to the CBO a schedule of facility design submittals, a Master Drawing List, and a Master Specifications List. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see a list of major structures and equipment below). To facilitate audits by Energy Commission staff, the project owner shall provide designated packages to the CPM when requested.

Table 1: Major Structures and Equipment List

Quantity	Description	Size/Capacity*	Remarks
2	Combustion Turbine (CT).	164.2 MW.	Dry low No_X combustion control and starter package.
2	CT inlet filters.		Two-stage, media type.
2	Inlet air cooling systems.		Evaporative type.
2	Fuel gas scrubbers.	43.80 MMSCFD.	340 psig minimum inlet pressure.
2	Fuel gas heat exchangers	1.4 million gal.	To feed water pumps.
2	CTG stacks		
2	Demineralized water transfer pumps		
1	Demineralized water storage tank.		
1	Wastewater collection basin		
2	Wastewater transfer pumps		
2	Generator transformers		
~~2~~ 4	Auxiliary transformers		
2	CEMS buildings		
2	Generator enclosure.		
2	Generator breakers.		
2	Step-up transformers.		
1	Common services building		
1	Switchyard, buses and towers.		
1	Feedwater storage tank.		
1	Electrical/equipment building.		
~~1~~	~~Wastewater collection basin~~		
1	Switchyard control building (Sunrise).		
1	Common Service Building.		
1	Hydrogen storage tank		
~~2~~ 4	Secondary Unit Substation (SUS) transformers		
2	Continuous emission monitoring buildings		
2	Closed cooling water pumps		
2	Closed cooling water heat exchangers		
1	Steam Turbine Generator (STG) With Pedestal		
2	Heat Recovery Steam Generators (HRSG)		
2	HRSG stacks		
2	Selective Catalytic Reduction (SCR) and skid		
1	Anhydrous ammonia storage tank		
2	Ammonia injection skid		
2	Oxidation catalysts		
1	Cooling Tower		
1	Deaerating surface condenser		
4	HRSG feedwater pumps		
2	Condensate pumps		
1	Wastewater sump		
1	ST Excitation Transfer		
1	Water treatment building		
1	Circulating water chemical feed		

	building		
2	HRSG I/O buildings		
2	Tubular Steel Transmission Pole		
1	HRSG & STG Pipe racks		
1	CW Electrical building		
1	STG Electrical building		

*All capacities and dimensions are approximate and may change during project final design**.**

Verification: At least 60 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading, the project owner shall submit the schedule, the Master Drawing List, and the Master Specifications List to the CBO and to the CPM. The project owner shall provide schedule updates in the Monthly Compliance Report.

REFERENCE

Sunrise II (Sunrise II Power Project). 2001a. Amendment to Application for Certification for the Sunrise Power Project (98-AFC-4). Submitted to the California Energy Commission, May 11, 2001.

Sunrise Power Project (98-AFC-4C)
Petition to Convert to Combined-Cycle Operations
Hazardous Materials Management
Prepared by Rick Tyler

BACKGROUND

Staff previously analyzed anhydrous ammonia use proposed for the Sunrise congeneration/combined-cycle project (98-AFC-4). Staff concluded that use of this material in the manner proposed did not pose a significant potential for impacts due to an accidental release. Subsequent to this analysis, the project proposal was amended to a simple-cycle process to expedite the project's completion date allowing the plant to be on-line earlier to address pressing energy needs in California this summer. The simple-cycle plant did not require SCR or use of ammonia.

The proposed combined-cycle power plant will require the use of SCR to control air emissions. As a result, combined-cycle operations also require the use of anhydrous ammonia as originally proposed and analyzed in the original AFC.

APPLICABLE LAWS, ORDINANCES AND REGULATIONS AND STANDARDS (LORS)

There are no new LORS associated with this amendment not considered staff's original analysis of the Sunrise combined cycle project.

ANALYSIS

Staff's previous analysis of the original Sunrise cogen/combined-cycle project remains valid and indicates no significant potential for impact. Staff recommends adoption of HAZ-2, as proposed in the previous analysis of the original Sunrise Power Plant cogen/combined-cycle project.

PROPOSED MITIGATION MEASURE AND NEW CONDITION OF CERTIFICATION

New text is shown in underline.

HAZ-2 The project owner shall provide a Risk Management Plan / Process Safety Management plan to the Kern County Environmental Health Department for review and comment, and to the CPM for review, at the time the plans are first submitted to the U.S. Environmental Protection Agency (EPA) and the California Occupational Safety and Health Administration (Cal OSHA). The project owner shall also reflect all recommendations of the Kern County Environmental Health Department and the CPM in the final plans. A copy of the final plans, reflecting all comments, shall be provided to the Kern County Environmental Health Department and the CPM.

***Verification**:* At least sixty (60) days prior to delivery of anhydrous ammonia to the facility , the project owner shall provide the final plans listed above to the CPM for approval.

Sunrise Power Project (98-AFC-4C)
Petition to Convert to Combined Cycle Operations
Land Use Staff Analysis
Prepared by Amanda Stennick

BACKGROUND

This assessment of land use impacts of the Sunrise Power Co. (SPC) May 11, 2001 petition to convert from simple cycle to combined cycle operations ("Sunrise II") for the Sunrise Power Project focuses on the conformity of the project with local land use plans, ordinances and policies, and the potential of the proposed project to have land use impacts with existing and planned uses.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Kern County General Plan

The general plan is the legal document that acts as a constitution for land use and development in Kern County. It consists of the seven mandatory elements: land use, circulation, open space, conservation, housing, safety and seismic safety, and noise; and four optional elements: recreation, energy, hazardous waste management, and public services and facilities. The following land use designations of the Kern County General Plan are specific to the proposed project.

Land Use Designations

Nonjurisdictional Land
State and Federal Land. All property under the ownership and control of various state and federal agencies.

Resource

Intensive Agriculture
Applies to areas devoted to the production of irrigated crops or having the potential for such use. Other agricultural uses may be consistent with the intensive agriculture designation. Minimum parcel size is 20 acres gross. Permitted uses include, but are not limited to:

- Primary: irrigated cropland, orchards, vineyards, ranch and farm facilities, etc.; one single-family dwelling unit.
- Compatible: livestock grazing, water storage, mineral and petroleum exploration and extraction, and public utility uses, etc., pursuant to provisions of the Zoning Ordinance.

Extensive Agriculture
Applies to agricultural uses involving large amounts of land with relatively low value-per-acre yields. Minimum parcel size is 80 acres gross, except lands not under Williamson Act Contract, in which case the minimum parcel size shall be 20 acres gross. Permitted uses include, but are not limited to:

- Primary: livestock grazing, dry land farming, ranching facilities, wildlife and botanical preserves, timber harvesting, etc.; one single-family dwelling unit.
- Compatible: irrigated croplands, water storage or ground water extraction, recharge areas, mineral, aggregate, and petroleum exploration, recreational activities, etc.

Mineral and Petroleum
Applies to area, which contains producing, or potentially productive, petroleum fields and mineral deposits. Uses are limited to activities directly associated with resource extraction. Minimum parcel size is 5 acres gross. Permitted uses include, but are not limited to:

- Primary: mineral and petroleum exploration and extraction.
- Compatible: extensive and intensive agriculture, mineral and petroleum processing, pipelines, power transmission facilities, communication facilities, equipment storage yards, and one single-family dwelling unit (subject to a Conditional Use Permit).

Solid Waste Facilities
Includes existing or planned public, semi-public, or private solid waste facilities. Permitted uses include, but are not limited to the following:

- Primary: Sanitary landfills, large volume transfer stations, waste-to-energy facilities, and non-hazardous oily waste disposal fields.
- Compatible: Small volume transfer stations and septic disposal fields.

Physical Constraints
Includes overlay zones denoting physical constraints. Those applicable include:

- Seismic Hazard: Includes the Alquist-Priolo Special Study Zone and other active fault zones.
- Flood Hazard: Based on the Flood Hazard Boundary Maps of the US Department of Housing and Urban Development and the Kern County Water Agency. These areas include, for example, flood channels and watercourses, riverbeds, and gullies. Development within these areas is subject to review by the County and will include conformity with adopted ordinances.

Special Treatment Areas
Areas within the county where localized issues, problems, and opportunities require specific treatment to ensure that solutions to problems or realization of opportunities reflects the needs of local residents.

Specific Plan Required
A land use designation used to identify areas in which large-scale projects are pending which will require detailed site-specific planning.

Land Use Plans and Policies Related to The Sunrise Cogeneration and Power Plant

The following provisions of the Kern County General Plan are specific to the proposed project.

Nonjurisdictional Land

- Coordination and cooperation will be promoted among the County, the incorporated cities and the various special districts where their planning decisions and actions affect more than a single jurisdiction (Policy No. 1).
- Land under state and federal jurisdiction will be considered as land designated for "Resource Management" on the General Plan map (Policy No. 4).

Physical Constraints

- Kern County will not permit new developments to be sited on land that is environmentally unsound to support such development (Policy No. 1).
- Development will not be allowed in natural hazard areas, pending the adoption of ordinances that establish conditions, criteria and standards in order to minimize risk to life and property posed by those risks (Policy No. 2).
- Zoning and other land use controls will be used to regulate and, in some instances, to prohibit development in hazardous areas (Policy No. 3).
- New development will not be permitted in areas of landslide or slope instability as designated in the Safety and Seismic Safety Element of the General Plan, and as mapped on the Kern County Seismic Hazard Atlas (Policy No. 6).
- Regardless of percentage of slope, development on hillsides will be sited in the least obtrusive fashion, thereby minimizing the extent of topographic alteration required (Nonjurisdictional Land - Policy No. 1, p. 1 - Policy no. 9)
- Development proposed in areas with steep slopes will be reviewed for conformity to the adopted Hillside Development Ordinance to ensure that appropriate stability, drainage, and sewage treatment will result (Policy No. 10).
- Designated flood channels and watercourses, such as creeks, gullies, and riverbeds, will be preserved as resource management areas or, in the case of the urban areas, as linear parks (Policy No. 12).
- New development will be required to demonstrate the availability of adequate fire protection and suppression facilities (Policy No. 13).
- Kern County will evaluate the potential noise impacts of any development-siting action or of any applications it acts upon that could significantly alter noise levels in the community and will require mitigative measures where significant adverse effects are identified (Policy No. 14).
- The air quality effects of a proposed land use will be considered when evaluating development proposals (Policy No. 15).
- Kern County will disapprove projects found to have significant adverse effects on Kern County's air quality, unless the Board of Supervisors, Board of Zoning Adjustment, or the Director of Planning and Development Services, acting as Hearing Officer or Parcel Map Advisory Agency makes findings under CEQA (Policy No. 16).

Resource

- Areas designated agricultural use, which include Class I and II agricultural soils with surface water delivery systems, will be protected against residential and commercial subdivision and development activities (Policy No. 1).
- Areas identified by the Soil Conservation Service as having high range-site value will be reserved for extensive agricultural use, or as resource reserves if located within a County water district (Policy No. 2).
- In areas with a Resource designation on the General Plan map, only industrial activities which directly and obviously relate to the exploration, production, and transportation of the particular resource will be considered to be consistent with this plan (Policy No. 4).
- Development will be constrained, pending adoption of ordinances which establish conditions, criteria, and standards, in areas containing valuable resources in order to protect the access to and economic use of these resources (Policy No. 9).
- Agriculture and other resources will be considered a compatible use in areas designated for Mineral and Petroleum Resource uses on the General Plan until such time as the oil activities become too intensive to enable other resource uses to continue (Policy No. 10).
- Rivers and streams in the County are important visual and recreational resources and wildlife habitats. Areas of riparian vegetation along rivers and streams, will therefore, be preserved when feasible to do so (Policy No. 11).
- The County will maintain and enhance air quality for the health and well-being of County residents by encouraging land uses which promote air quality and good visibility (Policy No. 13).
- Habitats of threatened or endangered species should be protected to the greatest extent possible (Policy No. 14).
- Areas designated as Resource Reserve, Extensive Agriculture, and Resource Management which are presently under Williamson Act Contracts will have a minimum parcel size of 80 acres until such time as a contract expires or is canceled, at which time the minimum parcel size will become 20 acres (Policy No. 15).
- The County will encourage development of alternative energy sources by tailoring its Zoning and Subdivision Ordinances and building standards to reflect Alternative Energy Guidelines published by the California State Energy Commission (Policy No. 17).

General Provisions

- Prior to issuance of any development or use permit, the County shall make the finding, based on information provided by California Environmental Quality Act (CEQA) documents, staff analysis, and the applicant, that adequate public or private services and resources are available to serve the proposed development. The developer shall assume full responsibility for costs incurred in service extensions or improvements that are required as a result of the proposed project (Policy No. 3).

- The air quality implications of new development will be considered in approval of major developments or area wide land use designations (Policy No. 15).

- The County will promote the preservation of designated historic buildings and the protection of cultural resources which provide ties with the past and constitute a heritage value to residents and visitors (Policy No. 16).
- Maintain the County's inventory of areas of potential cultural and archaeological significance (Implementation G).

KERN COUNTY ZONING CODE

The Kern County Zoning Ordinance was adopted in July 1997. The ordinance implements the Kern County General Plan by applying development standards and construction requirements on land as it is developed within the unincorporated areas of the county. The following divisions of the Kern County Zoning Ordinance apply to the project.

Zoning Districts

Exclusive Agriculture (A)

Areas that are suitable for agricultural uses. This designation is designed to prevent the encroachment of incompatible uses onto agricultural lands and the premature conversion of such lands to non-agricultural uses. Permitted uses in the A District are limited primarily to agriculture and other activities compatible with agriculture.

Limited Agriculture (A-1)

Areas that are suitable for a combination of estate-type residential development, agricultural uses, and other compatible uses.

Floodplain Secondary Combining District (FPS)

Applied to those areas lying within Zones AO and AH, and Zone A1-A30 on the Flood Insurance Rate Maps (FIRM), but excluding the floodway on the Flood Boundary Floodway Maps (FBFM). Permitted uses in an FPS District are those uses permitted by the base district with which the FPS District is combined.

Natural Resource (NR)

Lands with this designation are productive or potentially productive petroleum, mineral, or timber resource areas; the designation is designed to prevent the encroachment of incompatible uses onto such lands. Uses in the "NR" District are limited to resource exploration, production and transportation, and to compatible activities.

Floodplain Combining District (FP)

Applied to those areas lying within Zone A on the Flood Insurance Rate Maps (FIRM). Permitted uses in an FP District are those uses permitted by the base district with which the FP District is combined.

Platted Lands (PL) District

The purpose of the PL District is to recognize legally existing lots within recorded subdivisions which had been rendered nonconforming with regard to minimum lot size requirements.

Residential Suburban (RS) Combining District

This district expands the number and type of permitted domestic agricultural uses within rural residential areas.

Mobilehome (MH) Combining District
This district provides for the installation of mobilehomes with or without foundations in agricultural, resource-related, and residential zoned areas.

ANALYSIS

Staff's analysis evaluates the proposed water line and expansion of the plant site and laydown area for consistency with the Kern County General Plan and conformity with the Kern County Zoning Ordinance.

Proposed Water Line Route
Please refer to Table 8.4-1 in the Sunrise II Amendment Petition for a list of existing land uses in the vicinity of the proposed water line route. The proposed route will traverse lands zoned A (Exclusive Agriculture), A-1 (Limited Agriculture), PL (Platted Lands), RS (Residential Suburban Combining District), FPS (Floodplain Secondary Combining District), FP (Floodplain Combining District), NR (Natural Resource District), and MH (Mobilehome Combining District). Under the Kern County Zoning Ordinance, utility lines, including water lines located in the A, A-1, NR, and PL districts are permitted by right, and require no discretionary permits from the county. The RS, FPS, FP, and MH districts are combining districts and are combined with either A, A-1, or PL districts along the proposed water line route. The uses allowed in all combining districts are in addition to the uses and regulations of the base district with which they are combined. Therefore, no discretionary permits will be required from the county for the proposed water lines in these districts.

Sunrise Power Co. proposes to obtain permission for use of the water line route from private and public landholders through purchase of rights-of-way and easements. Landowners along the proposed transmission corridors are listed in the Sunrise II Amendment. On May 31, 2001, Sunrise Power Co. submitted an Application for Transportation and Utility Systems and Facilities on Federal Lands (Standard Form 299) to the U.S. Bureau of Land Management and the U.S. Department of Energy requesting rights-of-way on BLM and DOE lands. Negotiations for rights-of-way are underway with the various private landowners affected by the project.

Staff has determined that the construction of the water line route is consistent with the Kern County General Plan, conforms with the Kern County Zoning Ordinance, and will not result in any significant land use impacts.

AGRICULTURAL RESOURCES

Information provided by the Sunrise Power Company states that no prime or unique farmland, as designated by the Natural Resources Conservation District will be crossed or taken out of production. In addition, no farmlands of statewide importance, as designated by the California Department of Conservation will be taken out of production. However, approximately 14 acres of irrigated farmland will be traversed by Route E. The lands referred to are under designated Intensive Agriculture and occur between

mileposts 11 and 15 of the water supply line. These lands will be temporarily disturbed during the Sunrise II water line construction and returned to their original condition following construction.

Site plan
Sunrise II will use the same twenty-five acre parcel that was created through a lot line adjustment in Sunrise 98-AFC-4 (Lot Line Adjustment 101-00, Certificate of Compliance filed in Kern County on December 4, 2000). The original project footprint will be modified to allow for a seven-acre expansion of the construction laydown area and a 4.8 acre expansion of the plant site. Please refer to Figure 2.1 in the Sunrise II Amendment petition for the proposed site arrangement.

Staff has determined that the expansion of the site and laydown area is consistent with the Kern County General Plan, conforms with the Kern County Zoning Ordinance, and will not result in any significant land use impacts.

CONCLUSIONS AND RECOMMENDATIONS

Energy Commission staff has determined that the project is consistent with the Kern County General Plan and Zoning Ordinance and will have no land use impacts that cannot be mitigated to a level below significance. Staff recommends the following revised and new conditions of certification be adopted for the Sunrise II Amendment. If staff's conditions of certification are implemented, the project will comply with all applicable laws, ordinances, regulations, standards, plans and policies.

To correct the record for **LAND USE-1,** staff has replaced the incorrect reference to Chapter 9.12 with the correct referrence to Chapter 19.12 of the Kern County Zoning Ordinance. No changes have been made to **LAND USE-2. LAND USE-3** is new and addresses the restoration of land temporarily disturbed during construction.

MITIGATION MEASURES AND CONDITIONS

LAND USE-1 Prior to the start of construction for Sunrise II, the project owner shall submit a site plan for the project to Kern County for their review and comment, and to the California Energy Commission Compliance Project Manager (CPM) for review and approval. The site plan shall comply with all applicable provisions of Chapters ~~9.12~~ 19.12, 19,86, and 19.82 of the Kern County Zoning Ordinance. The project owner shall provide a letter of comment from the Kern County Planning Director stating that the project is consistent with the provisions of the Kern County General Plan and Zoning Ordinance.

At least 60 days prior to the start of any ground disturbance related to construction for Sunrise II, the project owner shall submit a copy of the letter of comment from the Kern County Planning Director to the CPM for review and approval. The project owner shall submit any required revisions within 30 days of notification by the CPM.

LAND USE-2 Within 90 days of commencement of construction, the project owner shall deposit in trust the sum of $30,000 to be used for beautification (to include landscaping and/or lighting) in the community of Derby Acres. The money may be

received by Kern County or by Derby Acres community non-profit organization for the beautification in Derby Acres by the County in coordination with the community of Derby Acres. After a period of three years from the date of deposit, any sums and accrued interest not used for such beautification shall revert to the project owner.

Verification: Within 90 days following the commencement of construction, the project owner shall submit evidence that $30,000 has been placed in trust in accordance with the above Condition. The project owner shall include in routine compliance reports a description of the date, amount, and purpose of any disbursements from the trust when made available by the trustee.

LAND USE-3 Immediately following the restoration of the 14.3 acres of land disturbed for construction of the Sunrise II water line route, the project owner shall provide a letter from the owner of the property stating that the 14.3 acres have been restored to their condition prior to construction.

Verification: Within 30 days following the restoration of the 14.3 acres of land disturbed for construction of the Sunrise II water line route, the project owner shall submit a copy of the letter from the property owner to the CPM.

REFERENCES

Kern County General Plan, adopted March 1982. Revised March 1994.

Kern County Zoning Ordinance, July 1997.

Rickels, David. Senior Planner, Kern County Planning Department. Conversations with Amanda Stennick during May and June 2001.

SCPP(Sunrise Cogeneration and Power Project) 1998a. Application for Certification, Sunrise Cogeneration and Power Company (98-AFC-4). Submitted to the California Energy Commission, December 21, 1998.

Sunrise II – Amendment to Sunrise Power Project (98-AFC-4). Submitted to the California Energy Commission, May 11, 2001.

Sunrise II – Application for Transportation and utility Systems and Facilities on Federal Lands. Submitted to the California Energy Commission, May 2001.

Sunrise Power Project (98-AFC-4C)
Petition to Convert to Combined-Cycle Operations
Worker Safety and Fire Protection
Prepared by Rick Tyler

BACKGROUND

Staff previously analyzed proposed worker safety and fire protection practices for the Sunrise cogen/combined cycle project in the first Sunrise Application for Certification (98-AFC-4). Staff concluded that the proposed practices did not pose a significant potential for impacts and provided for compliance with applicable LORS. Subsequent to this analysis the project proposal was amended to simple cycle process to expedite the project's completion so that the plant could be on line earlier in response to energy needs in California in the summer of 2001.

APPLICABLE LAWS, ORDINANCES AND REGULATIONS AND STANDARDS (LORS)

There are no new LORS associated with this amendment not considered staff's original analysis of the Sunrise combined cycle project.

ANALYSIS

Staff's previous analysis of the original Sunrise combined-cycle project remains valid and indicates no significant potential for impact. However, the Kern County Fire Department (KCFD) has reassessed its needs between the approval of the simple cycle project and this amendment. The KCFD has requested that the applicant provide fire hydrants along the new water line to aid in control of brush fires in the area. It is the KCFD's belief that this additional mitigation will provide for improved fire protection for the Sunrise project and all other development in the area. At present, the KCFD spends an excessive amount of time controlling brush fires in the project area as a result of inadequate water supply to the area. It is staff's understanding that the Sunrise Power Company agrees with the KCFD's request with the provision of reimbursement. Therefore, staff has prepared an optional condition of certification that the Commission may approve in order to assure that the Sunrise Power Company provides the proposed fire protection improvements proposed by KCFD. SAFETY-4 also requires that the Sunrise Power Company be reimbursed for these improvements from its future local tax liability.

PROPOSED CONDITION OF CERTIFICATION

SAFETY-4 The Sunrise Power Company shall develop an agreement with the Kern County Fire Department to provide for fire hydrants as negotiated with the KCFD. The agreement shall also include a mechanism to provide for reimbursement of costs from future local tax liability.

Verification: At least sixty (60) days prior to operation of the facility , the project owner shall provide the final agreement listed above to the CPM for review and approval.

SUNRISE POWER PROJECT (98-AFC-4C)
Amendment to Convert from Simple to Combined Cycle Operation
Staff Analysis
Soil & Water Resources
Prepared by Richard Sapudar, Tim Landis,
Linda Bond, and James Schoonmaker

Setting and Proposed Amendment
This Staff Analysis is for a post-certification amendment to the Sunrise Power Project (SPP). The SPP is an existing 320 MW simple cycle power plant. The SPP was amended previously to include the disposal of the project's wastewater discharge through transfer to Texaco California, Inc. (TCI) for enhanced oil recovery (EOR) uses, or though direct well injection by Sunrise Power Company (SPC), which included the construction of a new 2.5 mile pipeline to the underground injection wells. The transfer of the wastewater to TCI for EOR uses allows the SPP's wastewater to be injected into the oil field as steam in accordance with the existing Class II injection well permit held by TCI. The simple-cycle EOR option and underground injection well wastewater disposal options were reviewed and approved by the Energy Commission under a separate petition. This staff analysis evaluates the conversion of the SPP from a simple cycle plant to a combined cycle design (Sunrise II). The proposed Sunrise II amendment will add approximately 265 MW nominal generating capacity to the existing simple cycle project, resulting in a nominal 585 MW combined cycle facility.
The current Sunrise Power Project was certified on December 6, 2000. The existing project includes:

- **320 MW natural gas-fired simple cycle peaking project using a 23-mile transmission line of 235 kV nominal voltage.**
- **2.5-mile pipeline to two underground injection wells (Amendment I-A).**
- **Original power plant footprint.**
- **The license for the SPP required the project owner to either convert to a combined cycle or co-generation facility or shut down by December 31, 2002.**

The primary modifications associated with the Sunrise II Amendment include the addition of:

- **Two duct-fired (natural gas only) heat recovery steam generators (HRSGs).**
- **One 265 MW (gross) steam turbine generator.**
- **Cooling tower and condenser for the steam turbine generator.**
- **Upgrades to existing West Kern Water District (WKWD) system, including new WKWD supply wells, to accommodate increased water demand.**
- **Approximately 15.5-mile water supply line from WKWD.**
- **Expanded laydown and borrow areas – approximately 7 acres within previously surveyed area.**
- **Expanded power plant footprint of 4.8 acres for additional facilities.**

- **Pipeline to Texaco Enhanced Oil Recovery Plant (TCI) and up to six deep injection wells to be used for wastewater disposal, which was approved by previous amendments. The injection wells are necessary for those times when TCI is not able to use all of the wastewater produced by the Sunrise II combined cycle plant.**

The amendment proposes to increase significantly the amount of water needed due to the proposed cooling tower. It also proposes that the waste effluent will be piped to the TCI facility and used in TCI's thermally enhanced oil recovery process (EOR). The amount of waste water that can be used is in question, as well as the reliability of the water supply for the life of the project. The sections below discuss potentially significant issues with LORS compliance and impacts from the Sunrise II Amendment. Specifically, staff recommends consideration of cooling alternatives and water conservation options to those proposed by the project owner. Revised and new Conditions of Certification (COC) are listed in the COC section below.

AMENDMENT FACILITY AND PROCESS DESCRIPTION

The following describes the proposed Sunrise ll amendment modifications.

Heat Recovery Steam Generators (HRSGs)

Conversion of the simple cycle power plant into a combined cycle power plant requires the addition of HRSGs and a steam turbine. These "boilers" will be located immediately downstream of the Combustion Turbine Generators (CTG), so that they recover heat from the exhaust gas of the CTGs. In addition, auxiliary burners are provided to heat the steam even further. The CTGs are fed water that is supplied by WKWD and purified using reverse osmosis (RO).

Steam Turbine and Condenser

The steam generated by the HRSGs is directed to the steam turbine or the steam turbine generator (STG). The steam turbine generates electricity and exhausts the spent low pressure steam to a condenser, where the condensed water is returned to the HRSGs and the cycle is repeated. The STG does not consume water.

Cooling Tower

The cooling tower is the primary consumer of water in the system. Cooling is accomplished by evaporation of water. Approximately 4400 acre feet per year (afy) of water will be used for cooling in the proposed mechanical draft cooling tower.

Cooling Tower Design and Blowdown

No details for the cooling tower design were included in the Sunrise II petition, such as performance under various conditions or designs. The information presented indicates a cooling tower, with the capability to provide condensing for 115 °F ambient, 15 percent relative humidity, and 240 MW STG output, and a permit requirement for 0.0006 percent drift.

The existing simple cycle plant uses 52 gallons per minute (gpm) or 84 afy of water for cooling of the CTG inlet air stream, and under 1 gpm water for washing of the CTGs

and sanitary facilities. Upon conversion to combined cycle operation, the cooling tower and other new facilities will increase this water consumption to approximately 2,755 gpm (4400 afy), of which 2,593 gpm (4120 afy or 94 percent) of the water supply is used for evaporative cooling and blowdown, and 84 gpm or 3 percent for HRSG feed water. The project has since revised the water supply needs to 3900 afy, although it is unclear whether the water balance supplied is based on 3900 afy or 4400 afy.
As cooling tower water evaporates it concentrates the chemical constituents in the remaining water. This must be gradually "blown down" to reduce the concentration of solids in the cooling tower circuit to levels that are not detrimental to the condenser. This blowdown is combined with other wastewater streams and directed to a pipeline that terminates either at the TCI facility, or if that is not available, then to six new deep injection wells.

WATER SUPPLY REQUIREMENTS

The conversion to a combined cycle operation requires a significant increase in the plant's water requirement from an average of 280 afy to an annual maximum of 3,900 afy (SPC, May 2001). Although there is some inconsistency in the flow rates provided by SPC both in the petition and in responses to staff data requests, SPC has confirmed that its maximum annual water requirement will be 3,900 afy (SPC, Supplement, 2001)., which staff has used in its analysis of water supply impacts.

GROUNDWATER AND SUPPLY WELLS

The project owner proposes to purchase water from the West Kern Water District (WKWD). The WKWD serves domestic and industrial customers over a large geographic area, covering approximately 250 square miles of western Kern County. WKWD has agreed to provide the water supply for the Sunrise II project from 5 existing deep wells and 3 new proposed wells, located approximately 17 miles north of Taft in the underflow area of the Kern River.

Applicable Laws, Ordinances, Regulations and Standards (LORS)

FEDERAL

Clean Water Act

The Clean Water Act (33 USC section 1257 et seq.) requires states to set standards to protect water quality. Point source discharges to surface water are regulated by this act through requirements set forth in a National Pollutant Discharge Elimination System (NPDES) Permit. Stormwater discharges during construction and operation of a facility also fall under this act and must be addressed through either a project specific or general NPDES permit. In California, the nine Regional Water Quality Control Boards (RWQCB) administer the requirements of the Clean Water Act. The project will require NPDES permits for stormwater discharges for both construction and operation.

Section 404 of the act regulates the discharge of dredged or fill material into waters of the United States, including rivers, streams and wetlands. The Army Corps of Engineers (ACOE) issues site-specific or general (nationwide) permits for such

discharges. The project will be required to obtain the required permit(s) for the various pipeline crossings (see the Biological Resources Section).

Section 401 of the Clean Water Act provides for state certification of federal permits allowing discharge of dredged or fill material into waters of the United States. These certifications are issued by the RWQCBs. For this project, any 401 certification or waiver required will be in conjunction with Waste Discharge Requirements (WDRs) or Section 404 requirements.

The Safe Drinking Water Act (SDWA) provides EPA the authority to control underground injection (SDWA, Part C, Sections 1421-1426). The disposal of the SPP wastewater through use of injection wells will be classified as either Class I or Class V injection wells. These injection wells are used to dispose of non-hazardous wastewater. The USEPA permits the construction and operation of all injection wells with the exception of those used for the disposal of oil and gas field related wastes (Class II wells). The direct injection of the wastewater by the project's owner requires a Class I/V Nonhazardous Underground Injection Control permit issued by the USEPA Region IX Ground Water Office. In order for such a permit to be granted, the wastewater must be determined to be nonhazardous under 40 CFR Section 262.11. As discussed below, the issuance of this permit by the USEPA requires a waiver of Waste Discharge Requirements from the Regional Water Quality Control Board. A Condition of Certification has been developed to address these activities.

STATE

Porter-Cologne Water Quality Control Act

The Porter-Cologne Water Quality Control Act of 1967, Water Code section 13000 et seq., requires the State Water Resources Control Board (SWRCB) and the nine RWQCBs to adopt water quality criteria to protect state waters. These criteria include the identification of beneficial uses, narrative and numerical water quality standards and implementation procedures. The criteria for the project area are contained in the Central Valley Region Water Quality Control Plan. This plan sets numerical and/or narrative water quality standards controlling the discharge of wastes with elevated temperature to the state's waters. These standards would be applied to the proposed project through the Waste Discharge Requirements (WDRs).

In order for the USEPA to issue a UIC permit for the disposal of the project's wastewater using injection wells, the CVRWQCB must issue a waiver of WDRs. Should the USEPA not issue a UIC permit for the injection wells, the CVRWQCB would then be required to issue WDRs for the construction and operation of the injection wells. A Condition of Certification has been developed to address these activities.

California Water Code

Section 13552.6 of the Water Code specifically identifies that the use of potable domestic water for cooling towers, if suitable recycled water is available, is an unreasonable use of water. The availability of recycled water is based upon a number of criteria, which must be taken into account by the SWRCB. These criteria are that: (1) the quality and quantity of the reclaimed water are suitable for the use; (2) the cost is reasonable; (3) the use is not detrimental to public health; (4) will not impact downstream users or biological resources, and; (5) and will not degrade water quality.

Section 13552.8 of the Water Code states that any public agency may require the use of recycled water in cooling towers if certain criteria are met. These criteria include that recycled water is available and meets the requirements set forth in section 13550; the use does not adversely affect any existing water right; and if there is public exposure to cooling tower mist using recycled water, appropriate mitigation or control is necessary.

Section 13260 of the Water Code requires all persons proposing to discharge waste that may affect the quality of waters of the State to submit a Report of Waste Discharge to the Regional Water Quality Control Board. The Central Valley Regional Water Quality Control Board (Fresno Office) requires that a Report of Waste Discharge (ROWD) that has been determined to be complete by the CVRWQCB be provided by the discharger (Sunrise II). The CVRWQCB will then either provide Waste Discharge Requirements (WDRs) or issue a waiver. The CVRWQCB will only issue such a waiver to the Sunrise II project if the injection wells are permitted by USEPA Region IX. Should the USEPA not issue the Nonhazardous Underground Injection Control permit for the injection wells, the CVRWQCB will issue WDRs for the project.

State Water Resources Control Board Policies

The SWRCB has also adopted a number of policies that provide guidelines for water quality protection. The principle policy of the SWRCB which addresses the specific siting of energy facilities is the Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Powerplant Cooling (adopted by the Board on June 19, 1976 by Resolution 75-58). This policy states that use of fresh inland waters should only be used for powerplant cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound. This SWRCB policy requires that power plant cooling water should come from, in order of priority: (1) wastewater being discharged to the ocean; (2) ocean water; (3) brackish water from natural sources or irrigation return flow; (4) inland waste waters of low total dissolved solids, and; (5) and other inland waters. This policy also addresses cooling water discharge prohibitions.

Impact Analysis

COOLING WATER ISSUES

The major use of water in the proposed Sunrise II power plant will be in the cooling tower, which will operate at 7 cycles of concentration. The water use will increase from 280 afy to 3900 afy due primarily to the cooling water needs. This represents a

significant increase in water use. Based on the information made available to staff in the petition and in responses to Staff Data Requests to analyze, the WKWD appears to be an uncertain water source for the projected 30-year operational life of this project. Due to this uncertainty, staff has discussed several options to reduce or eliminate water use for cooling. Dry cooling is one option that is commonly used throughout the United States and would reduce water needs to about 300 afy. See analysis of these issues below.

WATER SUPPLY

Sunrise II proposes to purchase water from the West Kern Water District (WKWD). WKWD has provided a Will-Serve letter, which agrees to provide the Sunrise Power Company with water, "subject to suitable financial arrangements, the construction of system upgrades…and acceptance of the system upgrades by the District… the District can and will provide ample water to the proposed project." (WKWD, letter to Lindell Blair, 3/22/2001). Although there are some inconsistencies in the flow rates described in the Will-Serve letter, the actual amount of water that WKWD has agreed to provide Sunrise in the Will-Serve letter is open-ended.

West Kern Water District

To evaluate the reliability of the water supply proposed for Sunrise II, Staff analyzed WKWD's existing and proposed water supply and demand.

HISTORIC WATER SUPPLY

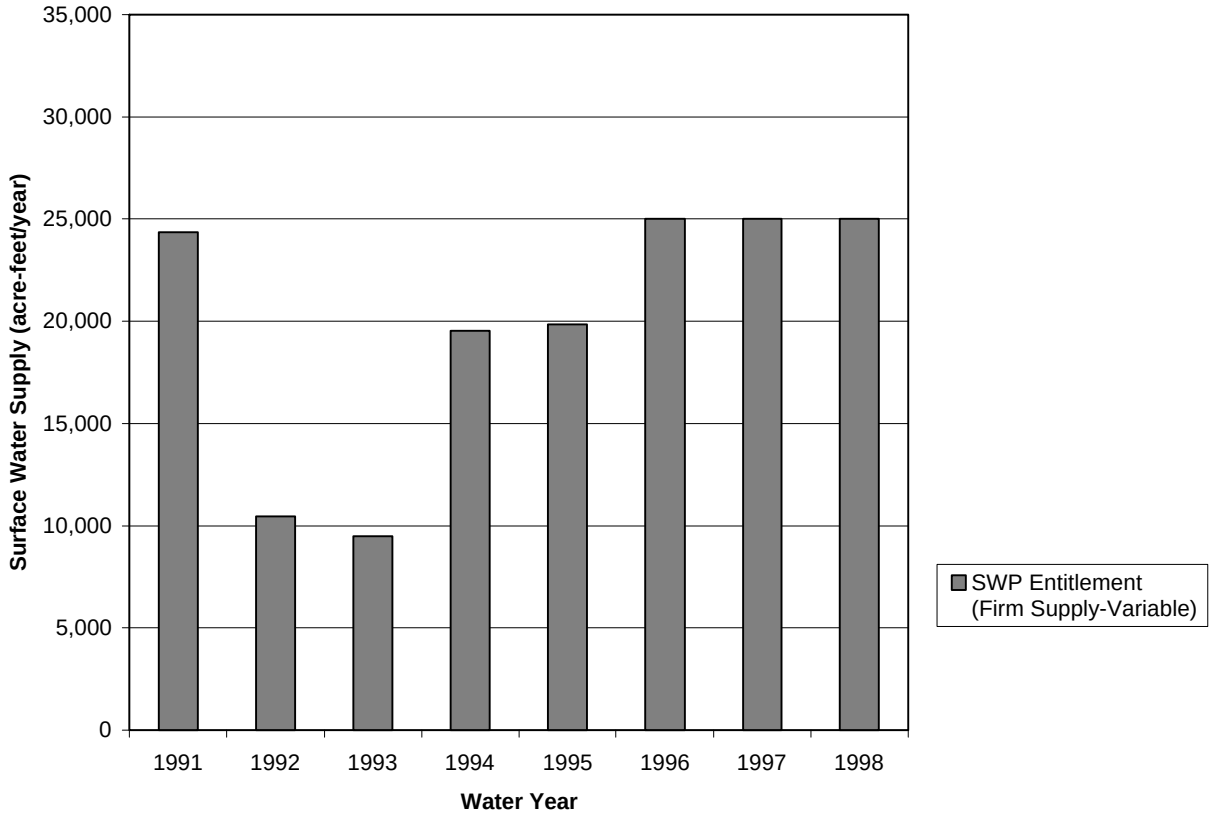
Annual Surface Water Entitlement and Groundwater Allocation

WKWD's firm water supply includes groundwater and surface water. WKWD has historical rights to pump 3,000 acre-feet of groundwater annually, which cannot be banked from year to year. WKWD contracted with the Kern County Water Agency (KCWA) in 1966 to obtain surface water through the State Water Project (KCWA and WKWD Contract, 1966). KCWA is a State Water Contractor and serves as a wholesaler to distribute water to 13 local water districts. WKWD holds an entitlement to purchase a maximum of 25,000 acre-feet of SWP water annually. However, the ability of the SWP to deliver water in a given year depends on each year's precipitation, water in storage, pumping capacity in the Delta and regulatory constraints (DWR, 1998). Historically, actual deliveries to WKWD by the SWP have averaged 80 percent (20,000 afy) of its maximum entitlement with a reported range of 9,500 afy to 25,000 afy (Figure 1). (Patrick, 8/14/2001)

WKWD has accessed its surface water through an in-lieu/groundwater exchange program with BVWSD. As described by SPC, WKWD and BVWSD established an Agreement for Banking and Recovered Water in 1983 whereby WKWD would deliver all of its SWP entitlement to BVWSD. In turn, BVWSD would inject WKWD's allotment of SWP water into the aquifer through its recharge program. The agreement allows WKWD to withdraw groundwater from the aquifer in an amount equal to 95 percent of the total amount injected. The total is reduced by 5 percent to account for evaporation.

For example, with a delivery of 20,000 acre-feet to BVWSD, 19,000 acre-feet would be credited to WKWD's groundwater supply. (SPC, Supplement, 2001)

Soil and Water Figure 1
West Kern Water District
State Water Project Entitlement - Annual Deliveries
(From Table 8.14-2 West Kern Water District Supply, SPC, May 2001)

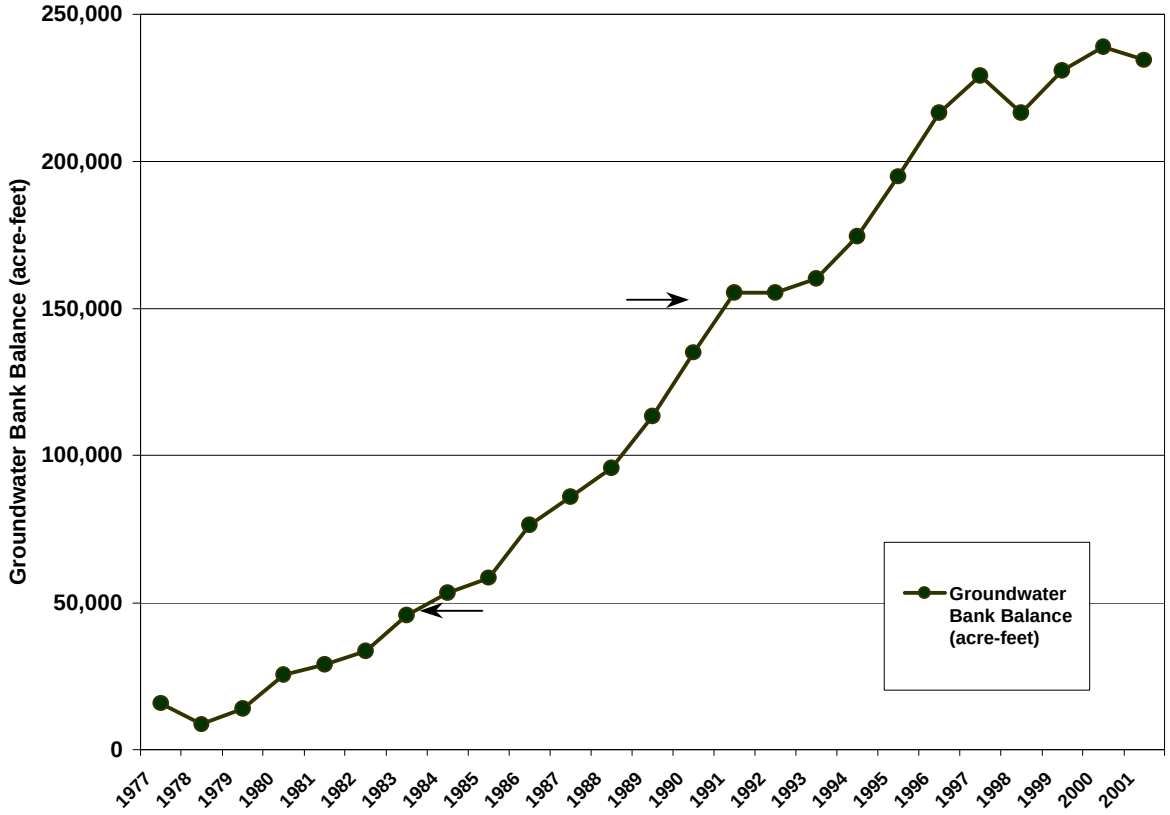


Therefore, based on the information provided by WKWD and SPC, WKWD has had a firm water supply that averages 22,000 acre-feet annually - 19,000 acre-feet (SWP Entitlement reduced by 5 %) through its in-lieu/groundwater exchange program plus 3,000 acre-feet through its annual groundwater allocation.

Banked Groundwater

Since 1976, WKWD has had a surplus of imported surface water. Historically, WKWD's groundwater pumping for water sales has been less than the amount of water it has recharged to the aquifer. For the period from water year 1977 through 2000, staff calculates that WKWD's net groundwater recharge averaged about 9,000 afy, based on data provided by SPC. WKWD has stored (or banked) much of its surface water supply within the groundwater basin. WKWD reports that it has banked a groundwater reserve of 234,521 acre-feet as of June 2001. Figure 2 shows the increase in WKWD's banked groundwater from water year 1977 through 2001. (SPC, Supplement, 2001)

Soil and Water Figure 2
West Kern Water District – Groundwater Bank History
(SPC, Supplement, 2001)
(Adapted from figure entitled WKWD Production and Groundwater Bank History)



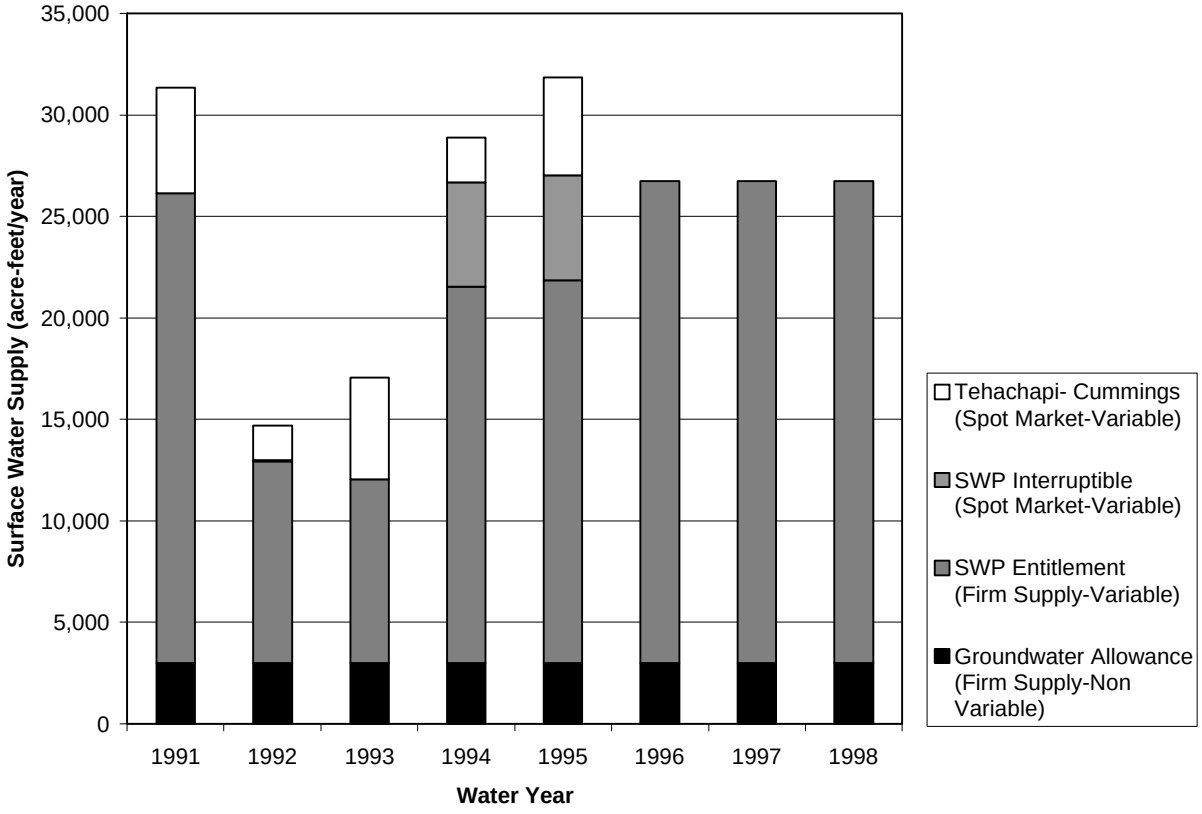
Additional Surface Water Purchases

In addition to its firm water supply, WKWD has also purchased additional surface water on the spot market (SPC, Supplement, 2001). WKWD has purchased additional water from 2 sources, the SWP's interruptible supply, which has been available during wet years, and from Tehachapi-Cummings. WKWD reported additional water purchases between 1990 and 1996, which averaged 5,140 afy and ranged from zero to 10,515 afy. (Patrick, 8/14/2001). This surface water supply was delivered to BVWSD, so, with 5 % deducted for evaporation, the actual increase in supply to WKWD from additional surface water purchases, has averaged 4,883 afy and ranged from zero to 9,989 acre-feet.

Summary of Historic Water Supply

To summarize WKWD water supply history, WKWD's total water supply from 1990 through 1996 averaged 25,100 afy and ranged from 14,700 acre-feet to 31,800 acre-feet, adjusted for evaporation (Figure 3).

Soil and Water Figure 3
West Kern Water District - Historic Water Supply
(adjusted for evaporations)
(From Table 8.14-2 West Kern Water District Supply, SPC, May 2001)



NEW WATER SUPPLY

BVWSD Contract Amendment

SPC has reported that WKWD has a new BVWSD water supply through an amendment to the WKWD/BVWSD water contract (SPC, Supplement, 2001). Last year, WKWD and BVWSD amended their Agreement for Banking and Recovered Water to allow WKWD to divert up to 6,500 afy of WKWD SWP Entitlement to the La Paloma Power Plant, rather than delivering the full allotment to BVWSD (WKWD, 7/26/2000). To compensate BVWSD, WKWD is required to either to deliver 6,500 afy of water purchased in addition to the SWP Entitlement water or to pay a water replacement fee. In exchange, BVWSD is required to supply 6,175 afy to WKWD in the form of additional groundwater pumping allotment from either injection of the new water delivery or a transfer of water allocation from BVWSD's banked groundwater account.

There are two possible conditions that could result from this new agreement. In the first case, if WKWD delivers additional surface water to BVWSD for injection, the new water will replace the SWP Entitlement water diversion to La Paloma. Staff notes that no firm water supply has been yet obtained by WKWD to provide this additional water to BVWSD. However, in the second case, if WKWD pays a water replacement fee, a "paper water transfer" will occur and the diverted water will not be replaced. In the latter case, although WKWD will receive an increase to its groundwater bank allotment, the diversion of WKWD SWP entitlement will result in a decrease of the actual amount of water annually recharged to the aquifer.

In either case, WKWD has obtained additional groundwater pumping rights through its new contract amendment with BVWSD. However, in the case of the water replacement fee and the paper water transfer, groundwater levels would be negatively impacted.

FUTURE WATER SUPPLY

The following two tables summarize WKWD projected water supply. The first table was provided by SPC (Table 1) (Supplement, 2001). The second table was prepared by staff and includes information on the status and variability for each water supply source (Table 2).

Soil and Water Table 1
West Kern Water District - Average Project Water Supply
(SPC, Supplement, 2001*)

	Annual Purchase (afy)	Annual Groundwater Supply (afy)	Annual Surface Water Supply (afy)
SWP Entitlement • Delivered to BVWSD for in lieu/groundwater exchange program • Delivered directly to La Paloma	20,000	12,825 6,500	
Historical groundwater supply allowance		3,000	
New BVWSD supply	6,500	6,175	
Historical interruptible surface water supply purchases	5,140	4,883	
New Interruptible purchase	900	855	
SUBTOTALS	**32,540**	**27,738**	**6,500**
TOTAL AVERAGE PROJECTED WATER SUPPLY		**34,238**	

Note: Original table entitled: Summary of WKWD Water Balance (SPC, Supplement, 2001)

Soil and Water Table 2
West Kern Water District - Average Project Water Supply
With Staff Comments
(Adapted from SPC, Supplement, 2001)

	Annual Surface Water Purchase (afy)	Annual Groundwater Supply (afy)	Annual Surface Water Supply (afy)
Firm Supply (Variable)			
SWP Entitlement=20,000 afy • Delivered to BVWSD for in-lieu/groundwater exchange program • Delivered directly to La Paloma	13,500 6,500	12,825	6,500
Firm Supply (Non-Variable)			
Historical groundwater supply allowance		3,000	
SUBTOTAL-FIRM WATER		**15,825**	**6,500**
New BVWSD supply (Contract Amendment)			
• Groundwater bank transfer (WKWD pays water replacement fee) ***OR*** Surface water purchased on spot market and delivered to BVWSD for in-lieu/ groundwater exchange)	Zero ***To*** 6,500	6,175 ("paper" water-right transfer) ***or*** 6,175 (new water injected into aquifer)	
SUBTOTAL-BVWSD AMENDMENT		**6,175**	
Additional Surface Water –Spot Market (Variable)			
Historical interruptible surface water supply purchases	5,140	4,883	
New Interruptible purchase *(4)*	900	855	
SUBTOTAL ADDITIONAL SURFACE WATER (Surface Water Delivery from Spot Market)		**5,738**	
SUBTOTALS		**27,738**	**6,500**
TOTAL AVERAGE PROJECTED WATER SUPPLY (Best Case: District purchases 12,540 afy of surface water on the Spot Market)		**34,238**	

Note: Worst Case: If no surface water can be purchased on the spot market, WKWD's water supply would be only 28,500 afy (22,325 acre-feet of new water plus a 6,175 acre-feet transfer from BVWSD's groundwater bank).

To meet its new water demands and contracts, WKWD plans to purchase additional surface water on the spot market. (See next section for a description of water demands.) However, WKWD has not yet obtained any new surface water supply contracts to date. If sufficient surface water is available on the spot market, the total average projected water supply is the same for both analyses. However, if surface water can not be purchased on the spot market, WKWD's total annual water supply would be only 22,325 acre-feet of new water plus a 6,175 acre-foot water-rights transfer from BVWSD's groundwater bank reserves.

WKWD does have alternatives to purchasing additional surface water. First, as indicated on the table prepared by staff (Table 2), WKWD may pay BVWSD a water replacement fee rather than purchase additional surface water on the spot market. Second, if WKWD cannot purchase additional surface water on the spot market to meet the rest of it's new water demands, WKWD can draw on its banked groundwater reserves.

Statewide Water Supply Forecast

Periodically, the California Department of Water Resources (DWR) reports on the status of the State Water Project, describes statewide water conditions, and provides a forecast of water supply and demands. This information is published in the California Water Plan, which was most recently updated in Bulletin 160-98.

DWR reports that the ability of the SWP to deliver water in a given year depends on rainfall, snowpack, runoff, water in storage, pumping capacity in the Delta and regulatory constraints. Total entitlement to SWP water is approximately 4.2 million acre feet (maf). Actual deliveries of SWP water have totaled an average of only about 2.8 maf (DWR 1998).

DWR (1998) simulated potential SWP delivery levels if the hydrologic conditions of the 73-year period from 1922 to 1994 were repeated. The model developed by DWR and known as DWRSIM, simulated SWP deliveries with existing facilities operated under the requirements of the State Water Resources Control Board's (SWRCB) interim Water Quality Control Plan for the San Francisco Bay-San Joaquin Delta Estuary. The model also took into account 1995 and estimated year 2020 levels of demand on the SWP, as depicted in the California Water Plan Update, Bulletin 160-98.

Under 1995 water demands, DWR estimates that the SWP has a 65 percent chance of delivering 3.25 maf (77 percent of total entitlements) and an 85 percent chance of delivering 2.0 maf (48 percent of total entitlements) in any given year within the range of hydrologic conditions considered. For year 2020 estimated demands, the model shows that full deliveries (4.2 maf) would occur less than 25 percent of the time.

The DWRSIM model parameters do not take into account Delta export reductions that are required to sustain protected, potentially threatened or endangered species, and listed threatened or endangered species. Nor does the model reflect other activities that may affect the Delta, such as the CALFED Bay-Delta Program and the Central Valley Project Improvement Act.

Development of new surface water reservoirs and of new infrastructure to route water through the Delta takes decades to plan, gain political approval, acquire financing and construct. As stated by DWR in the California Water Plan, "In the short-term, those areas of California relying on the Delta for all or a portion of their supplies face uncertain water supply reliability due to the unpredictable outcome of actions being taken to protect aquatic species and water quality. At the same time, California's water supply

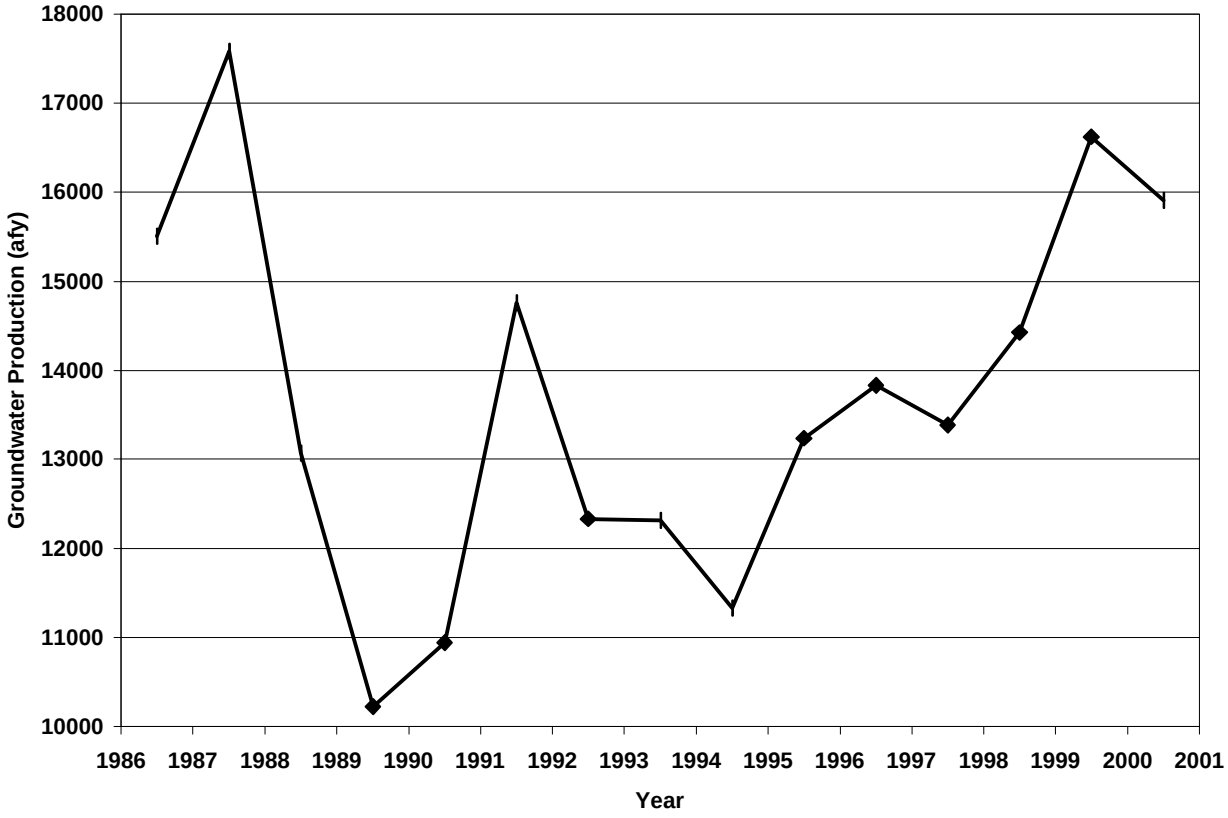
infrastructure is severely limited in its capacity to transfer marketed water through the Delta due to those same operating constraints. Until solutions to complex Delta problems are identified and put in place, and demand management and supply augmentation options are implemented, many Californians will experience more frequent and severe water supply shortages" (DWR 1998).

On the basis of this information, it is reasonable to assume that deliveries on SWP entitlements will not increase in the future. Furthermore, obtaining additional supplies from either the spot market or from DWR SWP surpluses will be a highly uncertain and competitive process during the life of the Sunrise II Power Plant.

HISTORIC WATER DEMANDS

WKWD provides water to a population of approximately 22,000 through 6,655 residential connections in the communities of Taft, Ford City, Maricopa, Tupman and several other smaller residential areas. Domestic water is also served to approximately 75 industrial accounts (WKWD, Letter to Sapudar, 8/1/2001). Industrial customers include 364 industrial oil field connections over a very large area. The WKWD provided a 15-year annual groundwater production record (Patrick, 8/14/2001), which shows production ranging from a high of 17,584 acre-feet in 1987-88 to a low of 10,227 acre-feet in 1989-90 (Figure 4). Water demands have increased through the 1990's, approaching the 1987-88 high.

Soil and Water Figure 4
West Kern Water District Groundwater Production (WKWD 8/14/2001)
(acre-feet per year)



In addition to its historical customer base, WKWD has several new and proposed service contracts.

NEW SURFACE WATER DEMANDS

WKWD's new surface water deliveries include the La Paloma Power Plant and, potentially, additional deliveries to BVWSD, as described in the previous section. WKWD has contracted to deliver up to 6,500 afy of surface water from its SWP Entitlement water to the La Paloma Power Plant, through a direct diversion from the California Aqueduct (CEC, 1999).

In response to this new water service agreement with La Paloma Power Plant, WKWD and BVWSD amended their Agreement for Banking and Recovered Water. The new amendment requires that WKWD must either purchase and deliver 6,500 afy of water to BVWSD, in addition to its SWP Entitlement water, or to pay a water replacement fee to BVWSD. Staff notes that no water supply has been obtained by WKWD to fulfill this agreement (WKWD, 2000).

NEW GROUNDWATER DEMANDS

WKWD will be providing groundwater to 3 recently-approved power plants in addition to the proposed Sunrise II power plant. The 3 new power plants include Elk Hills Power Plant, Midway Sunset Cogeneration Plant, and the simple cycle Sunrise Power Plant. WKWD's existing contracts with these new power plants total 6,480 afy (maximum annual delivery). The addition of Sunrise II will increase this total to 10,100 afy. .

In addition to its new power plant customers, DWR has indicated that WKWD is establishing a new water purchase agreement with DWR to provide water from its banked groundwater reserves. WKWD, along with 2 other KCWA member districts, BVWSD and Rosedale Rio-Bravo Water Storage District, are planning to sell banked groundwater to DWR for the Environmental Water Account, which is part of CALFED's long-term comprehensive Bay-Delta restoration program. According to the Initial Study and Proposed Negative Declaration prepared for the CALFED program, DWR would purchase banked groundwater from the 3 districts in 2001, and possibly 2002, upon completion of the agreement. Under this agreement, a maximum of 35,000 acre-feet could be sold in 2001 and a maximum of 25,000 acre-feet could be sold in 2002. These sales are part of a larger purchase plan in which DWR proposed to buy a total of 200,000 acre-feet of water from agencies within KCWA (DWR, 2000). Staff does not have information at this time on the portion of these sales that will come specifically from WKWD.

SUMMARY OF FUTURE DEMANDS – EXISTING AND PROPOSED

The following two tables summarize WKWD existing and projected water demand and contracts. The first table was provided by SPC (Table 3) (Supplement, 2001). The second table was prepared by staff and includes a description of the supply source for each demand or contract (Table 4). It also includes WKWD's new water delivery to BVWSD (WKWD/BVWSD Contract Amendment 7/26/2000), which was omitted from the SPC table. The difference in the total demand listed on SPC's table and the totals in staff's table results from this omission.

Soil and Water Table 3
West Kern Water District - Average Annual Demand/Contracts
(SPC, Supplement, 2001*)

	Demand (afy)
Existing Maximum Demand (15 year record)	17,584
La Paloma Contract	6,500
Elk Hills Power Plant Contract	3,000
Midway Sunset Cogeneration Plant Contract	3,200
Sunrise Power Plant Simple Cycle Contract	280
Proposed Sunrise II Power Project	3,620
TOTAL AVERAGE ANNUAL DEMAND/CONTRACT	**34,184**

From Table Entitled: Summary of WKWD Water Balance (SPC, Supplement, 2001)
Note: SPC table omits WKWD's new water delivery to BVWSD (WKWD/BVWSD Contract Amendment 7/26/2000).

Soil and Water Table 4
West Kern Water District - Average Annual Demand/Contracts
With Staff Comments
(Adapted from SPC, Supplement, 2001)

	Demand (afy)	Supply Source
Existing Maximum Demand (15 year record)	17,584	Groundwater
La Paloma Contract	6,500	Surface Water
New Delivery to BVWSD*	***Zero to 6,500***	***Water Replacement Fee or Surface Water***
Elk Hills Power Plant Contract	3,000	Groundwater
Midway Sunset Cogeneration Plant Contract	3,200	Groundwater
Sunrise Power Plant Simple Cycle Contract	280	Groundwater
Sunrise II Power Project **(proposed)**	3,620	Groundwater
TOTAL AVERAGE ANNUAL DEMAND/CONTRACT	**34,184 *to 40,684***	

Note: *This table is based on the information provided by SPC (Supplement, 2001) except that it includes the new water delivery to BVWSD (WKWD/BVWSD Contract Amendment 7/26/2000).

If WKWD fulfills its new contract amendment with BVWSD by paying a water replacement fee, WKWD's total average water demand/contracts would be 34,184 afy, as indicated on both SPC's table and the table prepared by staff (Tables 3 and 4, respectively). However, as indicated on the table prepared by staff, if WKWD fulfills its new contract amendment to BVWSD with a surface water delivery, WKWD's total average water demand/contracts would be substantially larger, 40,684 afy (Table 4).

Please note that neither table includes WKWD's new water delivery contract for the CALFED Environmental Water Account because DWR did not indicate that this would be a long-term project. DWR has indicated that WKWD will be providing groundwater in 2001 and 2002.

Water Balance

A water balance is an evaluation of supply and demand. WKWD's water balance includes annual supply and annual demand, as well as its banked groundwater reserve.

SPC provided a water balance for WKWD projected water supply and demand in its October Supplement (SPC, 2001). Table 6 shows the total supply and demand from SPC's water balance and the calculated difference. (Tables 1 and 3 show the components of supply and demand that were provided by SPC.) SPC's projected water balance, including water for Sunrise II, indicates that supply will exceed demand by an average of 54 afy.

Soil and Water Table 6
West Kern Water District Water Balance
Comparison of Annual Supply and Demand
From SPC Supplement, Table Entitled *Summary of WKWD Water Balance* (2001)

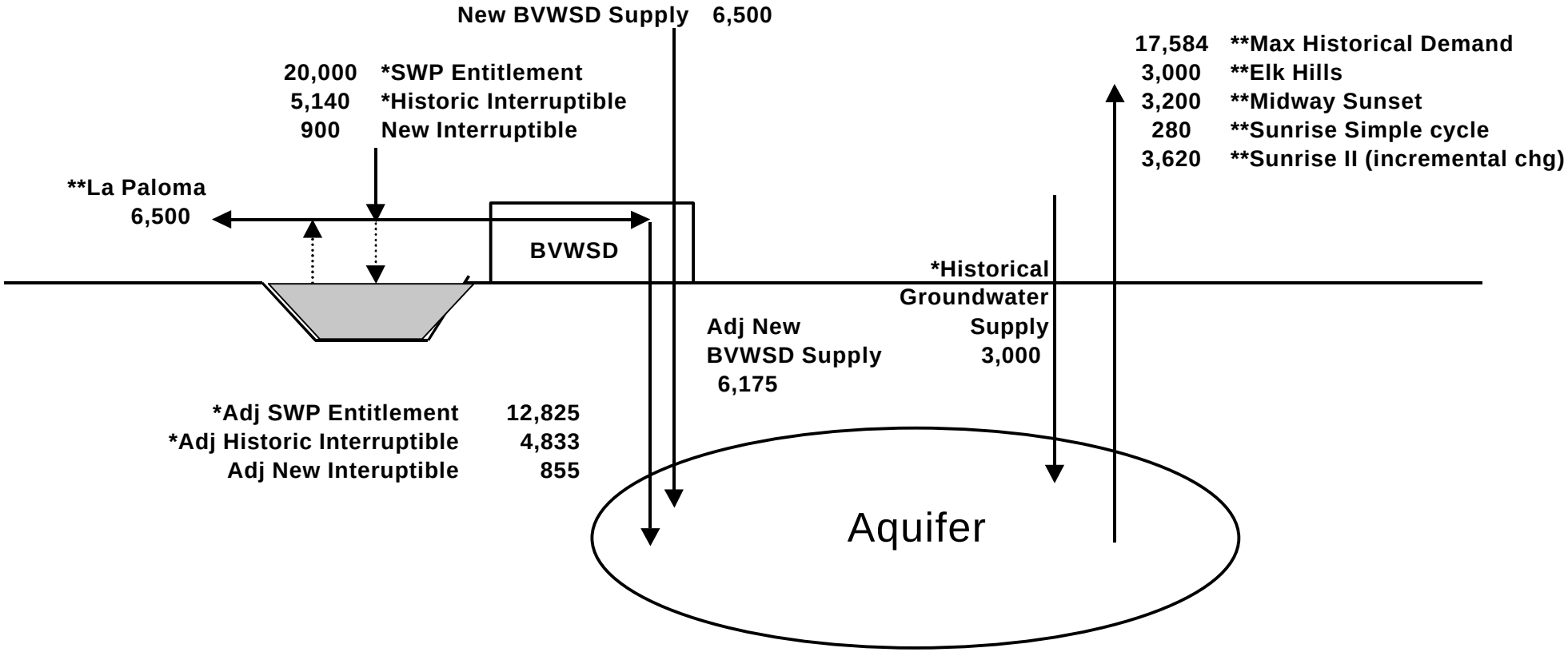
	Supply (afy)	Demand (afy)	Difference (afy)
WKWD Supply/Demand	34,238	34,184	+54

SPC also provided a diagram of WKWD projected water supply and demand in its Supplement, reproduced in Figure 5 below (SPC, 2001). This diagram shows SPC's analysis of the components of the water balance.

According to SPC's water balance, it appears that WKWD would not need to draw on any of its banked groundwater reserves.

Staff also analyzed WKWD's water balance by evaluating the water supply conditions that would be likely to occur, given WKWD's proposed water supply plan and DWR's forecast of increasingly frequent and severe water shortages. The two most likely cases are outlined in Table 6. These 2 cases are not mutually exclusive, but are rather the end results of the likely water supply conditions that will occur during the operational life of the Sunrise II project.

Soil and Water Figure 5
WKWD Water Balance with Sunrise II
Prepared by Sunrise Power Company (SPC 2001)



For each case, staff compared the demand, the corresponding supply, and amount of water that would be drawn from WKWD's banked groundwater reserves. Note that the water transferred from BVWSD's groundwater bank to WKWD's bank is included in WKWD's banked reserves and is not included in WKWD's annual supply because these transfers are only a change in accounting of water previously injected into the aquifer and not a transfer of new water into the aquifer.

Case 1 evaluates conditions that would occur if WKWD would be able to purchase 12,540 afy on the spot market, as indicated the WKWD water supply summary described in SPC's supplemental report (2001) and as listed in Tables 1 and 2. Figure 6 provides a diagram of Case 1. For Case 1, demand would exceed supply by about 6,000 afy (6,446 afy). Presumably, WKWD plans to meet this excess demand with withdrawals from its banked groundwater reserve.

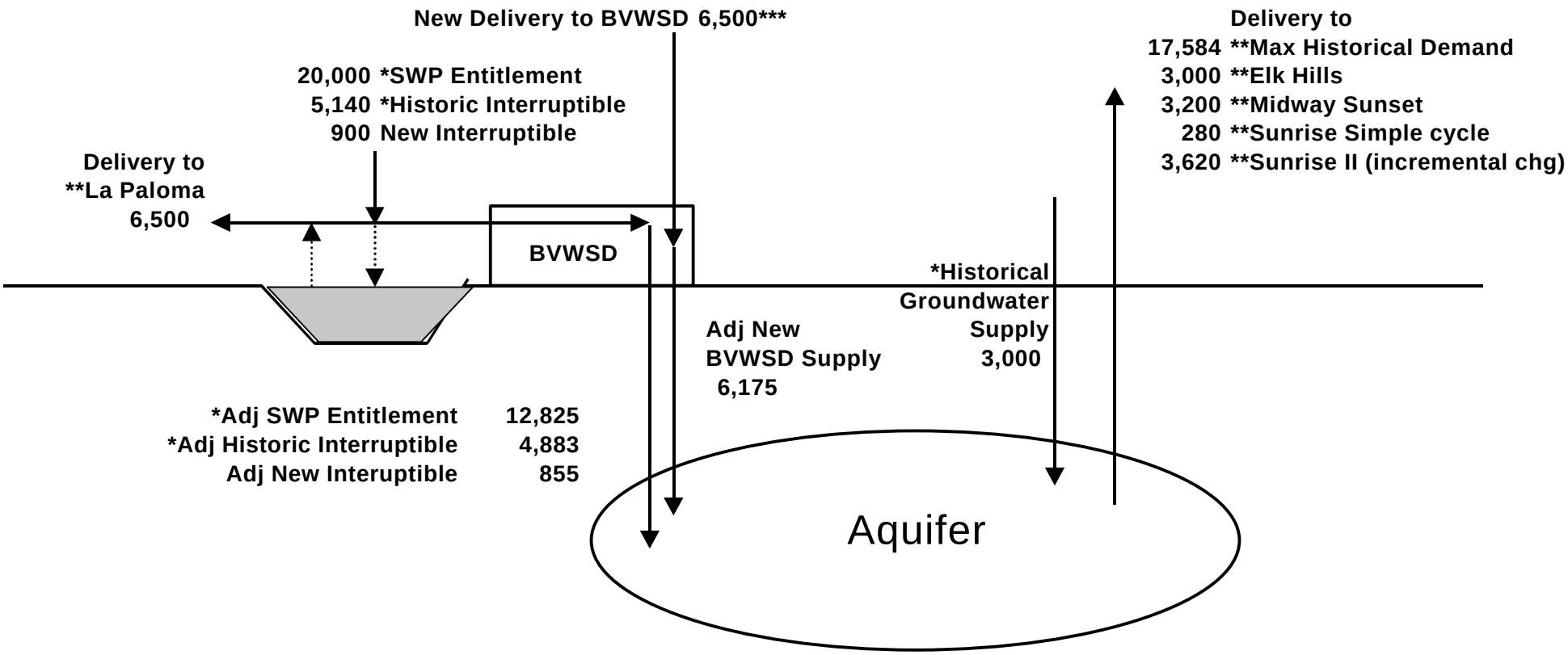
Case 2 evaluates conditions that would occur if WKWD were not able to purchase any additional surface water from the spot market (Figure 7). For this second case, demand would exceed supply by about 12,000 afy (11,859 afy). Staff assumes that WKWD also plans to meet this excess demand with withdrawals from its banked groundwater reserve.

Soil and Water Table 6
West Kern Water District Water Balance
Comparison of Annual Supply and Demand
Prepared by Staff

	Supply (afy) (not including Groundwater Bank Reserves[1])	Demand (afy)	Difference (afy) (To Be Drawn from Groundwater Bank Reserves)
CASE 1: District can purchase 12,540 afy of surface water on the Spot Market, as planned.	34,238	40,684	-6,446
CASE 2: No surface water can be purchased on the spot market.	22,325	34,184	-11,859[2]

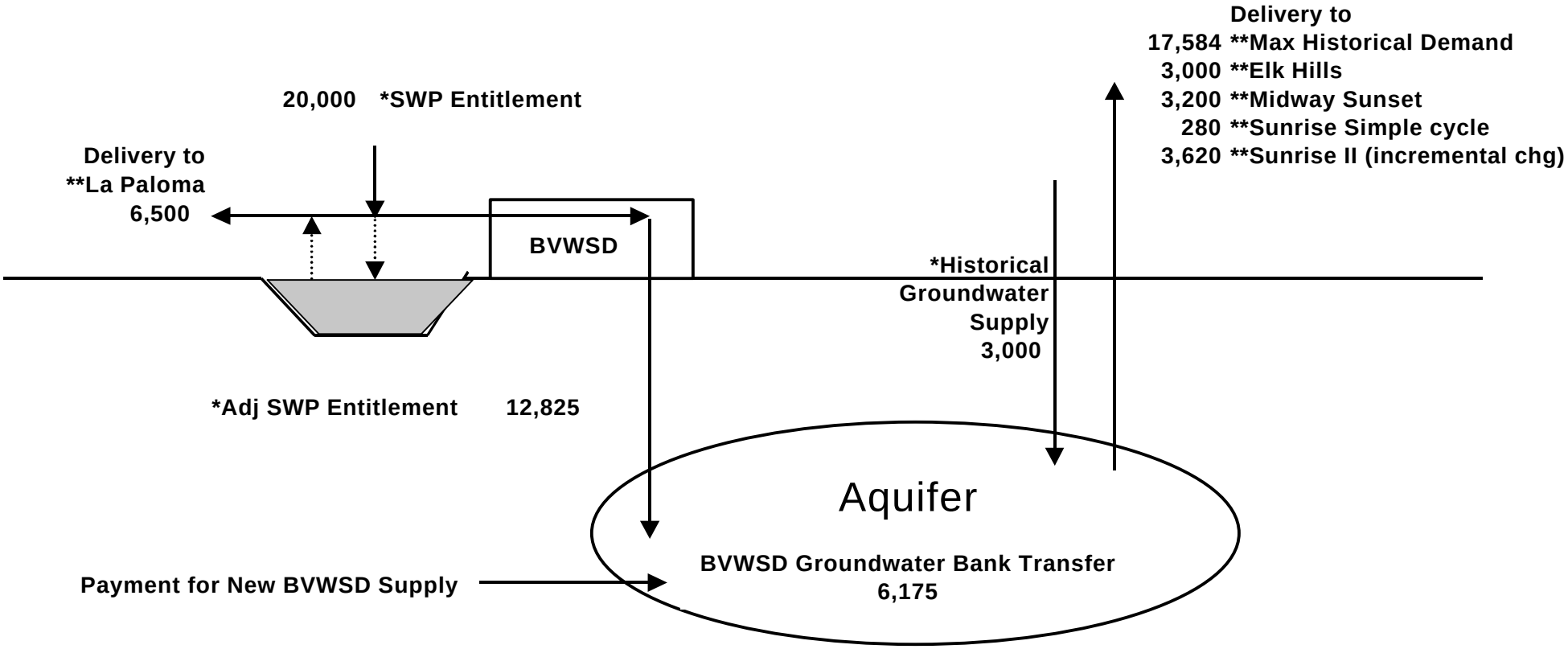
Note:
1. Supply does not include water transferred from BVWSD's groundwater bank.
2. Although BVWSD's water bank transfers to WKWD will not increase the water supply in the aquifer, the transfers will increase WKWD's water rights to stored water.

Soil and Water Figure 6
WKWD Water Balance with Sunrise II
CASE 1: WKWD Purchases 12,540 afy of Surface Water on the Spot Market
Prepared by Staff
(acre-feet/year)



* Historical averages
** Historical or contract maximums
*** WKWD has not identified water source for this new delivery to BVWSD. Presumably this water would be purchased on the spot market.

Soil and Water Figure 7
WKWD Water Balance with Sunrise II
CASE 2: No Surface Water Can Be Purchased on the Spot Market.
Prepared by Staff
(acre-feet/year)



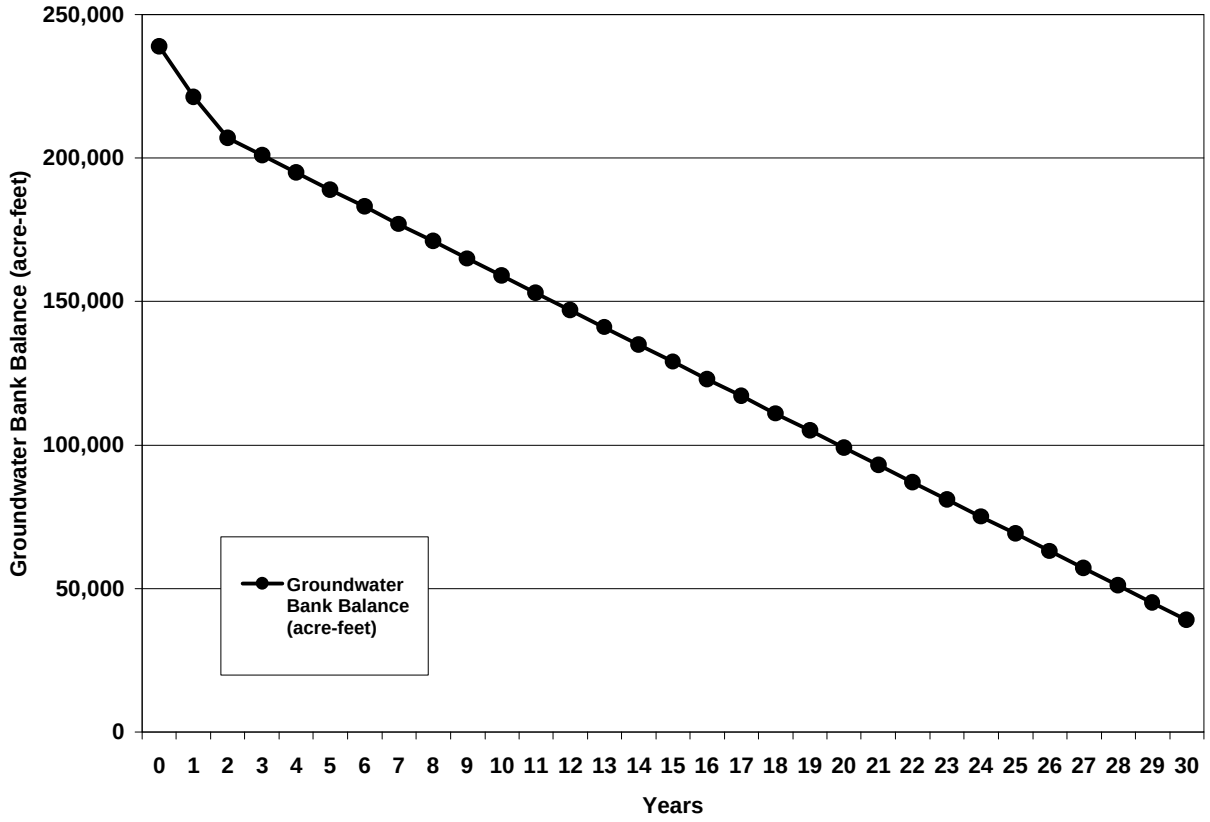
* Historical averages
** Historical or contract maximums

Staff's analysis of WKWD's water balance differs from SPC's analysis because SPC fails to account for the source of the new BVWSD water supply. The WKWD/BVWSD Contract Amendment clearly states that WKWD can either provide a new supply of 6,500 water to BVWSD to be injected into the aquifer or provide a payment of a water replacement fee to BVWSD fee in exchange for previously banked groundwater from BVWSD; however, SPC fails to make this distinction in its water budget. Furthermore, a review of SPC's water balance diagram (Figure 5) shows the "New BVWSD Supply – 6,500" with no indication of where this supply comes from. When staff analyzed these two alternatives, it became clear that WKWD would need to draw a substantial amount of water from its banked reserves to meet all of its projected water demands, including Sunrise II.

Staff's analysis indicates that WKWD will need to rely on banked groundwater reserve to meet its existing and proposed water demands under all likely conditions. Given WKWD's proposed water supply plan, its new contracts, and the proposed Sunrise II project, the annual demand would exceed the annual supply (not including banked groundwater) by about 6,000 afy to 12,000 afy. Based on the following assumptions, WKWD appears to have sufficient banked groundwater reserves to meet its water supply commitments, including Sunrise II, for a thirty year period (Figure 8)::

- Surface water and groundwater supply will not increase or decrease from historic and/or reported averages;
- Existing demand by residential and oil field customers will not continue to increase beyond the 15-year maximum rate;
- WKWD will provide a total of 20,000 acre-feet (one third of the maximum) of water to the DWR Environmental Water Account in 2001 and 2002.
- All of the new projects will begin at approximately the same time; and
- Annual shortfalls in supply would be met with banked groundwater.

Soil and Water Figure 8
Estimated Depletion of West Kern Water District Groundwater Bank
(acre-feet)



However, although the amount of water in the groundwater bank is sufficient to meet the demand, there are physical limitations in withdrawing these reserves. Although WKWD has the right to pump banked water, which would meet their needs for over 30 years, the hydrodynamics of the groundwater basin won't allow the needed level of pumping beyond approximately 10 years. For a discussion of this limitation, see the following Well Interference analysis in this Staff Analysis.

Groundwater

Groundwater levels would be expected to progressively decline each year as the WKWD draws on its reservoir of banked groundwater. In addition, groundwater levels would be expected to continue to fluctuate in response to seasonal pumping demand, to changes in recharge during cyclical periods of drought and wet years, and to other water districts' groundwater pumping and storage recharge. Therefore, although fluctuations will occur, the overall trend caused by WKWD's groundwater bank withdrawals will be a decline in groundwater levels in the vicinity of the WKWD well

field. Staff notes that SPC has not addressed the issue of groundwater level declines or well interference within the WKWD well field.

WELL INTERFERENCE

The two entities with existing wells that would be directly impacted by WKWD pumping are the Kern Water Bank Authority (KWBA) and the BVWSD; KWBA operates groundwater wells near the WKWD well field, and BVWSD wells are located within the same well field as WKWD's wells. Jon Parker, Manager of the Kern Water Bank Authority, has stated that WKWD, KWBA, and BVWSD are part of a monitoring committee, established by Kern Water Bank Memorandum of Understanding, that reviews groundwater level conditions for the member agencies' wells (Parker, 8/31/2001). This organization provides an administrative mechanism to resolve problems with drawdown. Therefore, according to the KWBA, no additional management or mitigation of groundwater levels is needed, as long as the water supply balance is maintained. (Parker, 8/31/2001) Based on this information, Staff did not perform a well interference analysis for nearby wells. Additionally, a time-consuming, comprehensive modeling analysis of impacts would be required to quantify the well interference caused by multiple wells.
However, a recent study by Kenneth D. Schmidt and Associates, entitled *Hydrogeologic Evaluation of Buena Vista WSD and West Kern WD Water Banking Project* and prepared for BVWSD and WKWD, provided the basis for evaluating the effect of a long-term increase in pumping on the WKWD well field (Schmidt, 2001). Schmidt's study evaluated, in part, the impacts of an increase in pumping that is similar to the increases currently under consideration by WKWD, as described in this Staff Analysis. Based on Schmidt's analysis, staff has determined that pumping within the WKWD well field will become infeasible in about 10 years, given WKWD's projected level of water supply and demand, including Sunrise II.

Schmidt evaluated the impact of a pumping increase of 11,300 gpm by WKWD and BVWSD within the WKWD well field. According to Schmidt's report, pumping at a rate of 11,300 gpm for 10 months causes a decline of 27 feet in WKWD well field, drawn from both the upper, more productive aquifer and the lower, less productive aquifer (Table 7). The thickness of the upper aquifer is 160 feet. Once the upper aquifer is dewatered, pumping at a rate of 11,300 gpm for an additional 10 months causes a decline of 53 feet in WKWD well field. The greater rate of decline is caused by drawing water solely from the lower, less productive aquifer. In his conclusions, Schmidt states that if a decline in groundwater levels of 400 feet occurred within the WKWD well field, pumping would be infeasible. (Schmidt, 2001)

Soil and Water Table 7
Results of Hydrogeologic Evaluation of Buena Vista WSD and West Kern WD Water Banking Project (Schmidt, 2001)

10-Month Pumping Rate	Aquifer(s)	Groundwater Decline in WKWD Well Field
11,300 gpm	Upper and Lower Aquifer	27 feet
11,300 gpm	Lower Aquifer only	53 feet

Historically, WKWD has had a surplus of imported surface water, and, as a result, WKWD's groundwater recharge has exceeded its groundwater pumping. Between water year 1977 and 2000, WKWD's net groundwater recharge averaged about 9,000 afy (SPC, Supplement, 2001). (See Figure 2.) WKWD's recharge has provided the annual additions to the district's groundwater bank account. If the rate of recharge to the aquifer declines, groundwater levels will correspondingly decline.

With the start-up of its new water delivery contracts, the balance of supply and demand in the WKWD will change. Groundwater conditions are likely to reverse. With the current proposed water supply plan, described in the previous section, WKWD's groundwater pumping would exceed groundwater recharge every year, and the district would draw on its banked groundwater, including any groundwater bank transfers from the BVWSD (See Figure 7.). In response, the reservoir of stored groundwater would decline by approximately 6,000 afy to 12,000 afy, and, correspondingly, groundwater levels would also decline.

Therefore, the historical long-term trend would be reversed. Instead causing a net increase of 9,000 afy to the aquifer, WKWD will cause a net decrease of 6,000 afy to 12,000 afy to the aquifer. In other words, instead of adding water to the aquifer, WKWD would be subtracting water from the aquifer each year. Combining these two effects, the net change would range between 15,000 afy to 21,000 afy, This change would be very likely to cause a substantial change in groundwater levels in the vicinity of the WKWD well field.

Based on Schmidt's analysis, staff estimated groundwater level declines in the immediate vicinity of the WKWD well field that would be caused by new projects, including Sunrise II. Net annual groundwater depletions caused by new projects served by WKWD would total about 15,000 afy to 21,000 afy or 9,000 gpm to 13,000 gpm over 12 months. Schmidt evaluated the impact of pumping at 11,300 gpm over 10 months. Since these rates are roughly equivalent, staff estimates that groundwater levels would decline about 27 feet per year within the WKWD well field until groundwater levels declined to about 160 feet at which point the upper, more transmissive aquifer zone would be dewatered. Groundwater levels within the lower zone would then decline at a rate of about 53 feet per year.

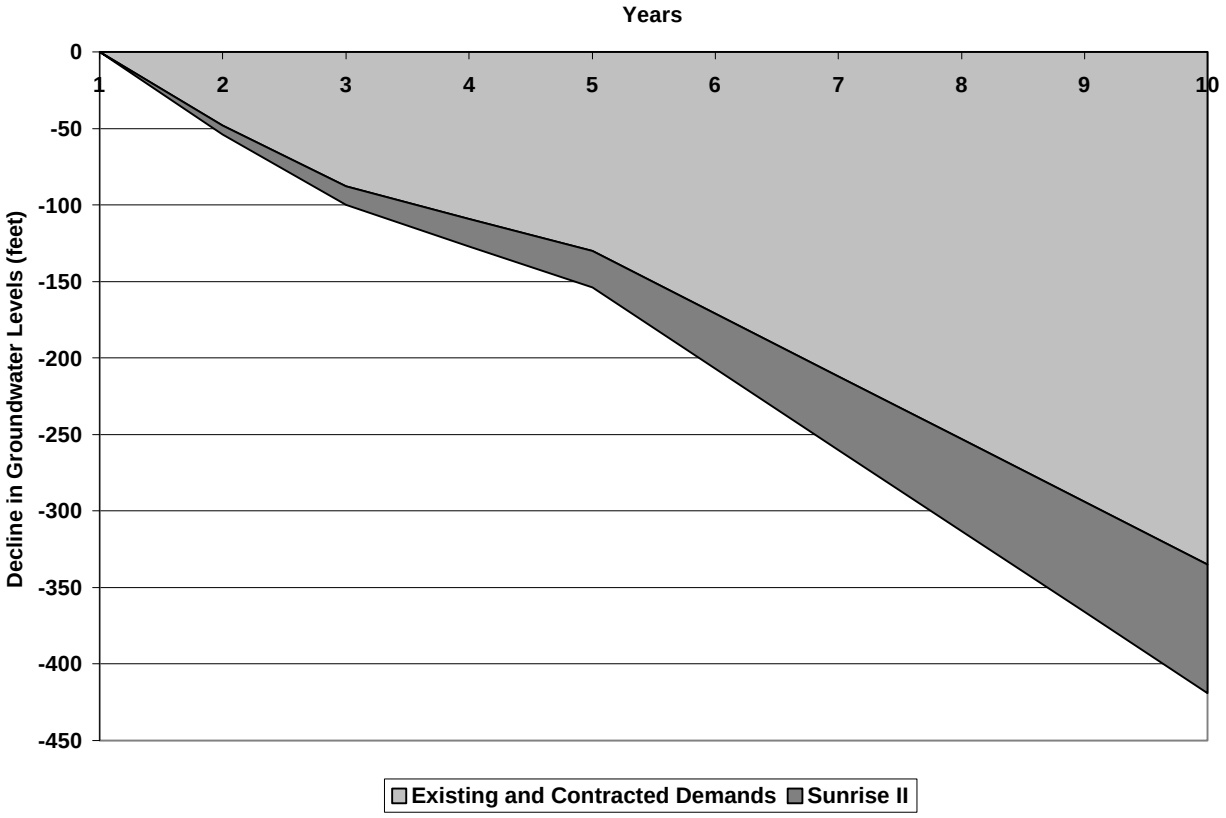
Within the overall declines in groundwater, the proposed Sunrise II project, which requires an average of 3,620 afy (3,900-280= 3,620 afy) of additional pumping, would

cause an initial decline in groundwater levels of about 6 feet per year until the upper aquifer is dewatered and about 12 feet per year thereafter. This is a significant lowering of the groundwater level and represents a potential for a significant impact on this groundwater basin and associated groundwater users. In addition, if WKWD provides banked groundwater to the DWR Environmental Water Account in 2001 and 2002, groundwater levels would decline an additional 27 feet the first year and another 19 feet the second year. The cumulative effect of these groundwater declines, including groundwater withdrawals for the Environmental Water Account, is shown in Figure 9.

According to Schmidt's conclusions (2001), pumping would be infeasible if groundwater levels declined to 400 feet below land surface in the WKWD well field, presumably owing to diminished well production capacity. Again, using Schmidt's analysis, groundwater levels would decline 400 feet in 10 years of project operation, owing to the cumulative impact of new contracted pumping demands and decreases in groundwater banking (Figure 9). Sunrise II would account for about 23 percent of this decline.

Soil and Water Figure 9
Calculated Decline of Groundwater Levels

Within the West Kern Water District Well Field



Note: For purposes of this analysis, Staff has assumed that WKWD will provide a total of 20,000 acre-feet of water to the 2001-2002 DWR Environmental Water Account, which is one-third of the maximum proposed purchase.

It is important to note that staff's estimated groundwater decline would be caused by the depletion of the WKWD Groundwater Bank. Other factors, including regional precipitation and recharge, other water banking activities, and other changes in groundwater pumping, would also cause additional increases and declines in groundwater levels within the WKWD well field.

Based on this analysis using the data available, even though WKWD has banked a sufficient supply of water for its current customers, including Sunrise II, withdrawals from the WKWD Groundwater Bank are likely to become infeasible within about 10 years. Therefore, this source of water does not appear to provide a reliable water supply for the life of the project. The loss of this groundwater resource will significantly adversely impact any users that are dependent on it. Specifically, the projected decline in groundwater levels within the WKWD well field has the potential to be a significant adverse impact that affects both the proposed Sunrise II combined cycle project and all other users of this water supply. Furthermore, staff finds that the proposed Sunrise II project, if operated as proposed and without mitigation, will contribute to the potential significant adverse cumulative impact on all other users of this resource. Staff has discussed cooling options that conserve water and will mitigate the significant

cumulative impacts, in the **Cooling Technology Alternatives** analysis later in this Staff Analysis.

CRITICAL GROUNDWATER LEVEL FOR PUMPING

Staff has determined that groundwater levels will become critical when the pumping levels in the WKWD wells reach 230 feet below ground surface (bgs). At this point, the significant adverse cumulative impact will begin to occur. When the critical groundwater level for pumping of 230 feet bgs is reached, the following has occurred:

- **The productive upper aquifer zone will be dewatered.**
- **The static groundwater levels will reach or will have exceeded the historic low for the groundwater basin.**
- **Wells will begin to dewater and the groundwater level will have dropped below top of well screens.**
- Wells will become increasingly less productive, i.e., the rate of decline of the specific capacities of wells will accelerate.

These conclusions were reached considering the following findings:

- **The depth to the base of higher permeability zone is 160 feet bgs.**
- **The lowest static groundwater levels on record occurred during the summer of 1993 and ranged from 200 feet bgs to 230 feet bgs.**
- **The top of WKWD well perforations range from 106 feet bgs to 225 feet bgs, at which point dewatering and loss of capacity will begin to occur.**
- The production-drawdown ratio will decrease (the same production rate will cause greater drawdown) as the groundwater levels decline and as wells dewater.

The conditions under which the determination of when the critical level has been reached are as follows:

- **Pumping levels must be measured for all 8 WKWD wells. Pumping levels shall be measured monthly Tests must be conducted after 24 hours of continuous pumping.**
- Tests must be conducted at a constant rate equal to the system-wide peak rate/6 (WKWD proposes to operate with 6 active wells plus 2 wells on standby).

Definitions:

Pumping level is defined as the groundwater level measured while a well is actively pumping. The system-wide peak rate is defined as the peak historic summer production rate plus the peak rate for all 3 new power plants, including Sunrise II.

The critical level will be reached when a pumping level of 230 feet bgs is measured in any 3 of the 8 WKWD wells during monthly monitoring. This threshold is based on the requirement that WKWD must maintain at least 5 wells at full pumping capacity to provide a sufficient water supply to all its customers.

A condition of certification (COC 5) has been developed to apply the critical groundwater level for pumping of 230 feet bgs as the threshold of significance to determine the point at which mitigation of significant adverse cumulative impacts will be required.

LAND SUBSIDENCE

The Kern Groundwater Basin has a history of groundwater overdraft and significant land subsidence caused by groundwater pumping. Land subsidence is caused by declining

water levels and the corresponding lowering water pressures in the aquifer. However, according to Barbara D. Houghton, consultant to WKWD, there is no evidence of subsidence in the vicinity of the WKWD well field, owing to the coarse-grained composition of the local aquifer.

WATER QUALITY

Based on staff's analysis, increased pumping for the Sunrise II project would not cause an impact to groundwater quality. Potentially, increased pumping could cause groundwater degradation by either induced transport of contaminated groundwater or by upwelling of brackish water.

According to the WKWD Drinking Water Source Assessment submitted to California Department of Health Services, there are no existing or potential sources of groundwater contamination in the vicinity of the WKWD well field (2001).

Although no site-specific analysis was undertaken, the location of the WKWD within the Kern Groundwater Basin would tend to diminish the potential for degradation from upwelling of brackish water from marine sediments underlying the freshwater aquifer. The location of the alluvial fan would tend to direct naturally occurring regional recharge to flush brackish water within the underlying marine sediments towards the center of the basin. This process would diminish the salinity of the groundwater water in the sediments that underlie the freshwater aquifer.

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES) PERMITS

The existing simple cycle project was determined to be exempt from a General Industrial NPDES Permit because the stormwater and industrial drainages would be segregated. The proposed combined cycle facility will be required to revisit this requirement due to an increase in the types and quantities of waste discharges. This will also apply to the Stormwater Runoff requirements of the combined facility. Due to the lack of specific facility design, a general Condition of Certification is proposed for both construction and for operation. COCs for the General Construction NPDES permit are also proposed.

Underground Injection Control (UIC) Permit

SPP discharges a maximum rate of approximately 63 gpm from the simple cycle phase, and proposes to discharge 452 gpm from the proposed combined cycle project. The discharge will contain approximately 1,500 parts per million total dissolved solids. This waste discharge will be injected into underground wells. Two of the six injection wells the project is proposing were approved for the simple cycle project under a previous amendment. Construction and operation of the six wells are pending approval of a UIC permit from the USEPA Region IX Groundwater Office.
These injection wells will be located on the TCI property at the northeast side of the Midway Sunset Oil Field. The stratigraphy of the injection area from 0-600 feet below ground surface (bgs) is clay, silt and sand derived from Quaternary Alluvium. Beneath

the base of this alluvium is a clay layer approximately 45-60 feet thick, which is above the proposed Tulare Formation injection zone located at 500-950 feet bgs. The injection zone is directly above a 60-125 foot thick layer of oil sands, with Middle Tulare shales beneath these oil sands.

Under these conditions, adverse impacts to the subsurface environment are not expected. U.S. EPA Region IX staff have indicated that special attention will be given during the permitting process to the prevention of any surface impacts related to construction and operation of these wells.

On May 24, 2001, SPC sent an application for a permit for the wastewater disposal injection well option (six injection wells) in a letter from Stephen Whaley of SPC to George Robin of U.S. EPA Region IX. A total of six injection wells are planned for the combined cycle facility. The application is now in the process of being reviewed for technical accuracy and completeness by EPA.

In a letter to George Robin of USEPA Region IX, dated August 21, 2001, SPC requested that the USEPA not only reconsider their permit, but also consider that there is no reason for such a permit. Additionally SPC has requested a review of the applicable regulations, which they believe will show the proposed Sunrise II wastewater injection wells should be classified as Class V wells. With such a status, SPC believes the wells construction and operation are currently authorized by rule and therefore do not require an individual UIC permit.

The USEPA has rejected this challenge in a letter dated September 13, 2001 from Alexis Strauss of USEPA Region IX to Kelly S. Lucas of the Sunrise Power Company. The extent of any further challenge by SPC of the USEPA's authority and regulatory responsibility to regulate these injection wells is currently unresolved between the SPC and the USEPA. to. A Condition of Certification has been developed requiring a final UIC permit from USEPA Region IX for the construction and operation of the injection wells. As discussed previously, should the USEPA not issue a UIC permit for these wells, the CVRWQCB will be required to issue WDRs for the construction and operation of any such injection wells operated for waste disposal purposes; an unregulated waste discharge will not be allowed.

Waste Discharge Requirements

The WDR volume flows have been calculated consistently with the water balances for ambient temperature of 115 °F and 65 °F. The figure at 65 °F ambient is titled "average annual" configuration. There is no discussion of the variations from these two ambient temperature points. A failure of the waste discharge system would result in shutting down the power plant within several minutes, thus the ability of the plant to discharge at both the TCI facility and the injection wells is a necessary redundancy. The applicant has pointed out that they are recycling certain wastes into the cooling water system, where they are beneficially used, rather than going directly to waste. This includes the HRSG blowdown, CTG evaporator cooler blowdown, and the RO system blowdowns. These waste streams are estimated to be 89 gpm on average.
SPC has provided data for a "zero discharge system", wherein all waste streams would be managed on-site. Their plan would require evaporation ponds and substantial

additional equipment. SPC has not selected this option because of capital cost ($10 million), operating cost, and added property requirements. The use of evaporation ponds, injection wells and EOR uses for the wastewater and any associated pipelines could be completely eliminated through the use of a zero discharge system using a brine concentrator/crystallizer. This type of system would result in maximum conservation of the water being used for heat rejection. Since there would no longer be a wastewater discharge, it would also eliminate the need for the wastewater pipeline construction while providing the overall benefit of reducing the project's water supply needs.

APPLICANT'S COOLING TECHNOLOGY ALTERNATIVES ANALYSIS

At staff's request, an analysis was prepared by SPC comparing three methods of cooling for the steam turbine condenser. The three methods considered were wet cooling (cooling tower using evaporative cooling), dry cooling (essentially dry "radiators"), and a hybrid of the two called wet/dry wherein 10 percent of the cooling is dry rather than evaporative. This last option provides minimal benefit and is not included in Table 8.

There were at least two separate studies conducted, one titled "Alternate Heat Rejection System Study". The other is a response from SPC to staff Data Requests. While these two studies seem to have been independently prepared, and used differing assumptions, the results are essentially the same.

Below is a summary for wet and dry cooling, of the study results, using SPC's Data Response values (Table 8). Soil and Water Table 8

Water Supply Requirements
Summary of Cooling Water Alternative Analysis

Option	Wet Cooling	Dry Cooling	Difference
STG output	265 MW	262 MW	3 MW[1)]
Plant Water Consumption	2,755 gpm 4,444 afy	189 gpm 280 afy	2,566 gpm 4,120 afy
Connecting Pipe to WKWD Capital Cost	$14.2 M	$0.0 M	
Condenser and Cooling System Capital Cost	$8.1 M	$39.7 M	
Total Capital Cost [2)]	$22.3 M	$39.7 M	$17.4 M
Annual Water Cost @ $1.25 / 100 cubic feet	$2.42 M	$0.17 M	$2.25 M

1) Difference increases on "hot days" to 22 MW for unfired and 33 MW for fully fired scenarios.
2) From Staff Data Request Response Table 17.1, excluding tax & finance costs

STAFF'S COOLING SYSTEM ALTERNATIVES

The analysis performed by staff using the available data indicates that there is a potential for significant adverse cumulative impacts resulting from the project's water use, that when combined with other users of this resource could adversely impact the

future status of the WKWD groundwater supply. Based on these findings, staff has identified mitigation options to reduce the project's significant impacts to less than significant. The alternative cooling and water conservation analysis performed by SPC, and reviewed, evaluated, and augmented by staff will provide the basis for the proposed mitigation.

The Sunrise II petition has focused on the use of a typical mechanical draft wet cooling tower as a cost-effective means of cooling. This option alone does not consider water conservation or the elimination of fresh surface water or groundwater use in cooling the Sunrise II project. It is appropriate to evaluate the project's water supply needs from a project design and operations perspective. Staff has considered cooling alternatives and conservation in addition to the applicant's proposal.
In addition to the use of water conservation measures to reduce fresh inland water use, which is proposed, there are two other solutions available for addressing the uncertainty of the WKWD cooling water supply. The two other solutions are:
1. Alternate water supply or multiple supplies,
2. Eliminate the need for cooling water by using a dry cooling condenser.
Type 1 solutions: Obtain an alternate water supply or multiple supplies, which include the following possibilities:

- **Groundwater has been categorized by SPC as "not cost-effective" because of its high chemical content. However, technology for reducing this chemical content is readily available. SPC II has proposed using reverse osmosis (RO) for reducing the chemical content of the KWKD feedwater. RO is obviously an available and widely used means of reducing feedwater chemical content. Possibly even more "cost-effective" would be thin film evaporation, brine concentrator, multiple-effect evaporation, or some other thermal means of separating the high chemical content water into two streams; one sufficiently pure for cooling tower use and the remainder of very high concentration directed to waste. All of these means are mature technologies that are commonly used in power plant applications**
- **The Texaco Enhanced Oil Recovery operation brings both oil and water from the ground; the water generally called "produced water". This is brought to the surface in the operation adjacent to the proposed power plant. This is a substantial water source, that can be used rather than WKWD potable water. Further processing would be required using the techniques mentioned for groundwater.**
- **The Sunrise II petition also makes reference to the recycled water generated by the City of Taft publicly owned treatment works (POTW). This source of water is rejected as "insufficient quantity of water to meet the needs of Sunrise II". However, this source could become useful as a partial provider of water in combination with one of the above.**
- **Staff has identified a potential source of recycled secondary treated water at Water Treatment Plant #3 in West Bakersfield that could furnish all of the required cooling water. This would involve a 25 mile pipeline and onsite RO treatment to furnish water that would meet facility design requirements. The treatment process would typically generate about 10**

percent wastewater, however this reject water (approximately 8000 TDS) could be injected in the local wells or reduced to zero discharge by techniques discussed below in the "Water Conservation Measures" **Section.**

Type 2 solution: Eliminate significant consumption of water for cooling by using a dry cooling condenser.
Typically, dry cooling is a very feasible solution, well tried and used in many power plants of all sizes and kinds around the U.S. and the world. The equipment is reliable, can be built in a reasonable time, and has proven to be both practicable and cost-effective in many places where fresh water is not readily available or will become more expensive and scarcer over the life of the project under consideration. The Applicant finds no impediment to its use other than "not cost-effective" compared to wet cooling tower.

Water Conservation Measures

These options would require more effective water management in the Sunrise II facility. The proposed wet cooling tower will need to evaporate 2,300 gpm "average", or approximately 3,700 afy. Approximately 407 gpm water flow "average" results from cooling tower blowdown. This waste stream could be treated using the following methods, and reused.

- **Side stream water conditioning. In order to save a large fraction of the cooling tower blowdown, it is possible to treat the basin water/blowdown water, by removing some portion of it and treating it, returning treated water with reduced chemical content to the cooling tower, and the smaller fraction with increased chemical content to a waste stream. Treatment method might be softening or reverse osmosis treatment, depending on the specific water chemistry. This method is commonly used, and depends on equipment that is common to power plants. It is a reliable and practical method of conserving cooling tower water.**
- **Cooling tower blowdown concentration. It is possible to further treat the cooling tower blowdown stream with what is commonly called a "brine concentrator". This can take even the higher TDS (total dissolved solids) stream from the above treated cooling tower, and further treat it so that two streams are developed; one being low TDS water which is returned to the cooling tower for use, and the other being directed to waste. This treatment will further reduce the wastewater flow, and of course reduce the requirement for cooling water source to the extent of the returned low TDS water. This again is equipment that has been used in power plants on a regular basis.**
- **Further cooling tower blowdown concentration. It is possible to even further reduce the blowdown stream to essentially zero by using a crystallizer. This is a method that is used most often to eliminate wastewater from a power plant rather than reduce cooling tower consumption. However it can certainly be used to return water to the cooling cycle.**

- **Use of plant and equipment drain water in the cooling tower. Plant drains collect water from leaks of feedwater or cooling water, and other miscellaneous sources. It is convenient to direct these drains to waste, as they can contain contaminates such as oil or chemicals or even floor sweepings, requiring additional treatment of the contaminated water before cooling tower use. However, these contaminants typically occur infrequently. With some effort, it is possible to test the drains continuously for contamination, and whenever none is found to direct the drains to the cooling tower. This could effect another savings of 28 gpm "average" flow.**

Conclusions and Recommendations

WASTEWATER

Staff recommends water conservation measures below that may eliminate the need for these wastewater disposal methods (see **Water Supply** section below). However, if needed, the Commission Decision for the Sunrise Power Project dated December 2000 contains Conditions of Certification that address the construction and operation of the wastewater pipeline transporting the SPP wastewater to the TCI facility.
The Storm Water Pollution Prevention Plan (SWPPP), and the Erosion Control and Revegetation Plan must be revised to reflect the final design, construction and operation of the amended project, and are required by Conditions of Certification Soil & Water 1 and 2. Compliance with these conditions will continue to provide adequate mitigation for any construction or operational impacts related to the pipelines and injection wells, if needed and approved. Staff is currently providing guidance to SPC staff to amend these plans.

WATER SUPPLY

Staff has determined that there is substantial uncertainty surrounding WKWD's ability to meet the water requirements of the Sunrise II project in addition to it's current water supply commitments. This uncertainty is related to the SWP's long-term ability to maintain the current level of deliveries and to the uncertainty of obtaining additional water supplies from other sources.

Using the information made available to staff, it appears that, even without the Sunrise II project, WKWD may have difficulty meeting the needs of its water users beyond 15 years. The Sunrise II project may accelerate the rate of depletion of the groundwater supply. Groundwater pumping by WKWD could become infeasible within about 10 years if the Sunrise II project is approved, as designed. This would seriously limit the water supply available for the Sunrise II project and other users of this resource. The projected decline in the groundwater level caused by this depletion has the potential to be a significant adverse impact that would adversely affect all users of this water supply, including the Sunrise II project.

These conclusions are based on available data and data supplied by WKWD, and the resulting analysis of these data. Staff acknowledges that there is a possibility, as

expressed by the WKWD, that additional water will be able to be obtained as needed. Additional data on the future availability of water were not provided by SPC or WKWD for this analysis. Staff used the statewide water-supply forecast developed by DWR as a means of generally estimating the availability of future additional surface water. DWR has specifically cautioned that areas of California that rely on transport of surface water supplies through the Delta, such as Kern County, will experience more frequent and severe water supply shortages until complex operational problems are solved (DWR 1998).

Staff believes the uncertainty of the water supply and the potential for significant adverse impacts can be reduced if SPP implements water conservation measures to reduce their use of groundwater within the affected groundwater basin. Such measures if implemented could reduce overall water demand by an average of 407 gpm (660 afy). Staff recommends that if the proposed groundwater source is used, that measures be implemented to reduce cooling water use by approximately 660 afy. While there are other options to cool the facility besides the use of the proposed source of fresh inland water, the applicant has not favored these alternatives. Specifically, if SPP used an alternative water source (see LORS discussion of Policy 75-58), such as reclaimed water or created/produced water that would not have been used for recharging the groundwater basin, the project would not impact the groundwater basin or those users that are dependent on it. One other option which is preferred in some circumstances is dry cooling. Another alternative would be for the project to use SWP water derived from source(s) outside of the Kern Water Bank or Kern County Groundwater Basin, but this option could have potentially significant impacts elsewhere.

RECOMMENDATION SUMMARY

Staff recommends that the project owner conserve approximately 600 afy of water by implementing within one year following the start of operation one or more of the cooling system alternatives and water conservation options discussed above Staff specifically recommends that all waste streams be combined and a brine concentrator e.g., a mechanical evaporator, be installed on the project's combined wastewater discharge. This brine concentrator should be sized and operated to provide concentration of the combined wastewater stream such that it is reduced by a factor of 90 percent, which is well within the capabilities of currently available and applied technology. All water recovered by the brine concentrator should be recycled back to the plant to reduce water supply needs.

In order to assure that groundwater levels are not adversely impacted, staff recommends that a groundwater monitoring plan be required (see COC 5) to determine if the significant adverse impacts to the groundwater basin are likely to occur prior to the time the impact becomes significant. By necessity, such a plan would contain a trigger that would require that the use of WKWD water cease and that the project be amended within a suitably short and reasonable time frame (one year), to transition to alternative water source or alternative cooling technologies, such as the **Type I or Type II** solutions/options recommended by staff (COC 6).

The trigger has been defined as a pumping level of 230 feet below ground surface, which is defined as the "critical groundwater level for pumping" or significance threshold which when reached would indicate that the significant impacts forecast by this analysis were actually beginning to occur. This critical groundwater level for pumping will be a required component of any groundwater monitoring workplan. The trigger will be reviewed and revised as necessary prior to the start of commercial operation. A Condition of Certification contingent on this scenario has been proposed (COC-5).

RECOMMENDED CHANGES TO EXISTING CONDITIONS OF CERTIFICATION

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SOIL & WATER 1 ~~Prior to beginning any clearing, grading or excavation activities associated with project construction, including any new linear facilities or site expansion, the project owner will develop and implement a Storm Water Pollution Prevention Plan (SWPPP).~~ Prior to site mobilization for the construction of the proposed project and any ground disturbance activities associated with construction of any on and/or off-site project elements, including linear facilities, the Project Owner shall develop a final Storm Water Pollution Prevention Plan (SWPPP) as required under the General NPDES Stormwater Construction Activity Permit for the project. The final plan must be approved by the CPM. The SWPPP shall include final drainage and facility design for all on and off-site SPC project facilities. This includes final site drainage plans, showing all of the detail necessary to evaluate the impacts of stormwater run-on and run-off of the site and associated off-site facilities. The final plan shall also be consistent with all other permit and design documents provided by the Applicant. Approval of the final plan by CPM must be received prior to the initiation of any site mobilization activities associated with construction of any project element.

Verification: ~~Two weeks prior to the start of construction~~ Sixty days prior to the site mobilization, the project owner shall submit to the Energy Commission Compliance Project Manager (CPM) a copy of the Storm Water Pollution Prevention Plan (SWPPP) for review and approval. Site mobilization will not begin prior to notification of a CPM approved plan. This plan shall contain the final project design, and will identify all new linear facilities and site expansion.

SOIL & WATER 2 Prior to the initiation of site mobilization activities associated with any new linear facilities or site expansion, the project owner shall submit a draft erosion control and revegetation plan to the CPM for review and approval. The final plan shall contain all the elements of the draft plan with changes made to address the final design of the project including new linear facilities and site expansion.

Verification: The final erosion control and revegetation plan shall be submitted to the Energy Commission CPM for approval ~~30 days~~ 60 days prior to the initiation of any earth moving activities associated with any new linear facilities or site expansion.

SOIL & WATER 3 The project owner shall provide a copy of the final Underground Injection Control (UIC) permit issued by the U.S. EPA Region IX for

the construction and operation of the wastewater disposal injection wells. A copy of the Report of Waste Discharge required by the CVRWQCB to issue a waiver allowing for the UIC permit to be issued by U.S. EPA Region IX, and a copy of the waiver itself will be provided to the Energy Commission CPM. The project shall not construct or discharge wastewater to these wells without the final permit in place, or without emergency/temporary authorization from U.S. EPA Region IX. The project owner shall provide on a continuing basis copies of all monitoring or other reports, and changes to the permit submitted to or received from the U.S. EPA related to the operation of these wells.

The final UIC permit and/or an emergency/temporary authorization issued by U.S. EPA Region IX for the injection wells, a copy of the ROWD accepted by the CVRWQCB, and a copy of the waiver issued by the CVRWQCB shall be provided to the Energy Commission CPM ~~30~~ 60 days prior to the start of construction of the disposal wells and/or receiving any wastewater for injection. Copies of permit changes and monitoring or other reports required by the U.S. EPA shall be provided on a continuing basis to the CPM within 30 days of their submittal to the U.S. EPA.

PROPOSED NEW CONDITIONS OF CERTIFICATION

SOILS & WATER 4: The maximum annual water use shall be limited to 3,900 acre-feet/year. The project owner shall record, on a monthly basis, the amount of groundwater purchased from WKWD by the project. This information shall be supplied to the Energy Commission in the Annual Compliance Reports.. Any significant changes in the water supply needs for the project during construction or operation of the plant shall be noticed in writing to the CPM at least 90-days prior to the effective date of the proposed change.

Verification: The project owner will submit a groundwater use summary to the CPM in the Annual Compliance Reports for the life of the project. The annual summary shall include the monthly range, monthly average, and total groundwater use by the project in both gallons-per-minute and acre-feet. Following the first year of operation, the annual summary will also include the yearly range and yearly average groundwater use by the project.

SOILS & WATER 5: The project owner shall submit a draft groundwater monitoring plan designed to monitor and report the groundwater levels within in the WKWD well field/groundwater basin on a monthly basis. The plan shall include and discuss in detail the application of the critical groundwater level for pumping, or trigger, of 230 feet bgs to the implementation of the groundwater monitoring plan. The plan will include the determination of the critical level under the following conditions:

- Groundwater levels during pumping shall be measured for all 8 WKWD wells.
- Groundwater levels shall be measured monthly.
- The pumping rate during the tests shall be monitored continuously and recorded.

- Tests must be conducted after 24 hours of continuous pumping.

- Tests must be conducted at a constant rate equal to the system-wide peak rate/6 (WKWD proposes to operate with 6 active wells plus 2 wells on standby).

The critical level will be reached when a pumping level of 230 feet bgs is measured in any 3 of the 8 WKWD wells during monthly monitoring. This threshold is based on the requirement that WKWD must maintain at least 5 wells at full pumping capacity to provide a sufficient water supply to all its customers.

The CPM shall confirm or revise the trigger level at the time the draft plan is reviewed based on further analysis of any available data. The groundwater monitoring plan shall discuss all materials, methods, information, and data used in its development. The project shall not operate without a final plan approved by the CPM in place.

Definitions:
a. Pumping level is defined as the groundwater level measured while a well is actively pumping.
b. The system-wide peak rate is defined as the peak historic summer production rate plus the peak rate for all 3 new power plants, including Sunrise II.

Verification: The project owner shall submit a draft Groundwater Monitoring Plan to the CPM that implements a procedure that uses the "trigger" or critical level of groundwater where significant impacts begin to occur for review and approval no later than 180 days prior to the start of commercial operation. A final plan must be approved by the CPM prior to the start of commercial operation.

SOILS & WATER 6: The project owner shall submit for review and approval a draft "Alternative Cooling Plan" at the end of the 2nd full year of operation that sets forth the alternative water source (e.g., reclaimed) or cooling technology option (e.g., dry cooling) or other equally effective option that the project owner shall implement if groundwater levels exceed the threshold of significant impact or trigger level. The final Alternative Cooling Plan must be approved by the CPM.

The alternatives selected in the Alternative Cooling Plan shall exhibit a high degree of water conservation and/or reuse, and shall preclude using water that would otherwise be used in the groundwater basin, or to recharge or supplement the groundwater in the basin. The "significant impact" level shall be detected using the monthly well monitoring information required by the plan designed to monitor the groundwater levels within the WKWD well field/groundwater basin in Soils and Water Condition 5.

If the critical level(s) is reached in the groundwater basin that results in significant impacts to the basin or other water users, the project owner shall have one year from the date of that determination to cease using water from this source and have a new alternative source of cooling water or alternative cooling technology in

operation, or the project shall be shutdown until the new alternative is in place and operating.

Verification: The project owner shall submit a draft Alternative Cooling Plan by the last day of the end of the 2nd full year of operation for review and final CPM approval. One year following a determination of "significant impact" notification based on the critical level trigger, the project owner shall implement the "Alternative Cooling Plan" or cease operation until such a time as the Alternative Cooling Plan is in effect.

SOILS & WATER 7: The project owner shall include in the project design and operational plan a brine concentrator, e.g., a mechanical evaporator, capable of reducing the project's total combined wastewater stream by a factor of 90 percent. The evaporated water shall be captured, condensed, and returned to the plant to reduce the water supply needs of the project. The project shall report both the pre-concentrator and post-concentrator volumes of flow and Total Dissolved Solids (TDS) of the wastewater discharge on a monthly basis. The brine concentrator shall be installed and operating within one year following the start of commercial power plant operation. The project will not operate more than one year past the start of commercial operation without the brine concentrator installed and operating.

Verification: The project owner shall submit a wastewater discharge summary to the CPM in the Annual Compliance Reports for the life of the project. The annual summary shall include the monthly range and monthly average for TDS and for total pre-concentrator and post-concentrator wastewater discharged by the project in both gallons-per-minute and acre-feet. Following the first year of operation, the annual summary will also include the yearly range and yearly average wastewater and TDS discharged by the project. The project owner will provide proof that the brine concentrator is installed and operating as required within one year following the start of commercial operation.

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