South Bay Power Plant
990 Bay Boulevard
Chula Vista, CA 91911

DYNEGY

June 14, 2010

Mr. David W. Gibson
Executive Officer
San Diego Bay Regional Water Quality Control Board
9174 Sky Park Court, Suite 100
San Diego, CA 92123

Attention: Mr. Brian Kelley

Subject: **NPDES Permit Renewal Application**
NPDES Permit No. CA0001368 (Order No. R9-2004-0154, as modified by Order No. R9-2009-0178)
Dynegy South Bay, LLC – South Bay Power Plant

Dear Mr. Gibson:

Dynegy South Bay, LLC (Dynegy) hereby submits the enclosed application to renew NPDES Permit No. CA001368 for the South Bay Power Plant (Order No. R9-2004-0154, as modified by Order No. R9-2009-0178). This renewal application seeks authorization to continue the discharge of once-through cooling water from Units 1 & 2 at the South Bay Power Plant for a five-year period commencing January 1, 2011 and continuing to December 31, 2016, or until such earlier time as the California Independent System Operator (ISO) determines that Units 1 & 2 are no longer required for reliability must run (RMR) service. As you are aware, Dynegy is contractually required by the ISO to acquire and maintain permits as long as any South Bay units remain designated as RMR. This is confirmed by the ISO's May 10, 2010 letter (copy attached) which requests that Dynegy prepare and submit an application for renewal of the NPDES permit. Given that the ISO has not provided Dynegy with any assurances that the plant will not be needed after a specified date, we are applying for renewal of the permit for the full five-year term, subject to earlier expiration upon ISO termination of RMR status for Units 1 and 2.

Please be advised that Dynegy intends to cease operations of the power plant immediately upon the termination of the RMR status of Units 1 and 2, or at such earlier time as may be required by any legally effective final compliance deadline applicable to the South Bay Power Plant, in accordance with the State Water Resources Control Board's Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (OTC Policy). Though not yet effective, the OTC Policy establishes a compliance deadline of December 31, 2011 for the South Bay Power Plant. However, that compliance deadline may be suspended or amended to maintain the reliability of the electric system, based on input from the ISO and other energy agencies, generally subject to approval by the State Board. Retrofitting the South Bay Power Plant to comply with OTC Policy-mandated reductions in impingement and entrainment is not required if the plant will not operate after its final compliance date, as such date may be suspended or amended.

Based on discussions with Brian Kelley, Senior Water Resource Control Engineer for the Regional Water Quality Control Board (RWQCB), this application includes operational and discharge data from January 1, 2010 to May 31, 2010, reflecting the time frame during which only Units 1 and 2 have been operational. This data is considered representative of current operational conditions and represents a 63% reduction in discharge flow as compared with the permit that was issued in November 2004. Units 3 and 4 have been shut down and decommissioned as of December 31, 2009 and are no longer in operation.

In response to staff's request for additional information concerning the conditions under which the plant is called upon to generate electricity, under the terms of the ISO RMR agreement, Dynegy may not operate the plant unless directed to do so by the ISO. South Bay is a Condition 2 RMR facility. Section 3.1(ii) of the contract allows the ISO to operate RMR units only for selected purposes, namely to (1) meet local reliability needs; (2) prevent overloads or to manage congestion on non-competitive paths; (3) provide reserves if and only if such reserves are not provided through the ISO markets, and (4) conduct certain tests needed to keep the unit in operation. In other words, except for infrequent tests, South Bay units run only when the ISO directs them to run, and the ISO only directs them to run when the circumstances described in the preceding sentence exist. As of the end of May 2010, Unit 1 has run 121 hours and Unit 2 has run 238 hours.

As discussed and agreed with Mr. Kelley, the California Toxics Rule Priority Pollutant data and the Storm Water Pollution Prevention Plan (SWPPP) are not being resubmitted as this information is currently contained in Dynegy's April 10, 2009 renewal application. That application (which is still pending) has been deemed complete and is hereby incorporated by reference and made a part of this application. There have been no operational changes that would adversely affect the representativeness of that data. Further, with the elimination of the discharge from Units 3 and 4 (both of which had copper condenser tubing), the amount of copper discharged by the South Bay Power Plant is necessarily less than the amount discharged when all four units were operating. We also note that the Unit 1 condenser is made of stainless steel, with no potential for contributing copper to the discharge. Accordingly, Mr. Kelley agreed that the prior data was adequate and that further analysis of the effluent is not necessary. The SWPPP that is on file at the RWQCB is unchanged and still current.

Dynegy has reviewed all pertinent regulatory requirements as they apply to this application and has determined that Dynegy has no obligation to perform or submit any additional supporting technical studies as part of this application. This conclusion has been substantiated by Mr. Kelley. In particular, we understand that the application, as submitted, contains all required information needed to demonstrate compliance with the water quality objectives, policies, plans and standards identified by staff in the Response to Comments dated May 6, 2010 (see Comment No. 25). While Dynegy, of course, will respond to any requests for additional information that RWQCB staff may need in order to draft the permit, Dynegy believes this application is complete and that it is sufficient to support renewal of the NPDES permit prior to December 31, 2010. We hereby request that the RWQCB confirm in writing that our application is timely and complete. It is our expectation that a draft permit can be prepared and presented to the Board (or State Board) for adoption no later than October of this year.

The following information is included with this letter:

- Signatory and Certification Statement; (Attachment 1)

- Contributions Disclosure Statement; (Attachment 2)

- RWQCB Form 200, including a description of Best Management Practices; (Attachment 3)

- EPA Form 1 of the Consolidated Permit Program, including Table 1 Existing Environmental Permits (Continued) and Figures 1, 2, and 3; (Attachment 4)

- EPA Form 2C of the Consolidated Permit Program, including a detailed Water Flow Diagram, Table 2 Discharge Flow Rates and Volumes, Table 3 Potential Discharges Not Covered by Analysis, and analytical data for the inlet and outfall discharge, S2; (Units 1 & 2 from 1/1/2010 through 5/31/10) (Attachment 5)

- Copy of ISO letter requesting Dynegy to prepare and submit an application for a new NPDES Permit. (Attachment 6)

In addition, at staff's request, we are also including with our application the following additional information:

- Portions of David Mayer's (Tenera Environmental) presentation from the May 12, 2010 hearing pertaining to the size of the thermal plume (mixing zone), temperature and turbidity in the vicinity of the discharge; (Attachment 7)

- Technical Memoranda prepared by Tenera Environmental analyzing the thermal, impingement and entrainment effects at a flowrate of 225 MGD (previously submitted to the RWQCB as part of the record of the proceedings on the permit); (Attachment 8)

- Oral and written testimony of Ken Andrecht, retired, Port of San Diego, relating to the historical distribution of eelgrass in the southernmost reaches of south San Diego Bay; (Attachment 9)

- Information on the plant's operating and rates of dispatch for 2010; (Attachment 10)

- Copy of RMR Agreement; (Attachment 11)

Previously submitted historical analytical data from routine monitoring of the inlet and outfall discharge is available upon request.

If you have any questions, please contact Barbara Irwin at 925-803-5121.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who managed the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Sincerely,

Daniel P. Thompson
Vice President
Dynegy West Region Operations

Enclosures and CD

cc: Barb Irwin – Dynegy
Meg Rosegay - Pillsbury
Len Cigainero – Dynegy South Bay
Andrew Ulmer - ISO

Attachment 1

Signatory and Certification Statement

SIGNATORY AND CERTIFICATION STATEMENT

I certify that:

(for a municipal, state, federal, or other public agency) I am a principal executive officer or ranking elected official; or

In the case of Federal agencies, I am the chief executive officer of the agency, or I am the senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency.

(for a partnership or sole proprietorship) I am a general partner (partnership) or a proprietor (sole proprietorship)

(for a corporation) I am President, Vice President, Secretary, or Treasurer of the corporation and in charge of a principal business function, or I perform similar policy or decision making functions for the corporation; or,

I am the manager of one or more manufacturing, production or operating facilities employing more than 250 person or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), and authority to sign documents has been assigned or delegated to me in accordance with corporate procedures.

****

SIGNATORY AND CERTIFICATION STATEMENT

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Date of Cover Letter	Description of Document
June 14, 2010	Application

Type of Organization: (please circle)

1. Sole proprietorship
2. Partnership
3. Corporation
4. Municipal
5. State, federal, or other public agency

Signature	
Name	Daniel P. Thompson
Title	Vice President, Dynegy West Region Operations
Date	June 14, 2010
Organization	Dynegy South Bay, LLC
Address	990 Bay Boulevard, Chula Vista, CA 91911
Phone Number	925-803-5102

Attachment 2

Contributions Disclosure Statement

CONTRIBUTIONS DISCLOSURE STATEMENT

Check the appropriate response:

_____X_____ I certify that Dynegy South Bay LLC
(name of applicant)
has **not** made contributions amounting to $250.00 or more to any of the current Regional Board members, within 12 months of the date of this application, for use in a federal, state, or local election.

__________ I certify that ____________________
(name of applicant)
has made contributions amounting to $250.00 or more to any of the current Regional Board members, within 12 months of the date of this application, for use in a federal, state, or local election.

Regional Board Member	Amount of Contribution

Signature	
Name	Daniel P. Thompson
Title	Vice President, Dynegy West Region Operations
Date	June 14, 2010
Organization	Dynegy South Bay, LLC
Address	990 Bay Boulevard, Chula Vista, CA 91911
Phone Number	925-803-5102

Attachment 3

RWQCB Form 200

CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY

State of California
Regional Water Quality Control Board

APPLICATION/REPORT OF WASTE DISCHARGE GENERAL INFORMATION FORM FOR WASTE DISCHARGE REQUIREMENTS OR NPDES PERMIT

I. FACILITY INFORMATION

A. Facility:

Name: Dynegy South Bay, LLC - South Bay Power Plant			
Address: 990 Bay Boulevard			
City: Chula Vista	County: San Diego	State: CA	Zip Code: 91911
Contact Person: Leonard J. Cigainero, Plant Manager		Telephone Number: (619) 498-5384	

B. Facility Owner:

Name: San Diego Unified Port District			Owner Type (Check One) 1. ☐ Individual 2. ☐ Corporation
Address: 3165 Pacific Highway			3. ☑ Governmental Agency 4. ☐ Partnership
City: San Diego	State: CA	Zip Code: 92101	5. ☐ Other:
Contact Person: Bill Hays		Telephone Number: (619) 686-6584	Federal Tax ID:

C. Facility Operator (The agency or business, not the person):

Name: Dynegy South Bay, LLC			Operator Type (Check One) 1. ☐ Individual 2. ☑ Corporation
Address: 990 Bay Boulevard			3. ☐ Governmental Agency 4. ☐ Partnership
City: Chula Vista	State: CA	Zip Code: 91911	5. ☐ Other:
Contact Person: Leonard J. Cigainero, Plant Manager		Telephone Number: (619) 498-5384	

D. Owner of the Land:

Name: San Diego Unified Port District			Owner Type (Check One) 1. ☐ Individual 2. ☐ Corporation
Address: 3165 Pacific Highway			3. ☑ Governmental Agency 4. ☐ Partnership
City: San Diego	State: CA	Zip Code: 92101	5. ☐ Other:
Contact Person:		Telephone Number: (619) 686-6200	

E. Address Where Legal Notice May Be Served:

Address: 990 Bay Boulevard		
City: Chula Vista	State: CA	Zip Code: 91911
Contact Person: Leonard J. Cigainero, Plant Manager		Telephone Number: (619) 498-5384

F. Billing Address:

Address: 990 Bay Boulevard		
City: Chula Vista	State: CA	Zip Code: 91911
Contact Person: Leonard J. Cigainero, Plant Manager		Telephone Number: (619) 498-5384

CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY

State of California
Regional Water Quality Control Board

APPLICATION/REPORT OF WASTE DISCHARGE GENERAL INFORMATION FORM FOR WASTE DISCHARGE REQUIREMENTS OR NPDES PERMIT

II. TYPE OF DISCHARGE

Check Type of Discharge(s) Described in this Application (A or B):

☐ **A. WASTE DISCHARGE TO LAND** ☑ **B. WASTE DISCHARGE TO SURFACE WATER**

Check all that apply:

☐ Domestic/Municipal Wastewater Treatment and Disposal
☑ Cooling Water
☐ Mining
☐ Waste Pile
☐ Wastewater Reclamation
☐ Animal Waste Solids
☐ Land Treatment Unit
☐ Dredge Material Disposal
☐ Surface Impoundment
☐ Industrial Process Wastewater
☐ Animal or Aquacultural Wastewater
☐ Biosolids/Residual
☐ Hazardous Waste (see instructions)
☐ Landfill (see instructions)
☑ Storm Water
☐ Other, please describe: ____________________

III. LOCATION OF THE FACILITY

Describe the physical location of the facility.

1. Assessor's Parcel Number(s)	2. Latitude	3. Longitude
Facility: 001-082-11-80	**Facility:** N32 36 50	**Facility:** W177 05 49
Discharge Point: 001-082-11-80	**Discharge Point:** N32 36 33	**Discharge Point:** W117 06 49

IV. REASON FOR FILING

☐ New Discharge or Facility
☐ Change in Design or Operation
☐ Change in Quantity/Type of Discharge
☐ Changes in Ownership/Operator (see instructions)
☑ Waste Discharge Requirements Update or NPDES Permit Reissuance
☐ Other: ____________________

V. CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

Name of Lead Agency: California Regional Water Quality Control Board, San Diego Region (SDRWQCB)

Has a public agency determined that the proposed project is exempt from CEQA? ☑ **Yes** ☐ **No**

If Yes, state the basis for the exemption and the name of the agency supplying the exemption on the line below.
Basis for Exemption/Agency: SDRWQCB per Section 13389 of the California Water Code

Has a "Notice of Determination" been filed under CEQA? ☐ **Yes** ☑ **No**

If Yes, enclose a copy of the CEQA document, Environmental Impact Report, or Negative Declaration. If no, identify the expected type of CEQA document and expected date of completion.

Expected CEQA Documents:

☐ **EIR** ☐ **Negative Declaration**

Expected CEQA Completion Date: ____________________

CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY

State of California
Regional Water Quality Control Board

APPLICATION/REPORT OF WASTE DISCHARGE
GENERAL INFORMATION FORM FOR
WASTE DISCHARGE REQUIREMENTS OR NPDES PERMIT

VI. OTHER REQUIRED INFORMATION

Please provide a COMPLETE characterization of your discharge. A complete characterization includes, but is not limited to, design and actual flows, a list of constituents and the discharge concentration of each constituent, a list of other appropriate waste discharge characteristics, a description and schematic drawing of all treatment processes, a description of any Best Management Practices (BMPs) used, and a description of disposal methods.

Also include a site map showing the location of the facility and, if you are submitting this application for an NPDES permit, identify the surface water to which you propose to discharge. Please try to limit your maps to a scale of 1:24,000 (7.5' USGS Quadrangle) or a street map, if more appropriate.

VII. OTHER

Attach additional sheets to explain any responses which need clarification. List attachments with titles and dates below:

See attached EPA Forms 1 and 2C and attachments.

You will be notified by a representative of the RWQCB within 30 days of receipt of your application. The notice will state if your application is complete or if there is additional information you must submit to complete your Application/Report of Waste Discharge, pursuant to Division 7, Section 13260 of the California Water Code.

VIII. CERTIFICATION

"I certify under penalty of law that this document, including all attachments and supplemental information, were prepared under my direction and supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment."

Print Name: Daniel P. Thompson   Title: VP, Dynegy West Region Operations

Signature: [signature]   Date: June 14, 2010

FOR OFFICE USE ONLY

Date Form 200 Received:	Letter to Discharger:	Fee Amount Received:	Check #:

Dynegy South Bay Power Plant
Description of Best Management Practices

Dynegy South Bay, LLC (Dynegy) implements and performs Best Management Practices (BMPs) related to potential sources of pollutants from plant activities which could be released to storm water, from the plant's service water system (closed-loop cooling water system), and the plant's once-through cooling water system.

Dynegy's Storm Water Pollution Prevention Plan (SWPPP) evaluates the facility and activities for their potential to release pollutants to storm water run-off from the site and identifies structural and nonstructural BMPs to minimize the release of pollutants. The SWPPP also addresses preventative maintenance, housekeeping, employee training, etc. The SWPPP was previously provided to the Region Water Board with the April 10, 2009 renewal application and is not attached with this application. This version of the SWPPP is current and up to date.

A general description of additional BMPs is included for the following systems:

Cooling Water Chlorination System

Sodium hypochlorite is used in the intermittent chlorination of the cooling water system. Bulk deliveries of sodium hypochlorite are made by tanker trucks to a single tank located on the cooling water deck. This tank has secondary containment to prevent the release of sodium hypochlorite in the event of a tank rupture. The containment has a locked drain for the release of storm water after visual inspections are performed. The chlorination system is routinely checked on a daily basis by operational and/or laboratory personnel.

Service Water System

The facility utilizes a closed-loop cooling water system to cool auxiliary equipment; these systems are referred to as service water systems. Anticorrosion chemicals are used in the systems to maintain reliable service. In the event of a leak from a service water heat exchanger tube or tubesheet, service water may discharge directly into the once-through cooling water system. Cooling Water Heat Exchangers have been retrofitted with impressed current cathodic protection systems to eliminate the use of zinc sacrificial anodes. The current cathodic protection systems are monitored weekly and protect the condenser waterboxes, tubesheets, and the portion of the tubes immediately adjacent to the tubesheets from corrosion. The routine checks of the system are used to determine whether maintenance needs to be performed and verifies that the protection system is operating properly and that an adequate level of cathodic protection exits. In addition, to detect leaks, the service water levels in the system collector tanks are measured once an hour. Any significant change is investigated to determine whether the change in tank level is from a leak or an operational change.

Dynegy South Bay Power Plant
Description of Best Management Practices

Cooling Water System

The condensers on all the units have been retrofitted with impressed current cathodic protection systems to eliminate the use of zinc sacrificial anodes in the condensers. The current cathodic protection systems are monitored weekly and protect the condenser waterboxes, tubesheets, and the portion of the tubes immediately adjacent to the tubesheets from corrosion. The routine checks of the system are used to determine whether maintenance needs to be performed and verifies that the protection system is operating properly and that an adequate level of cathodic protection exits.

There is potential to release significant amounts of toxic or hazardous pollutants to waters of the United States from all the above systems due to equipment failure, improper operation, or natural phenomena. The Best Management Practices listed above have been put in place to reduce the potential for releases to an insignificant level.

Attachment 4

EPA Form 1

Please print or type in the unshaded areas only
(fill-in areas are spaced for elite type, i.e., 12 characters/inch).

Form Approved. OMB No. 2040-0086. Approval expires 5-31-9

FORM 1 GENERAL	EPA	U.S. ENVIRONMENTAL PROTECTION AGENCY **GENERAL INFORMATION** *Consolidated Permits Program* *(Read the "General Instructions" before starting.)*	1. EPA I.D. NUMBER
			S F: CAT000619056 T/A . C D (1 2 14 15)

LABEL ITEMS

I. EPA I.D. NUMBER

III. FACILITY NAME

V. FACILITY MAILING ADDRESS

VI. FACILITY LOCATION

PLEASE PLACE LABEL IN THIS SPACE

GENERAL INSTRUCTIONS

If a preprinted label has been provided, affix it in the designated space. Review the information carefully; if any of it is incorrect, cross through it and enter the correct data in the appropriate fill- in area below. Also, if any of the preprinted data is absent (the area to the left of the label space lists the information that should appear,) please provide it in the proper fill-in area(s) below. If the label is complete and correct, you needs not complete Items I, III, V, and VI (except VI-B which must be completed regardless.) Complete all items if no label has been provided. Refer to the instructions for detailed item descriptions and for the legal authorizations under which this data is collected.

II. POLLUTANT CHARACTERISTICS

INSTRUCTIONS: Complete A through J to determine whether you need to submit any permit application forms to the EPA. If you answer "yes" to any questions, you must submit this form and the supplemental form listed in the parenthesis following the question. Mark "x" in the box in the third column if the supplemental form is attached. If you answer "no" to each question, you need not submit any of these forms. You may answer "no" if your activity is excluded from permit requirements; see Section C of the instructions. See also, Section D of the instructions for definitions of bold-faced terms.

SPECIFIC QUESTIONS	MARK "X" YES	NO	FORM ATTACHED	SPECIFIC QUESTIONS	MARK "X" YES	NO	FORM ATTACHED
A. Is this facility a publicly owned treatment works which results in a discharge to waters of the U.S. (FORM 2A)		X		B. Does or will this facility (*either existing or proposed*) include a concentrated animal feeding operation or aquatic animal production facility which results in a discharge to waters of the U.S.? (FORM 2B)		X	
	16	17	18		16	17	18
C. Is this a facility which currently results in discharges to waters of the U.S. other than those described in A or B above? (FORM 2C)	X		X	D. Is this a proposed facility (*other than those described in A or B above*) which will result in a discharge to waters of the U.S.? (FORM 2D)		X	
	22	23	24		22	23	24
E. Does or will this facility treat, store or dispose of hazardous wastes? (FORM 3)	X		No	F. Do you or will you inject at this facility industrial or municipal effluent below the lowermost stratum containing, within one quarter mile of the well bore, underground sources of drinking water?		X	
	28	29	30		28	28	29
G. Do you or will you inject at this facility any produced water or other fluids which are brought to the surface in connection with conventional oil or natural gas production, inject fluids used for enhanced recovery of oil or natural gas, or inject fluids for storage of liquid hydrocarbons? (FORM 4)		X		H. Do you or will you inject at this facility fluids for special processes wuch as mining of sulfur by the Frasch process, solution mining of minerals, in situ combustion of fossil fuel, or recovery of geothermal energy? (FORM 4)		X	
	34	35	36		34	35	36
I. Is this facility a proposed stationary source which is one of the 28 industrial categories listed in the instruction and which will potentially emit 100 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an attainment area? (FORM 5)		X		J. Is this facility a proposed stationary source which is NOT one of the 28 industrial categories listed in the instruction and which will potentially emit 250 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an attainment area? (FORM 5)		X	
	40	41	42		40	41	42

III. NAME OF FACILITY

C		
1	SKIP	Dynegy South Bay, LLC - South Bay Power Plant
15	16-29	30 ... 69

IV. FACILITY CONTACT

C	A. NAME & TITLE *(last, first & title)*	B. PHONE (area code & no.)		
2	Cigainero, Leonard J. Plant Manager	619	498	5384
15	16 ... 45	46 - 48	49 - 51	52-55

V. FACILITY MAILING ADDRESS

C	A. STREET OR P.O. BOX
3	990 Bay Boulevard
15	16 ... 45

C	B. CITY OR TOWN	C. STATE	D. ZIP CODE
4	Chula Vista	CA	91911
15	16 ... 40	41 42	47 - 51

VI. FACILITY LOCATION

C	A. STREET, ROUTE NO. OR OTHER SPECIFIC IDENTIFIER
5	990 Bay Boulevard
15	16 ... 45

B. COUNTY NAME
San Diego
46 ... 77

C	C. CITY OR TOWN	C. STATE	D. ZIP CODE	F. COUNTY CODE *(if known)*
6	Chula Vista	CA	91911	073
15	16 ... 60	41 - 42	47 - 51	52 - 54

CONTINUED FROM THE FRONT

VIII. SIC CODES (4 digit, in order of priority)

A. FIRST		B. SECOND	
4911	(SPECIFY) Electric Power Generation		(SPECIFY)
C. THIRD		**D. FOURTH**	
	(SPECIFY)		(SPECIFY)

VIII. OPERATOR INFORMATION

A. NAME: Dynegy South Bay, LLC

B. Is the name listed in Item VIII-A also the owner? ☐ YES ☒ NO

C. STATUS OF OPERATOR (Enter the appropriate letter into the answer box; if "Other", specify)

F= FEDERAL M= PUBLIC (OTHER THAN FEDERAL OR STATE)
S= STATE O= OTHER (SPECIFY)
P= PRIVATE

P (specify)

D. PHONE (area code & no.): 619 498 5385

E. STREET OR P.O. BOX: 990 Bay Boulevard

F. CITY OR TOWN	G. STATE	H. ZIP CODE
Chula Vista	CA	91911

IX. INDIAN LAND

Is the facility located on Indian lands? ☐ YES ☒ NO

X. EXISTING ENVIRONMENTAL PERMITS

A. NPDES (Discharge to Surface Water)	CA0001368, R9-2004-0154	D. PSD (Air Emissions from Proposed Sources)	(SPECIFY) Title V Air Permit
B. UIC (Underground Injection of Fluids)		E. OTHER (Specify): See Attached List on Table 1	(SPECIFY)
C. RCRA (Hazardous Wastes)		E. OTHER (Specify)	(SPECIFY)

XI. MAP

Attach to this application a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluids underground. Include all springs, rivers and other surface water bodies in the map area. See instructions for precise requirements.

XII. NATURE OF BUSINESS (provide a brief description)

Electric Power Generation

XIII. CERTIFICATION (see instructions)

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe that the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

A. NAME & OFFICIAL TITLE (type or print)	B. SIGNATURE	C. DATE SIGNED
Daniel P. Thompson Vice President, Dynegy West Region Operations		June 14, 2010

COMMENTS FOR OFFICIAL USE ONLY

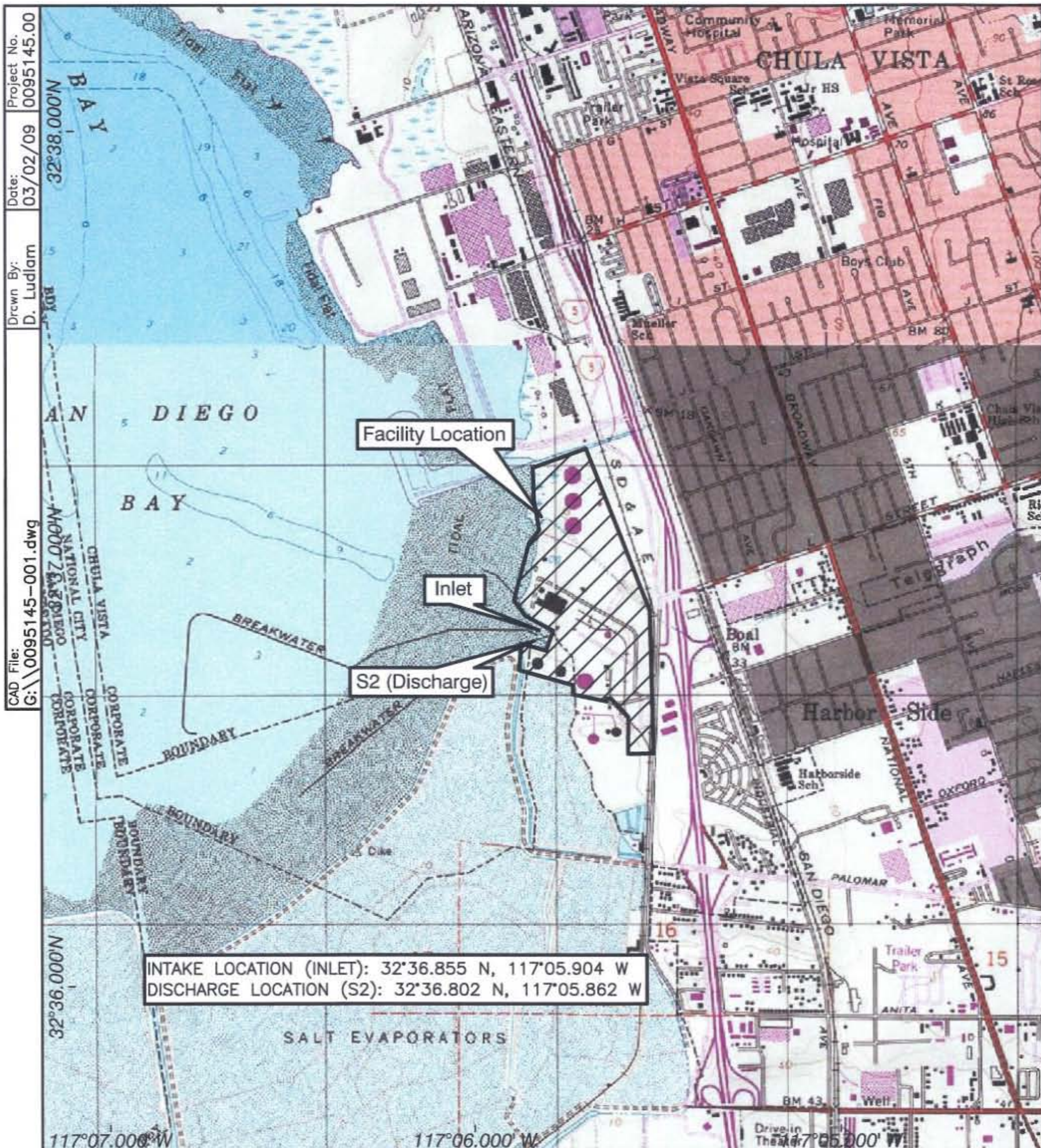
Dynegy South Bay Power Plant
Existing Environmental Permits (Continued)

Permit Name	Permit Number	Expiration Date	Jurisdictional Agency
Air Quality Permit to Operate (PTO) Boiler Number 1	000794	3/31/2011	San Diego Air Pollution Control District (SDAPCD)
Air Quality Permit to Operate (PTO) Boiler Number 2	000795	3/31/2011	SDAPCD
Air Quality PTO Emergency Fire Fighting Water Pump - Propane Engine Set	921148	3/31/2011	SDAPCD
Air Quality PTO Emergency Engine Generator Set	940438	3/31/2011	SDAPCD
Air Quality PTO Emergency Engine Generator Set	940439	3/31/2011	SDAPCD
Air Quality PTO Gas Turbine Generator	001276	3/31/2011	SDAPCD
Title V Permit and Title IV Permit	Renewal Application Submitted (11/30/07). No action to date by the SDAPCD on renewal application.	12/5/2008	SDAPCD, USEPA
Title V Permit and Title IV Permit	Notification made, removing Units 3 & 4 from permit	1/6/2010, 1/7/2010	SDAPCD, USEPA
Tiered Permit - Unit SB - WWT-1	EPA ID No. CAT000619056	Close by SD Department of Environmental Health - 6/15/2009	San Diego Department of Health
Business Emergency Plan/Hazardous Materials Inventory	H13939	Plan updated February 2010	San Diego Department of Environmental Health
Storm Water Discharge General Permit	NPDES General Permit No. CAS000001, Water Quality Order No. 97-03-DWQ	None	State Water Resources Control Board
Industrial User Discharge Permit	13-0279-03A	4/1/2011	Chula Vista Department of Public Works, San Diego Metropolitan Wastewater Department
Unified Program Facility Permit	HK07-113939	3/31/2011	San Diego Department of Health

CAD File:	Drawn By:	Date:	Project No.
G:\\0095145-001.dwg	D. Ludlam	03/02/09	0095145.00

Figure 1
Vicinity Map
Dynegy South Bay, LLC
South Bay Power Plant
Chula Vista, California

ERM *02/09*



SCALE 1:24,000

1 — 1/2 — 0 — 1 MILE

1000 — 0 — 1000 — 2000 — 3000 — 4000 — 5000 — 6000 — 7000 FEET

1 — .5 — 0 — 1 KILOMETER

N

References:
U.S.G.S. 7.5 Minute Series (Topographic) Quadrangle, Imperial Beach, California
Dated: 1980

Figure 2
Site Map
Dynegy South Bay, LLC
South Bay Power Plant
Chula Vista, California

ERM *02/09*

CAD File:	Drawn By:	Date:	Project No.
G:\\0095145-002.dwg	D. Ludlam	04/19/09	0095145.00

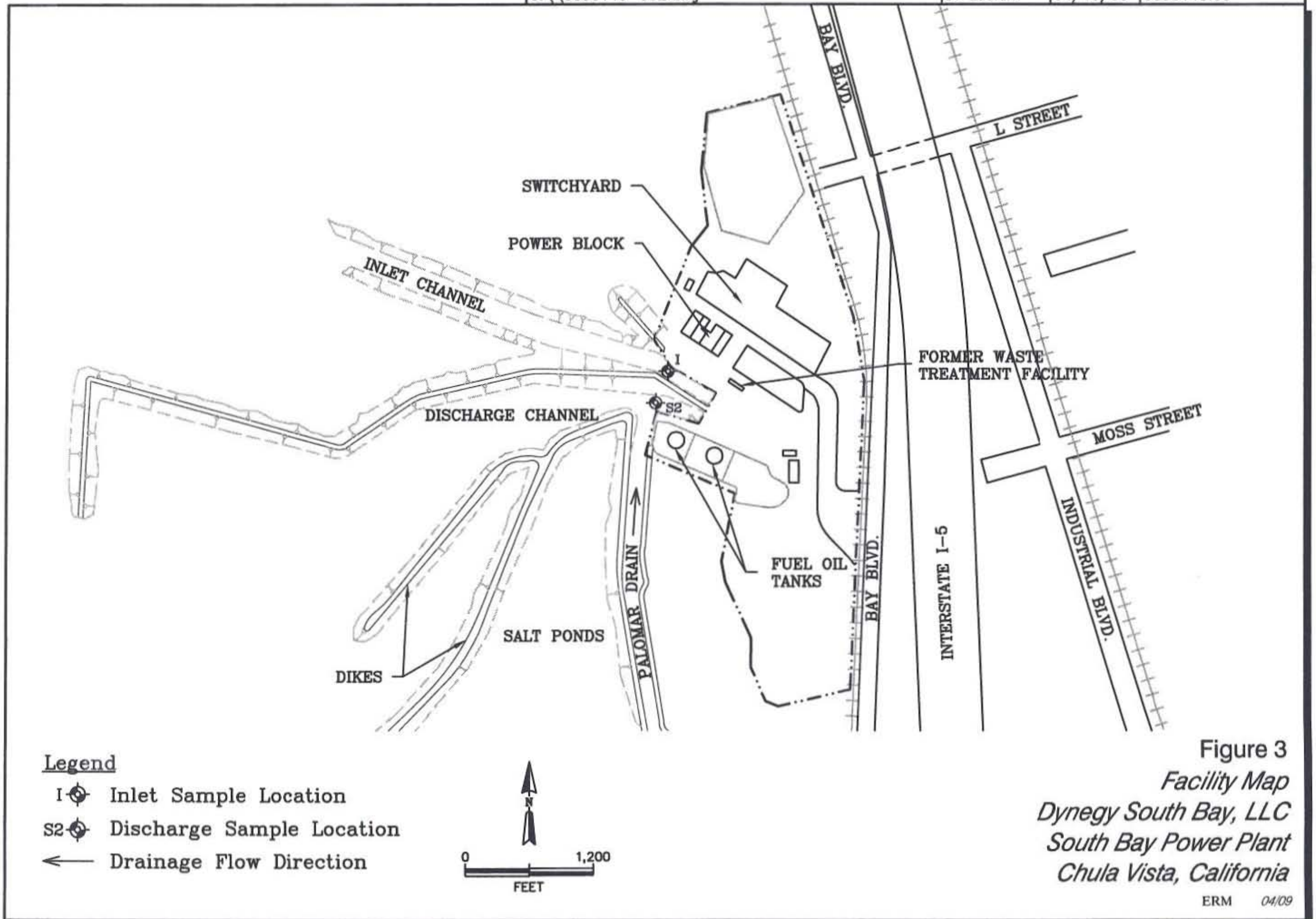


Figure 3
Facility Map
Dynegy South Bay, LLC
South Bay Power Plant
Chula Vista, California

ERM *04/09*

Attachment 5

EPA Form 2C

Please print or type in the unshaded areas only

EPA I.D. NUMBER (*copy from Item 1 of Form 1*)
CAT000619056

Form Approved
OMB No. 2040-0086
Approval expires 3-31-98.

FORM 2C NPDES

EPA

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR PERMIT TO DISCHARGE WASTEWATER
EXISTING MANUFACTURING, COMMERCIAL, MINING AND SILVICULTURAL OPERATION
Consolidated Permits Program

I. OUTFALL LOCATION

For each outfall, list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

A. OUTFALL NUMBER (*list*)	B. LATITUDE 1. DEG.	B. LATITUDE 2. MIN.	B. LATITUDE 3. SEC.	C. LONGITUDE 1. DEG.	C. LONGITUDE 2. MIN.	C. LONGITUDE 3. SEC.	D. RECEIVING WATER (*name*)
S2	32	36	48	117	5	52	San Diego Bay

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (*e.g., for certain mining activities*), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

1. OUT-FALL No. (*list*)	2. OPERATION(S) CONTRIBUTING FLOW: a. OPERATION (*list*)	b. AVERAGE FLOW[1] (*include units*)	3. TREATMENT: a. DESCRIPTION	b. LIST CODES FROM TABLE 2C-1	
S2	**Once-Through Cooling Water**	**225 mgd**	Discharge to Surface Water	4-A	
	(see Water Flow Diagram for complete		Screening	1-T	
	description of discharges associated with		Chlorination	2-F	
	with S2)				
	Traveling Screen Washwater	**0.78 mgd**	Discharge to Surface Water	4-A	
	Pump Lubrication and Seal Water and	**0.063 mgd**	Discharge to Surface Water	4-A	
	Pre-treatment Backwash		Screening	1-T	
	Storm Water Runoff	**0.05 mgd[2]**	Discharge to Surface Water	4-A	
			Best Management Practices		

[1] Continuous (during Plant operation), intermittent, and seasonal flow data to S2 are summarized in Table 2

[2] Total storm water average flow to intake and discharge channels is approximately 0.09 mgd, based on a 25-year, 24-hour storm. Storm water runoff is managed under SWRCB NPDES General Permit for Industrial Activities, Permit No. CAS000001, Order No. 97-03-DWQ.

OFFICIAL USE ONLY (*effluent guidelines sub-categories*)

CONTINUED FROM THE FRONT

C. Except for storm runoff, leaks, or spills, are any of the discharges described in Items II-A or B intermittent or seasonal?

☑ YES *(complete the following table)* ☐ NO *(go to Section III)*

1. OUTFALL NUMBER *(list)*	2. OPERATION(s) CONTRIBUTING FLOW *(list)*	3. FREQUENCY a. DAYS PER WEEK *(specify average)*	3. FREQUENCY b. MONTHS PER YEAR *(specify average)*	4. FLOW a. FLOW RATE *(in mgd)* 1. LONG TERM AVERAGE	4. FLOW a. FLOW RATE *(in mgd)* 2. MAXIMUM DAILY	4. FLOW b. TOTAL VOLUME *(specify with units)* 1. LONG TERM AVERAGE	4. FLOW b. TOTAL VOLUME *(specify with units)* 2. MAXIMUM DAILY	4. FLOW c. DURATION *(in days)*
S2	Forebay Cleaning Water	2 days per 6 months		0.001	0.114	0.4 mg	0.115 mg	4
	Units 1 and 2 Circulating Water Pump Station Sump Water	*	*	0.0002	0.004	0.06 mg	0.004 mg	*
		*Unable to quantify frequency. Intermittent, on-demand operation. Estimate annual and long-term average based on 15 days, 24-hour continuous operation of both pumps.						

III. PRODUCTION

A. Does an effluent guideline limitation promulgated by EPA under Section 304 of the Clean Water Act apply to your facility?

☑ YES *(complete Item III-B)* ☐ NO *(go to Section IV)*

B. Are the limitations in the applicable effluent guideline expressed in terms of production *(or other measure of operation)*?

☐ YES *(complete Item III-C)* ☑ NO *(go to Section IV)*

C. If you answered "yes" to Item III-B, list the quantity which represents an actual measurement of your level of production, expressed in terms and units used in the applicable effluent guideline, and indicate the affected outfalls.

1. AVERAGE DAILY PRODUCTION a. QUANTITY PER DAY	b. UNITS OF MEASURE	c. OPERATION, PRODUCT, MATERIAL, ETC. *(specify)*	2. AFFECTED OUTFALLS *(list outfall numbers)*

IV. IMPROVEMENTS

A. Are you now required by any Federal, State or local authority to meet any implementation schedule for the construction, upgrade or operation of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement orders, enforcement compliance schedule letters, stipulations, court orders, and grant or loan conditions.

☐ YES *(complete the following table)* ☑ NO *(go to Item IV-B)*

1. IDENTIFICATION OF CONDITION, AGREEMENT, ETC.	2. AFFECTED OUTFALLS a. NO.	2. AFFECTED OUTFALLS b. SOURCE OF DISCHARGE	3. BRIEF DESCRIPTION OF PROJECT	4. FINAL COMPLIANCE DATE a. REQUIRED	4. FINAL COMPLIANCE DATE b. PROJECTED

B. OPTIONAL: You may attach additional sheets describing any additional water pollution control programs (*or other environmental projects which may affect your discharges*) you now have underway or which you plan. Indicate whether each program is now underway or planned, and indicate your actual or planned schedules for construction.

☐ MARK "X" IF DESCRIPTION OF ADDITIONAL CONTROL PROGRAMS IS ATTACHED

CONTINUE ON PAGE 3

EPA I.D. NUMBER *(copy from Item 1 of Form 1)*
CAT000619056

CONTINUED FROM PAGE 2

V. INTAKE AND EFFLUENT CHARACTERISTICS

A, B, & C: See instructions before proceeding - Complete one set of tables for each outfall - Annotate the outfall number in the space provided.
NOTE: Tables V-A, V-B, and V-C are included on separate sheets numbered V-1 through V-9.

D. Use the space below to list any of the pollutants listed in Table 2c-3 of the instructions, which you know or have reason to believe is discharged or may be discharged from any outfall, For every pollutant you list, briefly describe the reasons you believe it to be present and report any analytical data in your possession.

1. POLLUTANT	2. SOURCE	1. POLLUTANT	2. SOURCE
None			

VI. POTENTIAL DISCHARGES NOT COVERED BY ANALYSIS

Is any pollutant listed in Item V-C a substance or a component of a substance which you currently use or manufacture as an intermediate or final product or byproduct?

☑ YES *(list all such pollutants below)* ☐ NO *(go to Item VI-B)*

Bromoform - byproduct of closed-loop cooling water system chlorination
Dichlorobromomethane - byproduct of closed-loop cooling water system chlorination
Chlorodibromomethane - byproduct of closed-loop cooling water system chlorination
Chloroform - byproduct of closed-loop cooling water system chlorination

See Table 3 for list of potential chemicals in water discharge.

CONTINUED FROM THE FRONT

VII. BIOLOGICAL TOXICITY TESTING DATA

Do you have any knowledge or reason to believe that any biological test for acute or chronic toxicity has been made on any of your discharge or on a receiving water in relation to your discharge within the last 3 years?

☑ YES *(identify the test(s) and describe their purposes below)* ☐ NO *(go to Section VIII)*

Dynegy contracts with Weston Solutions, Inc. to conduct monthly acute static renewal percent survival aquatic toxicity tests to mysid shrimp (*Mysidopsis bahia*, renamed *Americamysis bahia*) and monthly chronic definitive bioassays to giant kelp (Macrocystis pyrifera), as required by the NPDES permit.

VIII. CONTRACT ANALYSIS INFORMATION

Where any of the analyses reported in Item V performed by a contract laboratory or consulting firm?

☑ YES *(identify list the name, address, and telephone numbr of, and pollutants analyzed by, each such laboratory or firm below)* ☐ NO *(go to Section IX)*

A. NAME	B. ADDRESS	C. TELEPHONE *(area code & no.)*	D. POLLUTANTS ANALYZED *(list)*
San Diego Gas & Electric	**6555 Nancy Ridge Drive, Suite 300 San Diego, CA 92121**	**858-503-5371**	**All compounds tested in Item V are analyzed by San Diego Gas & Electric or one of their subcontracted laboratories such as:**
EMS Laboratories Inc.	**117 West Bellevue Drive Pasadena, CA 91105**	**(626) 568-4065**	**Asbestos**
Weston Solutions	**2433 Impala Drive Carlsbad, CA 92008**	**(760) 795-6900**	**Acute and Chronic Toxicity**

IX. CERTIFICATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

A. NAME AND OFFICIAL TITLE *(type or print)*	B. PHONE NO. *(area code & no.)*
Daniel P. Thompson **Vice President, Dynegy West Region Operation**	**(925) 803-5102**
C. SIGNATURE	D. DATE SIGNED **June 14, 2010**

Dynegy South Bay Power Plant
Discharge Flow Rates and Volumes

Table 2
EPA Form 2C
Section II

Outfall	Waste Stream Description	Duration	Nominal Flow Rate (gpm)	Maximum Flow Rate (gpm)	Annual Total Volume (gal)	Maximum Daily Volume (gal)	Long-Term Average Flow Rate Calculated (gpd)	Long-Term Average Flow Rate Rounded (gpd)
S2								
	Once-Through Cooling Water (Units 1-2 circulating pumps only)	Continuous	140,400	156,000	7.38E+10	2.25E+08	2.02E+08	2.02E+08
	Traveling Screen Washwater[1]	Continuous	494	549	2.60E+08	790,560	711,504	700,000
	Pump Lubrication and Seal Water and Pre-treatment Backwash	Continuous	40	44	2.31E+07	63,360	63,360	65,000
	Forebay Cleaning Washwater	Intermittent	71	79	180,120	113,760	493	500
	Units 1 and 2 Circulating Water Pump Station Sump Water[2]	Intermittent	3	3	64,800	4,320	178	200
	Storm Water Runoff [3]	*Seasonal*			*338,000*	*51,000*		

Footnotes:

[1] Combined traveling screen washwater from Units 1- 2 intake structures that discharges to San Diego Bay via traveling screen washwater conduit. Approximately 50 percent of washwater falls back into the intake and 50 percent is discharged via traveling screen washwater conduit to the discharge channel.

[2] Two sump pumps normally operate with only one pump operating at a time to maintain a dry sump. If water level is high, then both start and run as long as necessary for sump to be pumped down. Assumed annual average flow rate operation is 24 hours/day for 15 days with both pumps running.

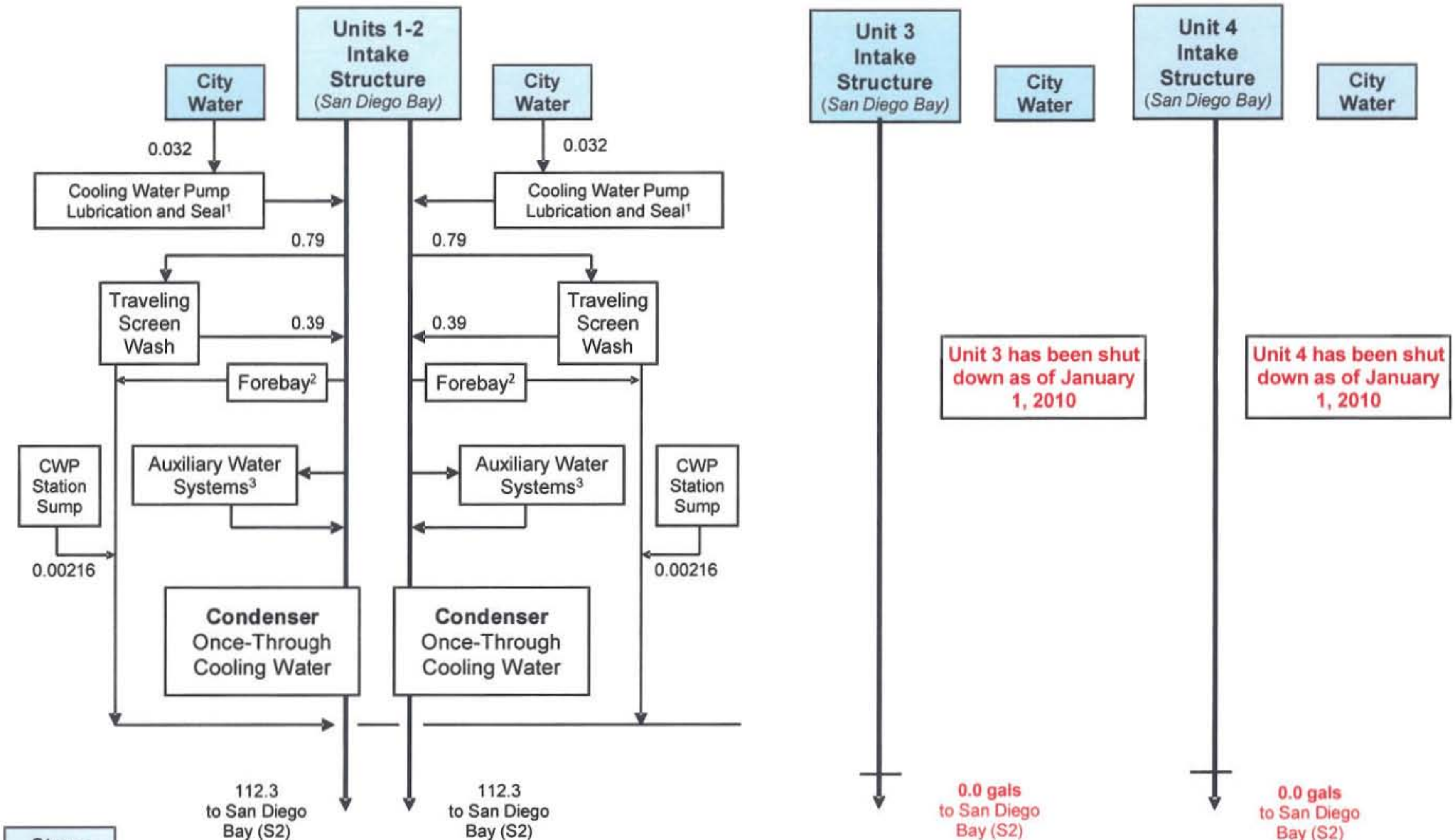
[3] Assumed annual average precipitation is 9.9 inches (San Diego County Water Authority 2008). Storm water runoff is managed under the State Water Board NPDES General Permit for Industrial Activities.

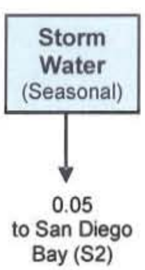
Dynegy South Bay Power Plant
Effluent Characteristics
Potential Discharges Not Covered By Analysis

A complete list of chemicals used in large quantities is updated annually in the Hazardous Materials Business Plan. The storage and use of chemicals at South Bay Power Plant is conducted in strict conformance with regulatory and internal procedures. As such, the discharge of any of these chemicals is highly unlikely because of the controls and operating procedures that are in place.

Chemical	Description
Aqueous solution of phosphate, polyacrylate, borate, tolytriazole, molybolate, sodium hydroxide	A corrosion inhibitor used in the closed-cycle cooling water system.
Alfalfa/hay pellets	Used to control or plug condenser leaks.
Dodecylguanidine hydrochloride methylene bis(thiocyanate) isopropyl alcohol	A biocide used to control microbial induced corrosion in the closed-cycle cooling water system.
Sodium hypochlorite	Used to control biofouling in the condensers.

Dynegy South Bay Power Plant
Water Flow Diagram





Notes:

CWP = circulating water pump

All flow rates are maximum rates in million gallons per day (mgd); traveling screen rates based on maximum 24-hour continuous operation

[1]Maximum combined flow rate from lubrication and seal water coupled with lubrication and seal water pre-treatment backwash is 0.063 mgd

[2]Forebay comprise dewatering discharge and forebay cleaning wash water on each unit once or twice a year, maximum combined daily flow rate is 0.115 mgd

[3]Auxiliary water systems comprise water from two salt water heat exchanger cooling systems (Units 1-2), condenser pre-filter and ball re-circulation system (Unit 1 only), and two condensate generator cooling systems (Units 1 and 2)

PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets *(use the same format)* instead of completing these pages.
SEE INSTRUCTIONS.

EPA I.D. NUMBER *(copy from Item 1 of Form 1)*
CAT000619056

V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO S2

PART A – You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details

1. POLLUTANT	2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE *(if available)*		c. LONG TERM AVRG. VALUE *(if available)*		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand *(BOD)*												
b. Chemical Oxygen Demand *(COD)*												
c. Total Organic Carbon *(TOC)*												
d. Total Suspended Solids *(TSS)*	**56.0**	**38.9**			**24.1**	**16.7**	**5**	**mg/L**	**ton**	**29.8**	**20.7**	**5**
e. Ammonia *(as N)*												
f. Flow	VALUE **167.0**		VALUE		VALUE **37.8**		**daily**	**MGD**		VALUE **225.0**		**daily**
g. Temperature *(winter)* Jan-Apr	VALUE **33.2**		VALUE		VALUE **19.0**		**daily**	°C		**16.6**		**daily**
h. Temperature *(summer)* May-Oct	VALUE **28.3**		VALUE		VALUE **24.0**					**21.8**		
i. pH	MINIMUM **7.50**	MAXIMUM **8.08**	MINIMUM	MAXIMUM			**20**	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete on table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. *(if available)*	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE *(optional)*		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE *(if available)*		c. LONG TERM AVRG. VALUE *(if available)*		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)														
b. Chlorine, Total Residual	X		**0.04**	**0.04**					**20**	**mg/l**	**ton**	**0.04**	**0.03**	**20**
c. Color														
d. Fecal Coliform														
e. Fluoride (16984-48-8)														
f. Nitrate-Nitrite (as N)														

Note: All data values , including intake long-term average, for total suspended solids, flow, temperature, pH, oil and grease, and total residual chlorine taken from January - May 2010. Temperature data based on monthly average temperatures, as reported in 2010 DMRs. Mass calculated using maximum daily flow from 2010 (167.0 mgd); nondetect (ND) mass calculations use RL or MDL as concentration. "<" = nondetect. Please see the April 10, 2009 application for all other data.

ITEM V-B CONTINUED FROM FRONT

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	a. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (2) MASS	d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	a. LONG TERM AVERAGE VALUE (2) MASS	b. NO. OF ANALYSES
g. Nitrogen, Total Organic (*as N*)														
h. Oil and Grease	X		2.5	1.7			1.6	1.1	5	mg/l	ton			
i. Phosphorus (*as P*), Total (7723-14-0)														
j. Radioactivity														
(1) Alpha, Total														
(2) Beta, Total														
(3) Radium, Total														
(4) Radium 226, Total														
k. Sulfate (*as SO_4*) (14808-79-8)														
l. Sulfide (*as S*)														
m. Sulfite (*as SO_3*) (14265-45-3)														
n. Surfactants														
o. Aluminum, Total (7429-90-5)														
p. Barium, Total (7440-39-3)														
q. Boron, Total (7440-42-8)														
r. Cobalt, Total (7440-48-4)														
s. Iron, Total (7439-89-6)														
t. Magnesium, Total (7439-95-4)														
u. Molybdenum, Total (7439-98-7)														
v. Manganese, Total (7439-96-5)														
w. Tin, Total (7440-31-5)														
x. Titanium, Total (7440-32-6)														

 CONTINUE ON PAGE V-3

Note: All data values for oil and grease taken from January - May 2010. Mass calculated using maximum daily flow from 2010 (167.0 mgd); nondetect (ND) mass calculations use RL or MDL as concentration. "<" = nondetect "J" = estimated value. Please see April 10, 2009 application for all other data.

EPA I.D. NUMBER (*copy from Item 1 of Form 1*)	OUTFALL NUMBER
CAT080011703	S2

CONTINUED FROM PAGE 3 OF FORM 2-C

PART C – If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant of you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (all 7 pages) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. (2) MASS	d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	a. (2) MASS	b. NO. OF ANALYSES
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)															
2M. Arsenic, Total (7440-38-2)	X			6.3	0.004					5	µg/l	ton	1.9 J	0.001 J	1
3M. Beryllium, Total (7440-41-7)															
4M. Cadmium, Total (7440-43-9)	X			ND (MDL = 0.040)	ND <0.0000					5	µg/l	ton	ND (MDL = 0.040)	ND <0.00003	1
5M. Chromium, Total (7440-47-3)	X			1.3	0.001					5	µg/l	ton	ND (MDL = 0.43)	ND <0.000	1
6M. Copper, Total (7440-50-8)	X			4.29	0.003					5	µg/l	ton	4.01	0.003	5
7M. Lead, Total (7439-92-1)	X			ND (MDL = 5.0)	ND <0.0035					5	µg/l	ton	ND (MDL = 5.0)	ND <0.0035	1
8M. Mercury, Total (7439-97-6)	X			ND (MDL = 0.0028)	ND <0.000002					5	µg/l	ton	ND (MDL = 0.0028)	ND <0.000002	1
9M. Nickel, Total (7440-02-0)															
10M. Selenium, Total (7782-49-2)															
11M. Silver, Total (7440-22-4)	X			ND (MDL = 0.017)	ND <0.000012					5	µg/l	ton	ND (MDL = 0.017)	ND <0.000012	1
12M. Thallium, Total (7440-28-0)															
13M. Zinc, Total (7440-66-6)	X			7.6 J	0.01 J					5	µg/l	ton	7.6 J	0.01 J	1
14M. Cyanide, Total (57-12-5)															
15M. Phenols, Total															
DIOXIN															
2,3,7,8 Tetra-chlorodibenzo-P Dioxin (1764-01-6)															

CONTINUE ON PAGE V-4

Note: All data values taken from 2010. Mass calculated using maximum daily flow from 2010 (167 mgd); nondetect (ND) mass calculations use method detection limit (MDL) as the concentration.
Data values for arsenic, cadmium, chromium, copper, mercury, and zinc taken from January - May 2010. "<" = nondetect "J" = estimated value. Please see April 10, 2009 application for all other data.

CONTINUED FROM THE FRONT

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATI	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Acrolein (107-02-8)															
2V. Acrylonitrile (107-13-1)															
3V. Benzene (71-43-2)															
4V. Bis (*Chloro-methyl*) Ether (542-88-1)															
5V. Bromoform (75-25-2)															
6V. Carbon Tetrachloride (56-23-5)															
7V. Chlorobenzene (108-90-7)															
8V. Chlorodi-bromomethane (124-48-1)															
9V. Chloroethane (75-00-3)															
10V. 2-Chloro-ethylvinyl Ether (110-75-8)															
11V. Chloroform (67-66-3)															
12V. Dichloro-bromomethane (75-27-4)															
13V. Dichloro-difluoromethane (75-71-8)															
14V. 1,1-Dichloro-ethane (75-34-3)															
15V. 1,2-Dichloro-ethane (107-06-2)															
16V. 1,1-Dichloro-ethylene (75-35-4)															
17V. 1,2-Dichloro-propane (78-87-5)															
18V. 1,3-Dichloro-propylene (542-75-6)															
19V. Ethylbenzene (100-41-4)															
20V. Methyl Bromide (74-83-9)															
21V. Methyl Chloride (74-87-3)															

 CONTINUE ON PAGE V-5

Note: Please see April 10, 2009 application for all other data.

CONTINUED FROM PAGE V-4

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE (1) CONCENTRATION	(2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	(2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	(2) MASS	d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	(2) MASS	b. NO. OF ANALYSES
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)															
23V. 1,1,2,2-Tetrachloroethane (79-34-5)															
24V. Tetrachloro-ethylene (127-18-4)															
25V. Toluene (108-88-3)															
26V. 1,2-Trans-Dichloroethylene (156-60-5)															
27V. 1,1,1-Trichloro-ethane (71-55-6)															
28V. 1,1,2-TriChloro-ethane (79-00-5)															
29V. Trichloro-ethylene (79-01-6)															
30V. Trichloro-fluoromethane (75-69-4)															
31V. Vinyl Chloride (75-01-4)															
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)															
2A. 2,4-Dichloro-phenol (120-83-2)															
3A. 2,4-Dimethyl-phenol (105-67-9)															
4A. 4,6-Dinitro-0-Cresol (534-52-1)															
5A. 2,4-Dinitro-phenol (51-28-5)															
6A. 2-Nitrophenol (88-75-5)															
7A. 4-Nitrophenol (100-02-7)															
8A. P-Chloro-M-Cresol (59-50-7)															
9A. Pentachloro-phenol (87-86-5)															
10A. Phenol (108-95-2)															
11A. 2,4,6-Trichloro-phenol (88-06-2)															

 CONTINUE ON PAGE V-6

Note: Please see April 10, 2009 application for all other data.

CONTINUED FROM PAGE V-4

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)															
2B. Acenaphthylene (208-96-8)															
3B. Anthracene (120-12-7)															
4B. Benzidine (92-87-5)															
5B. Benzo (*a*) Anthracene (56-55-3)															
6B. Benzo (*a*) Pyrene (50-32-8)															
7B. 3,4-Benzo-fluoranthene (205-99-2)															
8B. Benzo (*ghi*) Perylene (191-24-2)															
9B. Benzo (*k*) Fluoranthene (207-08-9)															
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)															
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)															
12B. Bis (*2-Chloroisopropyl*) Ether (102-60-1)															
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)															
14B. 4-Bromophenyl Phenyl Ether (101-55-3)															
15B. Butyl Benzyl Phthalate (85-68-7)															
16B. 2-Chloro-napthalene (91-58-7)															
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)															
18B. Chrysene (218-01-9)															
19B. Dibenzo (*a,h*) Anthracene (53-70-3)															
20B. 1,2-Dichloro-benzene (95-50-1)															
21B. 1,3-Dichloro-benzene (541-73-1)															

 CONTINUE ON PAGE V-7

Note: Please see April 10, 2009 application for all other data.

CONTINUED FROM PAGE V-4

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X" a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	3. EFFLUENT a. MAXIMUM DAILY VALUE (1) CONCENTRATION	(2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	(2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	(2) MASS	d. NO. OF ANALYSES	4. UNITS a. CONCEN-TRATION	b. MASS	5. INTAKE (*optional*) a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	(2) MASS	b. NO. OF ANALYSES
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichloro-benzene (106-46-7)															
23B. 3,3'-Dichloro-benzidine (91-94-1)															
24B. Diethyl Phthalate (84-66-2)															
25B. Dimethyl Phthalate (131-11-3)															
26B. Di-N-Butyl Phthalate (84-74-2)															
27B. 2,4-Dinitro-toluene (121-14-2)															
28B. 2,6-Dinitro-toluene (606-20-2)															
29B. Di-N-Octyl Phthalate (117-84-0)															
30B. 1,2-Diphenyl-hydrazine (*as Azo-benzene*) (122-66-7)															
31B. Fluoranthene (206-44-0)															
32B. Fluorene (86-73-7)															
33B. Hexachloro-benzene (118-74-1)															
34B. Hexachloro-butadiene (87-68-3)															
35B. Hexachloro-cyclopentadiene (77-47-4)															
36B. Hexachloro-ethane (67-72-1)															
37B. Indeno (*1,2,3-cd*) Pyrene (193-39-5)															
38B. Isophorone (78-59-1)															
39B. Naphthalene (91-20-3)															
40B. Nitrobenzene (98-95-3)															
41B. N-Nitro-sodimethylamine (62-75-9)															
42B. N-Nitrosodi-N-Propylamine (621-64-7)															

 CONTINUE ON PAGE V-8

Note: Please see April 10, 2009 application for all other data.

CONTINUED FROM PAGE V-4

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitro-sodiphenylamine (86-30-6)															
44B. Phenanthrene (85-01-8)															
45B. Pyrene (129-00-0)															
46B. 1,2,4-Tri-Chlorobenzene (120-82-1)															
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)															
2P. α-BHC (319-85-7)															
3P. ß-BHC (319-85-7)															
4P. γ-BHC (58-89-9)															
5P. δ-BHC (319-86-8)															
6P. Chlordane (57-74-9)															
7P. 4,4'-DDT (50-29-3)															
8P. 4,4'-DDE (72-55-9)															
9P. 4,4'-DDD (72-54-8)															
10P. Dieldrin (60-57-1)															
11P. α-Endosulfan (115-29-7)															
12P. ß-Endosulfan (115-29-7)															
13P. Endosulfan Sulfate (1031-07-8)															
14P. Endrin (72-20-8)															
15P. Endrin Aldehyde (7421-93-4)															
16P. Heptachlor (75-44-8)															

 CONTINUE ON PAGE V-9

Note: Please see April 10, 2009 application for all other data.

EPA I.D. NUMBER *(copy from Item 1 of Form 1)*	OUTFALL NUMBER
CAT000619056	#REF!

CONTINUED FROM PAGE V-4

1. POLLUTANT AND CAS NUMBER *(if available)*	2. MARK "X" a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	3. EFFLUENT a. MAXIMUM DAILY VALUE (1) CONCENTRATION	(2) MASS	b. MAXIMUM 30 DAY VALUE *(if available)* (1) CONCENTRATION	(2) MASS	c. LONG TERM AVRG. VALUE *(if available)* (1) CONCENTRATION	(2) MASS	d. NO. OF ANALYSES	4. UNITS a. CONCEN-TRATION	b. MASS	5. INTAKE *(optional)* a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	(2) MASS	b. NO. OF ANALYSES
GC/MS FRACTION – PESTICIDES *(continued)*															
17P. Heptachlor Epoxide (1024-57-3)															
18P. PCB-1242 (53469-21-9)															
19P. PCB-1254 (11097-69-1)															
20P. PCB-1221 (11104-28-2)															
21P. PCB-1232 (11141-16-5)															
22P. PCB-1248 (12672-29-6)															
23P. PCB-1260 (11096-82-5)															
24P. PCB-1016 (12674-11-2)															
25P. Toxaphene (8001-35-2)															

Note: Please see April 10, 2009 application for all other data.

Attachment 6

CAISO Letter

California ISO
Your Link to Power

California Independent System Operator Corporation

Jim Detmers
Vice President, Operations

May 18, 2010

Via Federal Express and Electronic Mail

Mr. Randy Hickok
Managing Director Asset Management & Trading
Dynegy, Inc.
4140 Dublin Boulevard, Suite 100
Dublin, California 94568

**Re: National Pollutant Discharge Elimination System Permit
South Bay Power Plant**

Dear Mr. Hickock:

As you are aware, the term of Dynegy South Bay's National Pollutant Discharge Elimination System (NPDES) permit for the South Bay power plant will expire on December 31, 2010. The California Independent System Operator Corporation continues to assess the role of the South Bay power plant to meet the reliability needs of the San Diego local area. This assessment may require that units 1 and 2 at the South Bay Power plant continue to operate beyond December 31, 2010. Accordingly, the ISO may seek to extend the term of the Reliability Must Run Agreement between Dynegy South Bay and the ISO. For this reason, the ISO requests that Dynegy prepare and submit an application for a new NPDES permit for South Bay power plant units 1 and 2 to the appropriate issuing authority.

Thank you for your consideration of this matter.

Sincerely,

Jim Detmers
Vice President, Operations

Cc: S. Davies
K. Edson
G. Grotta
N. Saracino
A. Ulmer

Attachment 7

Tenera Environmental
David Mayer
May 12, 2010
Presentation

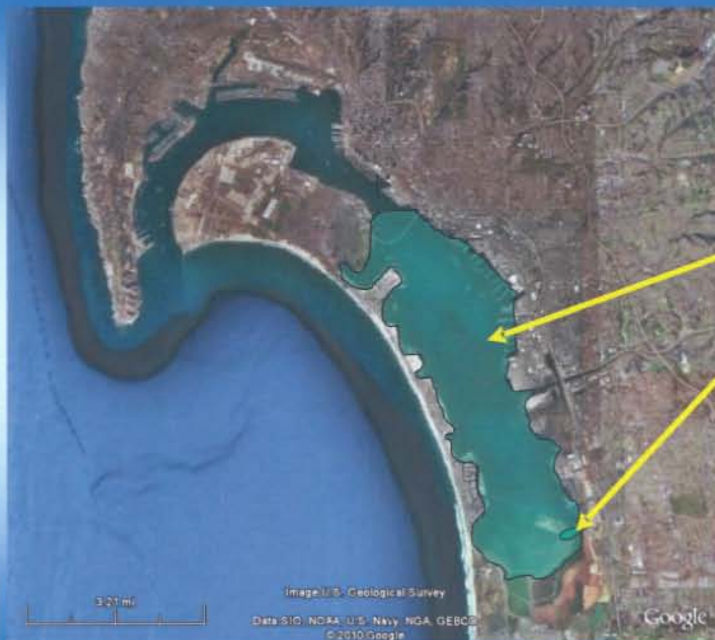
California Regional Water Quality Control Board
San Diego Region
Dynegy South Bay LLC
South Bay Power Plant

Testimony of David Mayer, PhD Tenera Environmental Regarding Evaluation of Water Intake and Cooling Water Discharge Effects on San Diego Bay and Consideration of Termination of Discharge May 12, 2010

TENERA
www.tenera.com

Endangerment Standard

- No established aquatic ecosystem "endangerment" criteria
- Ecosystem endangerment contemplates impacts beyond those acknowledged or anticipated by the permit
- Determination of endangerment requires assessment of impacts beyond borders of the ZID or mixing zone
- At a minimum, the entire South Bay Ecoregion must be evaluated for impacts attributed to SBPP
  - Ecoregion's Balanced Indigenous Community
  - Sustainability of Ecoregion's aquatic populations
- Unacceptable Ecoregion effects have not been observed over the 50-year life of the SBPP



Area of South Bay Ecoregion* compared to area of Units 1 and 2 mixing zone effects.

*Allen, L. G., A. M. Findlay, and C. M. Phalen. 2002. Structure and standing stock of the fish assemblages of San Diego Bay, California from 1994 to 1999. Bull. So. Cal. Acad. Sci. 101(2):4985.

In My Opinion

- Operating SBPP at the current permitted flow rate does not pose an unacceptable risk to the environment
- Even at 601 mgd, the intake and discharge effects did not pose an unacceptable risk
- A 63 percent smaller discharge volume, 63 percent less intake entrainment and 87 percent less impingement necessarily reduces impacts below what was contemplated by the permit when issued in 2004
- Power plant intake and discharge flows are commonly reduced to minimize effects
- No scientific or logical reason to conclude that reduced SBPP intake and discharge flow would now cause endangerment where none was found at higher flows
- This conclusion applies whether looking at "short term" or longer term operations at the reduced flow rate

TENERA
www.tenera.com

STAFF REPORT ON DISCHARGE EFFECTS

- Staff report analyzed potential for unacceptable risk (endangerment) to the environment for the remaining term of the permit
- Staff found studies used accepted methods, even lacking pre-discharge data *(note: historic site photographs show absence of aquatic habitat, but after dredging water flowed in.)*

TENERA
www.tenera.com

Pre-discharge Baseline Circa 1963

TENERA
www.tenera.com

DISCHARGE EFFECTS

STAFF FINDINGS

- Studies have not been performed on effects of discharge since:
- Relocation of the temperature compliance point;
- 63% reduction in intake flow; or
- The 63% reduction in plume volume.

TENERA CONCLUSION

- Cannot rely on past results at 601 mgd to assess endangerment at 225 mgd
- However, it can be said with certainty that the degree and extent of any effects of discharge are significantly less than observed prior to shut down of Units 3 and 4

TENERA
www.tenera.com

COPPER EFFECTS

STAFF FINDINGS

- Only Unit 2 has copper condenser tubing; Unit 1 replaced with stainless steel
- Retired Units 3 and 4 had copper tubing
- Discharge is in compliance and has not violated interim or final limits.
- No short-term unacceptable risk to human health or environment

TENERA CONCLUSION

- Copper WQBELs based on CTR applied end-of-pipe and are necessarily protective of water quality
- The continuing compliance of the WQBELs assures short-term and long-term discharges are protective of water quality
- No unacceptable environmental or human health risk.

TENERA
www.tenera.com

CHLORINE EFFECTS

STAFF FINDINGS

- SBPP is in compliance with the most stringent chlorine effluent limitations, which are protecting beneficial uses, and avoiding any short-term unacceptable human or environmental risk.

TENERA CONCLUSION

- The discharge limits for chlorine based on toxic effects research that is thoroughly reviewed and considered to assure protection of the receiving water community, including chlorine-formed compounds.
- SBPP continuing compliance with established chlorine discharge limit will continue to prevent any risk to the environment whether in the short or long term.

TENERA
www.tenera.com

TEMPERATURE EFFECTS

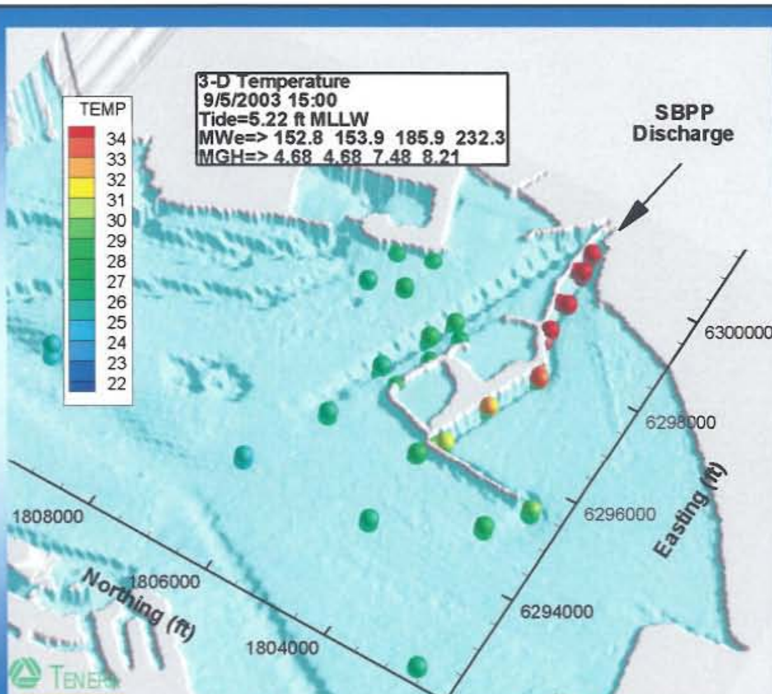
STAFF FINDINGS

- Effects of smaller, cooler Units 1 and 2 discharge have not been evaluated
- However, lower temperature and smaller volume of Units 1 and 2 discharge increase assurance that the balanced indigenous community of fish, shellfish and wildlife in the receiving water are fully protected
- Continued discharge does not pose unacceptable short-term risk

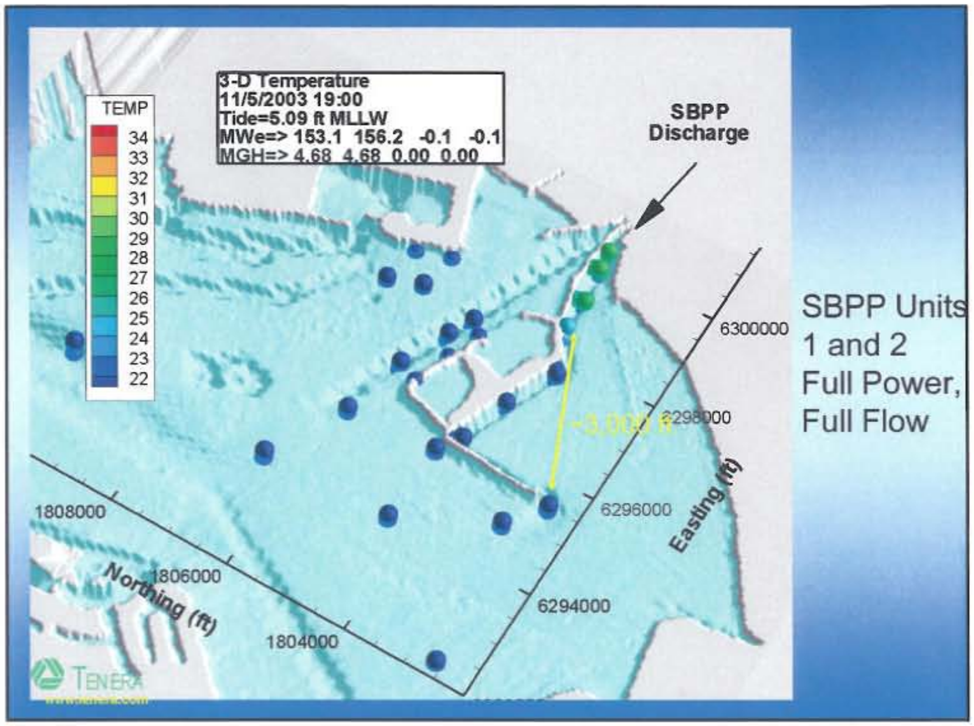
TENERA CONCLUSION

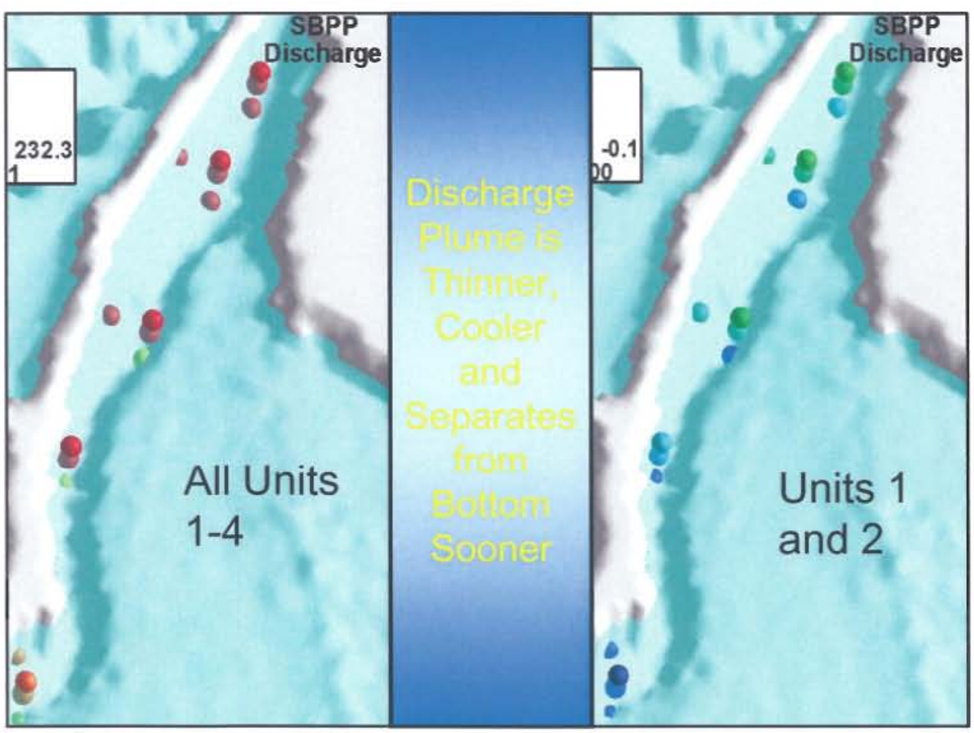
- Tenera's analysis of the reduced discharge volume, temperature and extent of the current plume demonstrated that the combined thermal plume from Units 1 and 2 would be 2,000 to 3,000 feet smaller, cooler by several degrees, and several feet thinner for quicker separation from benthic and shoreline communities.

TENERA
www.tenera.com



ALL SBPP Units (1-4) Full Power, Full Flow


3-D Temperature
11/5/2003 19:00
Tide=5.09 ft MLLW
MWe=> 153.1 156.2 -0.1 -0.1
MGH=> 4.68 4.68 0.00 0.00
TEMP
34
33
32
31
30
29
28
27
26
25
24
23
22
SBPP
Discharge
6300000
6298000
6296000
6294000
Easting (ft)
1808000
1806000
1804000
Northing (ft)
SBPP Units 1 and 2 Full Power, Full Flow
TENERA


SBPP
Discharge
232.3
1
All Units
1-4
Discharge Plume is Thinner, Cooler and Separates from Bottom Sooner
SBPP
Discharge
-0.1
00
Units 1
and 2

DISSOLVED OXYGEN EFFECTS

STAFF FINDINGS

- Based on information to date and the 63% reduction in flow in 2009, allowing the discharge to continue does not pose an unacceptable short-term risk to human heath or the environment.

TENERA CONCLUSIONS

- A numerical Water Quality Objective has not been clearly established for San Diego Bay
- Staff data showed discharge DO exceeded intake concentration 50% of the time and percent saturation 80% of the time.
- Staff analysis found no substantial difference between discharge DO and north San Diego Bay DO
- Study results show discharge DO supports (does not limit) fish populations

TENERA
www.tenera.com

Mr. John Robertus Letter to Mr. Alex P. Mayer, State Water Resources Control Board, March 4, 2005

"One of the recent study efforts by Duke Energy in the effort to support the reissuance of the NPDES permit adopted by the Regional Board on November 10, 2004 consisted of an investigation of a site-specific objective for DO in south San Diego Bay. The study demonstrated that existing DO levels in south San Diego Bay were protective of fish and other marine resources residing therein. The study also indicated that the DO levels in south San Diego Bay appear to support fish populations and do not appear to limit their distribution or species composition."

TENERA
www.tenera.com

SEDIMENT LOAD

STAFF FINDINGS

- Due to the reduced 2009 flow rate of 225 MGD from 2003 601 MGD and roughly half of 441 MGD shown in turbidity maps, 2010 turbidities are expected to be less

TENERA CONCLUSIONS

- No clear mechanism linking SBPP discharge to turbidity
- Wind generated,natural turbidity pushed north into the bay by SBPP discharge flow
- Turbidity of intake and discharge water always less than receiving water (measured in NTU)
- Net potential for SBPP flows to preclude eelgrass must account for enhancement effects of SBPP intake and discharge flows circulating clearer water into lower South Bay.

TENERA
www.tenera.com

EFFECTS ON EELGRASS

STAFF FINDINGS

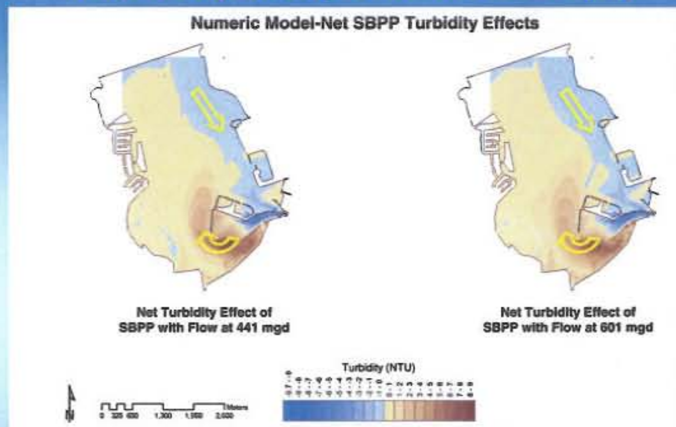
- Recognizes ecological importance of eelgrass
- Whether operations at 225 MGD preclude eelgrass from discharge channel has not been studied
- However, any preclusion is certainly less than that caused at flows of 601 and 441 MGD
- Based on available information, continuing the 2010 discharge does not pose unacceptable short-term risk to the environment

TENERA CONCLUSIONS

- Plant-induced, redistribution of turbidity will diminish with lower discharge flow.
- But turbidity will remain concentrated at end of bay.
- Eelgrass was not present in intake and discharge channels before SBPP construction.
- Eelgrass that has since colonized the discharge and intake areas will receive <u>less</u> light energy as SBPP intake and discharge flows end.

TENERA
www.tenera.com

Turbidity maps from 316(a)



SBPP acts to significantly circulate fresher, clearer San Diego Bay water from the north into the southernmost end of the bay, and in doing so creates a circular pattern of flow back to the north carrying with it wind disturbed sediment and turbidity from the shallows.

TENERA
www.tenera.com

EFFECTS ON BENTHIC ORGANISMS

STAFF FINDINGS

- The biotic communities in the immediate vicinity of the discharge and channel have been degraded by elevated temperature, flow and volume
- The 60% reduction will reduce the impact, although by an unknown amount
- Continuing the discharge does not pose a short-term environmental risk

TENERA CONCLUSIONS

- The original 601 MGD effects were modest
- Thermal plume's influence has been significantly reduced by 63% reduction in discharge
- Smaller, cooler and thinner plume will separate from benthos sooner and disperse more rapidly with loss of momentum
- Benthic organisms (worms) will return to small, affected area
- Neighboring populations of benthic organisms will rapidly re-colonize any changed habitat.

TENERA
www.tenera.com

EFFECTS ON TURTLES

STAFF FINDINGS

- Agreed with Dr. Seminoff's testimony that the turtles are adequately protected by existing NPDES Order No. R9-2004-0154
- Turtles do not depend on eelgrass, and are unaffected by its presence or absence
- Early closure of SBPP will not benefit the turtles
- The turtles will remain in San Diego Bay with or without the warm water associated with the SBPP discharge

TENERA CONCLUSIONS

- Concur with staff
- It will be of some scientific interest to observe the turtles' response (if any) to winding down plant operations.
- If turtles are attracted to SBPP warm water discharge, their presence in discharge area should decline with generation.
- Current generation (~10% annual capacity factor) has no apparent effect on resident turtle population.

TENERA
www.tenera.com

ENTRAINMENT EFFECTS

STAFF FINDINGS

- Units 1-4 larval fish losses in 2003 were "significant," e.g., mudsuckers entrainment equaled 50% of source water population
- Substantially reduced flows substantially reduced entrainment effects
- No unacceptable environmental risk on the short-term

TENERA CONCLUSIONS

- Retirement of Units 3 and 4 reduced entrainment by 63%
- Vacated Phase II standard required 65% reduction in entrainment
- EPA and SWRCB prefer flow reduction as optimal means of minimizing entrainment effects
- Mudsucker loss reduced from 50% in 2003 to 18% in 2009
- CDF&G sustainable harvest standard +40%

TENERA
www.tenera.com

IMPINGEMENT EFFECTS

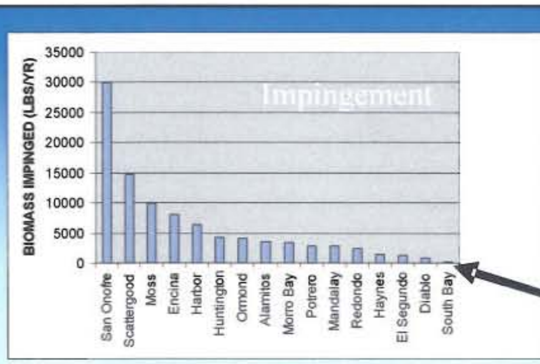
STAFF FINDINGS

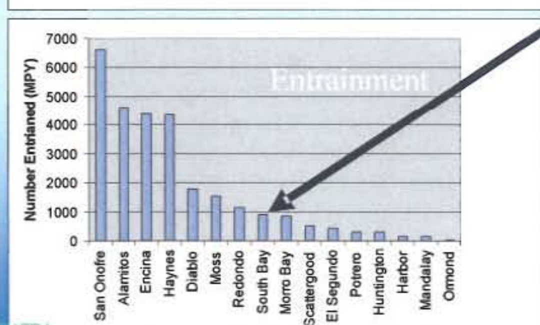
- Substantially reduced flows substantially reduced impingement effects
- No unacceptable environmental risk on the short-term

TENERA CONCLUSIONS

- SBPP impingement effects not "significant" even at 601 MGD
- Impingement reduced 87% by retirement of Units 3 and 4
- Vacated Phase II standard required 95% reduction and 0.5 fps through-screen velocity

www.tenera.com





Comparison of South Bay Power Plant Units 1 and 2 Impingement & Entrainment to All Other California OTC Power Plants

Data Source: Foster and Steinbeck for California State Water Resources Control Board, adjusted for the decommissioning of SBPP Units 3 and 4

www.tenera.com

QUESTIONS?

Attachment 8

Tenera Environmental Technical Memorandum

Technical Memorandum

Assessment of the 2009 Flow Reduction of South Bay Power Plant Intake and Discharge Effects

February 20, 2010

Prepared for:
Dynegy South Bay, LLC
990 Bay Blvd.
Chula Vista, CA 91911

Prepared by:
Tenera Environmental
971 Dewing Avenue
Lafayette, CA 94549
(925) 962-9769

ABSTRACT

South Bay Power Plant (SBPP) is a four-unit, fossil-fueled, electrical generating facility owned by the Port of San Diego and operated by Dynegy South Bay, LLC. SBPP is located at the southern end of San Diego Bay from which it both withdraws and discharges the water it uses for once-through cooling of its steam condensers and a variety of smaller heat exchangers and ancillary equipment. Units 3 and 4 ceased operation and were decommissioned as of December 31, 2009. Units 1 and 2 will continue to run at least through the end of 2010 based on their Reliability-Must-Run status.

This report assesses the potential benefits in the reduction of cooling water intake and discharge flow accompanying the shutdown of Units 3 and 4. Results of detailed studies presented to the San Diego Bay Regional Water Quality Control Board on the SBPP thermal discharge and the impingement and entrainment effects of the intake (Tenera 2004a, Tenera 2004b) are used to (i) quantify reductions in impingement and entrainment effects and (ii) quantify the degree and extent of the thermal discharge plume from remaining Units 1 and 2.

As of January 1, 2010, the entrainment intake effects have been reduced by at least 63 percent and impingement effects have been reduced by 86 percent of the levels previously calculated based on assumed Plant operations at maximum generating capacity and cooling water flow rates. This reduction in maximum pumping capacity, accompanied by a 91 percent reduction in Plant capacity, qualifies the facility for an EPA 316(b) Phase II finding of "no significant entrainment" impact. Based on the results of the 2004 impingement study of each unit group, a

further 86 percent reduction in impingement is projected to have occurred as a result of the shutdown of Units 3 and 4 pumps. Impingement effects are also considered insignificant.

This report also assesses the reduction in both the size and temperature of the SBPP discharge plume based on continuous detailed receiving water temperature measurements of Plant operation when only Units 1 and 2 were running. To be conservative, periods of time when Units 1-4 were operating at maximum generating capacity and discharge volume were compared to periods when only Units 1 and 2 and their circulating water pumps were also operating at maximum capacity. Data for the comparison were obtained from the large number of thermal monitoring stations deployed during 2003 in the discharge channel and surrounding receiving water that gathered data for the SBPP 316(a) study (Tenera 2004a).

The current SBPP thermal plume that extends beyond the Plant's point of discharge at the property line is 63 percent smaller, and several degrees cooler and thinner, as a result of the shutdown of Units 3 and 4. The volume of the present thermal plume is 63 percent smaller, and the temperature is 4 to 5 degrees F cooler at the point of discharge. This lower temperature is not only significant in minimizing the potential for effects on receiving water biota but, in combination with the loss of the plume's flow and momentum, creates a thinner plume that is less likely to contact receiving water shoreline and bottom habitats. The lower temperature and smaller volume of the discharge plume from Units 1 and 2 provide increased assurance that existing discharge temperature limits are fully protective of the balanced, indigenous community (BIC) of fish, shellfish and other wildlife in the receiving waters.

1.0 INTRODUCTION

South Bay Power Plant (SBPP) is a four-unit, fossil-fueled, electrical generating facility owned by the Port of San Diego and operated by Dynegy South Bay, LLC. SBPP is located at the southern end of San Diego Bay from which it both withdraws and discharges the water it uses for once-through cooling of its steam condensers and a variety of smaller heat exchangers and ancillary equipment. Unit 1 began operations in 1960 followed by three additional units in 1962, 1964, and 1971. Under the California State Thermal Plan, the cooling water discharge from SBPP Units 1 through 4 is classified as an existing discharge. Units 3 and 4 ceased operation and were decommissioned as of December 31, 2009. It is assumed for the purposes of this assessment that Units 1 and 2 will continue to run at least through the end of 2010 based on their Reliability-Must-Run status.

The purposes of this report are to (i) summarize the conclusions of the most recent technical assessment of the thermal discharge from SBPP and the impingement and entrainment effects of the intake (Tenera 2004a, Tenera 2004b), and (ii) to quantify the reduction in impingement and entrainment effects that has occurred at the SBPP intake, as well as reductions in the potential effects of the thermal discharge both in terms of temperature and areal effects resulting from the shutdown of Units 3 and 4. Not only has there been an immediate 63 percent reduction in impingement and entrainment effects, but a closer of examination of results from our 2004 year-long impingement study provides solid evidence of reductions in impingement effects of 86 percent and greater. This report also assesses the dynamics of the SBPP discharge plume for Units 1 and 2 by itself, particularly its extent and dispersal, based on periods of operation prior to December 31, 2009 when only these two units were running. The assessment is based our extensive receiving water temperature measurements during periods when only Units 1 and 2 were running. In so doing, we present contrasting scenarios of the thermal dynamics of the discharge plume during past operations with those anticipated for the period after December 31, 2009. To be conservative in the portrayal of the thermal plume, we have compared periods when all four units were at or near maximum generating capacity and discharge volume, with periods when only Units 1 and 2 and their circulating water pumps (CWPs) were in operation and generation approached the maximum capable by those units. The time periods selected for comparison occurred during 2003 when a large number of thermal monitoring stations had been established to gather data for the SBPP 316(a) study (Tenera 2004a).

Based simply on the reduction in cooling water flow,[1] there was at least a 63 percent reduction in 2009 impingement effects with only Units 1 and 2 intake pumps operating at the time. In fact the actual reduction in SBBP impingement effects at the present time, based on our published impingement study results (see following Table 3) is at least 86 percent, an amount nearly achieving the EPA's impingement reduction standard contained in the now-vacated 316(b) Phase II Rule. This conclusion is proven in the following review of our 2004 findings.

The calculated annual intake flow for Units 3 and 4 represented 63 percent of the SBPP intake volume. Eliminating the total annual flow from these two units, as occurred in 2009, immediately reduced the estimated entrainment effects of the power plant by the same amount, 63 percent, an amount greater than that required by EPA's 316(b) Phase II Rule.

This document also provides a description of the SBPP, a description of our 2004 impingement and entrainment study methods and results, and an account of our thermal effects study monitoring stations and the methods, collection, and analysis of the 2003 receiving water temperature data.

[1]The widely accepted impingement to flow relationship was relied upon to use the 63 percent reduction of intake from 2009 to 2010 to approximate a similar fractional reduction of the SBPP annualized impingement estimate reported for December 2002 to November 2003 (Tenera 2004b) for all units. More specifically, Tenera reported the estimated impingement for Units 1 and 2 separately from Units 3 and 4, making the assessment of an 86 percent reduction in impingement from 2009 to 2010 a similarly straightforward and accurate estimation.

2.0 PLANT DESCRIPTION

The South Bay Power Plant uses the waters of San Diego Bay for once-through cooling of its electric generating units. The generating capacities of the units range from 152 to 232 megawatts (MWe), making the total generating capacity of the facility 723 MWe (**Table 1**). Each unit is equipped with two circulating water pumps (CWP) that supply cooling water. CWP capacity varies between units, ranging from 148 m^3/min to 259 m^3/min (39,000 gallons per minute [gpm] to 68,400 gpm), based on the manufacturer's pump performance estimates. The quantity of cooling water circulated through the Plant is dependent upon the number of pumps in operation. With all eight pumps in operation, the cooling water flow through the Plant is 1,580 m^3/min (417,400 gpm) (**Table 1**) or 2,275,000 m^3/day (601 million gallons per day [mgd]). With the decommissioning of Units 3 and 4, the total generating capacity of the Plant has been reduced by 57 percent to 308 MWe. Total flow of the four remaining CWPs is 590 m^3/min (156,000 gpm) or 849,600 m^3/day (225 mgd), a reduction of 63 percent.

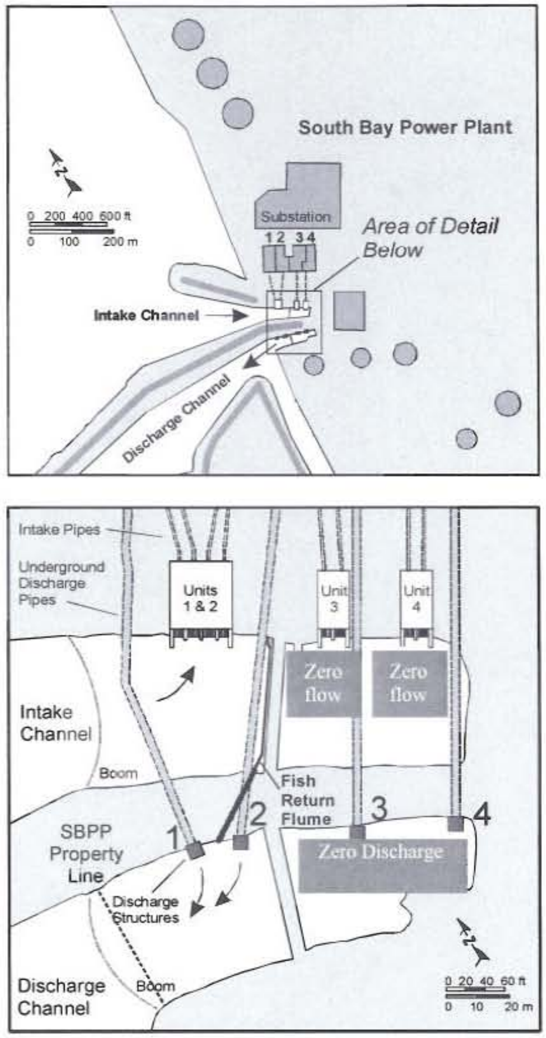
Table 1. South Bay Power Plant, generating capacity and cooling water flow by unit.

Unit	Gross Generation (MWe)	Total Flow per Unit (2 CWPs/Unit) (m^3/min)	Total Flow per Unit (2 CWPs/Unit) (gpm)
1	152	295	78,000
2	156	295	78,000
3 (retired)	183	472	124,600 (prior to 12/31/2009)
4 (retired)	232	518	136,800 (prior to 12/31/2009)
Total Prior to 12/31/2009	**723**	**1,580**	**417,400**
Total as of 01/01/2010	**308**	**590**	**156,000**

2.1 SBPP Intake

Cooling water is withdrawn from San Diego Bay via an intake channel that connects the SBPP with the southeast corner of the Bay (**Figure 1**). The intake channel is about 180 m (600 ft) in length, has a bottom width of about 60 m (200 ft) at its widest point, and tapers to 15 m (50 ft) width near the Unit 4 screenhouse. The maximum depth of the channel is approximately 5.4 m (17.7 ft) below mean lower low water (MLLW). The channel was constructed by dredging and diking operations during Plant construction in the early 1960s. Materials that were removed from the channel were used to form part of the Chula Vista Wildlife Island (CVWI), which separates the intake and discharge channels. Variations in water level due to tidal fluctuations range from a low of –0.7 m (–2.3 ft) to a high of +2.5 m (+8.2 ft) MLLW.

The cooling water intakes at the SBPP consist of three separate screenhouse structures for its four units. Units 1 and 2 share a single screenhouse structure while Unit 3 and Unit 4 each have individual screenhouses. The Unit 3 and Unit 4 screenhouses are no longer operational. As shown in **Figure 1**, water flow within the intake channel first approaches the screenhouse serving Units 1 and 2. The Unit 3 screenhouse is located an additional 40 m (131 ft) downstream, and the Unit 4 screenhouse another 28 m (92 ft) downstream, near the head of the channel.



Directly behind the screenhouses are the CWPs. Cooling water from the Units 1 and 2 CWPs exits the screenhouse via four 122 cm (48 in) diameter conduits that carry the flow approximately 61 m (200 ft) to the units' condensers. Intake conduits for Units 3 and 4 (one for each CWP and both of which are now blocked off) are 152 cm (60 in) in diameter, and 61 m long. At each of the condensers the cooling water is dispersed through several thousand thin-walled condenser tubes. Units 1 and 2, and former Unit 3, have dual-pass condensers that direct the cooling water through the condenser twice. The condenser for former Unit 4 was a single pass design. Tubing material in the Unit 1 condenser is AL-6X, a stainless steel alloy; the other condensers are equipped with copper-nickel.

2.2 SBPP Discharge

Exhaust steam exiting the Plant's turbines passes over the exterior of the tubes in the condenser boxes where it is condensed by cool seawater water flowing through the tubes. The resulting condensate is pumped back to the Plant's boilers as part of the continuing steam cycle and the cooling water exits the condenser as heated effluent. The change in cooling water temperature (delta T°) that occurs during passage through the condenser varies depending on a number of factors. Plant generating load and cooling water flow are the main factors affecting delta T°. Flow can be reduced by condenser tube micro-fouling, tube blockage (caused by debris), and fluctuations in cooling water flow caused by tidal shifts or degradation of CWP performance.

Upon exiting the condensers, warmed cooling water from the two (formerly four) units is carried through discharge pipes about 137 m (450 ft) to the discharge basin located at the head of the discharge channel. The diameter of the discharge pipe for Units 1 and 2 is 183 cm (72 in) and 213 cm (84 in) for Units 3 and 4 (flow to these discharge pipes has been eliminated). The discharge channel originates on the side of the jetty, opposite the head of the intake channel. The discharge channel is defined in the SBPP NPDES Permit (CA0001368, Order 96-05, Finding 23) as *"...the waters bounded by the jetty, a line extending from the southwesternmost end of the jetty to the eastern side of the mouth of the Otay River, the southern shoreline of San Diego Bay, and the shoreline of the discharge basin."* The SBPP discharge points are defined as the outlets of the cooling water discharge pipes.

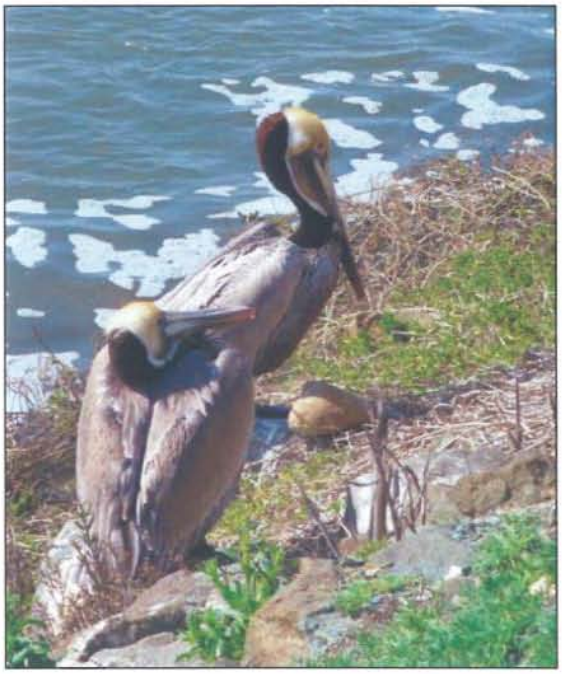
2.3 Environmental Setting

The SBPP intake and discharge channels and surrounding land is an area of south San Diego Bay rich in the abundance and diversity of wildlife. The Chula Vista Wildlife Refuge adjacent to SBPP is an artificially constructed peninsula that separates the intake and discharge areas of the power plant. The island itself was largely constructed from dredge spoils, and portions of the access causeway are armored with rock rip-rap to prevent erosion. Tidal inlets within the reserve form wetland areas, and adjacent areas provide seasonal habitat for several species of nesting shorebirds, including endangered California least terns *Sterna antillarum browni* and western snowy plovers *Charadrius alexandrinus nivosus*. Photographs of birds utilizing the area in the vicinity of the intake and discharge are provided below.

The nearby San Diego Bay National Wildlife Refuge protects a rich diversity of endangered, threatened, migratory, and native species and their habitats in the midst of the highly urbanized coastal environment near the SBPP. The Refuge manages nesting, foraging, and resting sites for a diverse assemblage of birds. It provides important habitat along the Pacific Flyway for migrating shorebirds and waterfowl to over-winter or stop to rest and feed. The refuge provides undisturbed expanses of cordgrass-dominated salt marsh that supports sustainable populations of light-footed clapper rail. Enhanced and restored wetlands provide new, high quality habitat for fish, birds, and coastal salt marsh plants, such as the endangered salt marsh bird's beak. Quiet nesting areas, away from adjacent urbanization, ensure the reproductive success of an array of ground nesting seabirds and shorebirds as well as the threatened western snowy plover and endangered California least tern.

Submerged lands in the south bay are also an important resting and feeding area for waterfowl migrating along the Pacific Flyway. Surveys by USFWS during 1993–1994 found almost 200,000 birds at a time utilizing the habitat available in the south bay (USFWS 1998). Common waterfowl include the surf scoter *Melanitta perspicillata*, scaup *Aythya* spp., black brant *Branta bernicla nigricans*, bufflehead *Bucephala albeola*, loons *Gavia* spp., and western grebe *Aechmophorus occidentalis*. Seabirds, such as gulls *Larus* spp. and cormorants *Phalacrocorax* spp., are also common in the area. Additionally, a number of listed (endangered and threatened) bird species, and species of special concern, have been observed in the south Bay. Bird species in the area that are protected under state or federal law include the California least tern, western snowy plover, brown pelican *Pelecanus occidentalis*, peregrine falcon *Falco peregrinus*, and bald eagle *Haliaeetus leucocephalus*.

The discharge channel supports an abundance and diversity of fish species distinctly greater than found in the immediate areas of south San Diego Bay. Studies comparing fish populations living the SBPP discharge channel to other fish habitats in close proximity found a healthy fish community rich in species and with persistently high numbers of individuals (Tenera 2004a, b). It has been reasoned that many of the fish are attracted to the power plant's discharge flow and warmer temperatures during periods of cooler Bay water temperatures. The presence and abundance of fish that are prey species such as bay anchovy support local food webs and may contribute prey to the tern colonies and other wildlife in the SBPP intake and discharge.



Source: Dynegy, 2010.

3.0 2004 INTAKE EFFECTS STUDY

The purpose of the 2004 SBPP entrainment and impingement studies was to evaluate the potential impacts of the cooling water intake system as required under Section 316(b) of the Federal Clean Water Act (CWA). As part of this evaluation, an earlier 316(b) study conducted in 1979 (SDG&E 1980) was updated and information from the 2001 and 2003 entrainment and impingement studies was used by the San Diego Regional Water Quality Control Board in support of the NPDES permitting process for SBPP. Data on larval fishes, megalopal crabs, and larval spiny lobster collected near the SBPP intakes were used to estimate entrainment losses, while impingement losses were based on direct measurements of the abundance and biomass of fishes and selected macroinvertebrates retained on the SBPP intake screens.

3.1 Entrainment and Source Water Sampling

Entrainment and source water sampling was conducted monthly from January 2001 through January 2002 and bi-monthly from December 2002 through October 2003. This provided a complete year of data in 2001 (including January 2002) to describe seasonal differences in species abundances, and a comparison year in 2003 (including December 2002) to describe interannual variability. While the results from the second sampling were expected to confirm our initial entrainment assessment, it was recognized that the bi-monthly sampling would affect estimates for species with short larval durations that do not have extended spawning periods. The same set of entrainment and source water stations was sampled (**Figure 2; Table 2**) using the same methods during each study period. The first survey in January 2001 ended before all stations were sampled when the boat experienced mechanical problems. Data from this incomplete survey were not included in the analyses presented in this section.

3.1.1 Entrainment Sampling

Sample collection methods were similar to those developed and used by the California Cooperative Oceanic and Fisheries Investigation (CalCOFI) in their larval fish studies (Smith and Richardson 1977) but modified for sampling in the shallow areas of south San Diego Bay where depths can be less than 2 m (6.6 ft) during low tides. Entrainment samples were collected from a single station (SB1; **Figure 2**) located in the SBPP intake canal by towing a bongo frame with two 0.71 m (2.33 ft) diameter openings, each equipped with 335-µm (0.013 in) mesh plankton nets and codends. The water volume filtered was measured by calibrated flowmeters (General Oceanics Model 2030R) mounted in the openings of the nets. Samples were collected over a 24-hour period, with each period divided into six 4-hour sampling cycles. Two replicate samples were collected at the entrainment station to improve the concentration estimate of entrained larvae. Concurrent surface water temperatures and salinity were measured at this station with a digital probe (YSI Model 30).

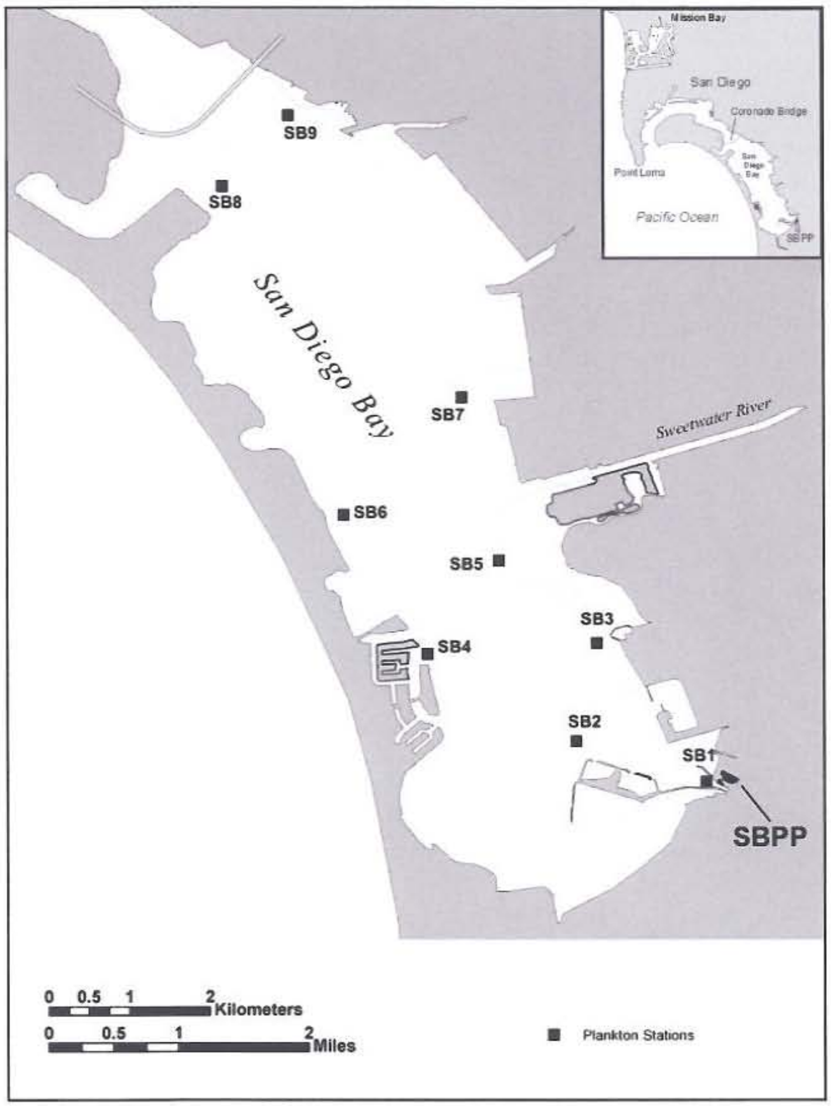


Figure 2. Location of 2001 and 2003 South Bay Power Plant entrainment (SB1) and source water plankton stations (SB2–SB9).

Source: Tenera Environmental. 2004b. Figure 3.2-1.

Table 2. Locations of entrainment (SB1) and source water (SB2–SB9) plankton stations. *Station location also sampled in LES (1981) study.

Station	Latitude (N)	Longitude (W)	Depth below MLLW	
			meters	feet
SB1	32° 36.869'	117° 05.942'	3.0	10
SB2	32° 37.140'	117° 06.805'	3.7	12
SB3	32° 37.795'	117° 06.668'	4.9	16
SB4	32° 37.723'	117° 07.794'	4.0	13
SB5*	32° 38.347'	117° 07.320'	6.7	22
SB6	32° 38.649'	117° 08.350'	3.7	12
SB7	32° 39.437'	117° 07.565'	11.0	36
SB8*	32° 40.846'	117° 09.153'	1.5	5
SB9*	32° 41.326'	117° 08.714'	11.0	36

Source: Tenera Environmental. 2004b. Table 3.2-1.

At all stations, the bongo nets were lowered as close to the bottom as practical without contacting the substrate. Once the nets were near the bottom, the boat was moved forward and the nets retrieved at an oblique angle (winch cable at a 45° angle) to sample the widest strata of water depths possible at each station. The winch retrieval speed was maintained at approximately 0.3 m/sec (1 ft/sec). At the shallowest stations, the boat was moved forward before the nets were lowered into the water so that the codend did not contact the bottom prior to beginning the tow.

The targeted combined volume of water filtered by both nets was approximately 60 m^3 (2,119 ft^3). The sample volume was checked when the nets reached the surface. If the target volume was not collected, the tow was repeated until the targeted volume was reached. The nets were then retrieved from the water, and all of the collected material was rinsed into the codend. The contents of both nets were combined into one sample immediately after collection. The sample was placed into a labeled jar and was preserved in 10 percent formalin. Each sample was given a serial number based on the location, date, time, and depth of collection. In addition, the information was recorded on a sequentially numbered data sheet. The serial number was used to track the sample through laboratory processing, data analyses, and reporting.

3.1.2 Source Water Sampling

Samples were collected at eight source water stations in the south and south-central regions of San Diego Bay (**Figure 2**). The source water stations ranged in depth from approximately –2 m (–6.6 ft) MLLW at SB8 to –12 m (–39.4 ft) MLLW at SB9. The stations were stratified to include four channel locations on the east side of the Bay and four shallower locations on the west side of the Bay. The station locations also included the three plankton tow stations sampled during the previous 316(b) studies in 1979–1980 (SDG&E 1980) (SB5 off Sweetwater River Marsh; SB8 near the U.S. Navy amphibious base; and SB9 in the navigation channel south of Coronado Bridge).

Source water sampling was conducted using the same methods and during the same time period described above for entrainment sampling with target volumes for the oblique tows of approximately 60 m^3 (2-minute tow at approximately 1 knot). A single tow was completed at each of the source water stations during each of the six 4-hr cycles.

3.1.3 Data Analysis

Sample concentrations of larval fishes, *Cancer* crab megalopae, and spiny lobster larvae were computed by dividing the number of each taxon or species in each sample by the volume of water filtered. The mean survey concentrations for each taxon for the entrainment station (SB1) were calculated by averaging the two replicates during each cycle and then calculating an average concentration for the survey from the six cycles. The mean survey concentrations for the source water were calculated by averaging the data from the six cycles at each station and then averaging the concentrations from the eight source water stations (SB2–SB9).

Data were summarized for the impact assessment models using the mean survey concentrations as described above. Entrainment estimates for each survey were computed by multiplying the mean concentration of larval fishes at Station SB1 times the maximum daily cooling water intake system (CWIS) flow rate of 2,275,244 m^3 (601,056,000 gal). Entrainment for each survey period was estimated by multiplying the daily entrainment estimate by the number of days in each survey period (ca. 30 days for the '2001' study period and about 60 days for the '2003' study period). These survey period entrainment estimates were summarized over each of the two study periods to determine the annual entrainment estimates used in the data summaries and demographic (*AEL*[2] and *FH*[3]) modeling approaches.

The estimates of total entrainment for the two study periods were used in two demographic models and one impact assessment model. The demographic models (*AEL* and *FH*) use

[2] The Adult Equivalent Loss (*AEL*) approach uses an estimate of the abundance of entrained or impinged organisms to forecast the loss of an equivalent number of adults. The approach requires survival estimates (had the larvae not been entrained) from entrainment to an age at recruitment to the adult population. In addition to life history information, the *AEL* model requires estimates of total entrainment for the study period and the average age of the larvae at entrainment.

[3] The Fecundity Hindcast (*FH*) approach combines larval entrainment losses with adult fecundity to estimate the adult female reproductive output eliminated by entrainment, assuming no compensatory reserve of the population. *FH* requires an estimate of survival for egg and early larval stages for the time period up to entrainment. The fact that *FH* only requires survivorship for the few days that the eggs or larvae are vulnerable to entrainment is an advantage of this approach over the *AEL* model that requires survival data from the average age at entrainment (a few days) through adult recruitment (up to a few years).

information on the life history of the target organisms to calculate the numbers of female adult (through use of the *FH* model) or adult fishes (through use of the *AEL* model) represented by the entrainment losses. Both models translate larval entrainment mortality into adult fish losses, which are familiar units to resource managers. The impact assessment model (*ETM*)[4] requires an additional level of field sampling to characterize the abundance and composition of source water larval populations. The fractional loss to the source water population represented by entrainment is provided by estimates of proportional entrainment for each survey that can then be expanded to predict regional effects on appropriate adult populations. Detailed computational descriptions of this methods and *AEL* and *FH* are found in Tenera (2004b).

3.1.4 Results

The relative species abundance of larval fish collected in the 2001 and 2003 entrainment studies are illustrated in **Figure 3**. Percent composition of entrained species varied little between the two years, but for the influx of anchovy in 2001 and their relative influence on the combined abundance of entrained larval fishes. The annual concentrations of larval fishes were remarkably similar among species. For example, similar concentrations of larval gobies (CIQ complex) in source water and entrainment samples in 2001 and 2003 are illustrated in **Figure 4**.

[4] The empirical transport model (*ETM*) has been proposed by the U.S. Fish and Wildlife Service to estimate mortality rates resulting from cooling water withdrawals by power plants (Boreman et al. 1978, and subsequently in Boreman et al. 1981) as an alternative to the demographic models. The *ETM* model provides an estimate of incremental (a conditional estimate in absence of other mortality; Ricker 1975) mortality imposed by SBPP on local San Diego Bay larval populations by using empirical data (plankton samples) rather than relying solely on hydrodynamic and demographic calculations.

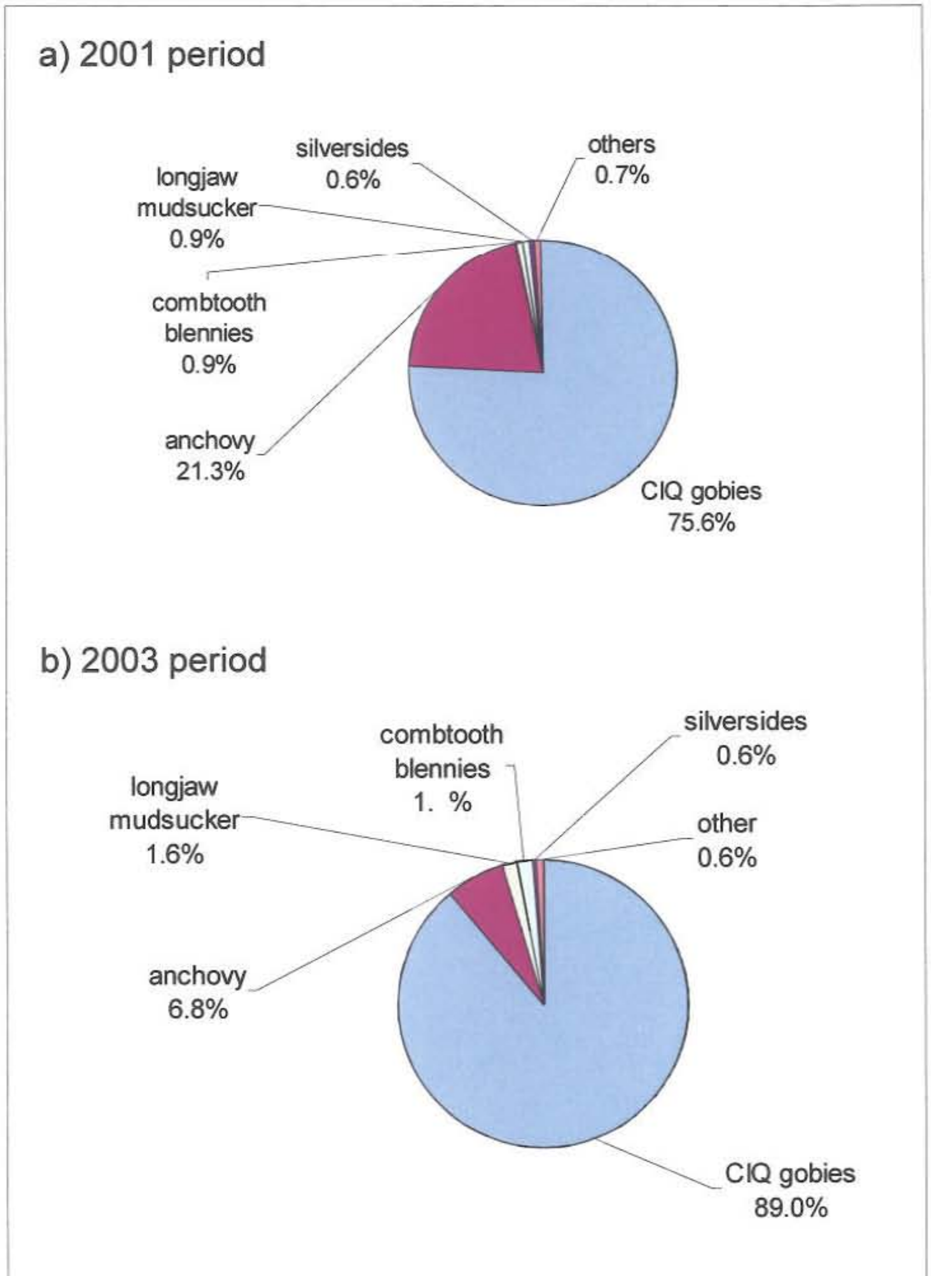


Figure 3. Percent composition of estimated total entrainment for a) 2001 period and b) 2003 period. The percentages for the taxa comprising the top 99 percent of the total estimated entrainment are listed while the remaining taxa are combined into 'others'.

Source: Tenera Environmental 2004b. Figure 3.3-3.

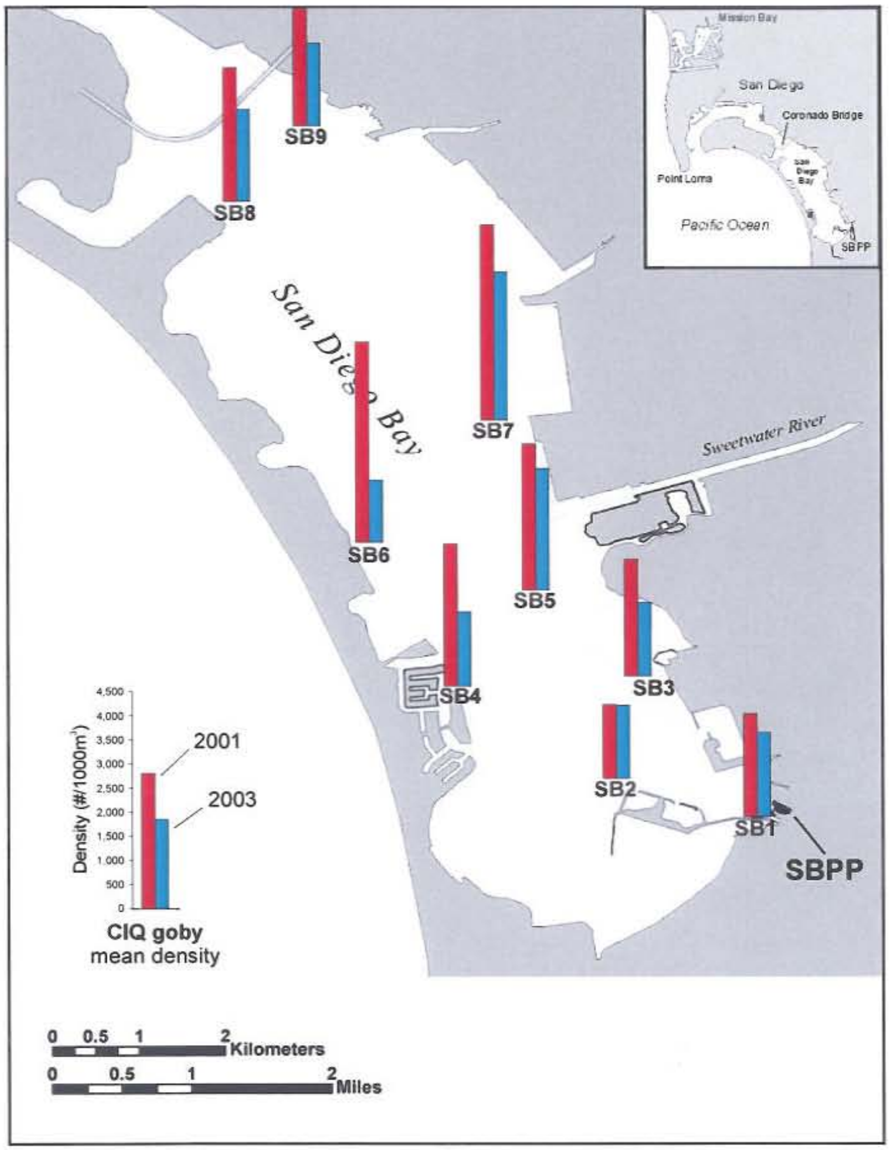


Figure 4. Annual mean concentration (#/1,000 m^3) of CIQ goby complex larvae at entrainment station (SB1) and source water stations.

Source: Tenera Environmental 2004b. Figure 3.3-9.

It should also be noted that most fish populations, including bay goby, are unaffected by natural mortality as high as 90 percent in the larval stage. In other words, even if the SBPP were not withdrawing water from south San Diego Bay, up to 90 percent of the larvae would be expected to die before recruitment to the adult population. *ETM* estimates of entrainment, which assume a stable population and no compensation, represent an extremely conservative comparison to the NMFS guidelines for sustainable harvest rates that are based on recruited adult stocks after natural compensation has already occurred. Although large numbers (in absolute terms) of larvae are entrained, *ETM* estimates of entrainment mortality using extremely conservative assumptions show that the entrained larvae represent a fraction of their source water population that is well below a removal rate required to sustain their adult populations even without compensation. The life history of component species in the community must be considered when discussing potential effect to the populations. Although the study focused on species potentially affected by entrainment and impingement processes, it is important to note that several fish species in south San Diego Bay have early life stages that are not susceptible to these processes. Live-bearers, such as surfperches, some sharks, and some rays, produce young that are fully developed and too large to be affected by entrainment. Live-bearers together comprise nearly 40 percent of the fish biomass in the Bay (Allen 1999). Another common species in south San Diego Bay, striped mullet, also is not susceptible to entrainment because it spawns offshore and only the juveniles and adults subsequently utilize the Bay habitat.

3.2 Impingement Sampling

Impingement sampling at SBPP was conducted during a 24-hr period one day each week from December 5, 2002 through November 26, 2003. Each sampling period was divided into six approximately 4-hr cycles. In almost every survey throughout this study all eight circulating water pumps (two per unit) were operated during the entire 24-hr sampling period. Before each weekly sampling effort, all of the screens were rotated and rinsed clean of all impinged material. A trap door in the screen wash trough was then opened so that all impinged material would fall into a collection basket. The collection baskets used during this study were the same ones used in the earlier impingement study and were constructed from stainless steel and had ¼ inch diameter holes. During each cycle the traveling screens remained stationary for a period of approximately 3.5 hr, and were then rotated and rinsed for 30 min. This rinse period allowed the entire traveling screen to be rinsed of all material that had been impinged since the last screen wash cycle. In a few instances during impingement collections, the screen wash system started automatically due to a high differential pressure prior to the end of the cycle. The material that was rinsed from the screens during the automatic screen washes was combined with the material collected at the end of that cycle. All debris and organisms rinsed from the Units 1 and 2 traveling screens were kept separate from the material from the Units 3 and 4 traveling screens.

All fishes and selected macroinvertebrates collected at the end of each 4-hr cycle were removed from the debris and then identified and counted. Individual weights and lengths of bony fishes and sharks and rays were recorded (standard length [SL] for the bony fishes and total length [TL] for the sharks and rays). Any mutilated fishes were identified, if possible, and the total weight recorded by taxa. No length measurements were recorded for mutilated fishes. Carapace width was measured for crabs and total length was measured for shrimps and cephalopod mollusks. Weight was also recorded for these invertebrates. Other invertebrates, including hydroids, anemones, sea jellies, barnacles, worms, brittlestars, bryozoans, tunicates, gastropods, and bivalves, were not enumerated or weighed but were only recorded as present when found in the impinged material.

3.2.1 Data Analysis

The circulating water flow during each of the six cycles of the 24-hr impingement surveys was calculated by multiplying the total time each pump had operated during each cycle (generally 4 hr) by the pump's manufacturer-rated flow. Each unit has two pumps with the following flow rates: Units 1 and 2 pumps–148 m^3/min /pump (39,000 gpm), Unit 3 pumps–236 m^3/min/pump (62,300 gpm), and Unit 4 pumps–259 m^3/min/pump (68,400 gpm). In the few instances when the traveling screen was not operational during sampling, the water flow for that pump was not added into the total for that cycle, as impinged organisms were not collected from that screen. The circulating water flow rate for each cycle (obtained from the Plant's operator pump logs showing which pumps were operating and manufacturer's rated flow for each operating pump) was then used to calculate an average daily impingement rate and associated standard error per volume of circulating water for each taxa for the two unit pairs (Units 1 and 2 or Units 3 and 4).

Although many of the impinged fishes were juveniles, for analysis purposes it was assumed that they were all adults and that none of the impinged organisms survived.

3.2.2 Results

A total of 50,970 fishes weighing a total of 74 kg (163 lb) and comprising approximately 50 taxa was impinged during the 12-month study (**Table 3**). The vast majority of the collected fishes (over 93 percent) were anchovies (*Anchoa* spp.). The next most common fishes were silversides Atherinopsidae (mainly topsmelt *Atherinops affinis*), pipefishes *Syngnathus* spp., California halfbeak *Hyporhamphus rosae*, specklefin midshipman *Porichthys myriaster*, gobies Gobiidae, and round stingray *Urolophus halleri*. The wet weight biomass was also dominated by anchovies (39.9 percent) followed by round stingray, specklefin midshipman, bat ray *Myliobatis californica*, and silversides.

The estimated total annual abundance of impinged fishes at SBPP was 385,588 based on continuous flow of all eight circulating water pumps for an entire year (**Table 3**). The estimated annual biomass of impinged fishes was 556.2 kg (1,226.4 lb). The intake screen wash system for Units 1 and 2 at SBPP is separate from that of Units 3 and 4, and impingement data were recorded separately for each of the two unit groups. About 80 percent of the total abundance and 86 percent of the total biomass of fishes was impinged at Units 3 and 4 (**Table 3**).

Table 3. Summary of SBPP Units 1-4 fish impingement from December 2002 through November 2003 for 52 24-hr surveys and extrapolated to 365-day impingement total.

		Sampled Abundance			Extrapolated Annual Impingement			
Taxon	Common Name	(#)	(kg)	(lb)	(#)	Std. Err.	(kg)	Std. Err.
Anchoa spp.	anchovies	47,746	29.53	65.12	359,420	105,476.2	222.01	58.62
Atherinopsidae	silversides	1,293	2.72	6.00	11,664	8,106.0	25.69	36.39
Syngnathus spp.	pipefishes	433	0.32	0.71	3,218	642.2	2.35	0.51
Hyporhamphus rosae	California halfbeak	361	0.43	0.95	2,765	722.6	3.21	1.05
Porichthys myriaster	specklefin midshipman	253	9.23	20.35	1,850	665.3	66.16	48.90
Gobiidae	gobies	241	0.17	0.37	1,791	420.2	1.25	0.42
Urolophus halleri	round stingray	203	16.46	36.29	1,532	490.6	124.57	45.56
Cymatogaster aggregata	shiner surfperch	77	0.28	0.62	549	216.2	2.24	1.71
Strongylura exilis	California needlefish	63	1.37	3.03	510	330.1	11.73	13.76
Cynoscion parvipinnis	shortfin corvina	60	1.57	3.46	428	178.3	10.93	9.85
Hypsopsetta guttulata	diamond turbot	54	0.63	1.38	382	197.8	4.52	4.20
Fundulus parvipinnis	California killifish	26	0.03	0.06	191	107.8	0.20	0.14
Myliobatis californica	bat ray	24	4.40	9.70	172	102.2	30.97	19.91
Hippocampus ingens	Pacific seahorse	23	0.19	0.42	165	83.1	1.27	1.41
Heterostichus rostratus	giant kelpfish	22	0.20	0.45	163	87.4	1.43	1.08
Seriphus politus	queenfish	21	0.52	1.15	152	91.0	3.66	6.10
Acanthogobius flavimanus	yellowfin goby	10	<0.01	0.01	73	73.2	0.03	0.03
Gymnura marmorata	California butterfly ray	8	1.46	3.21	56	48.8	10.37	11.07
Leptocottus armatus	Pacific staghorn sculpin	6	0.03	0.07	58	59.8	0.27	0.39
unidentified fish	unidentified fish	6	0.01	0.03	42	48.5	0.09	0.13
Cololabis saira	Pacific saury	6	0.01	0.02	42	39.1	0.05	0.06
Pleuronectidae	flounders	6	0.01	0.01	56	81.7	0.05	0.07
Sardinops sagax	Pacific sardine	4	0.15	0.33	28	42.0	1.05	1.86
Porichthys notatus	plainfin midshipman	4	0.15	0.32	28	34.3	1.03	2.50
Paralabrax spp.	sand basses	3	1.60	3.52	24	34.7	13.06	19.29
Gillichthys mirabilis	longjaw mudsucker	3	0.04	0.08	24	35.0	0.27	0.39
Pleuronichthys spp.	turbots	3	<0.01	0.01	21	51.7	0.02	0.05
Sciaenidae	croakers	3	<0.01	<0.01	26	35.7	0.01	0.01
Mugil cephalus	striped mullet	2	1.50	3.31	14	24.2	10.50	25.72
Cynoscion nobilis	white seabass	2	0.09	0.21	14	24.2	0.65	1.56
Engraulis mordax	northern anchovy	2	0.01	0.01	16	28.3	0.05	0.10
Lepidogobius lepidus	bay goby	2	<0.01	<0.01	14	24.2	0.01	0.01
Cheilotrema saturnum	black croaker	1	0.46	1.01	7	17.1	3.22	7.89
Dasyatis brevis	diamond stingray	1	0.42	0.93	7	17.1	2.94	7.21
Paralichthys californicus	California halibut	1	0.01	0.03	7	17.1	0.09	0.21
Blenniidae	combtooth blennies	1	0.01	0.03	5	11.3	0.06	0.14
Tridentiger trionocephalus	chameleon goby	1	0.01	0.02	9	21.7	0.09	0.23
Gibbonsia spp.	clinid kelpfishes	1	<0.01	0.01	9	20.0	0.03	0.07
Hypsoblennius spp.	combtooth blennies	1	<0.01	0.01	7	17.1	0.02	0.05
Pleuronichthys ritteri	spotted turbot	1	<0.01	<0.01	7	17.1	0.01	0.03
Porichthys spp.	midshipmans	1	<0.01	<0.01	7	17.1	0.01	0.02
Albula vulpes	bonefish	1	<0.01	<0.01	7	17.1	0.01	0.02
Lepidopsetta bilineata	rock sole	1	<0.01	<0.01	7	17.0	0.01	0.02
Stichaeidae	pricklebacks	1	<0.01	<0.01	7	17.1	<0.01	0.01
larval/post-larval fish	larval/post-larval fish	1	<0.01	<0.01	7	17.3	<0.01	0.01
Pleuronectiformes	flatfishes	1	<0.01	<0.01	6	14.6	<0.01	<0.01
	TOTAL	**50,984**	**74.03**	**163.23**	**385,588**		**556.18**	
	% impingement total from Units 1-2	20.3	14.4					
	% impingement total from Units 3-4	79.7	85.6					

Source: Tenera Environmental 2004b. Table 4.3-1.

3.3 Conclusion

Overall, the 2004 316(b) assessment relied on a synthesis of results from modeling the effects of larvae removed from the system through entrainment and juveniles and adults removed from the system through impingement. In both cases, estimated losses were calculated using the following set of conservative assumptions that would result in the greatest projected effects on a target species:

- all entrainment and impingement loss estimates were calculated based on maximum design cooling water flows, although actual cooling water withdrawals will be reduced by at least 63 percent due to the shutdown of Units 3 and 4, and further reduced due to the reduced capacity factors that are anticipated throughout the remainder of 2010;
- entrainment modeling assumed no survival of larvae through the cooling water system, yet entrainment survival has been documented in numerous studies;
- no density-dependent compensatory effects were included in the models that would result in increased survivorship for later life-stages not subject to CWIS effects; and
- estimated economic losses of impingement fishery species were scaled up to assume that all impinged individuals represented fishes of adult size potentially lost to the fishery, without applying projected mortality rates to the impinged juveniles.

Overall, our conclusions were consistent with those from the earlier 316(b) study done in 1979–1980 (SDG&E 1980), namely that the operation of SBPP does not substantially affect populations of the most abundant or economically important fishes and invertebrates in San Diego Bay. Studies by Allen (1999) found that slough anchovy comprised over half of the fishes by number in the south-central and south ecoregions of San Diego Bay. Results from the present study show that, at historical maximum flow rate of 601 MGD, SBPP may account for a loss of approximately 8–10 percent of the larval population annually and represent an equivalent loss of approximately 1–2 percent of the adult standing stock. Another major group of fishes in the Bay affected by entrainment was the CIQ goby complex, with larval losses estimated at 21–27 percent of the source water population. Prior to 2009 and the decommissioning of Units 3 and 4, using the most conservative assumptions, the SBPP CWIS may account for losses from 1.2 to 2.2 million adult CIQ gobies per year out of an estimated standing stock of over 10 million. Subsequently without Units 3 and 4, the losses would be no more than approximately 0.450 to 0.820 million adult CIQ gobies per year, and less by the amount of cooling water flow other than 24/7 operations. For the invertebrate species investigated, there were no substantial direct effects of the CWIS on their populations. Particularly for species with commercial fishery importance, such as lobsters, crabs, and squid, the results indicate that SBPP would not affect the adult populations of these species.

Gobies, one of the most abundant groups of entrained fish larvae, are not susceptible to impingement as adults because they are bottom-dwelling species that typically not found in the water column. Even fish species that swim in the water column are generally not susceptible to impingement effects as they mature because they are able to swim against the slow approach velocity of the cooling water inflow. For example, at the SBPP intakes it was not uncommon to see small schools of adult striped mullet swimming directly in front of the intakes and not being impinged during times when circulating water pumps were operating.

4.0 REANALYSIS OF 2003 THERMAL DISCHARGE EFFECTS STUDY RESULTS

4.1 Field Data Collection

Twenty-one subtidal and ten intertidal temperature-monitoring stations were established in the vicinity of the SBPP in 2003(**Table 4** and **Figure 5**). The majority of the stations were clustered around the power plant's intake and discharge channels to record the magnitude and distribution of the discharge plume. Several far-field stations were also established further to the north beyond the influence of the plume. The proximity of the stations to the power plant's discharge ranged from approximately 65 m (328 ft) to nearly 5 km (3 mi) (**Table 5**). These distances are estimates of the shortest flow-paths between the SBPP discharge and each monitoring station, not linear measurements between the points. Eleven of the subtidal stations (those designated A, C, D, E, F, or N) were placed at locations that were part of the ongoing NPDES receiving water monthly monitoring program for SBPP. All of the intertidal stations and the remaining ten subtidal stations (those designated R or T) were established at new locations that were concentrated around the intake and discharge channels. All of the temperature recorders were initially deployed on July 15–16, 2003.

Each of the subtidal stations was equipped with an array of three temperature recorders deployed below a buoy (**Figure 6**). One recorder was located just below the surface of the water, one at a depth of 1 m (about 3 ft), and one just above the sediment-water interface. The position of the upper two recorders, relative to the water's surface, remained constant regardless of tide height. The bottom recorder's position was fixed and the depth separating the recorder from the surface changed with the tides. The depth at which the bottom recorder was located also varied between stations, depending upon the position of the station within San Diego Bay. Subtidal station depth ranged from 0.4 m (1.2 ft) below MLLW (Station SR4) to 4.2 m (13.9 ft) below MLLW (Station SA3). Each of the intertidal stations was equipped with a single, fixed-position temperature recorder. The elevation of all ten intertidal recorders was approximately 0.3 m (1.0 ft) above MLLW. As such, the recorders were exposed to air during some low tide conditions. Air temperatures were deleted from the temperature database during data processing.

All of the monitoring stations were equipped with Stowaway Tidbit® temperature recorders manufactured by the Onset Computer Corporation. The units had a recording range from -5–37°C (24–99°F), were accurate to ± 0.2°C (± 0.4°F), and were programmed to synchronously record temperatures at 10-minute intervals. The recorders closest to the discharge were replaced in early September 2003 with similar instruments that had a range of -20–50°C (-4–122°F) and were accurate to ± 0.4°C (± 0.8°F). All recorders were calibrated and each was checked to verify its operability and accuracy after it was retrieved and the data were downloaded.

Table 4. Locations of subtidal (S series) and intertidal (I series) temperature stations. Subtidal stations consisted of a surface, 1-m (3.3 ft) subsurface, and bottom temperature recorder (see **Figure 5a**). *Intertidal stations were at a fixed elevation of 0.3 m (1.0 ft) above MLLW (see **Figure 5b**).

			Depth below MLLW*	
Station	**Latitude (N)**	**Longitude (W)**	**meters**	**feet**
SUBTIDAL				
SA3	32° 37.780'	117° 07.136'	4.2	13.8
SC3	32° 37.211'	117° 07.149'	2.3	7.5
SD4	32° 37.109'	117° 06.884'	1.4	4.6
SE3	32° 36.863'	117° 07.143'	1.1	3.6
SE4	32° 36.866'	117° 06.858'	1.3	4.3
SE5	32° 36.785'	117° 06.603'	1.7	5.6
SE7	32° 36.801'	117° 05.930'	1.7	5.6
SF2	32° 36.566'	117° 07.482'	0.4	1.3
SF3	32° 36.621'	117° 06.971'	1.4	4.6
SF4	32° 36.552'	117° 06.852'	1.8	5.9
SN2	32° 38.201'	117° 07.704'	2.0	6.6
SR1	32° 36.988'	117° 06.392'	3.1	10.2
SR2	32° 37.013'	117° 06.480'	2.2	7.2
SR3	32° 37.070'	117° 06.650'	2.6	8.5
SR4	32° 37.143'	117° 06.364'	0.9	3.0
SR5	32° 37.238'	117° 06.401'	0.4	1.3
ST1	32° 36.792'	117° 06.005'	2.0	6.6
ST2	32° 36.777'	117° 06.141'	2.0	6.6
ST3	32° 36.772'	117° 06.254'	1.6	5.2
ST4	32° 36.723'	117° 06.430'	1.9	6.2
ST5	32° 36.825'	117° 06.788'	2.0	6.6
INTERTIDAL				
IR1	32° 36.955'	117° 06.438'	+0.3	+1.0
IR2	32° 36.984'	117° 06.547'	+0.3	+1.0
IR3	32° 37.018'	117° 06.683'	+0.3	+1.0
IR4	32° 37.131'	117° 06.217'	+0.3	+1.0
IR5	32° 37.223'	117° 06.257'	+0.3	+1.0
IT1	32° 36.816'	117° 06.006'	+0.3	+1.0
IT2	32° 36.799'	117° 06.144'	+0.3	+1.0
IT3	32° 36.777'	117° 06.288'	+0.3	+1.0
IT4	32° 36.741'	117° 06.403'	+0.3	+1.0
IT5	32° 36.853'	117° 06.804'	+0.3	+1.0

Source: Tenera Environmental 2004a. Table 2.

Table 5. Distance of subtidal (S series) and intertidal (I series) temperature stations from the SBPP discharge boom (property line). Distances are the shortest drift path to the station from the Plant discharge. Order of stations reflects increasing distance.

	Drifter distance from discharge boom	
Station	**meters**	**feet**
SUBTIDAL		
SE7	65	213
ST1	181	594
ST2	396	1,299
ST3	572	1,877
ST4	857	2,812
SE5	1,150	3,773
ST5	1,445	4,741
SF4	1,591	5,220
SF3	1,817	5,961
SE3	2,294	7,526
SE4	2,305	7,562
SF2	2,624	8,609
SD4	2,728	8,950
SR3	2,805	9,203
SC3	2,938	9,639
SR2	3,089	10,135
SR1	3,234	10,610
SR4	3,272	10,735
SR5	3,301	10,830
SA3	4,017	13,179
SN2	4,917	16,132
INTERTIDAL		
IT1	182	597
IT2	362	1,188
IT3	621	2,037
IT4	833	2,733
IT5	1,475	4,839
IR3	3,345	10,974
IR2	3,570	11,713
IR1	3,742	12,277
IR5	3,999	13,120
IR4	4,038	13,248

Source: Tenera Environmental 2004a. Table 3.

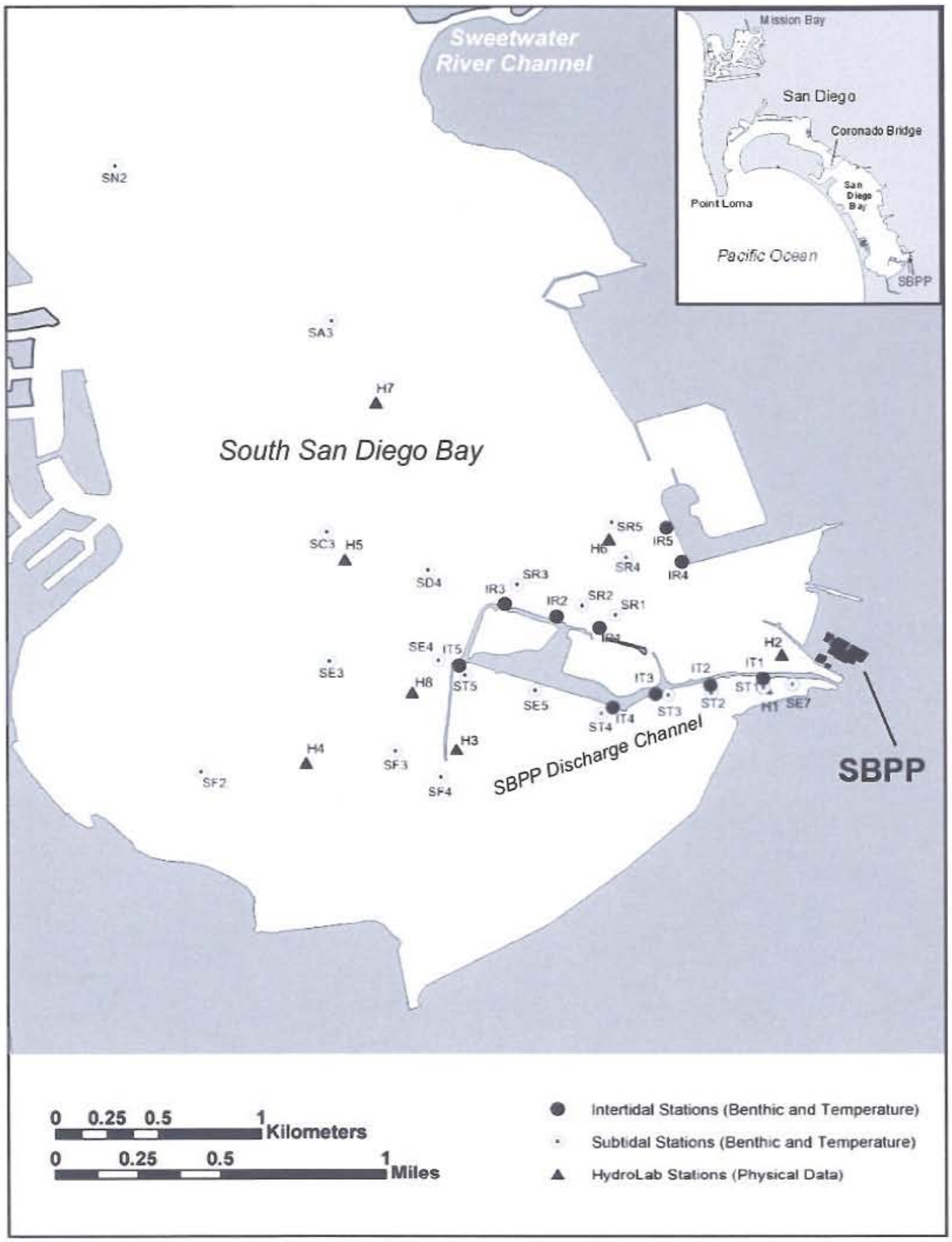


Figure 5a. Station location map of intertidal and subtidal thermal monitoring stations.

Source: Tenera Environmental 2004a.

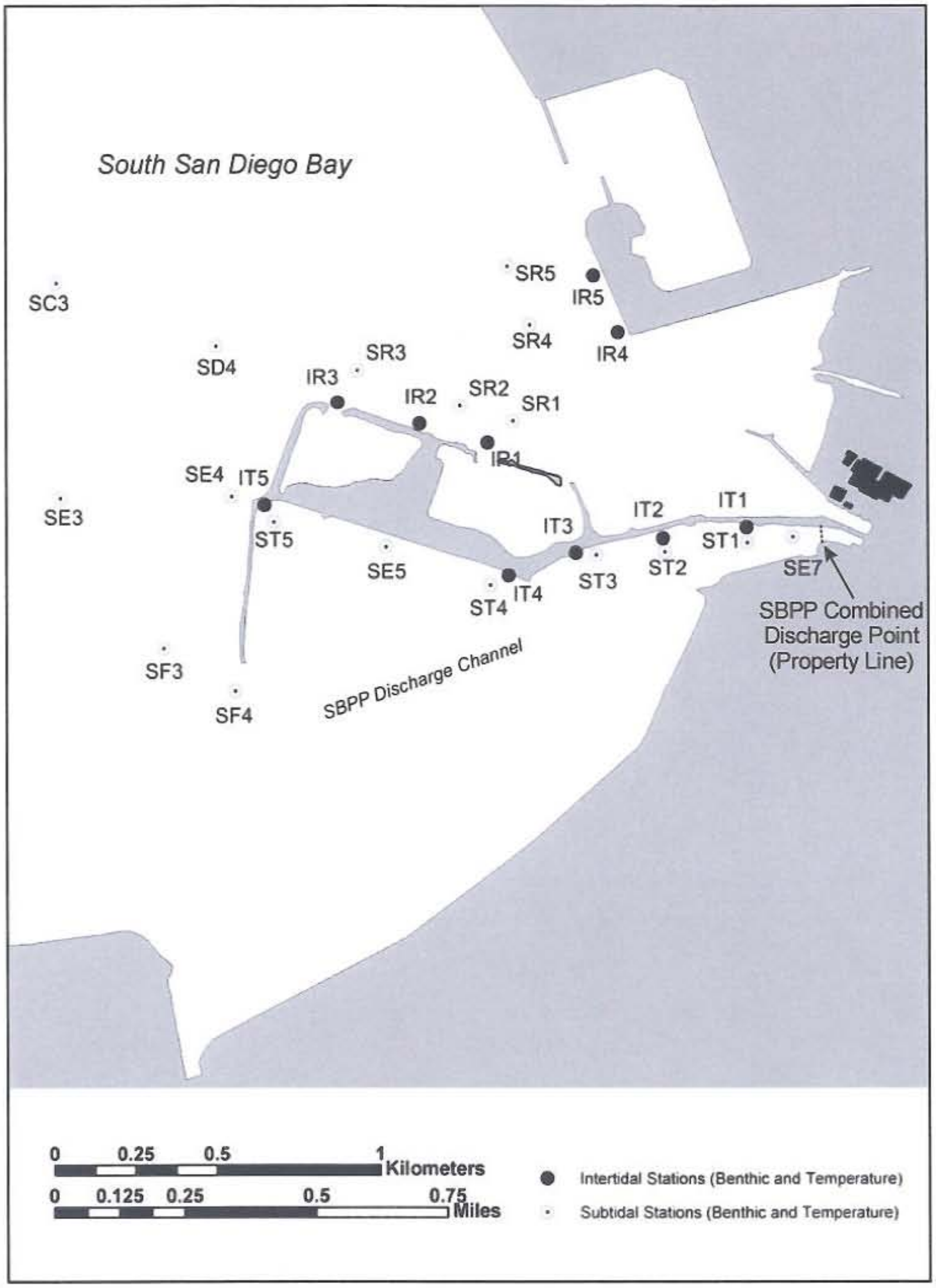


Figure 5b. Station location map of intertidal and subtidal thermal monitoring stations.

Source: Tenera Environmental 2004a.

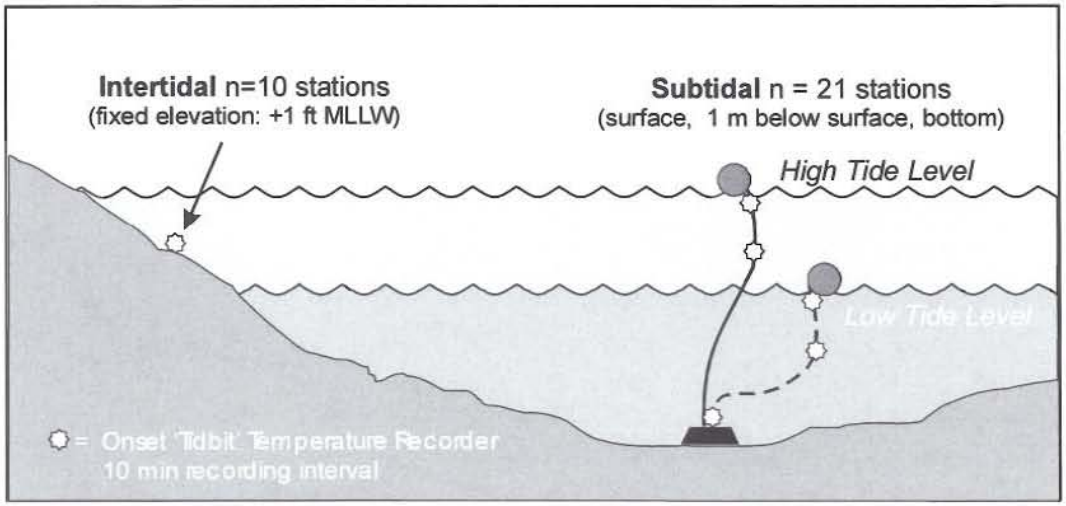


Figure 6. Diagram of intertidal and subtidal temperature arrays in relation to tidal elevation and channel morphology.

Source: Tenera Environmental 2004a.

4.2 Data Analysis

For the purpose of this comparison eight days were selected from the July–November 2003 thermal monitoring period that fell into three different Plant operation categories. The three operating categories were:

A) Four unit operation with high Plant generation output and high discharge volume (conditions approaching the four unit maximum of 723 MWe and 25.0 mgh);

B) Two unit operation (Units 1 and 2) with high Plant generation output and high discharge volume (conditions approaching the two unit maximum of 308 MWe and 9.4 mgh);

C) Two unit operation (Units 1 and 2) with Plant generation output at about 2/3 of maximum with full discharge volume (about 200 MWe and 9.4 mgh).

Categories A and B are representative of the maximum operating conditions prior to and after December 31, 2009. The days falling into these categories that were selected for this document were July 16, 2003, September 5, 2003, October 21, 2003, and October 28, 2003 (Category A), and October 10, 2003, October 14, 2003, and November 5, 2003 (Category B) (**Figure 7**). Category C conditions are representative of a regularly occurring operating condition for which the data collected on September 29, 2003 were selected (**Figure 7**).

Data analysis was limited to those time periods when the Plant was operating at, or near, the conditions described above. Only those data collected while the delta T calculated at the SBPP property equaled or exceeded 4.5 degrees C at the surface monitoring level were included (**Table 6**).

Table 6. Data analysis periods (property line delta T $\geq$ 4.5° C) on the dates selected for comparison.

Start of Data Analysis Period	End of Data Analysis Period
July 16, 2003 10:40	July 17, 2003 00:20
September 5, 2003 07:20	September 5, 2003 22:30
September 29, 2003 09:00	September 29, 2003 20:00
October 10, 2003 09:30	October 10, 2003 23:50
October 14, 2003 05:20	October 14, 2003 23:50
October 21, 2003 08:30	October 21, 2003 22:00
October 28, 2003 00:00	October 28, 2003 23:50
November 5, 2003 08:30	November 5, 2003 23:50

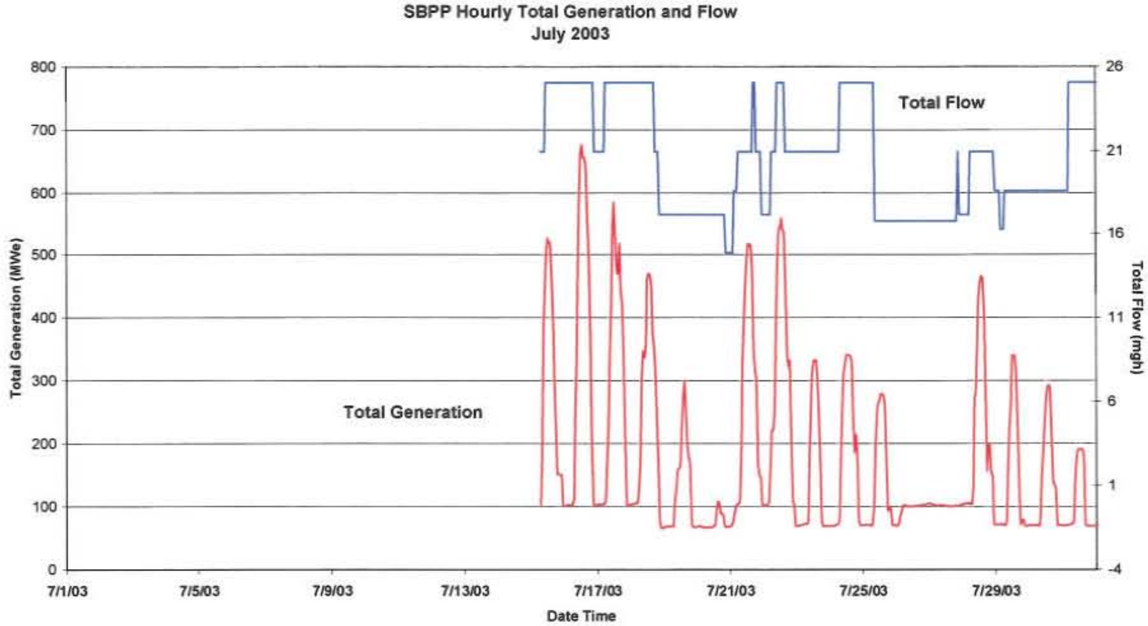
Data source: Tenera Environmental 2004a.

Statistical analysis for comparing the eight periods (**Table 6**) and the units' conditions followed that used in the previous SBPP 316(a) study. The difference in temperature, or delta T°, between the reference stations and discharge stations was calculated for each of the synoptic 10 min readings. For intertidal stations, the mean reference temperature was calculated from the readings taken at Stations IR1, IR2, and IR3, and was subtracted from the readings taken at the same time at each of the intertidal stations. For subtidal stations, temperature readings from Stations SR1, SR2, and SR3 were used as reference. The mean of the three stations was calculated for each of the monitoring depths (surface, -1 meter, and bottom), for each 10-min reading. In the 316(a) study a paired t-test of the daily mean reference and SBPP intake temperatures found no significant difference between the two.

Linear regressions were fit to delta T° at each 10 min. Temperature as a function of distance x from the discharge were fit to stations within 2,800 m (9,186 ft) from the discharge boom (about the distance to the first reference station). The synoptic mean temperatures at the reference stations (T_{SR}) used in calculating station delta T° (*i.e.*, SR1, SR2, and SR3) were not included in regressions,

$$\text{Model :} \qquad \left(T - \frac{\sum_{i=1}^{3} T_{SRi}}{3} \right) = a + b\,x + \quad .$$

The mean and standard deviation of the regressions' *a* and *b* parameters were calculated for the eight periods. These means and standard deviations were used to test the hypothesis that the plume differed between conditions A, B and C. For example, a significantly smaller intercept in the B condition with similar slope would indicate a significantly reduced thermal plume when only Units 1 and 2 are operating.



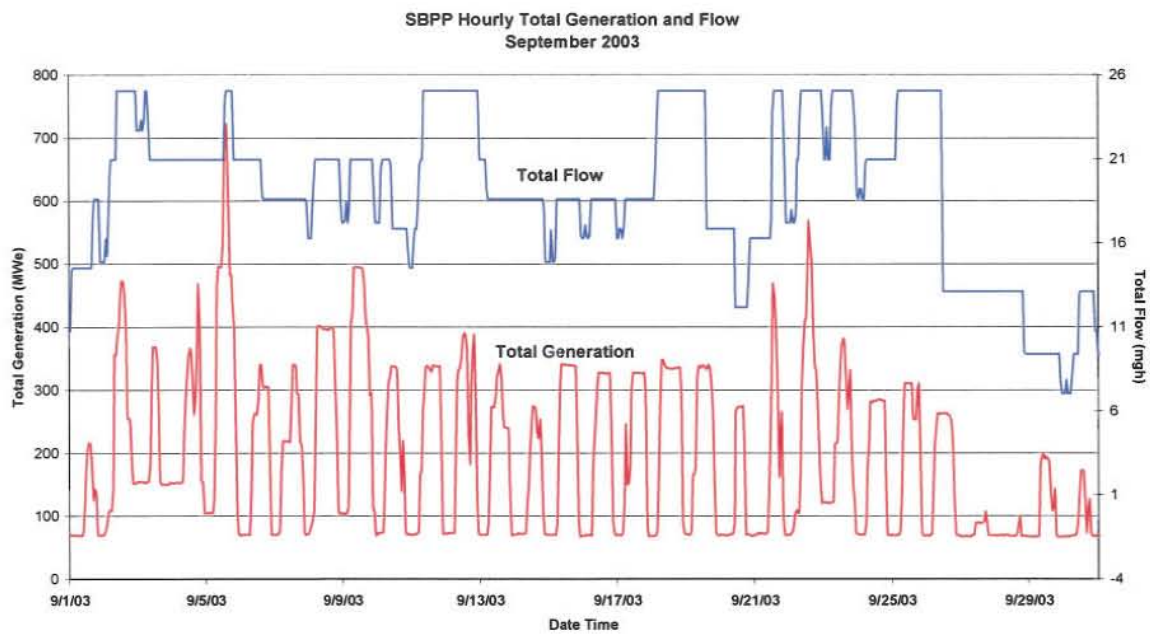
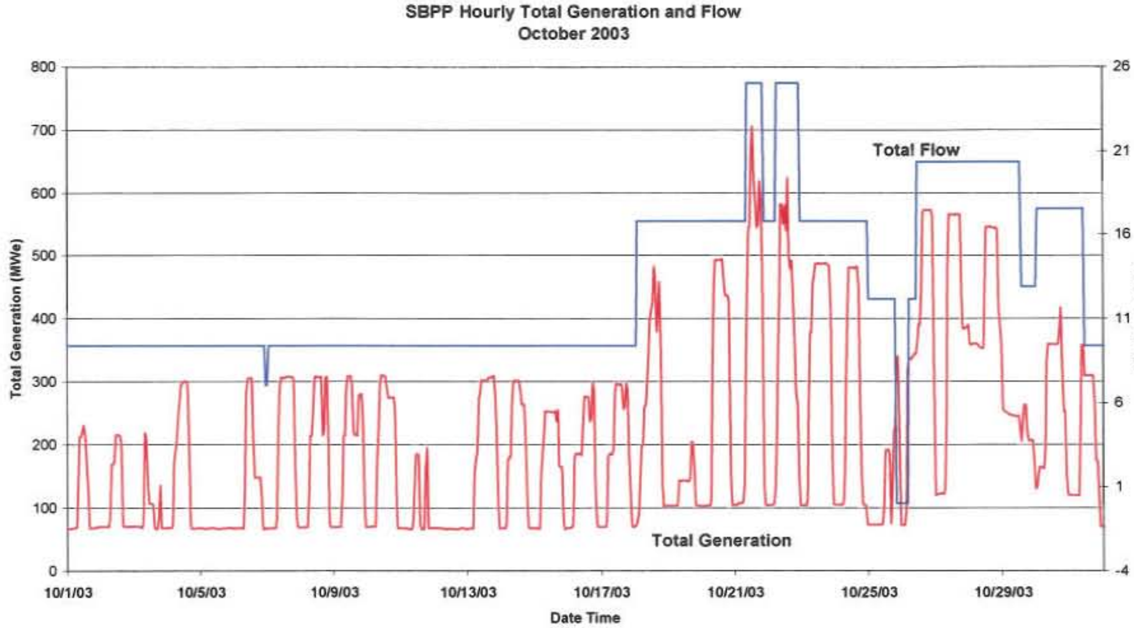


Figure 7a. Averaged total Plant output (MWe) and Plant discharge volume (mgh) calculated hourly for July15-31, 2003 and September 2003. Thermal Monitoring stations were established on July 15&16, 2003.

Source: Tenera Environmental 2004a. Figure 4a.



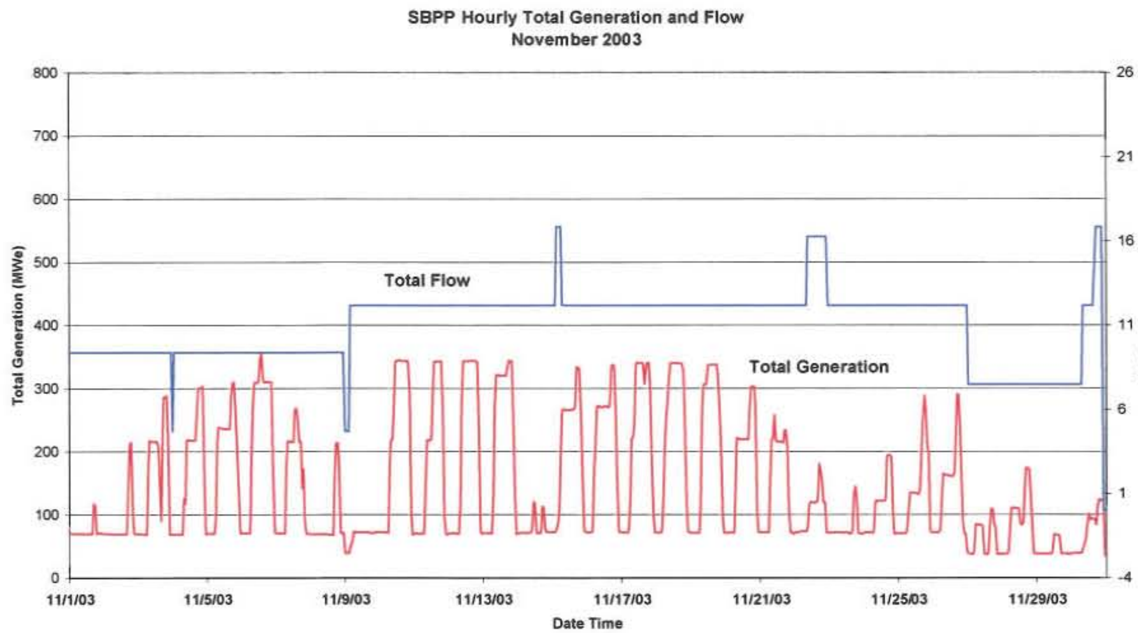


Figure 7b. Averaged total Plant output (MWe) and Plant discharge volume (mgh) calculated hourly for October and November 2003.

Source: Tenera Environmental 2004a. Figure 4b.

4.3 Results

Figure 8 shows a three dimensional view of one of the 10-minute readings made about one hour after peak output for the four periods when all units were operating. **Figure 9** shows similar views for the four periods when only Units 1 and 2 were operating. **Figure 10** shows enlarged views when only Units 1 and 2 were operating (November 5, 2003) and when Units 1, 2, 3 and 4 were operating (September 5, 2003). Operating conditions for the eight analysis periods are summarized in **Table 7**.

Table 7. Mean, minimum and maximum power generation and pump flow in periods for data analysis (property line surface model delta T ≥ 4.5° C) of temperature plume assessment.

Analysis Period (start, end)	Mean MWe	Max MWe	Min MWe	Mean Flow (mgh)	Max Flow (mgh)	Min Flow (mgh)
7/16/2003 10:40 7/17/2003 00:20	437.0	678.9	101.2	24.5	25.0	20.9
9/5/2003 07:20 9/5/2003 22:30	488.8	726.0	104.1	22.5	25.0	20.9
10/21/2003 08:30 10/21/2003 22:00	525.5	706.2	104.5	24.0	25.0	16.8
10/28/2003 00:00 10/28/2003 23:50	436.4	545.5	352.8	20.4	20.4	20.4
10/10/2003 09:30 10/10/2003 23:50	244.7	310.5	67.8	9.4	9.4	9.4
10/14/2003 05:20 10/14/2003 23:50	209.5	301.7	67.3	9.4	9.4	9.4
11/5/2003 08:30 11/5/2003 23:50	230.5	309.3	69.7	9.4	9.4	9.4
9/29/2003 09:00 9/29/2003 20:00	156.1	200.4	67.2	9.4	9.4	9.4

Data source: Tenera Environmental 2004a.

Delta T° calculations made for each of the readings taken at 10-minute intervals during each period were used for estimating linear regression parameters *a* (intercept) and *b* (slope) for each 10-minute interval. The regression slope intercept *a* estimates a discharge delta T near the property line and the slope *b* is a measure of the rate of temperature decrease with increasing distance from the SBPP discharge.

Tables 8 to **11** summarize the regression parameters corresponding to three operating conditions in periods when the model property line delta T was greater than 4.5°C. **Figures 11 to 14** depict the regressions for all conditions and plume levels. At the surface, the mean intercepts (model property line delta T) over the selected periods were 8.61°C (n=401, condition A: all units operating), 7.76°C (n=292, condition B: Units 1 and 2 operating) and 5.82°C (n=67, condition C: Units 1 and 2 operating at 2/3 capacity). Means slopes from the surface model were -3.23°C/km (condition A), -2.99°C/km (condition B) and -2.22°C/km (condition C). One meter below the surface, the mean intercepts were less than on the surface: 7.70°C (condition A), 6.50°C (n=292, condition B) and 4.80°C (condition C). Means slopes from the subsurface model were also reduced: -3.10°C/km (condition A), -2.57°C/km (condition B) and -1.87°C/km (condition C). On the bottom, the mean intercepts were less than the subsurface: 5.48°C (condition A), 3.79°C (n=292, condition B) and 2.39°C (condition C). Means slopes from the bottom model were also reduced: -2.12°C/km (condition A), -1.33°C/km (condition B) and -0.69°C/km (condition C).

In the intertidal region, the mean intercepts (model property line delta T) over the selected periods were 7.73°C (n=393, condition A: all units operating), 6.62°C (n=275, condition B: Units 1 and 2 operating) and 4.42°C (n=43, condition C: Units 1 and 2 operating at 2/3 capacity). Means slopes from the intertidal model were -3.50°C/km (condition A), -3.14°C/km (condition B) and -2.64°C/km (condition C).

The probability that the regression models' means of parameters differed was tested using an analysis of variance (ANOVA). **Table 12** presents the ANOVA test results. In addition to testing if differences occurred in the total grouping (conditions A, B, and C), *a priori* comparisons were made in A versus B and B versus C. The results showed differences in the surface plume property line intercept, including a 0.066 probability of rejecting the hypothesis that the conditions with all units running is the same than with Units 1 and 2 running a full capacity. Slopes were not rejected as being similar (Pr>F=.2754). This can be interpreted as the surface plume is reduced by about 1° C. The difference is even greater when comparing all units to 2/3 capacity on Units 1 and 2. All comparisons of parameters in the subsurface layer showed probabilities less than 0.05. At that probability level one cannot say that the plume is similar at all conditions examined. The subsurface plume at the property line is smaller when Units 1 and 2 are operating and even smaller with reduced capacity. The rate of change becomes steeper with all units operating and indicates that convergence between conditions occurs at lower delta T temperatures in the farfield. On the bottom there was no difference detected between the two conditions if Unit 1 and 2 operations, however the similarity to all units running is rejected. The plume is thinner by almost 2° C near the property line and converges in the farfield. The hypothesis that the intertidal plume was different between conditions cannot be rejected at the 0.05 probability level. However, the mean intercepts become smaller with Units 1 and 2 operations. As in the subsurface and bottom plumes, the mean change in temperature is diminished with Units 1 and 2 operations.

Table 8. Mean regression parameters of data analysis periods (property line surface delta T ≥ 4.5° C) on the dates selected for comparison of temperature plume on surface.

Analysis Period (start, end)	Condition	N	(°C)	stdev *a* (°C)	(°C/m)	stdev *b* (°C/m)
7/16/2003 10:40 7/17/2003 00:20	A-All Units	83	8.44	1.51	-0.003321	0.000783
9/5/2003 07:20 9/5/2003 22:30	A-All Units	92	9.38	1.84	-0.003690	0.001110
10/21/2003 08:30 10/21/2003 22:00	A-All Units	82	9.04	1.98	-0.003350	0.000896
10/28/2003 00:00 10/28/2003 23:50	A-All Units	144	7.96	1.09	-0.002808	0.000456
10/10/2003 09:30 10/10/2003 23:50	B-Units 1&2	87	7.67	1.94	-0.003057	0.000896
10/14/2003 05:20 10/14/2003 23:50	B-Units 1&2	112	7.86	1.81	-0.002953	0.000708
11/5/2003 08:30 11/5/2003 23:50	B-Units 1&2	93	7.74	1.17	-0.002983	0.000681
9/29/2003 09:00 9/29/2003 20:00	C-Units 1&2 ~2/3 output	67	5.82	0.72	-0.002225	0.000542

Data source: Tenera Environmental 2004a.

Table 9. Mean regression parameters of data analysis periods (property line delta T ≥ 4.5° C) on the dates selected for comparison of temperature plume one meter subsurface.

Analysis Period (start, end)	Condition	N	(°C)	stdev *a* (°C)	(°C/m)	stdev *b* (°C/m)
7/16/2003 10:40 7/17/2003 00:20	A-All Units	83	7.47	1.60	-0.003149	0.000729
9/5/2003 07:20 9/5/2003 22:30	A-All Units	92	8.29	1.93	-0.003465	0.001081
10/21/2003 08:30 10/21/2003 22:00	A-All Units	82	8.11	1.97	-0.003277	0.000952
10/28/2003 00:00 10/28/2003 23:50	A-All Units	144	7.22	1.41	-0.002746	0.000404
10/10/2003 09:30 10/10/2003 23:50	B-Units 1&2	87	6.45	2.17	-0.002645	0.000981
10/14/2003 05:20 10/14/2003 23:50	B-Units 1&2	112	6.71	1.97	-0.002569	0.000779
11/5/2003 08:30 11/5/2003 23:50	B-Units 1&2	93	6.29	1.60	-0.002506	0.000765
9/29/2003 09:00 9/29/2003 20:00	C-Units 1&2 ~2/3 output	67	4.80	0.45	-0.001870	0.000297

Data source: Tenera Environmental 2004a.

Table 10. Mean regression parameters of data analysis periods (property line delta T ≥ 4.5° C) on the dates selected for comparison of temperature plume on the bottom.

Analysis Period (start, end)	Condition	N	(°C)	stdev *a* (°C)	(°C/m)	stdev *b* (°C/m)
7/16/2003 10:40 7/17/2003 00:20	A-All Units	83	5.39	1.70	-0.002308	0.000660
9/5/2003 07:20 9/5/2003 22:30	A-All Units	92	5.40	1.41	-0.002169	0.000703
10/21/2003 08:30 10/21/2003 22:00	A-All Units	82	5.77	2.02	-0.002318	0.000965
10/28/2003 00:00 10/28/2003 23:50	A-All Units	144	5.42	2.86	-0.001858	0.000972
10/10/2003 09:30 10/10/2003 23:50	B-Units 1&2	87	3.56	1.85	-0.001298	0.000812
10/14/2003 05:20 10/14/2003 23:50	B-Units 1&2	112	3.59	0.95	-0.001181	0.000385
11/5/2003 08:30 11/5/2003 23:50	B-Units 1&2	93	4.26	1.66	-0.001527	0.000762
9/29/2003 09:00 9/29/2003 20:00	C-Units 1&2 ~2/3 output	67	2.39	1.57	-0.000692	0.000513

Source: Tenera Environmental 2004a.

Table 11. Mean regression parameters of data analysis periods (property line delta T ≥ 4.5° C) on the dates selected for comparison of temperature plume on intertidal locations.

Analysis Period (start, end)	Condition	N	(°C)	stdev *a* (°C)	(°C/m)	stdev *b* (°C/m)
7/16/2003 10:40 7/17/2003 00:20	A-All Units	83	7.99	3.20	-0.004132	0.003215
9/5/2003 07:20 9/5/2003 22:30	A-All Units	84	9.10	1.55	-0.004801	0.001317
10/21/2003 08:30 10/21/2003 22:00	A-All Units	82	8.26	1.86	-0.004003	0.001365
10/28/2003 00:00 10/28/2003 23:50	A-All Units	144	6.47	2.34	-0.002100	0.002606
10/10/2003 09:30 10/10/2003 23:50	B-Units 1&2	70	5.98	2.38	-0.003382	0.001677
10/14/2003 05:20 10/14/2003 23:50	B-Units 1&2	112	6.67	2.74	-0.002616	0.002127
11/5/2003 08:30 11/5/2003 23:50	B-Units 1&2	93	7.05	0.83	-0.003596	0.000789
9/29/2003 09:00 9/29/2003 20:00	C-Units 1&2 ~2/3 output	43	4.42	1.41	-0.002640	0.001117

Data source: Tenera Environmental 2004a.

Table 12. Significant levels (Pr>F) from ANOVA tests of mean *a* (modeled property line delta T) and *b* (rate of temperature change) parameters for temperature plume comparisons in three condition groups. Groups were condition A: all units operating, condition B: Units 1 and 2 operating, and condition C: Units 1 and 2 operating at 2/3 capacity. Significant levels less than 0.05 are highlighted (reject hypothesis that means are same at that level).

Plume Level	Means in A	Means in B	Means in C	Pr>F ABC	Pr>F AB	Pr>F BC	SNK Groups
Surface *a* (°C)	8.61	7.76	5.82	**0.0192**	0.0664	**0.0045**	ABvsC
b (°C/km)	-3.22	-2.99	-2.22	0.1084	0.2754	**0.0083**	ABC
Subsurface *a*	7.70	6.50	4.80	**0.0059**	**0.0122**	**0.0288**	ABvsC
b	-3.10	-2.57	-1.87	**0.0222**	**0.0345**	**0.0158**	ABvsBC
Bottom *a*	5.48	3.79	2.39	**0.0004**	**0.0005**	0.1136	AvsBvsC
b	-2.12	-1.33	-0.69	**0.0037**	**0.0041**	0.1142	AvsBC
Intertidal *a*	7.73	6.62	4.42	0.1109	0.1321	0.1129	ABC
b	-3.50	-3.14	-2.64	0.7041	0.5291	0.5813	ABC

Data source: Tenera Environmental 2004a.

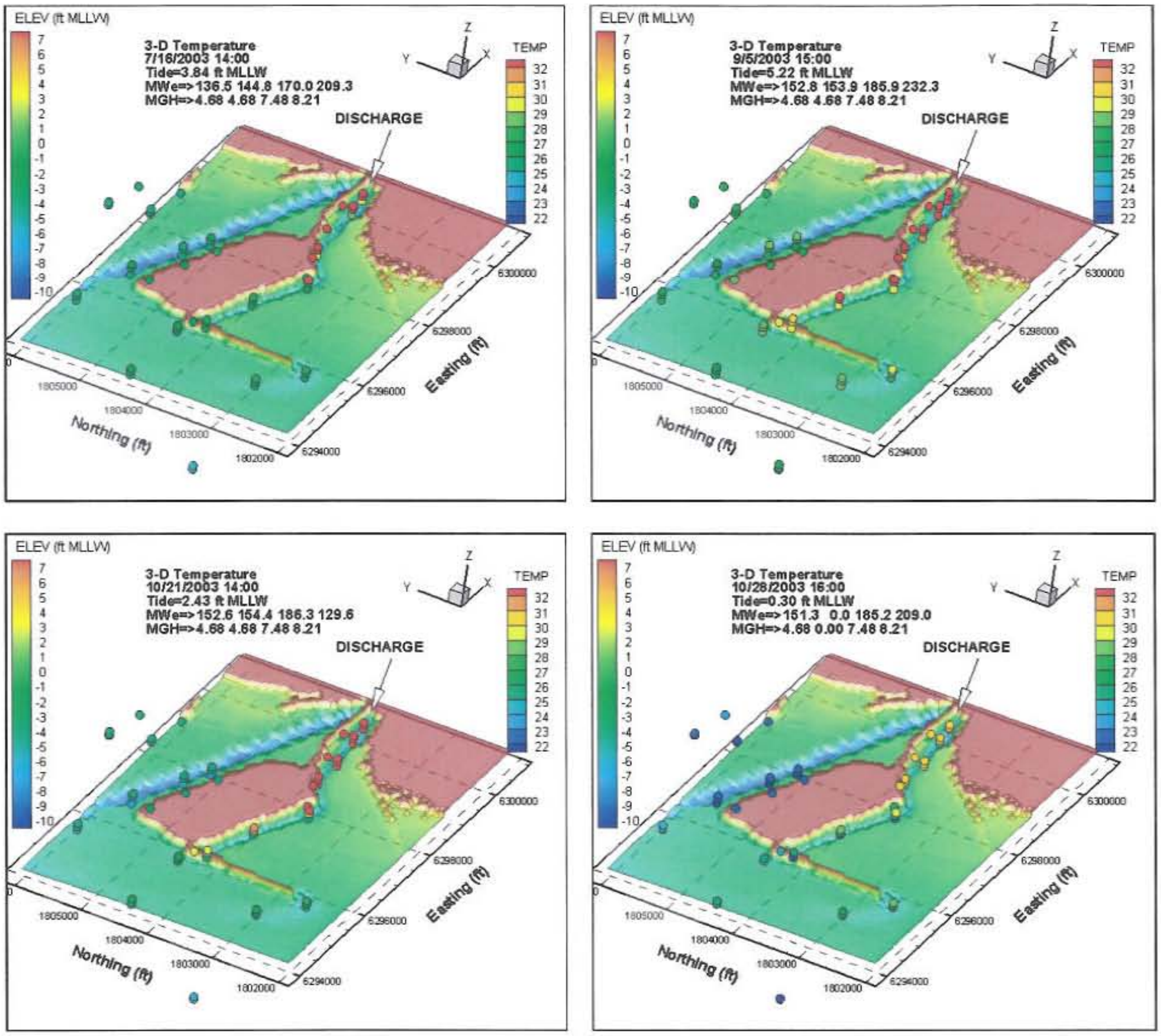


Figure 8. Three-dimensional view of temperatures near SBPP discharge for selected times when all units were operating (Condition A: July 16, September 5, October 21, and October 28, 2003). Time captured is one to two hours post the day's maximum generation. Bathymetry, tide, SBPP pump flow and output per unit are also shown.

Data source: Tenera Environmental 2004a.

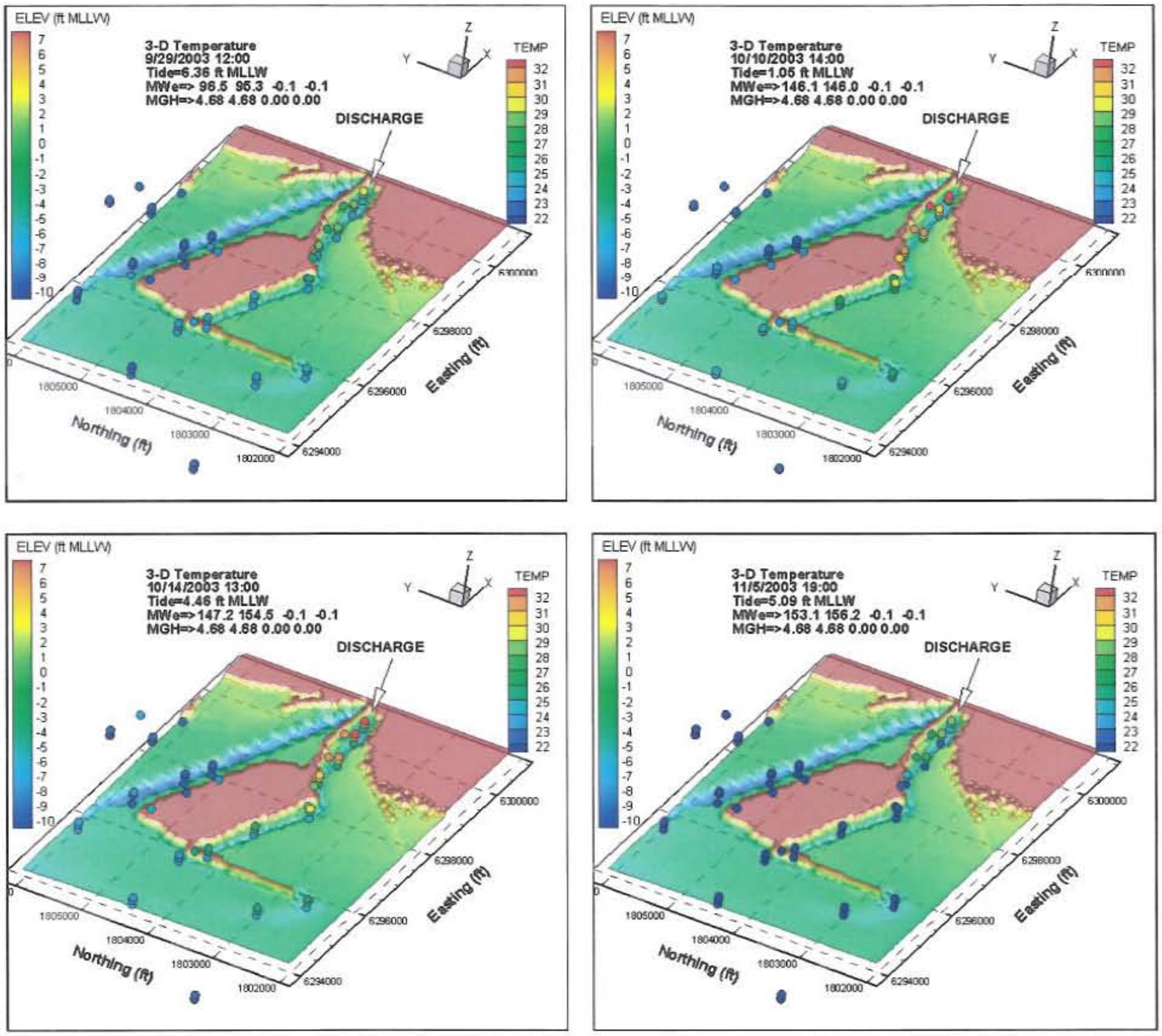
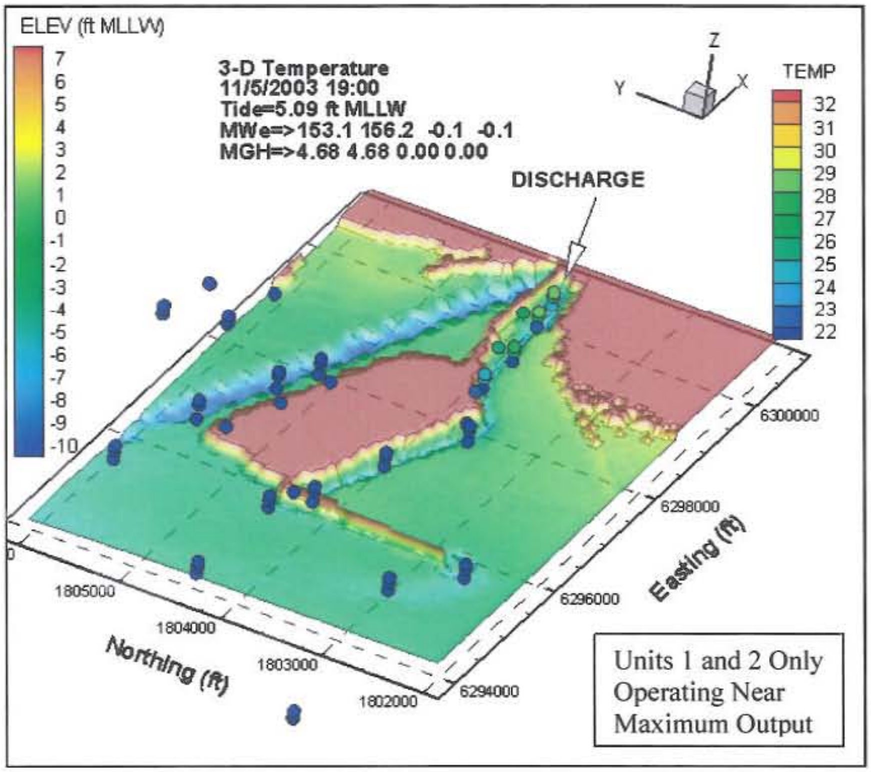


Figure 9. Three-dimensional view of temperatures near SBPP discharge for selected times when Units 1 and 2 only were operating (Condition B: October 10, October 14, and November 5, 2003; Condition C: September 29, 2003). Time captured is one to two hours post the day's maximum generation. Bathymetry, tide, SBPP pump flow and output per unit are also shown.

Data source: Tenera Environmental 2004a.



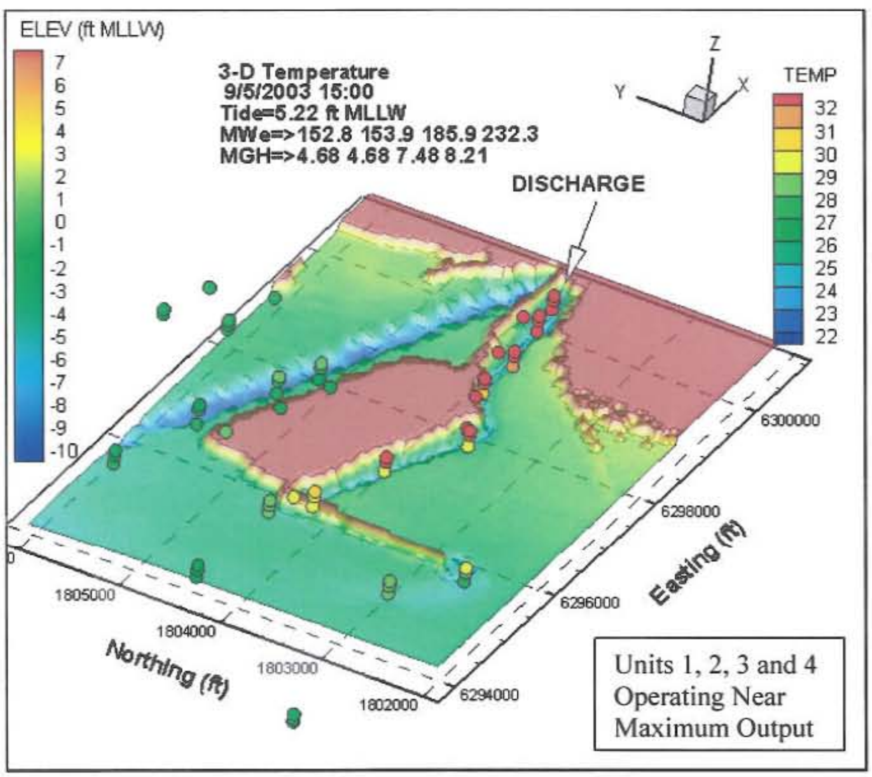


Figure. 10. Enlarged three-dimensional view of temperatures near SBPP discharge for selected times from previous Figures 8 and 9 when Units 1 and 2 only were operating (November 5, 2003) and Units 1, 2, 3 and 4 were operating (September 5, 2003). Time captured is one to two hours post the day's maximum generation. Bathymetry, tide, SBPP pump flow and output per unit are also shown.

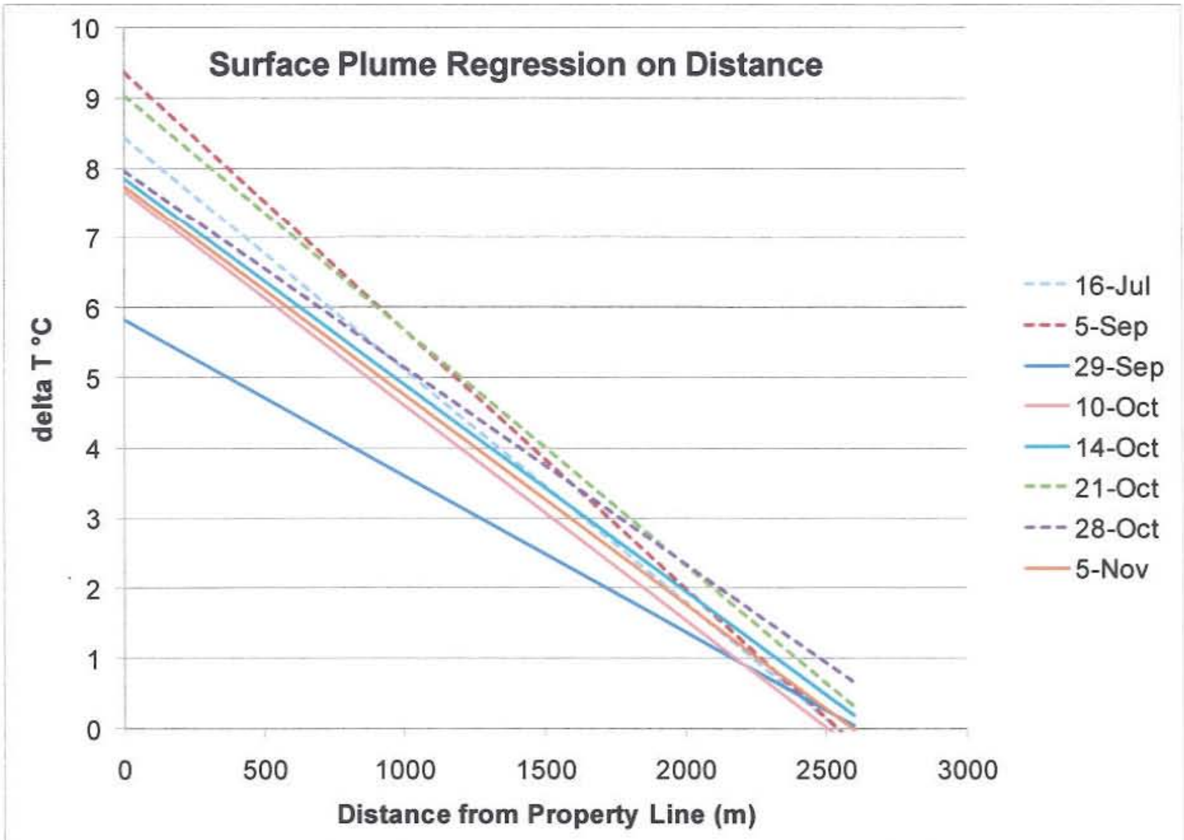


Figure 11. Lines representing average intercepts and slopes for linear regressions of year 2003 SBPP surface plume delta T* as a function of distance from the property line point of discharge across the area of observed benthic effects. Dotted lines are shown when all units were running. Solid lines are shown when Units 1 and 2 only were running. Power output of the Units 1 and 2 on September 29, 2003 was reduced to ~2/3 of maximum. *Delta T is the difference between ambient water temperature and receiving water temperatures recorded every 20 minutes. The slope shows the decay of delta T from the property line point of discharge at its intercept on the left hand vertical axis to ambient temperature on the horizontal axis showing distance from the discharge.

Data source: Tenera Environmental 2004a.

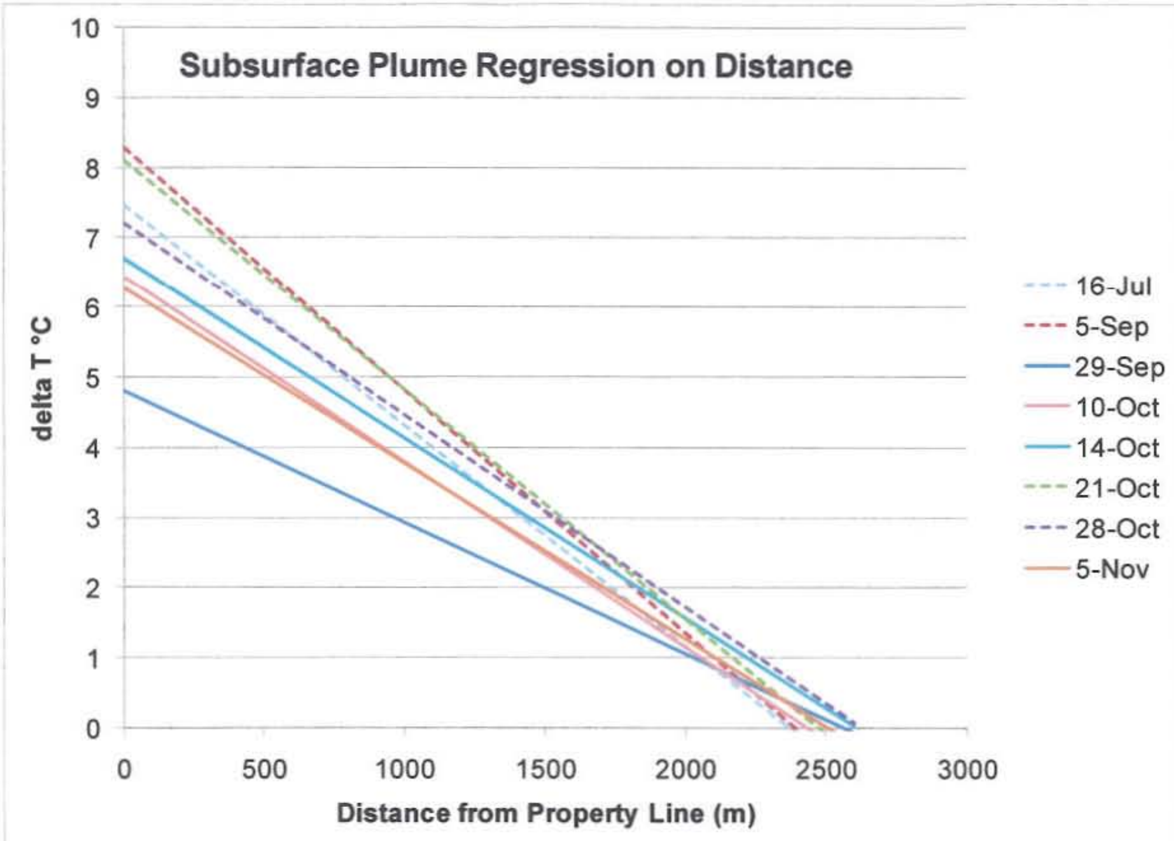


Figure 12. Lines representing average intercepts and slopes for linear regressions of year 2003 SBPP one meter subsurface plume delta T* as a function of distance from the property line point of discharge across the area of observed benthic effects. Dotted lines are shown when all units were running. Solid lines are shown when Units 1 and 2 only were running. Power output of the Units 1 and 2 on September 29, 2003 was reduced to ~2/3 of maximum. *Delta T is the difference between ambient water temperature and receiving water temperatures recorded every 20 minutes. The slope shows the decay of delta T from the property line point of discharge at its intercept on the left hand vertical axis to ambient temperature on the horizontal axis showing distance from the discharge.

Data source: Tenera Environmental 2004a..

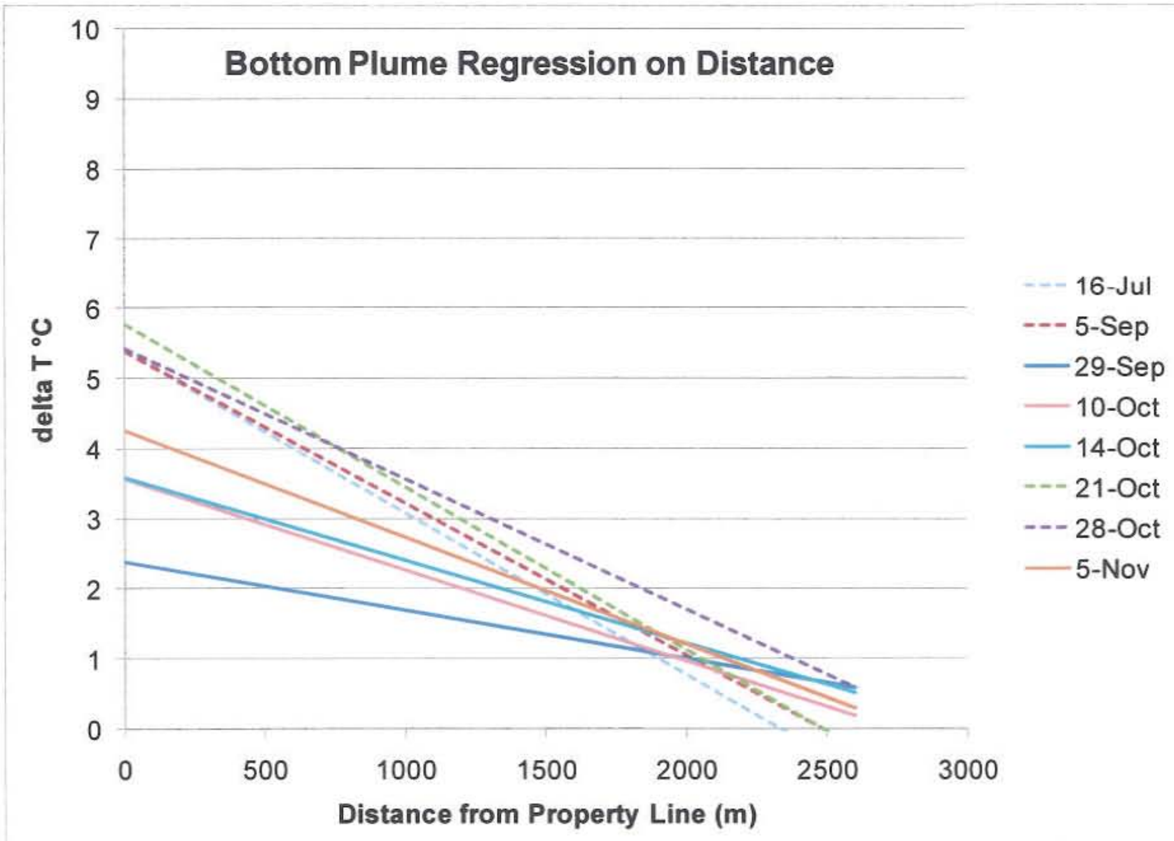


Figure 13. Lines representing average intercepts and slopes for linear regressions of year 2003 SBPP bottom plume delta T* as a function of distance from the property line point of discharge across the area of observed benthic effects. Dotted lines are shown when all units were running. Solid lines are shown when Units 1 and 2 only were running. Power output of the Units 1 and 2 on September 29, 2003 was reduced to ~2/3 of maximum. *Delta T is the difference between ambient water temperature and receiving water temperatures recorded every 20 minutes. The slope shows the decay of delta T from the property line point of discharge at its intercept on the left hand vertical axis to ambient temperature on the horizontal axis showing distance from the discharge.

Source: Tenera Environmental 2004a. Figure 9.

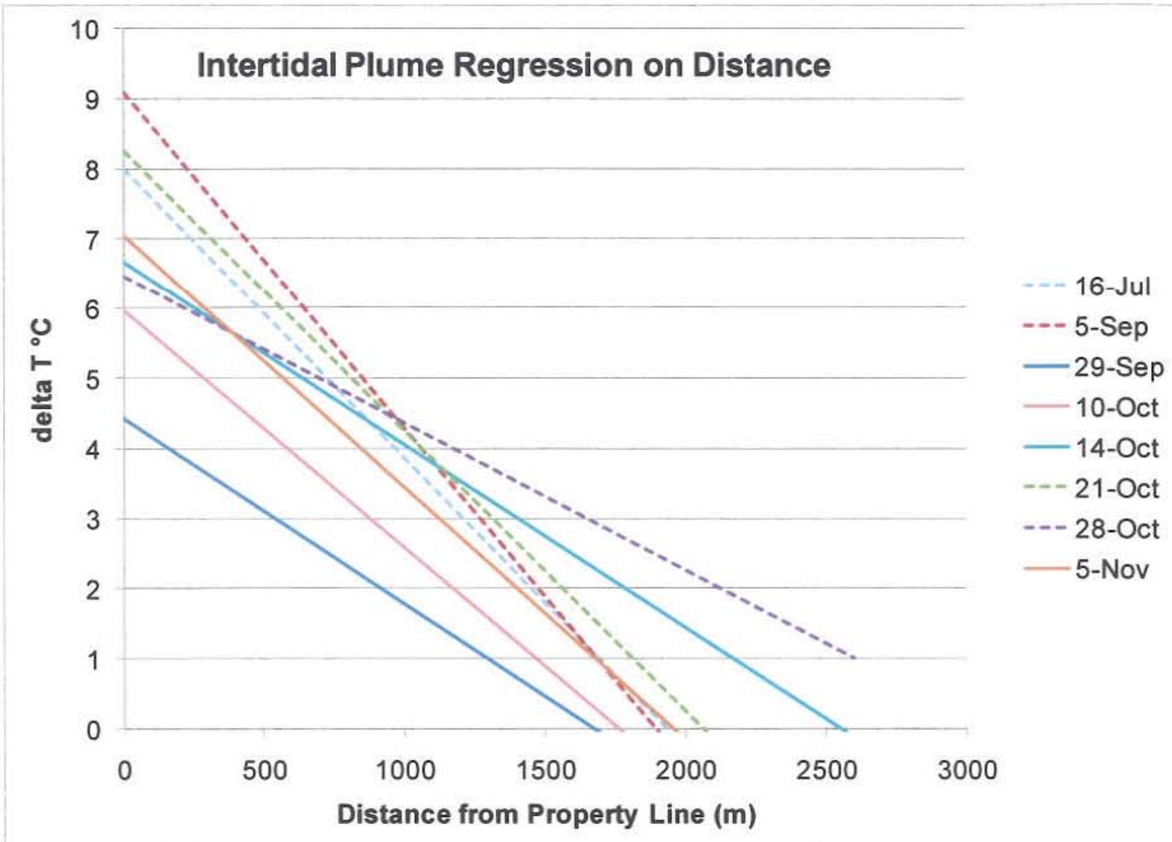


Figure 14. Lines representing average intercepts and slopes for linear regressions of year 2003 SBPP plume delta T in the intertidal zone as a function of distance from the property line point of discharge across the area of observed benthic effects. Dotted lines are shown when all units were running. Solid lines are shown when Units 1 and 2 only were running. Power output of the Units 1 and 2 on September 29, 2003 was reduced to ~2/3 of maximum. *Delta T is the difference between ambient water temperature and receiving water temperatures recorded every 20 minutes. The slope shows the decay of delta T from the property line point of discharge at its intercept on the left hand vertical axis to ambient temperature on the horizontal axis showing distance from the discharge.

Source: Tenera Environmental 2004a. Figure 9.

5.0 DISCUSSION OF SBPP INTAKE AND DISCHARGE EFFECTS

5.1 Impingement and Entrainment Effects

The purpose of the SBPP 2001 and 2003 entrainment and impingement studies was to evaluate the potential impacts of the cooling water intake system as required under Section 316(b) of the Federal Clean Water Act (CWA). As part of this evaluation, an earlier 316(b) study conducted in 1979 (SDG&E 1980) was updated and information from the 2001 and 2003 entrainment and impingement studies was used by the San Diego Regional Water Quality Control Board in support of the NPDES permitting process for SBPP. Data on larval fishes, megalopal crabs, and larval spiny lobster collected near the SBPP intakes were used to estimate entrainment losses, while impingement losses were based on direct measurements of the abundance and biomass of fishes and selected macroinvertebrates retained on the SBPP intake screens.

Our ability to evaluate CWIS effects was limited to the fishes and invertebrates that were in high abundances in entrainment or impingement samples. The abundances of the majority of the entrained and impinged species were low and would not result in any risk of population-level effects. However, by focusing on the most abundant species, we were able to estimate the magnitude of effects on the component species in the biological community. After evaluating the sampling results only two groups of fishes—anchovies and silversides—were found to be abundant enough to be affected by both entrainment and impingement. Based on the data collected in our studies, it was determined that the collective entrainment and impingement losses with all SBPP units running at 100 percent 24/7 would have some small but undetectable effect on biological community functioning. However, the slight potential of these losses to cause harm (see impact assessment in Tenera 2004b) has been essentially eliminated by the 63 percent reduction in entrainment and the 86 percent reduction in impingement resulting from the shutdown of Units 3 and 4.

The maximum number of larval fishes that could be entrained in 2010 will be at least 63 percent fewer than the maximum number that could have entrained in 2002 and 2003. While the number of individual larvae that were entrained by SBPP in 2003 and 2004 was a large number in absolute terms (e.g., in excess of two billion for the goby species complex), this loss of larval-aged fish, which does not translate directly into loss of adult-aged fish, did not pose a risk to fish populations in San Diego Bay then and even less so with the present day 63 percent reduction in entrainment losses. Even the highest estimates of *ETM* for the South Bay species (e.g., the overall 17 percent average from sampling years 2001 and 2003, or the species-specific range of approximately 17 to 50 percent, which in 2010 is now reduced to 8 to 25 percent, for the longjaw mudsucker) are within the range of sustainable harvest considered acceptable by the NMFS. Other considerations further reduce the apparent biological significance of these larval losses, namely, that many of the most frequently entrained species are not fished commercially or recreationally, and that the compensatory reserve of these species is disregarded altogether in this analysis. Compensatory reserve (or compensation) refers to known biological mechanisms that act to increase growth rates, survival, and reproduction by the surviving members of a population in the face of biological or ecological pressure on the population. Indeed, from a fisheries standpoint, biomass production in a stock is maximized when it is subject to harvest at maximum sustainable yield. NMFS believes that, given the compensatory reserve inherent in most fish stocks, up to 60 to 70 percent of a virgin stock's reproductive potential may be removed without compromising the species long-term sustainability of the stock. Under the NMFS guidelines, 60 to 70 percent of the virgin stock's reproductive potential may be removed and still afford the fishery manager a substantial margin of safety against the occurrence of a decline. The CDFG acknowledges similar sustainable harvest levels in its Nearshore Fishery Management Plan. This resource management practice is supported by the scientific literature and provides broad-based evidence of the robustness of fish populations to thrive in the face of a wide range of exploitation rates, based on their compensatory reserve.

In addition, we have assumed for purposes of this study that 100 percent of the larvae that are entrained by the power plant are killed despite documentation through intensive through-plant entrainment survival studies at power plants across the U.S. that survival of larval fish and invertebrates can be very high (EPRI 2000). Mean survival rates for most taxonomic groups have exceeded 50 percent, the only major exceptions being the relatively fragile herrings (Clupeidae) and anchovies (Engraulidae), which have mean survival rates around 25 percent. Survival rates of 65 percent or higher (up to 100 percent) have been common. For example, total survival rates of 88 and 98 percent were reported for naked goby *Gobiosoma bosc* in entrainment survival studies at the Calvert Cliffs Power Plant in southern Maryland. Gobies make up nearly 76 percent in 2001 and 89 percent in 2003 of the larval fish entrained at SBPP.

<u>It should also be noted that most fish populations, including bay goby, are unaffected by natural mortality as high as 90 percent in the larval stage. In other words, even if the SBPP were not withdrawing water from south San Diego Bay, up to 90 percent of the larvae would be expected to die before recruitment to the adult population.</u> *ETM* estimates of entrainment, which assume a stable population and no compensation, represent an extremely conservative comparison to the NMFS guidelines for sustainable harvest rates that is based on recruited adult stocks after natural compensation has already occurred. Although large numbers of larvae are entrained, *ETM* estimates of entrainment mortality using extremely conservative assumptions show that the entrained larvae represent a fraction of their source water population that is well below a removal rate required to sustain their adult populations even without compensation. The life history of component species in the community must be considered when discussing potential effect to the populations. Although the study focused on species potentially affected by entrainment and impingement processes, it is important to note that several fish species in south San Diego Bay have early life stages that are not susceptible to these processes. Live-bearers, such as surfperches, some sharks, and some rays, produce young that are fully developed and too large to be affected by entrainment. Live-bearers together comprise nearly 40 percent of the fish biomass in the Bay (Allen 1999). Another common species in south San Diego Bay, striped mullet, also is not susceptible to entrainment because it spawns offshore and only the juveniles and adults subsequently utilize the Bay habitat. From the standpoint of impingement effects, one of the

most abundant groups of species in the Bay, gobiid fishes, are generally not susceptible to impingement after transformation to the juvenile life stage because they are bottom-dwelling species that typically do not move up into the water column. Even fish species that swim in the water column are generally not susceptible to impingement effects as they mature because they are able to swim against the slow approach velocity of the cooling water inflow. For example, at the SBPP intakes it was not uncommon to see small schools of adult striped mullet swimming directly in front of the intakes and not being impinged during times when circulating water pumps were operating.

5.2 Thermal Effects

General conclusions from earlier studies (Ogden 1994) concerning the importance of temperature in defining assemblages were substantiated in this study, although several of the specific conclusions regarding temperature responses of individual taxa differed between the two studies. Based on regression analysis, Ogden (1994) found a significant positive relationship between temperature and infaunal density (i.e., taxa increased in abundance as temperatures increased) for the following taxa: Armandia, Capitella, Marphysa, Neanthes, Streblospio, Oligochaeta, and Paracereis. From this list, Capitella, Streblospio and Oligochaeta showed a significant positive relationship with temperature in the Tenera (2004a) study and Paracereis had a negative relationship. The other taxa were not abundant enough to draw any conclusions about their relationship to temperature. The earlier study identified significant negative relationships between temperature and infaunal density (i.e., taxa decreased in abundance as temperatures increased) for the following taxa: Leitoscoloplos, Mayerella, Acteocina (Cylichnella), Solen, Tagelus, and Phoronida. Of these taxa, the Tenera (2004a) analysis confirmed that only Leitoscoloplos followed this relationship between temperature and abundance, with Tagelus, Acteocina (Cylichnella), and Phoronida showing a statistically significant opposite response. The distributions of Solen and Mayerella had no significant relationship to temperature. The Tenera (2004a) study also identified other positive and negative relationships between temperature and faunal abundances that were not seen in the earlier studies. The differences between the results in the two studies were probably due to the lack of spatial resolution within the discharge zone in the earlier study which was unable to measure infaunal densities where the greatest temperature changes occurred. The weighting of the station array in far-field and reference areas in the Ogden (1994) analysis masked the relationship between temperature and faunal distributions, or in some cases, yielded contradictory results. By increasing the number of stations from 11 to 21, we could delineate temperature-faunal relationships for some taxa more accurately than in the previous study design (Tenera Environmental 2004a).

5.3 Conclusion

The South Bay Power Plant has operated its cooling water intake and discharge for nearly five decades in south San Diego Bay. Although a frequent target over the years of claims that the Plant has had a devastating effect on San Diego Bay, the scientific study confirms that the Plant has operated without significant effect on either its source water or receiving water populations of fish. This fact has been repeatedly demonstrated in the findings of studies of both the impingement and entrainment in the Plant's cooling water intake flow and the absence of any effect on their source water populations, and in surveys of fish distribution in the Plant's discharge plume.

5.3.1 Intake Effects

The potential effects of the SBPP intake on source water populations of fish and shellfish–as slight as they were even assuming the pumps for all four units (Units 1-4) would be running 24/7 for a year (i.e. at a capacity factor of 100%)–are now dramatically reduced with the decommissioning and shutdown of the Units 3 and 4 pumps.

An annual capacity factor is determined by dividing the actual unit gross generation by the maximum potential generation during the year. The capacity factor gives an indication of the amount of generation units produce versus the maximum generation units can produce. The annual capacity factors of SBPP Units 1-4 from 2000–2009 are provided in **Figure 15**. Capacity factors have declined over the past nine years from a high of over 35 percent in 2000 to a low of only 9 percent in 2009 (**Figure 15**). The EPA Phase II Rule standard for entrainment specified that a facility must reduce entrainment by 60 percent to 90 percent if capacity factors were greater than 15 percent. The SBPP met the EPA standard for no significant entrainment impacts (<15 percent capacity rate) in 2006, 2007 and 2009.

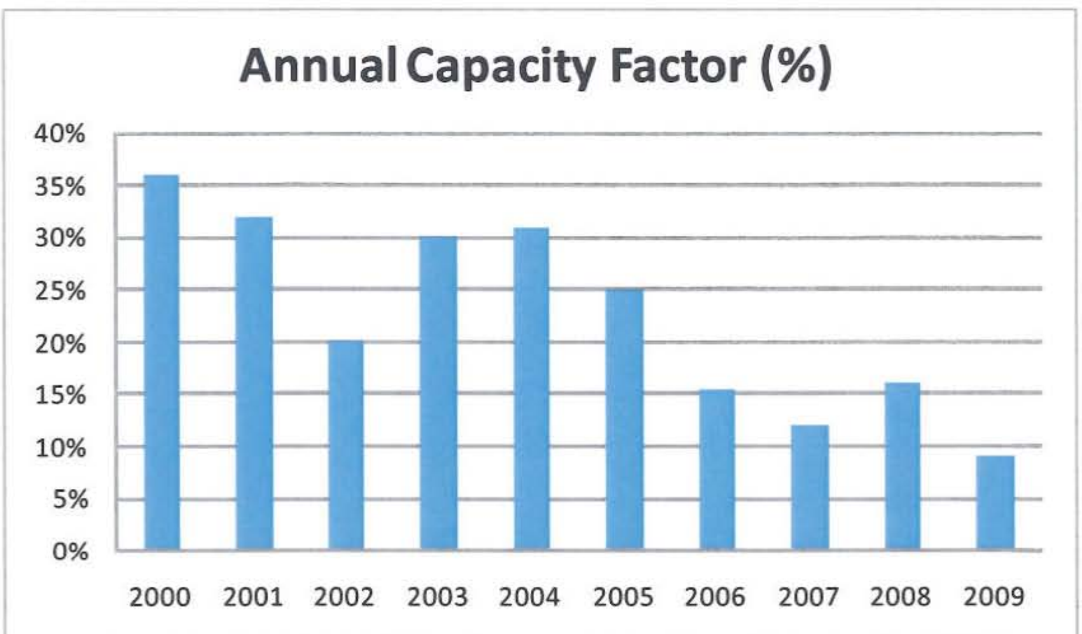


Figure 15. Annual capacity factors for South Bay Power Plant Units 1-4 from 2000 through 2009.

The reductions in intake losses took effect immediately in 2010:

- Entrainment—with the decommissioning of SBPP Units 3 and 4, the total number of organisms entrained by SBPP is immediately reduced by at least 63 percent and more to the extent actual operation of Units 1 and 2 pumps is less that 24/7.
- Impingement—with the decommissioning of SBPP Units 3 and 4, the total number of organisms impinged by the power plant intake screens has been reduced by approximately 80 percent, and the total biomass impinged has been reduced by 86 percent.

These reductions of 63 percent of entrainment losses and 86 percent impingement losses exceed the EPA Phase II Rule standard of 60 percent entrainment reduction and closely approach the Phase II Rule standard of 95 percent for impingement. Given the permanent retirement of Units 3 and 4, these reductions will continue to be realized over time.

The estimated SBPP intake losses for both the 2004 and the present 2010 assessment of intake impacts were calculated using the following set of conservative assumptions that would result in the greatest projected effects on a target species:

- all entrainment and impingement loss estimates were calculated based on maximum design cooling water flows, although actual cooling water withdrawals were only a small fraction of the maximum due to variable demand for power generation throughout the year;
- entrainment modeling assumed no survival of larvae through the cooling water system;
- no density-dependent compensatory effects were included in the models that would result in increased survivorship for later life-stages not subject to CWIS effects; and
- estimated economic losses of impingement fishery species were scaled up to assume that all impinged individuals represented fishes of adult size potentially lost to the fishery, without applying projected mortality rates to the impinged juveniles.

Overall, our conclusions in 2004 were consistent with those from the earlier 316(b) study done in 1979–1980 (SDG&E 1980) that the operation of SBPP does not substantially affect populations of the most abundant or economically important fishes and invertebrates in San Diego Bay. Studies by Allen (1999) found that slough anchovy comprised over half of the fishes by number in the south-central and south ecoregions of San Diego Bay. Results from the 2003 study show that SBPP may account for a loss of approximately 8–10 percent of the larval population annually and represent an equivalent loss of approximately 1–2 percent of the adult standing stock. A major group the Bay's non-commercial/recreational fishes entrained in SBPP intake flow were the CIQ goby complex, with larval losses estimated in 2004 at 21–27 percent, but now in 2010 reduced to 14 to 18 percent of the source water population. Under the most conservative assumptions (24/7 operations), the SBPP CWIS (which in 2004 might have accounted for losses from 1.2 to 2.2 million adult CIQ gobies per year out of an estimated standing stock of over 10 million), in 2010 and going forward, would account for an estimated 0.8 to 1.5 million out of the same source water population of over 10 million. For the invertebrate species investigated, there were no substantial direct effects of the CWIS on their populations. Particularly for species with commercial fishery importance, such as lobsters, crabs, and squid, the results indicate that SBPP would not affect the adult populations of these species.

Impingement generally varies with intake flow. Lower intake flow brings fewer organisms in into the area of intake screens and reduces the likelihood of their impingement on the screens by lower approach and through-screen velocities. If this widely accepted direct relationship of impingement to flow is relied upon to adjust the SBPP annualized impingement estimate reported for December 2002 to November 2003 for all units, there is no uncertainty that there would have been at least a 63 percent reduction in impingement based simply on the reduced volume resulting from only Units 1 and 2 intake pumps operating at the time. In fact the actual SBBP impingement effects reduction at the present time, based on our published impingement study results, is at least 86 percent, an amount nearly achieving the EPA's impingement reduction standard in the 316(b) Phase II Rule.

5.3.2 Discharge Effects

The results of our analysis demonstrate that the SBPP cooling water discharge plume will be smaller, cooler, and thinner. To the degree and extent that the temperature of the cooling water discharge prior to the 2009 shutdown of Units 3 and 4 was affecting receiving water populations, any such effect has now been reduced by at least 63 percent due simply to the reduction in discharge volume. As we discussed in our analysis of the Units 1 and 2 thermal discharge plume, a smaller discharge volume also has less horizontal momentum, allowing the buoyancy of the plume to separate from the bottom sooner and avoid contact with the receiving water's benthic community of clams and worms. The smaller volume and momentum of the thermal discharge also reduced the linear distance of shoreline contact as shown in our graphic analysis of projected temperature at the discharge channel's intertidal stations.

6.0 LITERATURE CITED

Allen, L. G. 1999. Fisheries Inventory and Utilization of San Diego Bay, San Diego, California. Final Report: Sampling Period July 1994 to April 1999. Prepared for U.S. Navy and the San Diego Unified Port District.

Boreman, J., C.P. Goodyear, and S.W. Christensen. 1978. An Empirical Transport Model for Evaluating Entrainment of Aquatic Organism by Power Plants. United States Fish and Wildlife Service. FWS/OBS-78/90, Ann Arbor, MI.

Boreman, J., C.P. Goodyear, and S.W. Christensen. 1981. An Empirical Methodology for Estimating Entrainment Losses at Power Plants Sited on Estuaries. Transactions of the American Fishery Society. 110:253-260.

Electric Power Research Institute (EPRI). 2000. Review of entrainment survival studies: 1970 – 2000. Final Report December 2000. Document Number 1000757. Electric Power Research Institute. Palo Alto, California. 54 pp + Appendix.

Lockheed Environmental Sciences (LES). 1981. South Bay Power Plant Receiving Water Monitoring Program – A Four-year Cumulative Analysis Report (1977-1980).

Ogden Environmental and Energy Services Co., Inc. (Ogden). 1994. Review of the long-term receiving water monitoring done for the South Bay San Diego Power Plant. Prepared for San Diego Gas & Electric. 29 pp. + App.

Ricker, W.E. Computation and Interpretation of Biological Statistics of Fish Populations. Fishery Research Board of Canada Bulletin 91. 382 pp. 1975.

Tenera Environmental. 2004a. SBPP Cooling Water System Effects on San Diego Bay. Volume I Compliance with Section 316(a) of the Clean Water Act A.2 for the South Bay Power Plant. Submitted to: San Diego Regional Water Quality Control Board. Submitted by: Duke Energy South Bay, LLC. Prepared by: Tenera Environmental Lafayette, CA.

Tenera Environmental. 2004b. Duke Energy South Bay Power Plant, SBPP Cooling Water System Effects on San Diego Bay. Volume II: Compliance with Section 316(b) of the Clean Water Act A.2 for the South Bay Power Plant. Submitted to: San Diego Regional Water Quality Control Board. Submitted by: Duke Energy South Bay, LLC. Prepared by: Tenera Environmental Lafayette, CA.

San Diego Gas and Electric Company (SDG&E). 1980. South Bay Power Plant Cooling Water Intake System Demonstration Summary. Prepared for: California Regional Water Quality Control Board San Diego Region, San Diego, CA.

Smith, P. E. and S. L. Richardson. 1977. Standard Techniques for Pelagic Fish Egg and Larva Surveys. FAO Fisheries Technical Paper 175:1-100.

U. S. Fish and Wildlife Service. 1998. Proposed South San Diego Bay Unit, National Wildlife Refuge. Draft Environmental and Land Protection Plan. U.S. Fish Wild. Serv. 89 pp.

Attachment 9

Testimony of Ken Andrecht

Hearing before San Diego Regional Water Quality Control Board
December 16, 2009
Transcription DS300093 WMA
KENNETH ANDRECHT
(39:01 – 44:01)

SPEAKER	
Chairman King	Patty Krebs followed Kenneth Andrecht
Kenneth Andrecht	Kenneth from the Port of San Diego here to ask, please… I hope it says Port of San Diego, Retired?
Chairman King	It does, yes.
Kenneth Andrecht	Thank you. My name is Kenneth Andrecht. I'm from Julian, California. I have no stake in the political land use aspects of this project and I've never met anyone from Dynegy. So, however, I do have something to tell you. I received information from the Environmental Health Coalition that I think was also provided to you, that indicated that the South Bay Power Plant may be responsible for the destruction of hundreds of acres of eelgrass in South Bay. About eelgrass I am knowledgeable. I worked 26 years for the Port District, 13 years in the Engineering Department, 13 years in the Environmental Department. I was a Director of Property Engineering for 10 years, and I was Assistant Director and Acting Director for 13 years in Environmental. My responsibility was, of course, the CEQA/NEPA process you're all aware of. Also, I was the on-hand manager for the Chula Vista Wildlife Reserve from about 10 years after – no about 5 years – after it was built until about 1998. I was also responsible for the "D" Street fill tern colony in Chula Vista. Eelgrass — my first statement is going to be anecdotal because I don't have any written documentation. In 1960, coming from the "G" Street boat launch ramp over to Silverstrand, San Diego Bay, the whole bottom was filled with brown and green algae – photomus (sp?) algae. I don't recall any eelgrass in the early… in 1960 itself. In fact, huge algal mats – depending on the weather and time of year – huge algal mats would float up and make it really stinky down there. In 1972, the Port District decided and the City of Chula Vista decided to build the Chula Vista small boat basin which is now named Chula Vista Harbor. In 1973, we had one of the very first EIRs done (CEQA was 1970). In that EIR, the benthic communities in the area

SPEAKER	
	were dived and walked. As I recall, there were two patches of eelgrass found in the mudflats, which is now renamed Chula Vista Harbor. And they were about one meter around. We didn't have to mitigate for it. The benthic survey was over 300 acres. We had a dredge disposal site which was called Mud Island. It was 80 acres in size and was built on the north side of the cooling water separation dike. That benthic survey showed almost a barren benthos; actually it was mainly populated with annelid worms, but there was no eelgrass sited in that survey. We built the Chula Vista Harbor and the Mud Island. By 1978, we breached the dikes and Mud Island, we let the mud out and we started planting sea grasses – not sea grasses, Spartina Foliosa and Salcornias and such. Everything was percolating just well as far as the Engineering and Environmental Departments were concerned. We had a need to realign the Chula Vista Channel in about 1988, I think it was. We had a capital improvement program; we knew it was coming. In 1986, I and two of my staff personally went out, harvested eelgrass from the Chula Vista Bayside Park area, took it down and planted it on the north dike of the Chula Vista Wildlife Reserve. Am I taking too long?
Chairman King	Yeah. If you could conclude…
Kenneth Andrecht	Okay. The eelgrass down there – in three years, it bloomed to 19 acres. We had two subsequent transplants; the eelgrass is fine. The deepening of the channel for the power plant and a deep realignment of the Chula Vista Channel has allowed for increased water flushing, and turbidity is not really that much of an issue. I submit to you that eelgrass is thriving in South San Diego Bay.
Chairman King	Thank you very much.
	END OF TRANSCRIPTION

February 19, 2010

Kenneth L. Andrecht
1056 Venture Valley Road
Julian, CA 92036

San Diego Regional Water Quality Control Board
9174 Sky Park Court
San Diego, California

Re: South Bay Power Plant Discharge Effects on Eelgrass (Zostera Marina) Distribution in South San Diego Bay

Self Introduction: I am Ken Andrecht, South Bay resident from 1960 until 2007. I worked for the Port of San Diego for 25 years, eight years as the Chief of Property Engineering, and fourteen years as the Assistant Director or Acting Director of Environmental Management. My environmental duties included CEQA and NEPA compliance; the preparation of EIRs and EISs; Bay clean up activities, including water quality issues; and management of the Bay's natural resources, including the Chula Vista Wildlife Reserve, which lies between the South Bay Power Plant's (SBPP) cooling water intake and discharge channels.

Eel Grass History in South Bay: This first is anecdotal. As a South Bay user in 1960, I remember the bay water to be very warm, with vast mats of bottom algae which would often become detached, and float and rot on the water surface. There was no eelgrass in South Bay south of the old Chula Vista G Street Boat launching ramp, nor south of the Silver Strand Beach Park's bayside cove. The bay bottom was covered with red and green algae.

In 1974, the Port District conducted a Biological Reconnaissance of the mudflats and shallow water areas just north of the SBPP cooling water separation dike. The area was found to be sparsely populated with benthic biota typically associated with conditions of high organic loading and restricted water circulation, including domestic waste discharges. No eelgrass was found within the study area. The Biological Reconnaissance was undertaken as a part of the environmental and permitting processes for the dredging of the Chula Vista Harbor, and the construction of the 80-acre Chula Vista Wildlife Reserve by the Port District.

The Harbor dredging and Wildlife Reserve construction commenced in 1977 and was completed in 1980. In 1984, the Port District began the development of a salt marsh within the Reserve, with the initial planting of cordgrass (Spartina foliosa) in the Reserve's tidal basins. A second planting of Spartina and other salt marsh species was subsequently conducted. The salt marsh was monitored yearly, and the 40 acre marsh creation project was found to be a great success. No eelgrass was found within the 80 acre Reserve area, nor adjacent water areas.

In 1985, Chula Vista requested the realignment of the Chula Vista Harbor entrance channel. A benthic survey found that eelgrass had migrated south into the northern portions of the channel. Mitigation for the disruption of this eelgrass would be required for the project to proceed.

Introduction of Eelgrass alongside SBPP Cooling Water Channel: In early1986, I with two assistants, conducted an experimental eelgrass transplant along the north shore of the Reserve, adjacent to the SBPP cooling water intake channel. Approximately 200 eelgrass transplants were made along eleven transects at elevation minus 1.9 feet MLLW. This was the first introduction of eelgrass into the area near the SBPP. Monitoring of these transplants was conducted by me and my staff in 1986, 1987 and 1988. The transplants succeeded. Based on this success, the Port District undertook a large scale (approximately six acre) eelgrass transplant along the south side of the SBPP cooling water channel in 1988. This transplant was monitored annually for ten years. By 1995, over thirteen (13) acres of eelgrass had established itself alongside the cooling water channel.

South Bay Power Plant Cooperation: It must be noted that the management, crew, and guards of the SBPP have extended the utmost cooperation over the years to me and my staff. Access to the Wildlife Reserve is through the Power Plant and over it's cooling water separation dike. Our activities at the Reserve included years of salt marsh plantings and monitoring, eelgrass monitoring, California least tern nesting site preparation, and bi-weekly tern monitoring during the nesting season.

Conclusion: It has been stated by some that the SBPP has negatively impacted eelgrass in South Bay. I believe this to be incorrect. It is my conclusion that the SBPP has, in fact, facilitated the introduction of eelgrass into South Bay. The SBPP cooperated with the construction of the Chula Vista Wildlife Reserve through the concession of some of it's water lease area to the Port in 1976 and by allowing access through it's plant for the Port's construction of the Reserve. The Reserve provided approximately 20 acres of new eelgrass habitat within South Bay. This habitat now supports a viable eelgrass meadow directly adjacent to, and within, the SBPP cooling water intake channel. Further, two of the Port's environmental consultants, Merkle & Associates and MBC Applied Environmental Sciences, have speculated that the increased water circulation provided by the SBPP intake channel have assisted the proliferation of the Reserve's eelgrass beds by providing for the introduction of nutrients into the beds, and by dispersing the turbidity associated with the gradual erosion of the Reserve's containment dikes.

Sincerely,

KENNETH L. ANDRECHT

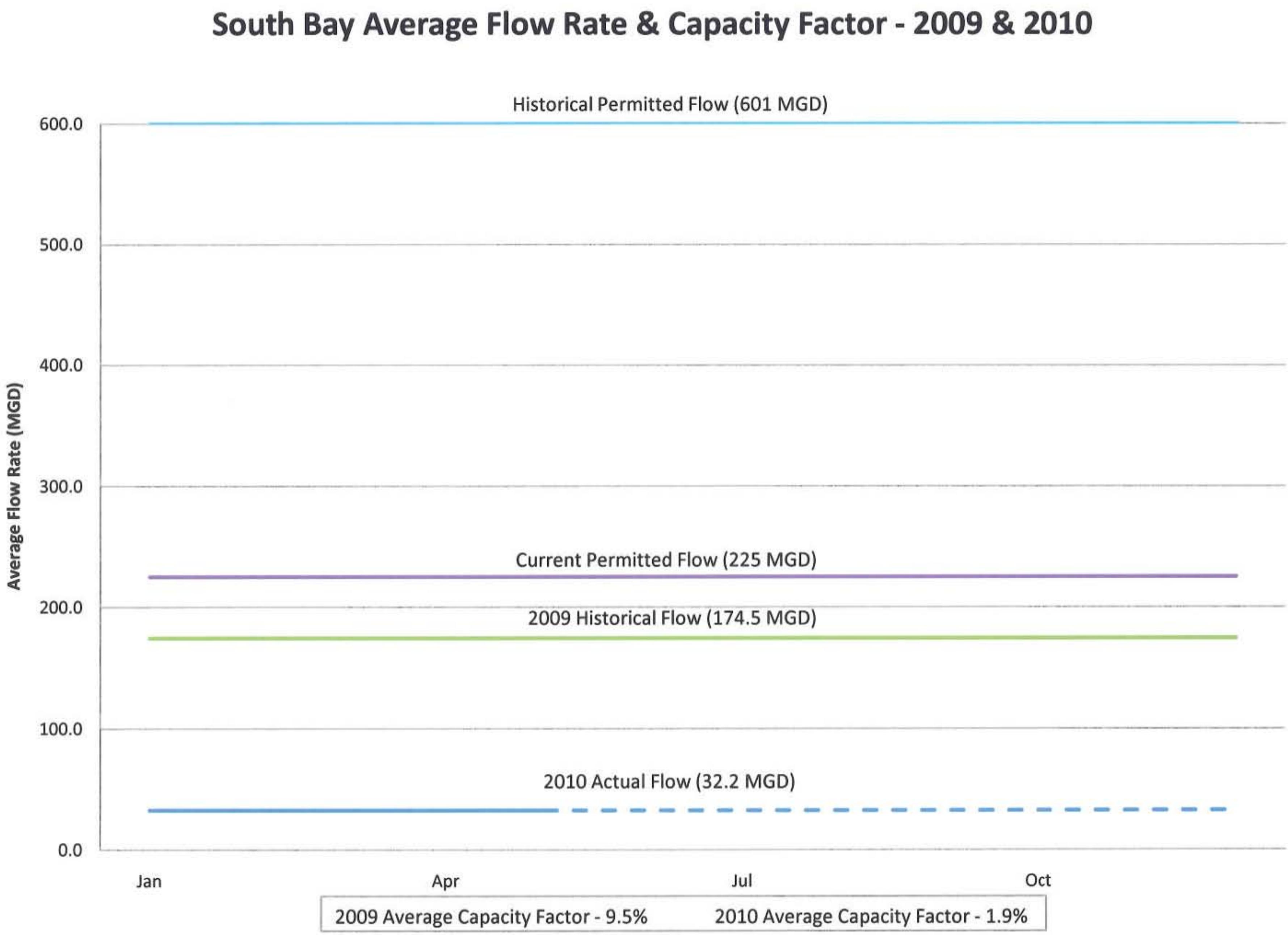
Kenneth L. Andrecht

References:

1. Biological Reconnaissance and Sediment Chemistry Study, Chula Vista Small Boat Basin, February 15, 1975, UPD #EM74/1.1
2. Eelgrass Transplanting at Chula Vista Wildlife Reserve, Specification #87-37, San Diego Unified Port District
3. Development of a Coastal Salt Marsh in South San Diego Bay, Andrecht, May 1990
4. Eelgrass Distribution Mapping and Vegetation Survey Bayward of the North Dike, Chula Vista Wildlife Reserve, July 1994, MBC Applied Environmental Sciences
5. Eelgrass Survey of the North Kike of the Chula Vista Wildlife Reserve, May 25, 1995, Merkel & Associates, Inc.
6. Eelgrass Distribution, Chula Vista Wildlife Reserve, San Diego Bay, California, May 1996, Merkel & Associates, Inc.

Attachment 10

Plant 2010 Operating Data


South Bay Average Flow Rate & Capacity Factor - 2009 & 2010
Historical Permitted Flow (601 MGD)
600.0
500.0
400.0
300.0
200.0
100.0
0.0
Average Flow Rate (MGD)
Current Permitted Flow (225 MGD)
2009 Historical Flow (174.5 MGD)
2010 Actual Flow (32.2 MGD)
Jan
Apr
Jul
Oct
2009 Average Capacity Factor - 9.5%
2010 Average Capacity Factor - 1.9%

South Bay Power Plant – Operating Hours

Unit 1
Jan-May 2008
1945 hrs.

Unit 2
Jan-May 2008
935 hrs.

Unit 1
Jan-May 2009
7628 hrs.

Unit 2
Jan-May 2009
1718 hrs.

	Unit 1	Unit 2	Unit 3	Unit 4	GT
Jan-08	744	504	678	744	1
Feb-08	531	110	696	81	0
Mar-08	0	95	600	0	3
Apr-08	384	134	475	79	16
May-08	286	93	676	139	5
Jun-08	0	0	455	143	1
Jul-08	66	45	744	42	0
Aug-08	45	170	576	14	3
Sep-08	184	313	720	198	2
Oct-08	78	535	744	568	10
Nov-08	408	721	0	545	1
Dec-08	744	374	276	119	0
Total 2008	**3471**	**3093**	**6640**	**2673**	**43**
Jan-09	355	671	50	167	7
Feb-09	120	142	458	102	1
Mar-09	0	213	0	26	4
Apr-09	134	277	320	211	3
May-09	152	413	447	51	1
Jun-09	13	112	84	8	1
Jul-09	87	287	612	52	10
Aug-09	295	437	526	181	0
Sep-09	454	300	493	423	1
Oct-09	110	282	134	14	0
Nov-09	328	62	48	25	0
Dec-09	223	41	62	0	0
Total 2009	**2272**	**3239**	**3234**	**1259**	**28**
Jan-10	93	63	Units Shut Down		0
Feb-10	0	9	Units Shut Down		0
Mar-10	29	58	Units Shut Down		0
Apr-10	0	109	Units Shut Down		6
May-10	0	0	Units Shut Down		0
Total Jan-May 2010	**121**	**238**			**6**

Attachment 11

RMR Agreement

MUST-RUN SERVICE AGREEMENT

dated _______________, 19___

between

DYNEGY SOUTH BAY, LLC

and

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Note: Includes tariff changes effective 1/1/2009

TABLE OF CONTENTS

MUST-RUN SERVICE AGREEMENT

THIS MUST-RUN SERVICE AGREEMENT is made as of the ___ day of ___________, 19___, between Dynegy South Bay, LLC, a limited liability company organized under the laws of the State of Delaware (the "Owner"), and the CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION, a not-for-profit public benefit corporation incorporated under the laws of the State of California (the "ISO").

RECITALS

A. Owner is the owner or lessee of, or is otherwise entitled to dispatch and market the Energy and Ancillary Services produced from and provided by, the electrical generating Units located at the Facility described in Schedule A to this Agreement;

B. Under Section 345 of the California Public Utilities Code, ISO is responsible for the efficient use and reliable operation of the ISO Controlled Grid;

C. ISO has determined that it needs the ability to dispatch Units under the terms and conditions of this Agreement to have Owner deliver Energy into or provide Ancillary Services to the ISO Controlled Grid when required by ISO to ensure the reliability of the ISO Controlled Grid; and

D. Each Unit covered by this Agreement has been designated as a Reliability Must-Run Unit.

In consideration of the covenants and agreements contained in this Agreement, the Parties agree as follows:

ARTICLE 1

DEFINITIONS

Terms, when used with initial capitalization in this Agreement and the attached schedules shall have the meanings set out below. The singular shall include the plural and vice versa. "Includes" or "including" shall mean "including without limitation." References to a section, article or schedule shall mean a section, article or schedule of this Agreement, unless another agreement or instrument is specified. Unless the context otherwise requires, references to any law shall be deemed references to such law as amended, replaced or restated from time to time. Unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal identity. References to "Owner" or "ISO" shall, unless the context otherwise requires, mean Owner and ISO respectively and their permitted assigns and successors. References to sections or provisions of the ISO Tariff include any succeeding sections or provisions of the ISO Tariff.

"Adjusted RMR Invoice" is defined in Section 9.1(b).

"ADR" means alternative dispute resolution pursuant to Section 11.1 and Schedule K.

"Agreement" means this Must-Run Service Agreement, including schedules, as amended from time to time.

"Ancillary Services" means those ancillary services identified in Schedule E.

"Applicable UDC Tariff" means the applicable retail tariff(s), of the utility distribution company in whose service territory the Unit is located, under which the Unit is eligible to purchase power to meet its auxiliary power requirements, whether or not the Unit actually purchases auxiliary power under the tariff(s). The Applicable UDC Tariff for the Facility is set out on Schedule A.

"Availability" means, in relation to a Unit, the maximum quantity of Energy or Ancillary Services, measured at the Delivery Point, the Unit is capable of producing at any given time assuming adequate time to ramp the Unit to that maximum quantity. For hydroelectric Units, Availability measures the extent to which the Unit is capable of producing Energy or providing Ancillary Services, given sufficient usable water to produce Energy or provide Ancillary Services. The Availability of a Unit is measured in MW.

"Availability Deficiency Factor" is calculated as set forth in Section 8.5.

"Availability Payment" means the payment to Owner described in Section 8.1 for Condition 1 and 8.2 for Condition 2.

"Availability Test" means a test of a Unit's Availability requested by ISO or Owner pursuant to Section 4.9(a).

"Bid Sufficiency Test" means the test described in Section 4.1(c).

"Billable MWh" is defined in Section 8.3(a).

"**Billing Month"** is defined in Section 9.1(b).

"Black Start" means the ability of a Unit to start without an external source of electricity or the process of doing so.

"Business Day" means any of Monday through Friday, excluding any day which is a Federal bank holiday.

"Calculation Hour" is defined in Section 8.3(c)(i)(A).

"California Agency" means the agency or agencies responsible for representing the State of California in FERC proceedings involving the rates, terms and conditions of service under this Agreement.

"Capital Item" means an addition or modification to, change in or repair, replacement or renewal of plant, equipment or facilities used by Owner to fulfill Owner's obligations under this Agreement. A Capital Item does not include Repairs to such plant, equipment or facilities. A Capital Item does not include an Upgrade, unless recovery of costs of the Upgrade has been approved by ISO. For purposes of this Agreement, Capital Items are "retirement units" or other items the costs of which are properly capitalized in accordance with the FERC Uniform System of Accounts, 18 C.F.R. Part 101.

"Closed" is defined in Section 2.5.

"Collateral" is defined in Section 9.7.

"Comparable RMR Unit" is defined in Section 4.7 (f).

"Condition 1" means the terms of this Agreement applicable to a Unit providing service under Condition 1 as described in Section 3.1.

"Condition 2" means the terms of this Agreement applicable to a Unit providing service under Condition 2 as described in Section 3.1.

"Confidential Information" is defined in Section 12.5.

"Contract Service Limits" for a given Unit means the Maximum Annual MWh, Maximum Annual Service Hours, Maximum Annual Start-ups, and, if applicable, the Maximum Monthly MWh as stated in Section 13 of Schedule A.

"Contract Year" means a calendar year; provided, however, that the initial Contract Year shall commence on the Effective Date and expire at the end of the calendar year in which the Effective Date occurred. If the Agreement terminates during a calendar year, the last Contract Year shall end on the termination date.

"Counted MWh" is defined in Section 5.3.

"Counted Service Hours" is defined in Section 5.3.

"Counted Start-ups" is defined in Section 5.3.

"Credit Carryforward" is defined in Section 9.1(e) and Section 9.1(f).

"Deliver" means to deliver Energy into the ISO Controlled Grid or Distribution Grid (at the Delivery Point or such other point as the Parties may otherwise agree) or to provide Ancillary Services (whether or not any Energy is Delivered as part of the Ancillary Service) pursuant to a Dispatch Notice (including deliveries for which a Dispatch Notice has been issued under Section 4.5 and deliveries in substitute Market Transactions under Section 5.2) and the terms "Delivered" and "Delivering" shall be construed accordingly.

"Delivered Ancillary Services" means the type and, if applicable, the MW of Ancillary Services Delivered by Owner.

"Delivered MWh" means the MWh of Energy Delivered by Owner, including any Ramping Energy, and shall be equal to the sum of Billable MWh, Hybrid MWh, MWh deemed Delivered under Section 5.1 (f); and MWh Delivered from Substitute Units under Section 5.1 (c) or Section 5.1 (d).

"Delivery Point" means the point identified in Section 4 of Schedule A where Energy and Ancillary Services are to be Delivered.

"Direct Contract" means a contract between Owner and one or more identified persons for the sale of Energy or Ancillary Services other than under this Agreement, and shall in no event include a transaction in a market run by ISO or the PX.

"Dispatch Notice" means a notice delivered by ISO to Owner's Scheduling Coordinator on a daily, hourly or real-time basis requesting dispatch of one or more Unit(s) to provide Energy or Ancillary Services under this Agreement. A Dispatch Notice shall include a notice deemed to have been given by ISO for the Energy actually Delivered by a Unit that starts or increases Energy output as a result of a "system emergency" as defined in the ISO Tariff whether the start or increase occurs automatically (for Units specified in Section 2 of Schedule A as having the ability to Start-up or ramp automatically) or pursuant to a standing written order of the ISO. A Dispatch Notice shall also include a

Test Dispatch Notice given by ISO under Section 4.9 other than a Test Dispatch Notice issued at Owner's request to test Availability or heat input of the Unit.

"Distribution Grid" means the radial lines, distribution lines and other facilities used to transmit or distribute Energy from the Facility other than the ISO Controlled Grid.

"Due Date" means the date which is the 30th day after the date on which a Party submits an invoice to the other Party. Notwithstanding the above, the Due Dates for the Revised Estimated RMR Invoice, the Revised Adjusted RMR Invoice, and the ISO Invoice shall be as specified in Section 9.1(b). If the 30th day, or other Due Date as specified in Section 9.1(b), is not a Business Day, the Due Date shall be the next Business Day.

"Effective Date" means the date this Agreement becomes effective pursuant to Section 2.1 thereof.

"Energy" means electrical energy.

"Estimated RMR Invoice" is defined in Section 9.1(b).

"Existing Contractual Limitation" means a contractual limitation on the Start-up or operation of a Unit existing prior to the date the Unit was designated as a Reliability Must-Run Unit. All Existing Contractual Limitations are described in Section 14 of Schedule A.

"Facility" means the electrical generating facility described in Schedule A. A hydroelectric facility may include one or more electric generating facilities which are hydraulically linked by a common water system.

"Facility Trust Account" is defined in Section 9.2.

"FERC" means the Federal Energy Regulatory Commission, any successor agency, or any other agency to whom authority under the Federal Power Act affecting this Agreement has been delegated.

"Final Invoice" is defined in Section 9.10(a).

"Final Settlement Statement" is defined in the ISO tariff master definitions.

"Financing Agreement" means agreements for financing the Facility or any portion of the Facility.

"Fixed Option Payment Factor" is set forth in Section 2 of Schedule B.

"Force Majeure Event" means any occurrence beyond the reasonable control of a Party which causes the Party to be unable to perform an obligation under this Agreement in whole or in part and which could not have been avoided by the exercise of Good Industry Practice. Force Majeure Event includes an act of God, war, civil disturbance, riot, strike or other labor dispute, acts or failures to act of Governmental Authority, fire, explosion, flood, earthquake, storm, drought, lightning and other natural catastrophes. A Force Majeure Event shall not include lack of finances or the price of fossil fuel.

"Forced Outage" means a reduction in Availability of a Unit for which sufficient notice is not given to allow the outage to be factored into ISO's day-ahead or hour-head scheduling process.

"Good Industry Practice" means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric power industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Industry Practice does not require use of the optimum practice, method, or act, but only requires use of practices, methods, or acts generally accepted in the region covered by the Western Systems Coordinating Council.

"Governmental Authority" means the government of any nation, any state or other political subdivision thereof, including any entity exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to a government.

"Hourly Metered Total Net Generation" means the electric generation in MWh for the Unit in any Settlement Period as measured by the Unit's electrical meter described in Schedule A, Section 5, "Metering and Related Arrangements", minus any auxiliary loads metered on the load side of such electrical meter for that Settlement Period in accordance with the ISO Tariff.

"Hybrid MWh" is defined in Section 8.3(b).

"Hydroelectric Dependable Capacity" is the amount of MWh forecast to be produced by a hydroelectric Facility in an adverse hydrologic year.

"Interest Rate" means the lesser of the rate of interest per annum calculated in accordance with 18 C.F.R. 35.19a of the FERC's Regulations or the maximum rate permitted by law.

"ISO Availability Notice" means a notice given by ISO to Owner modifying the Availability of the Unit under Section 4.9 (a)(vi) or Section 5.4 (b).

"ISO Controlled Grid" means the system of transmission lines and associated facilities that from time to time are under ISO's operational control.

"ISO Invoice" is defined in Section 9.1(b).

"ISO's Repair Share" is defined in Section 7.5 (g).

"ISO Settlements Calendar" is defined in Section 9.1(b).

"ISO Tariff" means the California Independent System Operator Tariff on file with FERC and in effect from time to time.

"Long-term Planned Outage" means a planned interruption, in whole or in part, in the electrical output of a Unit to permit Owner to perform a major equipment overhaul and inspection or for new construction work but only if the outage is scheduled to last 21 consecutive days or more (which may span more than one Contract Year) and either (a) is scheduled in accordance with the ISO's outage coordination protocol prior to the beginning of the Contract Year or (b) was scheduled as a Long-term Planned Outage for the last quarter of the expiring Contract Year but, with approval of the ISO Outage Coordination Office, was postponed and rescheduled into the new Contract Year.

"Market Ramping Energy" is defined in Section 8.3.

"Market Schedule" is defined in Section 8.3(c)(i)(C).

"Market Transaction" means a delivery of Energy or provision of Ancillary Services from a Unit pursuant to a Direct Contract or bids into markets run by the PX, ISO or any similar entity.

"Maximum Annual MWh" means, for each Unit, the maximum MWh of Energy that Owner may be obligated to Deliver from the Unit in each Contract Year without becoming entitled to charges for excess service under Schedule G. The Maximum Annual MWh for each Unit is set out in Section 12 of Schedule A. The rules for counting MWh are set out in Section 5.3.

"Maximum Annual Service Hours" means, for each Unit, the maximum Service Hours that Owner may be obligated to provide service from the Unit in each Contract Year without becoming entitled to charges for excess service under Schedule G. The Maximum Annual Service Hours for each Unit is set out in Section 12 of Schedule A. The rules for counting Service Hours are set out in Section 5.3.

"Maximum Annual Start-ups" means, for each Unit, the maximum number of times Owner may be obligated to Start-up the Unit in each Contract Year without becoming entitled to charges for Start-ups under Schedule G. The Maximum Annual Start-ups for each Unit is set out in Section 12 of Schedule A. The rules for counting Start-ups are set out in Section 5.3.

"Maximum Monthly MWh" means, for each hydroelectric Unit, the maximum MWh of Energy that Owner may be obligated to Deliver from the Unit without becoming entitled to charges for excess service under Schedule G. The Maximum Monthly MWh for each hydroelectric Unit is set out in Section 12 of Schedule A. The rules for counting MWh are set out in Section 5.3

"Maximum Net Dependable Capacity" means the amount shown in Section 1 of Schedule A as the Maximum Net Dependable Capacity of a Unit.

"Minimum Load" means, for each Unit, the higher of (1) the lowest level in MW at which the Unit can maintain stable continuous operations, or (2) the Minimum Load for the Unit as shown in Section 9 of Schedule A.

"Minimum Off Time" means, for each Unit, the minimum time following Shutdown that the Unit must remain off line before initiation of the next Start-up. The Minimum Off Time for each Unit is shown in Section 11 of Schedule A.

"Minimum Run Time" means, for each Unit, the minimum time the Unit must remain Synchronized following Start-up. The Minimum Run Time for each Unit is shown in Section 10 of Schedule A.

"Month" means a calendar month.

"Monthly Option Payment" is defined in Section 8.1(a) for Condition 1 and Section 8.2(a) for Condition 2.

"Motoring Charge" means the payment in accordance with Schedule E for the Energy required to spin a generator or condenser that is electrically connected to the ISO Controlled Grid or Distribution Grid to provide Ancillary Services in circumstances where the generator is not producing Energy.

"MW" means one megawatt.

"MWh" means one megawatt hour.

"Net Repair Costs" is defined in Section 7.5(a).

"New Responsible Utility" is defined in Section 9.4 (f).

"Nonmarket Transaction" means a Delivery of Energy or Ancillary Services other than Hybrid MWh from a Unit pursuant to a Dispatch Notice.

"Non-Performance Penalty" means a penalty computed pursuant to Section 8.5.

"Other Outage" means any reduction in the Availability of a Unit as reflected in an ISO Availability Notice or Owner's Availability Notice (whether characterized by the North American Electric Reliability Council ("NERC") as a "forced outage", "planned outage" or "maintenance outage") other than a Long-term Planned Outage.

"Owner's Availability Notice" means a notice given under Section 4.9(a)(vii) or Section 7.3(b) by Owner to ISO notifying ISO of the Availability of a Unit.

"Owner's Repair Cost Obligation" is an allowance for Repairs to be made during the Contract Year calculated pursuant to Section 7.5 (k). Owner's Repair Cost Obligation is set out in Section 13 of Schedule A.

"Party" means either ISO or Owner, and "Parties" means ISO and Owner.

"Penalty Period" is defined in Section 8.5 (a).

"Pre-empted Dispatch Payment" is defined in Schedule E.

"Prepaid Start-ups" is defined in Section 8.4.

"Prepaid Start-up Charge" means the payment to Owner for Prepaid Start-ups described in Section 8.1.

"Prepaid Start-up Cost" is defined in Schedule D.

"Prior Period Change(s)" is defined in Section 9.1(g).

"Prior Period Change Examples" is defined in Section 9.1(l).

"Prior Period Change Guidelines" is defined in Section 9.1(l).

"Prior Period Change Worksheet" is defined in Section 9.1(g).

"PX" means the California Power Exchange Corporation, a non-profit, public benefit corporation incorporated under the laws of the State of California or any successor to the PX.

"Ramping Constraint" means the limits on ramping a Unit to higher or lower output as set out in Section 7 of Schedule A.

"Ramping Energy" is defined in Section 8.3.

"Ramp Rate" is the applicable Ramp Rate as stated in Section 8 of Schedule A.

"Reliability Must-Run Unit" means a "reliability must-run unit" as defined in the ISO Tariff.

"Repair" means repairs or replacement required to remedy or prevent any loss or damage that impairs the capability of the Unit to Deliver Energy or Ancillary Services, the cost of which is properly treated as an expense in accordance with the FERC Uniform System of Accounts, 18 C.F.R. Part 101.

"Repair Payment Factor" is determined pursuant to Section 7.5(g).

"Requested Ancillary Services" means the type and, if applicable, the MW of Ancillary Services ISO requests Owner to Deliver from a Unit pursuant to a Dispatch Notice.

"Requested MW" means the MW of Energy ISO requests Owner to Deliver pursuant to a Dispatch Notice.

"Requested MWh" means the product of the Requested MW of Energy and the time in hours (or fraction thereof) during which the Dispatch Notice requested Delivery of the Requested MW.

"Requested Operation Period" means the time during which ISO requests that a Unit Deliver Energy or Ancillary Services pursuant to a Dispatch Notice.

"Response Notice" is defined in Section 14.3(b)(ii).

"Responsible Utility" is an entity which, under the ISO Tariff, is responsible for paying all or part of the costs incurred by ISO under this Agreement.

"Responsible Utility Facility Trust Account" is defined in Section 9.2.

"Revised Adjusted RMR Invoice" is defined in Section 9.1(b).

"Revised Estimated RMR Invoice" is defined in Section 9.1(b).

"RMR Invoices" means the four invoices issued each Billing Month by Owner to ISO pursuant to Section 9.1 for payment of charges under this Agreement. The four invoices are the Estimated RMR Invoice, Revised Estimated RMR Invoice, Adjusted RMR Invoice, and Revised Adjusted RMR Invoice.

"RMR Invoice Template" is defined in Section 9.1(d).

"RMR Owner Facility Trust Account" is defined in Section 9.2.

"RMR Payments Calendar" means the calendar issued by ISO pursuant to Article 3 of Annex 1 of the Settlement and Billing Protocol of the ISO Tariff.

"RMR Ramping Energy" is defined in Section 8.3.

"Scheduling Coordinator" means an entity certified by ISO for the purposes of undertaking the functions specified in Section 2.2.6 of the ISO Tariff with respect to a unit.

"Scheduling Coordinator Revenues" is defined in Section 9.1(f).

"Service Hours" means the amount of time (measured in hours or fractions thereof) a Unit is Delivering Energy or Ancillary Services pursuant to a Dispatch Notice.

"Settlement Period" means the period beginning at the start of the hour and ending at the end of the hour.

"Shutdown" means the condition of a Unit when it is not Synchronized and not in Start-up.

"Small Project Estimate" is defined in Section 7.4 (b).

"Start-up" means the action of bringing a Unit from Shutdown to being Synchronized and the terms "Starts-up", "Started-up" and "Starting-up" shall be construed accordingly.

"Start-up Lead Time" means, for each Unit, the amount of time required to Start-up the Unit, as shown in Section 6 of Schedule A.

"Start-up Payment" is defined in Schedule D.

"Substitute Unit" means a generating unit or combination of units, other than the Unit identified in the Dispatch Notice (whether or not located at the Facility, whether or not designated as a Reliability Must-Run Unit and whether or not owned by Owner), which, under the circumstances existing at the time, is capable of providing system reliability benefits equivalent to the system reliability benefits provided by the Unit identified in the Dispatch Notice. In the case of Units providing Ancillary Services, a Substitute Unit must (i) be certified to provide the requested type of Ancillary Service, (ii) provide the same or higher ramp rate and MW of capacity and, (iii) if there is inter-zonal congestion, be located in the same zone as the Unit identified in the Dispatch Notice.

"Surcharge Payment" means the payment to Owner for Capital Items described in Section 8.1 for Condition 1 and Section 8.2 for Condition 2.

"Surcharge Payment Factor" means the percentage of the cost of a Capital Item that ISO is obligated to pay.

"Synchronized" means the condition where a Unit is electrically connected to and capable of delivering Energy to the ISO Controlled Grid or Distribution Grid.

"Termination Fee" means amounts determined pursuant to the termination fee formula contained in Section 2.5(b).

"Termination Fee Invoice" is defined in Section 9.9(a).

"Test Dispatch Notice" means a notice issued to test a Unit pursuant to Section 4.9.

"Trading Day" means the day on which Energy or Ancillary Services are to be Delivered.

"Unit" means an individual electricity generating unit which has been designated a Reliability Must-Run Unit and is part of the Facility identified in Schedule A.

"Unit Availability Limit" means for any hour the maximum MW which Owner is obligated to make available to ISO from a Unit. The Unit Availability Limit shall be the lower of (a) the Maximum Net Dependable Capacity of the Unit or (b) the Availability of the Unit as stated in the currently effective Owner's Availability Notice or ISO Availability Notice.

"Unplanned Capital Item Notice" is defined in Section 7.6(b).

"Unplanned Repair Notice" is defined in Section 7.5(b).

"Upgrade" means any change or modification to the Facility that increases the nameplate capacity rating of an existing Unit or adds a new unit.

"Variable Cost Payment" means the payment to Owner for Billable MWh described in Schedule C.

ARTICLE 2

TERM

2.1 Term

(a) This Agreement shall become effective on the later of June 1, 1999, or the date it is permitted to become effective by FERC, and shall continue in effect for one Contract Year.

(b) ISO may extend the term of this Agreement for an additional calendar year as to one or more Unit by notice given not later than October 1 of the expiring Contract Year. ISO may extend the term for less than a full calendar year as to one or more Unit but only if ISO gives notice not less than 12 months prior to the date to which it proposes to extend the term.

2.2 Termination

(a) Subject to any necessary authorization from FERC, this Agreement may be terminated as to one or more Unit in accordance with this Section 2.2; provided, however, that if this Agreement applies to a Facility having hydroelectric Unit, this Agreement may be terminated only as to all hydroelectric Units at the Facility. If this Agreement terminates as to fewer than all Units, the Agreement shall remain in effect as to the remaining Units. If this Agreement terminates as to all Units, the Agreement shall terminate.

(b) This Agreement may be terminated as to one or more Units:

(i) by ISO pursuant to Section 11.4 in the event of default by Owner;

(ii) by Owner pursuant to Section 11.4 in the event of default by ISO;

(iii) by Owner pursuant to Section 7.4 (f), 7.5 (i) or 7.6 (h);

(iv) by Owner or ISO, if the Unit is condemned by a Governmental Authority; or

(v) by Owner or ISO, if Owner's authorization from a Governmental Authority (including, where applicable, licenses under Part I of the Federal Power Act) that is necessary to site, operate or obtain access to such Unit is terminated or expires or is reissued or modified so that it becomes illegal, uneconomical or otherwise impractical for the Owner to continue operating the Facility. Owner shall be obligated to use its best efforts to renew and keep effective its licenses and authorizations and to oppose conditions or modifications which would make continued operation illegal, uneconomical or otherwise impractical.

(c) To the extent that Owner transfers the right to control the dispatch of the Facility or Unit which right is necessary to satisfy its obligations under this Agreement, Owner shall assign this Agreement to the transferee in accordance with Section 13.1.

(d) If ISO terminates the Agreement or does not extend the term of the Agreement as to a Unit, ISO shall not redesignate the same Unit, or designate another non-reliability must-run unit at the same Facility, as a Reliability Must-Run Unit during the one year period following termination or expiration of the Agreement as to that Unit unless (i) ISO demonstrates that the unit is required to maintain the reliability of the ISO Controlled Grid or any portion thereof and the need to designate the unit as a Reliability Must-Run Unit is caused by an extended outage of a generation or transmission facility not known to ISO at the time of the termination or expiration or (ii) the unit is selected through an ISO competitive process in which Owner participated. For purposes of the foregoing, ISO's need for spinning reserves, nonspinning reserves, replacement reserves or regulation as defined in the ISO Tariff shall not be grounds for redesignating the Unit or designating another unit at the Facility as a Reliability Must-Run Unit.

(e) Subject to any necessary authorization from FERC, this Agreement shall terminate as to any Unit leased by Owner in the event that, for any reason, the lease expires or is terminated unless Owner acquires ownership of such Unit upon such expiration or termination. Any termination under this Section 2.2 (e) shall not affect any right ISO may have thereafter to designate such Unit as a Reliability Must-Run Unit and the conditions in Section 2.2 (d) shall not apply to such redesignation.

2.3 Effective Date of Expiration or Termination

If FERC authorization is required to give effect to expiration or termination of this Agreement as to one or more Units, the effective date of the expiration or termination shall be the date FERC permits the expiration or termination to become effective. Owner shall promptly file for the requisite FERC authorizations to terminate service under this Agreement as of the proposed effective date of expiration or termination; provided, that nothing in this Agreement shall prejudice the right of either Party to contest the other Party's claim that a termination or expiration has occurred. If FERC authorization is not required to terminate service under this Agreement, the effective date of expiration or termination shall be the later of (i) the date specified in ISO or Owner's notice of termination or (ii) the date that all conditions to the termination or expiration have been satisfied.

2.4 Effect of Expiration or Termination

Expiration or termination of this Agreement shall not affect the accrued rights and obligations of either Party, including either Party's obligations to make all payments to the other Party pursuant to this Agreement or post-termination audit rights under Section 12.2.

2.5 Termination Fee

(a) ISO shall pay Owner a Termination Fee calculated pursuant to Section 2.5 (b) if the Unit is Closed within six months after the Unit ceases to be subject to this Agreement as a result of termination pursuant to Sections 2.2 (b) (ii), (iii), (iv) or (v) or because ISO does not extend the term under Section 2.1 (b). Within 60 days after the Unit is Closed, Owner will send ISO a notice stating (i) the date the Unit Closed and (ii) the amount of the Termination Fee due Owner pursuant to this Section 2.5 including detailed calculations of each component of the formula in Section 2.5(b) identifying the source of each input used. For purposes of this Section, "Closed" shall mean that the Unit is not producing Energy or providing capacity and there are no Direct Contracts obligating any entity to deliver Energy or provide capacity from the Unit during the 36 month period beginning at the date the Unit Closed. A Unit shall cease to be Closed if, during the 36 month period beginning at the date the Unit Closed, any entity: (i) sells Energy or capacity; (ii) executes a Direct Contract for service or (iii) obtains a new permit from any Governmental Authority for operations, in each case that would involve use of the Capital Item for which a Termination Fee is being paid.

(b) The Termination Fee shall be determined using the following formula:

$$T = NCI + CWIP - S$$

Where:

T	=	Termination Fee ($)
NCI	=	Undepreciated portion of the cost of Capital Items which constitute part of the Closed Unit which were approved in accordance with Section 7.4 or 7.6 and were in service at the date the Unit Closed with the cost and depreciation rates determined under Section 7.4 or 7.6, as applicable. In calculating NCI, the undepreciated cost of each Capital Item shall be multiplied by the Surcharge Payment Factor applicable to that Capital Item.
CWIP	=	The actual cost, at the date the Unit Closed, of Capital Items for the Closed Unit which were approved in accordance with Section 7.4 or 7.6, as applicable, but were not in service at the date the Unit Closed, plus the cost to pay or terminate any remaining obligations incurred in connection with installation of the Capital Items. In calculating CWIP, the cost of each Capital Item shall be multiplied by the Surcharge Payment Factor applicable to that Capital Item.
S	=	The salvage value, if any, of the Capital Items included in the calculation of either NCI or CWIP.

The cost for each Capital Item shall be determined by agreement or ADR pursuant to Section 7.4 or 7.6. Except for those items for which a ten-year depreciation life is specified in Section 7.4 of this Agreement, the depreciation rate for each

Capital Item shall be determined by agreement or ADR in connection with the applicable Capital Item approval process under Section 7.4 or 7.6.

(c) The Termination Fee shall be payable in 36 equal monthly installments calculated using the following formula:

$$M = T\left[\frac{r}{1-(1+r)^{-36}}\right]$$

Where

M = the monthly payment,

T = Termination Fee under Section 2.5(b), and

r = an annual discount rate equal to the interest rate used by FERC for the calculation of refunds (as set forth in 18 C.F.R. § 35.19a) in effect on the date that Owner provides notice to the ISO pursuant to Section 2.5(a) of this Agreement, divided by 12.

(d) If the Unit ceases to be Closed at any time within 36 months following the date the Unit Closed, ISO shall cease payment of Termination Fee installments as of the Month in which the Unit ceased to be Closed, but Owner shall not be obligated to refund installments for any Month in which the Unit was Closed. Once a Unit has ceased to be Closed, ISO shall not be required to pay any remaining Termination Fee installments even if the Unit again Closes.

(e) Any dispute regarding an element of the Termination Fee (*e.g.* salvage value) not resolved at the time the Capital Item was approved shall be subject to ADR. If the amount of the Termination Fees associated with a single termination or expiration is \$5 million or more as billed by Owner, the Responsible Utility shall have the same rights as ISO to receive notice that the Unit(s) Closed and to initiate or participate in ADR.

ARTICLE 3

CONDITIONS OF MUST-RUN AGREEMENT

3.1 Conditions Under Which Units Will Operate

This Agreement includes two conditions of service under which Owner may provide service from its Unit(s). By way of general description and subject to the specific provisions set forth in this Agreement:

(i) A Unit under Condition 1 may participate in Market Transactions and Owner will retain all revenues from participation in Market Transactions;

(ii) A Unit under Condition 2 shall bid in accordance with Section 6.1 (b) to participate in Market Transactions when ISO has issued a Dispatch Notice for the Unit and Owner will not retain revenues from participation in Market Transactions. A Unit under Condition 2 shall not participate in a Market Transaction when ISO has not issued a Dispatch Notice for the Unit.

Owner shall begin operating each Unit under the Condition designated by Owner prior to the Effective Date and thereafter may transfer the Unit to a different Condition pursuant to Section 3.2.

3.2 Transfer Between Conditions

(a) Except for a hydroelectric Unit, Owner may, from time to time, transfer a Unit from one Condition to the other Condition, provided that it may not do so without ISO's consent unless, as of the transfer date, the Unit will have been subject to its existing Condition for at least twelve months. If a transfer is to become effective at the beginning of a Contract Year, Owner shall provide ISO at least 30 days prior notice of the transfer. For a transfer to become effective at any other time, Owner shall give ISO notice at least 90 days prior to the transfer. If a Unit is transferred from Condition 1 to Condition 2 during a Contract Year, Owner shall credit to ISO on the first invoice after the transfer is effective an amount computed by multiplying (i) the positive difference, if any, of the Prepaid Start-ups minus the Counted Start-ups by (ii) the Prepaid Start-up Cost. If a Unit is transferred from Condition 2 to Condition 1, ISO shall not be required to pay a Condition 1 Prepaid Start-up Charge for the remainder of the Contract Year in which the transfer occurred, but shall pay, for each Start-up, the Condition 1 Start-up Payment calculated pursuant to Equation D-1 in Schedule D.

(b) A hydroelectric Unit may only operate under Condition 1.

(c) ISO may not transfer a Unit from one Condition to the other Condition.

(d) Any transfer of a Unit from one Condition to the other Condition shall be effective on the first day of the Month following expiration of the applicable notice.

(e) If a Unit is transferred from Condition 1 to Condition 2, Surcharge Payments for Capital Items shall be changed prospectively from the effective date of the transfer to reflect a Surcharge Payment Factor of 1.0. If a Unit is transferred from Condition 2 to Condition 1, Surcharge Payments for Capital Items shall be changed prospectively from the effective date of the transfer to reflect the Condition 1 Surcharge Payment Factor previously determined for the Capital Item, or if the factor was not previously determined, the Surcharge Payment Factor agreed to by ISO and Owner. If Owner and ISO do not agree on the Surcharge Payment Factor, the Surcharge Payment Factor shall be determined through ADR in accordance with Schedule B.

ARTICLE 4

DISPATCH OF UNITS

4.1 ISO's Right to Dispatch

(a) Subject to the limitations set forth in this Agreement, ISO shall direct dispatch of a Unit by delivering a Dispatch Notice to Owner's Scheduling Coordinator in accordance with the ISO Tariff.

(b) Dispatch Notices for Energy, other than Energy associated with Ancillary Services, shall be issued solely for purposes of meeting local reliability needs or managing intra-zonal congestion. For purposes of dispatching Energy, local reliability needs do not include Energy required to manage inter-zonal congestion. ISO shall issue Dispatch Notices to meet local reliability needs or manage intra-zonal congestion whenever market bids cannot be used to meet those needs or manage such congestion or such market bids cannot be used to meet those needs or manage such congestion without taking a bid out of merit order or requiring ISO to decrement another supplier's schedule to accommodate the unit which provided the bid. ISO may not issue a Dispatch Notice to fill a need for imbalance energy.

(c) Except as needed for black start or voltage support required to meet local reliability needs, to meet operating criteria associated with Potrero and Hunters Point power plants, or as outlined below, ISO may issue Dispatch Notices for Ancillary Services only if the available bids in Ancillary Service capacity markets do not provide sufficient capacity to meet ISO's requirements.

(i) The ISO may elect to procure from the day-ahead market less than the amount of an Ancillary Service that it knows to be needed as of the close of that market and instead procure the balance from the hour-ahead markets. Before doing so, the ISO must communicate to all Scheduling Coordinators its intention to procure a portion of its needs from the hour-ahead market. Such communication shall state the projected hourly megawatt amounts of each Ancillary Service it has shifted from day-ahead to hour-ahead procurement. Amounts shifted under this provision are not subject to the Bid Sufficiency Test described below.

(ii) If, after the close of the day-ahead market for a Trading Day, but before ISO issues final hour-ahead schedules for the first hour of the Trading Day, ISO determines it needs additional Ancillary Services for the Trading Day, ISO shall use unused, available day-ahead market bids for Ancillary Services for the Trading Day in merit order (and in the appropriate zone, if ISO is procuring Ancillary Services on a zonal basis) to fill its Ancillary Services needs before issuing a Dispatch Notice for Ancillary Services.

(iii) If unused day-ahead Ancillary Services bids are not sufficient to meet the ISO's Ancillary Service needs for the Trading Day, or if ISO determines on the Trading Day that it needs additional Ancillary Services on the Trading Day, ISO shall use the following procedures:

(A) ISO shall communicate such needs to all Scheduling Coordinators as quickly as possible after such needs are identified.

(B) After completing (A), ISO shall attempt to procure those additional Ancillary Services from the hour-ahead Ancillary Services markets (in the appropriate zone if ISO is procuring Ancillary Services on a zonal basis) that have not closed, subject to the Bid Sufficiency Test described below.

(C) ISO shall not issue a Dispatch Notice for Ancillary Services for any hour of the Trading Day before the earlier of (a) the time at which the hour-ahead market for that hour closes or (b) if a Start-up would be required to provide the Ancillary Service, such earlier time as is necessary to comply with the applicable Start-up Lead Time and Ramping Constraints on Schedule A.

(iv) ISO shall not be required to accept any bid for an Ancillary Service above applicable bid caps then in effect under the ISO Tariff before issuing a Dispatch Notice for Ancillary Services.

(v) Bid Sufficiency Test

(A) The Bid Sufficiency Test may only be applied:

(1) To purchases from the hour-ahead Ancillary Services market;

(2) If ISO has fully complied with its obligation to promptly notify Scheduling Coordinators of its need to acquire additional ancillary services from the hour-ahead market; and

(3) To the extent that the approved ISO Tariff does not preclude such a test.

(B) The Bid Sufficiency Test may not be applied to Ancillary Service requirements that have been shifted from the day-ahead market to the hour-ahead market at the discretion of the ISO.

(C) The Bid Sufficiency Test shall be applied on an individual hourly basis and for an individual Ancillary Service type. The test result shall be considered "insufficient" in an hour-ahead market if, and only if - (1) bids in the hour-ahead market for the particular Ancillary Service (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 2.5.3.6 of the ISO Tariff) that remain after first procuring the megawatts of the Ancillary Service that the ISO had notified Scheduling Coordinators it would procure in the hour-ahead market pursuant to Section 4.1(c)(i) ("remaining Ancillary Service requirement") represent, in the aggregate, less than two times such remaining Ancillary Service requirement; or (2) there are fewer than two unaffiliated bidders to provide such remaining Ancillary Service requirement. If the application of the Bid Sufficiency Test results in a determination of "insufficiency", the ISO may issue a Dispatch Notice to satisfy its needs for that hour and that individual Ancillary Service.

(D) If the result of the Bid Sufficiency Test is a finding that available bids are "insufficient", ISO may nonetheless accept available market bids if it determines in its sole discretion that the prices bid and the supply curve created by the bids indicate that the bidders were not attempting to exercise market power.

4.2 Timing of Dispatch Notices

Subject to the terms and conditions of this Agreement, ISO shall issue all Dispatch Notices promptly after it makes a determination that it will require Energy or Ancillary Services under this Agreement, but ISO shall not issue Dispatch Notices earlier than establishment of the "final schedule" (as defined in the ISO Tariff) for the day-ahead market unless the ISO Tariff is revised to permit ISO to dispatch Reliability Must-Run Units prior to such establishment.

4.3 Form and Content of Dispatch Notices

(a) All Dispatch Notices shall be in writing if circumstances permit. If circumstances require that a Dispatch Notice be given or changed orally, the Dispatch Notice shall be confirmed in writing within 24 hours after the oral notice or change was given.

(b) Each Dispatch Notice shall specify the Unit from which ISO requests Owner to Deliver Energy or Ancillary Services, the time of commencement and termination of the Requested Operation Period and, for each hour of the Requested Operation Period, the Requested MW or the Requested Ancillary Services. A Dispatch Notice for a hydroelectric Facility must request that Owner Deliver Energy from the entire Facility rather than from a specific Unit. However, ISO may request that Owner Deliver Ancillary Services from specific Units in a hydroelectric Facility; provided that Energy associated with such Ancillary Services shall be Delivered from the Facility and not the specified Units. ISO may issue Dispatch Notices in real time without specifying the time the Requested Operation Period is to terminate and may adjust the Requested MW or Requested Ancillary Services in real time if ISO provides all such information in writing as provided in Section 4.3(a).

4.4 Non-complying Dispatch Notices

Owner shall not be obligated to comply with a Dispatch Notice that does not comply with Section 4.3 or 4.6 and Owner shall not be liable, suffer any penalties or suffer any reduction in payments for failure to comply with a Dispatch Notice which is not in compliance with those Sections, provided that Owner promptly notifies ISO that the notice does not comply with Section 4.3 or 4.6 and provides the reasons the Dispatch Notice does not comply. Owner may provide such notice after the Requested Operation Period if the notice concerns a Dispatch Notice given during, or less than one-half hour prior to, the Requested Operation Period. Compliance with a Dispatch Notice shall not be deemed a waiver of objections to the Dispatch Notice.

4.5 Dispatch Notices to a Unit Scheduled in Market Transactions

Notwithstanding Section 4.1, ISO shall issue a Dispatch Notice for all Energy required from a Unit for reliability purposes even if the Unit is scheduled to operate at or above the required level in a Market Transaction.

4.6 Limitations on ISO's Right to Dispatch

ISO's Dispatch Notice may not request Owner to, and Owner shall not be obligated to:

(i) Provide service from a Unit at less than the Minimum Load for the Unit;

(ii) Provide service from a Unit for less than the Minimum Run Time;

(iii) Start-up a Unit after less than the Minimum Off Time;

(iv) Start-up a Unit unless the time between the delivery of the Dispatch Notice requesting such Start-up and the commencement of the applicable Requested Operation Period equals at least the Start-up Lead Time for the Unit and the Dispatch Notice provides sufficient time to satisfy the Ramping Constraint of the Unit;

(v) Provide service from a Unit in excess of its Unit Availability Limit;

(vi) Provide service from a Unit when to do so would violate environmental limitations applicable to the Unit as set forth in Section 3 of Schedule A;

(vii) Start-up or provide service from a Unit in violation of any applicable law, regulation, license or permit; or

(viii) Start-up or provide service from a Unit to the extent that doing so would cause a breach of an Existing Contractual Limitation; or

(ix) Deliver Energy or Ancillary Services to the extent such Delivery would cause a breach of a contract for capacity made available through an Upgrade or a Capital Item or Repair for which ISO is not obligated to make a Surcharge Payment or pay ISO's Repair Share.

4.7 Dispatch in Excess of Contract Service Limits

(a) ISO shall use its best efforts in accordance with Good Industry Practice not to issue a Dispatch Notice that would cause a Unit's Counted Start-ups, Counted MWh, or Counted Service Hours to exceed any of the Unit's Contract Service Limits.

(b) ISO may issue a Dispatch Notice requiring a Unit to Deliver Energy or Ancillary Services after the Unit has exceeded a Contract Service Limit only if the Requested MWh or Requested Ancillary Services cannot be obtained by ISO either (i) by accepting market bids in accordance with Section 4.1 or (ii) from Comparable RMR Unit(s) without exceeding the contract service limits or violating other operational limitations under ISO's agreement with the Comparable RMR Unit(s). Owner shall use its best efforts, in accordance with Good Industry Practice, to comply with such Dispatch Notice.

(c) If Owner of a hydroelectric Facility complies with a request to exceed the Maximum Monthly MWh, Owner may reduce the Maximum Monthly MWh for remaining Months of the Contract Year to reflect the accelerated use of available water. Not later than 15 days after any delivery in excess of Maximum Monthly MWh, Owner shall provide ISO a notice showing revised Maximum Monthly MWh for remaining Months of the Contract Year.

(d) If the Owner does not comply with a Dispatch Notice under Section 4.7(b), Owner at ISO's request shall provide a written explanation.

(e) If Owner, in compliance with a Dispatch Notice, Starts-up a Unit and the Counted Start-ups for the Contract Year exceed the Maximum Annual Start-ups for the Unit, ISO shall pay for each such excess Start-up at the rate set out in Schedule G. If Owner, in compliance with a Dispatch Notice, Delivers Energy and the Counted MWh for the Unit for the Contract Year exceeds the Maximum Annual MWh, the Counted Service Hours from the Unit for the Contract Year exceed the Maximum Annual Service Hours, or if applicable, the Counted MWh for the Month exceed the Maximum Monthly MWh, ISO shall pay for the Billable MWh Delivered in response to such Dispatch Notice and exceeding the Contract Service Limit at the rates set forth in Schedule G.

(f) For purposes of this Section 4.7:

(i) "Best efforts" does not require Owner to provide service inconsistent with the limitations set forth in Section 4.6 or if Owner reasonably believes providing the service might cause significant physical harm to the Unit.

(ii) The term "Good Industry Practice" shall not be applied to permit ISO to consider the relative costs of Comparable RMR Units when determining whether to request dispatch of a Unit in excess of the Contract Service Limits.

(iii) "Comparable RMR Unit" means a unit which has been designated a Reliability Must-Run Unit and which, in ISO's reasonable judgment, is capable of providing system reliability benefits to ISO equivalent to the system reliability benefits provided by the Unit which otherwise would be subject to the Dispatch Notice. In the case of Units providing Ancillary

Services, a Comparable RMR Unit must: (A) be certified to provide the Requested type of Ancillary Service, (B) provide the same or higher ramp rate and MW capacity and (C) if there is interzonal congestion, be located in the same zone as the Unit which otherwise would be subject to the Dispatch Notice.

(g) ISO and Owner shall have the right to dispute the other Party's actions or inactions under this Section 4.7 and any dispute shall be subject to resolution through ADR.

4.8 Air Emissions

If ISO determines that it is necessary to reserve MWh to satisfy potential dispatches under this Agreement without violating present or future limitations on the discharge of air pollutants or contaminants into the atmosphere specified by any federal, state, regional or local law by any regulation, air quality implementation plan, or permit condition promulgated or imposed by any Governmental Authority, the terms and conditions of such reservation shall be set out on Schedule P.

4.9 Test Dispatch Notices

(a) Availability Tests

(i) ISO may from time to time test the Availability of a Unit by requiring the Unit to Deliver Energy pursuant to a Test Dispatch Notice provided to Owner's Scheduling Coordinator using the procedures described in Section 4.2 and 4.3. ISO, without cause, may request one Availability Test each Contract Year. ISO may request additional Availability Tests if the Unit fails to comply fully with a Dispatch Notice. ISO shall not request an Availability Test for a hydroelectric Unit during periods of constrained water availability. Lack of available water shall not be deemed to result in a failed test and reduction of the Unit Availability Limit for a hydroelectric Unit.

(ii) Owner may request an Availability Test at any time. ISO shall issue a Test Dispatch Notice within three days after receipt of Owner's request, but for good cause, ISO may reschedule the test to a date acceptable to Owner. Owner's request shall state the amount of Energy to be produced. The effect of operations pursuant to such a request is set out in Section 5.3.

(iii) The Test Dispatch Notice shall be marked "Availability Test Dispatch Notice." The Test Dispatch Notice shall specify a Requested Operation Period of four hours of continuous operations at the requested output plus any applicable Start-up Lead Time, time to satisfy Ramping Constraints and time for Shutdown (or for hydroelectric Units the time sufficient water is available, if that is less).

(iv) Subject to the other conditions or restrictions expressed in this Agreement, Owner shall provide service from the Unit and Deliver the Requested MWh in accordance with the Availability Test Dispatch Notice; provided, however, that Owner, in response to such Test Dispatch Notice, may deliver all or part of the Requested MWh in a Market Transaction by complying with the procedures set forth in Section 5.2.

(v) An Availability Test shall be treated as having been successfully completed if the average MW Delivered at the Delivery Point during the Availability Test was not less than 99% of the Requested MW for the Requested Operation Period. The average MW Delivered during the Availability Test shall be computed by dividing (i) the total MWh produced during the four- hour period immediately following completion of the ramp up, multiplied by the appropriate ambient temperature correction factors for the Unit as set out in Section 3 of Schedule A, by (ii) four hours.

(vi) If a Unit fails an Availability Test, ISO may issue an ISO Availability Notice restating the Availability of the Unit to a level not less than the average MW Delivered during the Availability Test. Following the notice, Owner shall not issue an Owner's Availability Notice increasing the Availability of the Unit above the level determined through such failed Availability Test until (A) the Unit has successfully completed a subsequent Availability Test, (B) the Unit has delivered in Market Transactions, pursuant to a Dispatch Notice or in a combination of the two, during a continuous four hour operating period, average MW in excess of those determined in the Availability Test or (C) Owner has otherwise demonstrated to ISO's reasonable satisfaction that the Availability of the Unit has been restored.

(vii) If the average MW Delivered during the Availability Test exceed 101% of the Unit Availability Limit in effect prior to the Availability Test, Owner may issue an Owner's Availability Notice setting Availability retroactive to the time the request was received by ISO to the lesser of (A) the average MW Delivered during the Availability Test or (B) the Maximum Net Dependable Capacity.

(b) Emissions Test

If it is necessary for Owner to operate a Unit to fulfill regulatory requirements for emissions testing, Owner may request ISO to issue a Dispatch Notice for such operation. Owner shall provide a request specifying the test date at least seven days in advance of the emissions test. ISO shall issue a Dispatch Notice to schedule the requested operation on the date specified in Owner's request, or for good cause, ISO may cause the test to be rescheduled to a date acceptable to Owner, provided that ISO shall not delay the test by more than seven days without Owner's consent. The Test Dispatch Notice shall be marked "Emissions Test Dispatch Notice".

(c) Black Start Test

ISO may from time to time test Unit(s) designated to provide Black Start service by requiring the Unit to deliver Black Start service pursuant to a Test Dispatch Notice provided to Owner's Scheduling Coordinator using the procedures described in Sections 4.2 and 4.3. Such Test Dispatch Notice shall be marked "Black Start Test Notice." The Black Start Test shall be performed in accordance with the Ancillary Services Requirements Protocol in the ISO Tariff. ISO shall not request a Black Start Test for a hydroelectric Unit during periods of constrained water availability.

(d) Heat Input Test

Not more frequently than once each Contract Year, Owner may, by giving at least seven days' prior notice to ISO, request ISO to issue a Test Dispatch Notice in order for Owner to determine the heat input of a Unit. ISO shall not unreasonably refuse to issue a Test Dispatch Notice for a heat input test. The Test Dispatch Notice shall be marked "Heat Input Test Notice." The heat input test shall be conducted in accordance with testing standards and procedures agreed to by ISO and Owner. In the absence of such agreement, the standards and procedures shall be determined through ADR before such test may be conducted. The arbitrator shall specify procedures for testing which are consistent with Good Industry Practice. Following such a heat input test, Owner shall be permitted to make a filing under Section 205 of the Federal Power Act limited to modifying the heat inputs used in the Variable Cost Payment, Start-up Payment, Preempted Dispatch Payment and Mandatory Energy Bid in Schedules C, D, E and M, respectively, to reflect the results of such test.

4.10 Forecasts Of ISO's Requirements

Not later than November 15 of each year, ISO shall provide Owner and the Responsible Utility with a non-binding forecast representing ISO's then current best estimate of the monthly MWh, monthly peak day MW, and monthly Service Hours that ISO will require each Unit to provide each month during the ensuing Contract Year ("Annual Forecast"). In addition, not later than June 15 of each year, ISO shall provide Owner and with a non-binding forecast ("Update") representing ISO's then current best estimate of the monthly MWh, monthly peak day MW, and monthly Service Hours that ISO will require each Unit to provide each month from June through the end of the Contract Year. Each Annual Forecast and Update will take into account the Long-term Planned Outages. The Annual Forecasts and Updates shall be treated as confidential pursuant to Section 12.5 and shall not be binding.

4.11 Determination of Contract Service Limits

(a) If ISO has extended the term of this Agreement pursuant to Section 2.1 (b), then not later than October 31 of the expiring Contract Year Owner shall make a filing under Section 205 of the Federal Power Act limited to revising Schedule A to reflect the Contract Service Limits for all Units other than hydroelectric Units for the ensuing Contract Year. The Contract Service Limits for each year after the initial Contract Year shall be determined through application of the following rules:

(i) Maximum Annual MWh for each Unit shall be the average annual MWh produced in Market and Nonmarket Transactions by the Unit during the 60 month period ending June 30 of the expiring Contract Year;

(ii) Maximum Annual Service Hours for each Unit shall be the average annual Service Hours the Unit operated in Market and Nonmarket Transactions during the 60 month period ending June 30 of the expiring Contract Year; and

(iii) Maximum Annual Start-Ups shall be the number of Start-ups of the Unit for Market and Nonmarket Transactions during the year selected by ISO. ISO may select any of the five preceding years to determine Maximum Annual Start-Ups but shall select the same year for all Units at the Facility. For purposes of the foregoing sentence only, a year shall mean a 12-month period ending June 30. Thus, by way of example, ISO may determine Maximum Annual Start-ups for calendar year 2002 based on the Maximum Annual Start-ups during any of the following five periods: (A) 12 months ended June 30, 2001; (B) 12 months ended June 30, 2000;

(C) 12 months ended June 30, 1999; (D) 12 months ended June 30, 1998; or (E) 12 months ended June 30, 1997.

Owner shall provide the information necessary to determine the Contract Service Limits to ISO and the Responsible Utility not less than 15 days prior to the filing. ISO shall give notice to Owner and Responsible Utility identifying the year to be used to determine Maximum Annual Start-ups not later than five Business Days after it receives the information from Owner.

(b) If ISO has extended the term of this Agreement pursuant to Section 2.1 (b), then not later than 15 days prior to the beginning of the ensuing Contract Year, Owner of a hydroelectric Facility shall make a filing under Section 205 of the Federal Power Act to reflect the revised Contract Service Limits to be in effect during the ensuing Contract Year for the hydroelectric Facility. Such filing shall be based on Owner's current water management forecast and shall reflect the water expected to be available for electric generation above the Hydroelectric Dependable Capacity. Such filing, if accepted or approved, shall set the Maximum Monthly MWh in Schedule A for the ensuing Contract Year, subject to adjustment in accordance with the notice described below giving revised Monthly Maximum MWh. The Maximum Monthly MWh in Schedule A of this Agreement on the Effective Date reflects the Hydroelectric Dependable Capacity. Not later than April 15 of each Contract Year, Owner shall provide notice to ISO giving revised Maximum Monthly MWh for each remaining Month of the Contract Year based on its then current water management forecast. For the Contract Year ending December 31, 1999, Owner shall provide ISO with such notice prior to the Effective Date. If, during any Contract Year, Owner determines that drought conditions jeopardize its ability to supply Hydroelectric Dependable Capacity, Owner shall promptly give notice to the ISO of this determination, including revised Maximum Monthly MWh for each remaining Month of the Contract Year. Following such a determination, Owner shall provide ISO with weekly updated water management forecasts until the earlier of the end of the Contract Year or Owner's determination that its ability to supply the Hydroelectric Dependable Capacity is no longer jeopardized by such conditions. ISO acknowledges that the accuracy of a water management forecast may be substantially affected by a Force Majeure Event at any time after the Owner provides the forecast and consequently Owner shall not be liable for the accuracy of the water management forecast or any reliance on it other than a Monthly Maximum MWh amount.

ARTICLE 5

DELIVERY OF ENERGY AND ANCILLARY SERVICES BY OWNER

5.1 Owner's Delivery of Energy and Ancillary Services

(a) Subject to the limits in this Agreement, Owner shall provide service from the Units and Deliver the Requested MWh or Requested Ancillary Services in accordance with each Dispatch Notice. To the maximum extent practical, and except for regulation, Owner shall Deliver at each moment of each hour during the Requested Operation Period not less than the Requested MW or Requested Ancillary Services. If Owner has disputed a Dispatch Notice under Section 4.6 (i) *(Minimum Load)* (ii) *(Minimum Run Time)* (iii) *(Minimum Off Time)* (iv) *(Start-up Lead Time and Ramping Constraint)*, or (v) *(Unit Availability Limit)* and such dispute is not resolved prior to the time for delivery, Owner will use reasonable efforts to comply with the Dispatch Notice, but shall not be liable to ISO if it is unable to do so and Owner prevails in the dispute.

(b) If Owner has disputed a Dispatch Notice under Section 4.6 (vi) (*environmental*), (vii) (*violation of law*), (viii) *(Existing Contractual Limitations)* or (ix) *(Upgrade Contract)*, Owner shall not be required to Deliver Energy or Ancillary Services pending resolution of the dispute as to whether the Dispatch Notice violated such Section; provided, however, that Owner shall not be relieved from any liability that it would otherwise have for failure to comply with the disputed Dispatch Notice if it subsequently is determined that the Dispatch Notice did not violate Section 4.6 (vi), (vii), (viii) or (ix).

(c) Subject to ISO approval, if Owner cannot Deliver the Requested MWh or Requested Ancillary Services by providing service from the Unit identified in a Dispatch Notice, Owner may Deliver the requested services by providing service from a Substitute Unit. Owner shall provide oral or written notice to ISO prior to the Requested Operation Period stating why it cannot provide the requested service from the Unit identified in the Dispatch Notice, identifying the Substitute Unit, describing the services it will provide from the Substitute Unit and specifying the charges applicable to service from the Substitute Unit. ISO may deny approval only if the proposed unit does not qualify as a Substitute Unit. The total cost to ISO for service from the Substitute Unit shall be at the rate specified by the Owner, provided that the total cost will not exceed the total costs for the same amount of service from the Unit specified in the Dispatch Notice.

(d) If Owner can Deliver the Requested MWh or Requested Ancillary Services by providing service from the Unit identified in the Dispatch Notice, Owner may Deliver the requested services by providing service from (i) the Unit identified in ISO's Dispatch Notice or (ii) with ISO's consent, a Substitute Unit. Owner of a hydroelectric Unit will Deliver the Requested MWh from the Facility and will Deliver the Voltage Support and Black Start requested in a Dispatch Notice from the specified Unit or a Substitute Unit. If Owner proposes to satisfy its delivery obligations by providing service from a Substitute Unit, Owner shall provide oral or written notice to ISO prior to the Requested Operation Period identifying the Substitute Unit, describing the services it will provide from Substitute Unit and specifying the charges applicable to service from the Substitute Unit. Owner may Deliver the agreed services from the Substitute Unit and will be paid at the agreed rates if ISO accepts Owner's proposal, or ISO and Owner otherwise agree on the services and applicable rates for service from a Substitute Unit. ISO's decision shall not be subject to ADR.

(e) Owner shall Deliver the Requested MWh or Requested Ancillary Services at the Delivery Point or such other point(s) reasonably acceptable to ISO and shall comply with the metering and related arrangements set forth in Section 5 of Schedule A to this Agreement or as otherwise specified in Owner's applicable Meter Service Agreement.

(f) If Owner would have been able to Deliver the Requested MWh or Requested Ancillary Services but for an outage in the ISO Controlled Grid or Distribution Grid beyond Owner's reasonable control, Owner shall be deemed to have complied with the Dispatch Notice for purposes of Sections 5.4 and 8.5.

5.2 Substitution of Market Transactions for Dispatch Notices

(a) Owner may satisfy, in whole or in part, its obligation to Deliver Energy, but not Ancillary Services, during a Requested Operation Period by delivering Energy under a Market Transaction from the Unit identified in a Dispatch Notice if Owner complies with the requirements and procedures of this Section 5.2.

(b) Within 30 minutes after receipt of the Dispatch Notice, Owner shall give notice of its intent to substitute a Market Transaction, designate the amount of MWh for each hour to be substituted in the market (hour-ahead, day-ahead or real-time imbalance market) and the Direct Contracts in which it will participate. All substitute MWh (except substitute MWh to be delivered under Direct Contracts) must be in the same market (i.e. hour-ahead, day-ahead or real-time imbalance).

(c) Owner may substitute a Market Transaction (other than a Direct Contract) only if the deadline for bids into the market selected by Owner has not passed. If Owner intends to substitute a Market Transaction in the hour-ahead or real-time markets, Owner shall submit a bid of zero dollars to ISO or PX, as applicable, to provide not less than the MWh it has proposed to substitute. If Owner's bid is not successful, Owner will nonetheless Deliver the MWh requested in the Dispatch Notice and will be paid the applicable price under the ISO Tariff for additional generation resulting from "uninstructed imbalance energy" as defined in the ISO Tariff.

(d) Owner may substitute deliveries under a Direct Contract for Requested MWh only by including the Direct Contract in the initial preferred or revised preferred schedules for the applicable market with the result that its Scheduling Coordinator's schedule remains balanced.

5.3 Rules for Calculating Counted Start-ups, Counted MWh and Counted Service Hours

(a) The following rules shall govern calculation of Counted Start-ups:

(i) Except as limited below, all Start-ups successfully completed in compliance with a Dispatch Notice shall be included in Counted Start-ups for the Unit for which the Dispatch Notice was issued.

(ii) If a Start-up required by a Dispatch Notice is canceled by ISO after the Start-up is initiated, Counted Start-ups shall include a fractional Start-up computed by dividing (i) the lesser of (a) the time elapsed between initiation of the Start-up and cancellation or (b) the Start-up Lead Time by (ii) the applicable Start-up Lead Time for the Unit.

(iii) For Units under Condition 1, if a Dispatch Notice is issued pursuant to Section 4.5 for a period in which the Unit is scheduled to operate or is operating in a Market Transaction for which a Start-up was required, or Owner substitutes a Market Transaction under Section 5.2 for a Requested Operation Period for which a Start-up was required, Counted Start-ups shall include one-half of the Start-up for the Unit for which the Dispatch Notice was issued. No Start-up shall be counted more than once.

(iv) For Units under Condition 2, Counted Start-ups shall include each Start-up whether the Energy is Delivered to the ISO in a Nonmarket Transaction or is delivered in a Market Transaction pursuant to bids made under Section 6.1 (b).

(v) If Owner complies with a Dispatch Notice by Delivering the Requested MWh or Ancillary Services from a Substitute Unit, any Start-ups of the Substitute Unit will not be included in Counted Start-ups for the Unit specified in the Dispatch Notice or the Substitute Unit.

(vi) Except as provided in Section 5.3(a)(iii), any Start-up not required to comply with a Dispatch Notice will not be included in Counted Start-ups.

(b) The following rules shall govern calculation of Counted MWh:

(i) Except as limited below, all MWh Delivered in compliance with a Dispatch Notice shall be included in Counted MWh for the Unit for which the Dispatch Notice was issued.

(ii) For Units under Condition 1, if a Dispatch Notice is issued pursuant to Section 4.5 for a period in which a Unit is scheduled to operate or is operating in a Market Transaction or if Owner, in response to a Dispatch Notice, substitutes a Market Transaction under Section 5.2 for all or part of the Requested MWh, MWh equal to the sum of (A) Billable MWh plus (B) 50% of the Hybrid MWh, will be included in Counted MWh for the Unit for which the Dispatch Notice was issued.

(iii) If a Unit operating under Condition 2 sells Energy pursuant to bids made under Section 6.1 (b), the Billable MWh shall be included in Counted MWh for the Unit.

(iv) 50% of all RMR Ramping Energy not included in Billable MWh will be included in Counted MWh for the Unit specified in the Dispatch Notice.

(v) If Owner Delivers Requested MWh or Energy associated with Ancillary Services from a Substitute Unit, the MWh Delivered from the Substitute Unit will not be included in Counted MWh for the Unit specified in the Dispatch Notice or the Substitute Unit.

(c) The following rules shall govern calculation of Counted Service Hours:

(i) Except as limited below, all Service Hours expended in compliance with a Dispatch Notice other than Service Hours expended for Ancillary Services during which the Unit is not Synchronized shall be included in Counted Service Hours for the Unit for which the Dispatch Notice was issued.

(ii) For Units under Condition 1, if a Dispatch Notice is issued pursuant to Section 4.5 for a period in which a Unit is scheduled to operate or is operating in a Market Transaction or if Owner, in response to a Dispatch Notice, substitutes a Market Transaction under Section 5.2 for all or part of the Requested MWh, one-half of the Requested Operation Period will be included in Counted Service Hours for the Unit for which the Dispatch Notice was issued.

(iii) If a Unit operating under Condition 2 sells Energy pursuant to bids made under Section 6.1 (b), each Service Hour expended by the Unit to produce the Energy shall be included in Counted Service Hours.

(iv) If Owner Delivers Requested MWh or Ancillary Services from a Substitute Unit, the Service Hours expended by the Substitute Unit will not be included in Counted Service Hours for the Unit specified in the Dispatch Notice or the Substitute Unit.

(d) Counted MWh, Counted Service Hours and Counted Start-ups for the Contract Year ending December 31, 1999 shall include MWh, Service Hours and Start-ups for the period January 1, 1999 through the Effective Date under the reliability must-run rate schedule which is superseded by this Agreement using the rules set out in this Section 5.3 as if this Agreement had been in effect during that period. Owner's initial report under Section 5.5 shall show the MWh, Service Hours and Start-ups for the period January 1, 1999 through the Effective Date calculated using the rules set out in this Section 5.3.

5.4 Owner's Failure To Deliver Requested MWh or Requested Ancillary Services

(a) Owner shall promptly notify ISO if Owner will not be able to Deliver all or part of the Requested MWh or Requested Ancillary Services from the Unit identified in the Dispatch Notice or from the Substitute Unit previously accepted by ISO.

(b) If a Unit fails to Deliver the full amount of Requested MWh or Requested Ancillary Services, ISO may issue an ISO Availability Notice restating the Availability to a level not less than the Availability indicated by the actual deliveries. If ISO has issued an ISO Availability Notice under this Section 5.4 (b), Owner shall not issue an Owner's Availability Notice increasing the Availability of the Unit until (i) the Unit has successfully completed an Availability Test, (ii) the Unit has delivered in Market Transactions or in a combination of Market Transactions and Nonmarket Transactions pursuant to a Dispatch Notice during a continuous four hour operating period, average MW in excess of those shown in the ISO Availability Notice, or (iii) Owner has otherwise demonstrated to the ISO's reasonable satisfaction that the Availability of the Unit has been restored. ISO's only other remedies for Owner's failure to Deliver

Requested Ancillary Services or Requested MWh are as set out in Sections 8.5, 11.3 and 12.6.

5.5 Reports

Not less than two days prior to the beginning of every Month during the Contract Year, Owner or Owner's Scheduling Coordinator shall provide ISO and the Responsible Utility a report for each Unit setting forth as of the day before the date of the report the Counted MWh, Counted Service Hours and Counted Start-ups for the current Contract Year. All reports shall be treated as confidential pursuant to Section 12.5.

ARTICLE 6

MARKET TRANSACTIONS

6.1 Right To Engage In Market Transactions

(a) In addition to the right to substitute a Market Transaction pursuant to Section 5.2, if a Unit is operating under Condition 1, Owner may enter into Market Transactions for Energy or Ancillary Services at any level outside of a Requested Operation Period. If ISO has issued a Dispatch Notice for Energy to a Unit under Condition 1, Owner may enter into Market Transactions for Energy at any level during the Requested Operation Period, and may enter into a Market Transaction for Ancillary Services at any level that does not preclude compliance with the Dispatch Notice. If ISO has issued a Dispatch Notice for Ancillary Services to a Unit under Condition 1, Owner may enter into Market Transactions for Energy or Ancillary Services at any level that does not preclude compliance with the Dispatch Notice.

(b) If ISO issues a Dispatch Notice for a Unit operating under Condition 2, Owner shall submit bids in succeeding available Energy and Ancillary Services markets for the Requested Operation Period in accordance with the following requirements:

(i) If the next available market is an Energy market, Owner shall bid all Energy the Unit can produce, up to the Unit Availability Limit, in excess of the higher of (A) Energy or Ancillary Services capacity cleared in a prior market; or (B) capacity required to Deliver Requested Ancillary Services. Owner shall bid all Energy at the bid price calculated using the formula in Part I of Schedule M.

(ii) If the next available market is an Ancillary Services market, Owner shall bid all available capacity, up to the Unit Availability Limit, in excess of the higher of the capacity needed to (A) deliver Energy and Ancillary Services cleared in a prior market or (B) Deliver the Requested MWh or Ancillary Services different from the Requested Ancillary Service.

(iii) If the markets are concurrent, Owner shall bid in the Ancillary Services market all available capacity, up to the Unit Availability Limit, in excess of the higher of the capacity needed to (A) deliver Energy and Ancillary Services cleared in a prior market or (B) Deliver the Requested MWh or Ancillary Services different from the Requested Ancillary Service.

(iv) Owner shall bid all Ancillary Service capacity at the bid price calculated using the formula in Part II of Schedule M.

(v) Owner shall not bid Energy or Ancillary Services in excess of the quantities the Unit can provide during the Requested Operation Period given the Unit's ramp rates, Ramping Constraints and any other applicable operating limitations, with due allowance for a Unit's ability to change output during the Requested Operation Period.

(vi) Neither Owner nor Owner's Scheduling Coordinator shall bid Energy or Ancillary Services to the extent that participating in a Market Transaction would conflict with a contract entered into prior to the Effective Date. Owner shall include in Section 14 of Schedule A a description of all contract restrictions affecting Owner's ability to participate in Market Transactions.

ISO may order Owner not to bid to participate in a Market Transaction if ISO determines that participation in Market Transactions would cause a Unit to exceed

Contract Service Limits or impair ISO's ability to dispatch the Unit to meet reliability needs at other times during the Contract Year. A Unit operating under Condition 2 shall not otherwise engage in Market Transactions.

ARTICLE 7

OPERATION AND MAINTENANCE

7.1 Owner's Obligation

Owner shall fuel, operate and maintain each Unit, or cause the Unit to be fueled, operated and maintained, in accordance with applicable law and Good Industry Practice and with due regard for the reliability purpose of this Agreement. Owner is not required to have or maintain fuel oil burning capability, fuel oil inventories, or permits to burn fuel oil and shall not be required to burn fuel oil to respond to a Dispatch Notice unless, and then only to the extent that, the Unit's primary fuel is distillate fuel oil or Schedule H requires Owner to maintain fuel oil capability.

7.2 Outages and Overhauls

(a) Owner shall be entitled to take a Unit out of operation or reduce the Availability of the Unit to repair and maintain the Unit in accordance with Good Industry Practice and the requirements of the ISO Tariff. The dates and times of the outages and any changes to those dates and times shall be determined in accordance with the ISO Tariff. For purposes of complying with the requirements of the ISO Tariff, Other Outage shall be separated between "maintenance outage" and "forced outage," as defined in the ISO Tariff.

(b) Owner shall have the right to curtail or discontinue, in whole or in part, Deliveries of Energy or Ancillary Services from a Unit for so long as, and to the extent that, a Forced Outage affecting the Unit continues or when, in Owner's judgment in accordance with Good Industry Practice, operating conditions at the Unit so require. Curtailment or discontinuance under this Section shall give rise to applicable remedies under Article 8.

7.3 Reports and Notices

(a) As soon as practical after commencement of a Forced Outage, Owner shall give ISO notice of the Forced Outage, the expected duration of the outage, and the expected time when the Unit will be available to generate electricity and the expected Availability during and following the Forced Outage. Owner shall keep ISO informed of any developments that will affect either the duration of the Forced Outage or the Availability of the Unit during or after the end of the Forced Outage.

(b) Owner shall keep ISO advised of the Availability of each Unit by promptly issuing Owner's Availability Notices any time Owner becomes aware that the Unit's Availability changed. Owner may not reduce a Unit's Availability due to the cost of fuel. An Owner's Availability Notice shall become effective when issued, provided, however, that if Owner becomes subject to a Non-Performance Penalty under Section 8.5, any Owner's Availability Notice given during the Penalty Period shall not become effective until 72 hours after the Owner's Availability Notice is given. An Owner's Availability Notice or ISO's Availability Notice shall continue in effect until it is superseded by a subsequent Owner's Availability Notice or ISO's Availability Notice.

7.4 Planned Capital Items

(a) On or before March 1 of each year, Owner shall provide ISO a preliminary report in the form required by this Section 7.4 showing Owner's proposed Capital Items for the next Contract Year and a five-year forecast of anticipated Capital Items in the Form attached as Schedule L-1, assuming the Agreement will be extended. Owner shall submit a final report in the form required by this Section 7.4 reflecting updated information by August 1 of each year. Owner may, but shall not be obligated to, include an Upgrade as a proposed Capital Item in either the preliminary or final report.

(b) The preliminary and final reports for proposed Capital Items for the next Contract Year shall be submitted on the form attached as Schedule L-1. Owner shall provide additional information requested by the ISO necessary to evaluate the proposal. Each preliminary and final report shall separately list individual projects expected to cost more than $500,000 and shall include two "Small Project Estimates." One Small Project Estimate shall identify Capital Items (projected to cost less than $500,000 each) required to maintain or enhance reliability. The second Small Project Estimate shall identify all other Capital Items projected to cost less than $500,000 each. Individual Capital Items projected to cost more than $50,000 shall be identified separately in one of the two Small Project Estimates. If the Facility did not include any Reliability Must-Run Units on September 1, 1998, the initial report shall show amounts spent on each category (reliability and other) of small (less than $500,000) Capital Items during each of the three years prior to designation of a unit at the Facility as a Reliability Must-Run Unit. All Capital Items covered by the Small Project Estimate will be depreciated over 10 years.

(c) Within 60 days after submission of the final report, ISO will notify Owner of the proposed Capital Items ISO has approved and the Capital Items it has not approved. If ISO fails to provide notice within such 60 day period, all Capital Items included in the final report shall be deemed approved as proposed by Owner. Approval constitutes ISO agreement that the ISO's share of the estimated cost of the Capital Item will be recovered through Surcharge Payment under Article 8 and will be eligible for recovery through a Termination Fee pursuant to

Section 2.5. If the actual cost of the Capital Item exceeds the estimated cost, ISO may initiate ADR to determine whether the additional costs were reasonable and shall not be obligated to pay through Surcharge Payments or as a Termination Fee any portion of the overrun found to be unreasonable in such ADR proceeding. If ISO contests the additional costs, Owner shall have the burden of proving that the additional costs were reasonable. If ISO does not initiate ADR or makes a separate agreement with Owner, the additional costs shall be deemed reasonable and ISO shall be obligated to pay ISO's share of the actual costs through Surcharge Payments or as a Termination Fee.

(d) If a proposed Capital Item is not approved, ISO shall provide Owner a detailed statement of the reasons for the disapproval and, if the proposal would be acceptable with modifications, a detailed list of the proposed modifications. Owner may accept the modifications proposed by ISO, or ISO or Owner may initiate an ADR proceeding to review ISO's rejection or proposed modification if the Capital Item is necessary for Owner to meet its obligations under this Agreement. In such proceeding, ISO may not support its disapproval on any basis not shown in its detailed statement of the reasons for disapproval. Any Capital Items approved through such ADR proceeding shall be recovered by Owner through Surcharge Payments under Article 8 and will be eligible for recovery through a Termination Fee pursuant to Section 2.5. Owner shall not be obligated to install any Capital Item unless ISO is obligated to pay a Surcharge Payment for the Capital Item.

(e) The preliminary and final reports and all additional information about proposed Capital Items provided to ISO shall be treated as Confidential Information in accordance with Section 12.5.

(f) If ISO rejects a proposed Capital Item, such rejection is not reversed by ADR and it would be uneconomical, impractical or illegal to continue operation without the Capital Item, then Owner, subject to obtaining authorization from FERC (if required by law to do so), may terminate this Agreement with respect to the affected Unit without cost or liability therefor, except as provided in Section 2.4.

7.5 Unplanned Repairs

(a) In the event of any loss or damage to the Facility that impairs the capability of one or more Units to Deliver Energy or Ancillary Services, Owner shall, without additional charge, make necessary Repairs, to the extent that:

(i) the total cost (net of proceeds received by Owner from Insurers and other third parties pursuant to applicable insurance, warranties and other contracts in connection with all Repairs and excluding costs covered by clause (ii)) of all Repairs for all Units ("Net Repair Costs") during the Contract Year does not exceed Owner's Repair Cost Obligation for the Facility; or

(ii) the loss or damage impairing the Unit's capability to produce Energy or Ancillary Services was caused by Owner's failure to comply with Good Industry Practice or by any wrongful act or omission by Owner.

If the Units are not hydroelectric Units, then for all Contract Years through and including the Contract Year ending December 31, 2001, the reference to "Units" in clause (i) above includes all Reliability Must-Run Units (except hydroelectric Units), whether or not located at the Facility, (A) covered by a reliability must-run agreement with Owner or its affiliates as defined in 18 C.F.R. Section 161.2 and (B) the costs of which are allocated in whole or in part to the Responsible Utility under Section 5.2.8 of the ISO Tariff. If the Units are hydroelectric Units, then for all Contract Years through and including the Contract Year ending December 31, 2001, the reference to "Units" in clause (i) above includes all hydroelectric Reliability Must-Run Units, whether or not located at the Facility, covered by a reliability must-run agreement with Owner or its affiliates as defined in 18 C.F.R. Section 161.2 and located within the service area of the entity which is the Responsible Utility for costs arising under this Agreement. For all subsequent Contract Years, the reference to "Units" in clause (i) includes all Reliability Must-Run Units located at the Facility, but no other Reliability Must-Run Units. Except as provided above, Owner shall not be obligated to make any Repairs unless ISO is obligated to pay ISO's Repair Share for the Repairs.

(b) If the Net Repair Costs incurred by Owner for all Repairs since the beginning of the Contract Year exceed Owner's Repair Cost Obligation, then Owner shall provide a notice thereof ("Unplanned Repair Notice") in the form attached as Schedule L-1 to ISO. Owner shall provide such additional information as ISO may reasonably require to evaluate such proposed Repairs.

(c) ISO shall submit a written acceptance or objection to Owner's proposal within 21 days of receipt of an Unplanned Repair Notice. ISO shall be deemed to have accepted Owner's proposal in the Unplanned Repair Notice if ISO does not submit a written objection within 21 days after receipt of the Unplanned Repair Notice, as provided above. Any objection shall be based on one or more of the following grounds:

(i) the loss or damage was caused by Owner's failure to comply with Good Industry Practice;

(ii) the loss or damage was caused by a wrongful act or omission by Owner;

(iii) the Repairs are not required or are more extensive than required in order to make good the loss or damage concerned or to comply with applicable law;

(iv) the Net Repair Costs for the Contract Year will not exceed or has not exceeded the Owner's Repair Cost Obligation;

(v) the estimated cost of Repairs exceeds that which is reasonably necessary to effect such Repairs;

(vi) the Repair will not result in benefits to ISO as compared to alternatives available to ISO;

(vii) Owner's proposals for carrying out the Repairs or the proposed ISO's Repair Share are unreasonable;

(viii) Owner's proposal includes estimated costs which are not properly treated as an expense under FERC's Uniform System of Accounts; or

(ix) Owner has not provided sufficient information to evaluate Owner's proposal. In addition to providing the basis of the objection, any objection of ISO shall include a list of all changes ISO contends should be made to Owner's proposal and justification of all such changes.

(d) If ISO submits an objection to an Unplanned Repair Notice, the Parties shall attempt to reach agreement on changes to Owner's proposal. If the Parties have not reached agreement within 30 days after ISO's receipt of the Unplanned Repair Notice, Owner or ISO may refer the matter to ADR under a schedule (specified by the arbitrator if the participants cannot agree) requiring a decision within 30 days following appointment of the arbitrator. The ADR decision will be effective without delay.

(e) Owner shall proceed with the Repairs if it is agreed or determined pursuant to ADR that ISO will pay ISO's Repair Share or that Owner is otherwise obligated to make the Repairs. Owner shall keep full and detailed records of the cost of the Repairs and shall make them available to ISO for inspection upon reasonable request.

(f) If the actual cost of the Repairs exceeds the estimated cost, ISO may initiate ADR to determine whether the additional costs were reasonable and shall not be obligated to pay any portion of the additional cost found to be unreasonable in such ADR proceeding. Owner shall have the burden of proving that the additional costs were reasonable.

(g) If it is agreed or determined pursuant to ADR that ISO will pay for a Repair, ISO shall pay ISO's Repair Share of the actual cost as a lump sum within 60 days after the later of (i) the completion of the Repair and (ii) the effective date of authorization by FERC, if any is necessary, for Owner to charge such cost to ISO. "ISO's Repair Share" means the Repair Payment Factor for the Repair at issue multiplied by the amount by which (i) the agreed or determined cost of Repairs at issue plus the Net Repair Costs of all prior Repairs for the Contract Year minus the cost of all prior Repairs for which ISO is obligated to pay ISO's Repair Share during the Contract Year exceeds (ii) Owner's Repair Cost Obligation. The Repair Payment Factor shall be as agreed to by Owner and ISO. If Owner and ISO do not agree on the Repair Payment Factor, the Repair Payment Factor shall equal the Fixed Option Payment Factor, unless the Owner demonstrates in ADR that it would not have made the proposed Repair in accordance with Good Industry Practice but for its obligations under this Agreement, in which case the Repair Payment Factor shall be as determined in ADR.

(h) Owner shall use commercially reasonable efforts to recover its full entitlements under applicable insurance policies, warranties and other contracts even after ISO has paid ISO's Repair Share. Owner shall keep ISO informed of the status of such recovery efforts and will refund to ISO any portions of ISO's Repair Share payment that is later recovered from any other party as a credit to ISO on the next invoice with interest at the Interest Rate from the date such proceeds are received by Owner to the Due Date of such next invoice, or if this Agreement is terminated, as a payment upon submission of the Final Invoice.

(i) If Owner is not obligated to make a Repair and does not do so, and if it would be uneconomical, impractical or illegal to continue operation without the Repair, then Owner, subject to obtaining authorization from FERC (if required by law to do so), may terminate this Agreement with respect to the affected Unit without cost or liability therefor, except as provided in Section 2.4.

(j) If Owner makes a Repair notwithstanding that ISO is not obligated to pay for the Repair, Owner shall not be entitled to recover the costs of the Repair from ISO unless FERC approves recovery of the costs.

(k) Owner's Repair Cost Obligation shall be an amount computed as follows:

(i) For all Contract Years through and including the Contract Year ending December 31, 2001, Owner's Repair Cost Obligation shall be equal to 7% of the sum of the fixed operation and maintenance costs underlying the as-filed rates applicable to all of the Reliability Must-Run Units of Owner and its affiliates, as defined in 18 C.F.R. § 161.2, that are allocated in whole or in part to the Responsible Utility under Section 5.2.8 of the ISO Tariff. The only repair costs that may be considered in determining whether, and to what extent, an Owner has exceeded its Owner Repair

Cost Obligation during the period ending December 31, 2001 are costs that (1) are the result of a Force Majeure Event, (2) are not the result of ordinary wear and tear, and (3) cannot be capitalized under the FERC's Uniform System of Accounts. If the Units covered by this Agreement are hydroelectric Units, Owner's Repair Cost Obligation will include only costs of other hydroelectric Units. If the Units covered by this Agreement are not hydroelectric Units, Owner's Repair Cost Obligation will include only costs of other non-hydroelectric Units. The reference to "as-filed rates" refers to rates filed by Owner, or its predecessor and in effect on July 1, 1998 or, if Owner or its predecessors did not have rates in effect on such date, rates filed by Owner and in effect on the Effective Date.

(ii) For all subsequent Contract Years, Owner's Repair Cost Obligation shall be equal to 3% of the fixed operation and maintenance costs for all Units at the Facility, underlying the rates in effect at the beginning of the Contract Year.

7.6 Unplanned Capital Items

(a) To the extent a Capital Item is required to remedy or prevent impairment of the Unit's capability to Deliver Energy or Ancillary Services and the impairment was caused by Owner's failure to comply with Good Industry Practice or by any wrongful act or omission by Owner, Owner shall install such Capital Item at Owner's expense. Otherwise, Owner shall not be obligated to install any Capital Item unless ISO is obligated to pay a Surcharge Payment for the Capital Item. The issue of whether Owner is obligated to install a Capital Item is subject to ADR.

(b) If, during the Contract Year, Owner determines it is necessary to install Capital Items not approved under Section 7.4 and Owner has expended all amounts covered by the approved Small Project Estimates under Section 7.4, Owner shall provide a notice thereof ("Unplanned Capital Item Notice") on the form attached as Schedule L-1 to ISO. Owner shall provide such information as ISO may reasonably require in order to evaluate the proposed Capital Items.

(c) ISO shall submit a written acceptance or objection to Owner's proposal within 21 days after receipt of a complete Unplanned Capital Item Notice provided that if the proposal does not involve either loss or damage to the Facility or a Capital Item required by law or regulation, ISO shall respond within 60 days. If ISO fails to provide notice within such period, Owner's proposal in the Unplanned Capital Item Notice shall be deemed approved. Any objection shall be based on one or more of the following grounds:

(i) the impairment being remedied or prevented was caused by Owner's failure to comply with Good Industry Practice;

(ii) the impairment being remedied or prevented was caused by a wrongful act or omission by Owner;

(iii) the Capital Item is not required or is more extensive than required in order to remedy or prevent impairment to the Facility or to comply with applicable law;

(iv) the estimated cost of the Capital Item exceeds that which is reasonably necessary;

(v) installation of the Capital Item will not result in benefits to ISO as compared to alternatives available to ISO;

(vi) Owner's proposals for installing or testing the Capital Item are unreasonable;

(vii) Owner's proposals for depreciation of the cost of the Capital Item or calculation of the Annual Capital Item Cost and Surcharge Payment Factor are unreasonable; or

(viii) Owner has not provided sufficient information to evaluate Owner's proposal. In addition to providing the basis of the objection, any objection of ISO shall include a list of all changes ISO contends should be made to Owner's proposal and justification of all such changes.

(d) If ISO submits an objection to an Unplanned Capital Item Notice, the Parties shall attempt to reach agreement on changes to Owner's proposal. If Owner's proposal involves either loss or damage to the Facility or the Capital Item is required by law and the Parties have not reached agreement 30 days after ISO's receipt of the Unplanned Capital Item Notice, either Owner or ISO may refer the matter to ADR under a schedule (specified by the arbitrator if the participants cannot agree) requiring a decision within 30 days following appointment of the arbitrator. The ADR decision will be effective without delay. Failure to agree on other proposed Capital Items may also be referred to ADR but without an expedited schedule.

(e) Owner shall proceed to install the Capital Item if it is agreed or determined pursuant to ADR that ISO will pay a Surcharge Payment for the Capital Item or that Owner is otherwise required to install the Capital Item. Owner shall keep full and detailed records of the cost of the Capital Item and shall make them available to ISO for inspection upon reasonable request.

(f) If the actual cost of the Capital Item exceeds the estimated cost, ISO may initiate ADR to determine whether the additional costs were reasonable and shall not be obligated to pay any portion of the additional cost found to be unreasonable in such ADR proceeding. Owner shall have the burden of proving that the additional costs were reasonable.

(g) If it is agreed or determined pursuant to ADR that ISO will pay for the Capital Item, ISO shall be deemed to have agreed that the cost of the Capital Item will be recovered through a Surcharge Payment under Article 8 and will be eligible for recovery through a Termination Fee pursuant to Section 2.5. The costs included in Surcharge Payments and Termination Fees to be paid by ISO shall be net of all proceeds received by Owner from insurers and other third parties pursuant to applicable insurance, warranties and other contracts after deducting all costs Owner incurred to collect the proceeds. Owner shall use commercially reasonable efforts to recover its full entitlements under applicable insurance policies, warranties and other contracts. Owner shall keep ISO informed of the status of such recovery efforts and will adjust future Surcharge Payments to reflect proceeds later recovered from any other party.

(h) If the capability or performance of a Unit is impaired, if Owner is not obligated to install a Capital Item to remedy such impairment under Section 7.6(a) and does not do so, and if it would be uneconomical, impractical or illegal to continue operation without the Capital Item, then Owner, subject to obtaining authorization from FERC (if required by law to do so), may terminate this Agreement with respect to the affected Unit without cost or liability therefor except as provided in Section 2.4.

(i) If Owner installs a Capital Item notwithstanding that ISO is not obligated to pay for the Capital Item, Owner shall not be entitled to recover the costs of the Capital Item from ISO unless FERC approves recovery of the costs.

(j) Notwithstanding any other provision of this Agreement, if a Capital Item is required to remedy impairment of the Facility, the Unit's Monthly Option Payment shall not be decreased for any of the period of time during which Owner is waiting for ISO's response to an Unplanned Capital Item Notice or during which ADR concerning an Unplanned Capital Item Notice is pending unless it is determined that Owner is required to install the Capital Item pursuant to Section 7.6 (a).

7.7 Adjustments to Performance Characteristics

(a) If Owner installs any Capital Item or makes any Repairs the costs of which are paid by ISO under this Agreement, Owner shall modify the Maximum Net Dependable Capacity, Unit Availability Limit, and performance characteristics of the affected Unit to reflect the resulting changes in operating costs effective as of the date ISO's payment of ISO's Repair Share of the Repairs is made, or in the case of a Capital Item, the date the cost of the Capital Item is included in a Surcharge Payment or the rates paid by ISO.

(b) If FERC authorization is required to permit Owner to recover the ISO's Repair Share from ISO or to include the costs of a Capital Item in a Surcharge Payment or the rates paid by ISO hereunder, Owner shall make a Section 205 filing limited to recovery of the costs and implementation of related changes to performance characteristics, shall request that the filing become effective as of the date the Capital Item or Repair was placed in service and request expedited consideration of the filing. If ISO has approved the Capital Item or Repair, ISO shall intervene in support of such filing including support of requests to place the change in effect without suspension or hearing.

(c) If Owner makes Repairs or installs a Capital Item when not required to do so and ISO has not agreed or is not required by ADR to pay for such Repair or Capital Item, Owner may either:

(i) make an appropriate adjustment to the Maximum Net Dependable Capacity, Unit Availability Limit and performance characteristics of the affected Unit to reflect the capability the Unit would have had if the Capital Item had not been installed or the Repairs had not been made; or

(ii) make appropriate adjustment to the Maximum Net Dependable Capacity, Unit Availability Limit and performance characteristics of the affected Unit to reflect the Repairs or installation of the Capital Item.

(d) Any adjustment to the Heat Input characteristics of the Unit shall be made in accordance with Section 4.9(d).

7.8 Upgrades of Generating Units

Owner may Upgrade any Unit at the Facility, provided that no Upgrade shall release Owner from Owner's performance obligations under this Agreement. ISO shall secure no rights under this Agreement to any capacity or services increased or enhanced by any Upgrade unless the Parties agree as to the terms of ISO's rights and the amount of ISO's payment for such Upgrade. If the Parties so agree, the Maximum Net Dependable Capacity, Unit Availability Limit and performance characteristics of the affected Unit shall be adjusted to reflect ISO's agreed upon rights to the Upgrade provided that any adjustment in heat input shall be made in accordance with Section 4.9(d). If FERC authorization is required to permit Owner to recover the portion of the Upgrade cost ISO has agreed to pay for the agreed revisions to the Unit characteristics, Owner shall make a Section 205 filing limited to recovery of the costs and implementation of related changes to the Maximum Net Dependable Capacity, Unit Availability Limit and performance characteristics, shall request that the filing become effective as of the date ISO begins paying its agreed portion of the cost of the Upgrade and request expedited consideration of the filing. ISO shall intervene in support of such filing including support of requests to place the change in effect without suspension or hearing.

7.9 Third-Party Participation in ISO Review Process

(a) Subject to fulfillment of the requirements of Section 7.9 (b), ISO shall consult with the Responsible Utility and the California Agencies prior to approving Capital Items or Repairs. ISO may approve Capital Items or Repairs aggregating less than $5,000,000 for the Facility in a Contract Year without approval of the Responsible Utility or the California Agencies. After Capital Items and Repairs aggregating $5,000,000 for the Facility in a Contract Year have been approved by ISO, ISO's approval of all other Capital Items and Repairs for that Contract Year shall not be effective unless the Responsible Utility has consented to such Capital Item or Repair.

(b) The requirements of Section 7.9 (a) relating to Responsible Utilities shall apply only if and to the extent that the Responsible Utility agrees to waive its right to challenge before the FERC Owner's recovery of approved costs of Repairs or Capital Items. The requirement of Section 7.9 (a) relating to the California Agency shall apply only if and to the extent that each California Agency agrees to waive its right to challenge Owner's recovery of costs associated with the proposed Repairs or Capital Item on any grounds not set out in written objections provided by the California Agencies to ISO and Owner within 30 days of the California Agencies' receipt of the preliminary and final reports under Section 7.5 or Section 7.6.

(c) Provided that the California Agencies and Responsible Utility are bound by the provisions of the Confidentiality and Non-disclosure Agreement attached as Schedule N and make the waivers required in Section 7.9 (b), Owner will provide copies of the required reports and notices under Section 7.4, Section 7.5 or Section 7.6, and any additional information provided to the ISO pursuant to Sections 7.4, 7.5 and 7.6, as the case may be, to the California Agencies and Responsible Utility at the same time as the reports, notices and information are provided to ISO, and ISO will provide copies of all information provided to Owner pursuant to such Sections to the California Agencies and Responsible Utility.

ARTICLE 8

RATES AND CHARGES

8.1 Condition 1

When a Unit is under Condition 1, ISO shall pay Owner each Month for each Unit the sum of:

(a) the Monthly Option Payment which shall be equal to the Monthly Availability Payment *plus* the Monthly Surcharge Payment, *minus* the sum of all Non-Performance Penalties for the Month. In no event shall (i) the Monthly Option Payment for any month be less than zero, (ii) the sum of the Monthly Availability Payments for a Contract Year exceed the Annual Fixed Revenue Requirement for the Contract Year, or (iii) the sum of the Monthly Surcharge Payments for the Contract Year exceed the Annual Capital Item Cost (as defined in Schedule B) for the Contract Year. The Monthly Availability Payment and the Monthly Surcharge Payment shall each be computed in accordance with Schedule B. The Non-Performance Penalties for the Month shall be calculated in accordance with Section 8.5;

(b) the Variable Cost Payment computed in accordance with Schedule C;

(c) one-twelfth of the Prepaid Start-up Charge as set out on Schedule D;

(d) the sum of the Start-up Adjustments calculated in accordance with Schedule D for each Start-up during the Month which was a Prepaid Start-up;

(e) the sum for all Settlement Periods in the Month of the Pre-empted Dispatch Payments and Motoring Charges calculated in accordance with Schedule E;

(f) once the Counted MWh for the Contract Year equals the Maximum Annual MWh, the Counted Service Hours for the Contract Year equals the Maximum Annual Service Hours, or the Counted MWh for hydroelectric units for the Month equals the Maximum Monthly MWh, a payment for each subsequent Billable MWh at the rate set out on Schedule G;

(g) once the Counted Start-ups for the Contract Year equals the Maximum Annual Start-ups, a payment for each additional Start-up calculated in accordance with Schedule G; and

(h) charges for services Delivered from Substitute Units pursuant to Sections 5.1(c) and (d).

8.2 Condition 2

When a Unit is operating under Condition 2, ISO shall pay Owner the sum of:

(a) the Monthly Option Payment, which shall be equal to the Monthly Availability Payment *plus* the Monthly Surcharge Payment, *minus* the sum of all Non-Performance Penalties for the Month. In no event shall (i) the Monthly Option Payment for any month be less than zero, (ii) the sum of the Monthly Availability Payments for a Contract Year exceed the Annual Fixed Revenue Requirement for the Contract Year or (iii) the sum of the Monthly Surcharge Payments for the Contract Year exceed the Annual Capital Item Cost (as defined in Schedule B) for the Contract Year. The Monthly Availability Payment and the Monthly Surcharge Payment shall each be computed in accordance with Schedule B. The Non-Performance Penalties for the Month shall be calculated in accordance with Section 8.5.

(b) the Variable Cost Payment computed in accordance with Schedule C;

(c) the sum of all Start-up Payments for the Month until Counted Start-ups equal Maximum Annual Start-ups computed in accordance with Schedule D;

(d) the sum for all Settlement Periods in the Month of Motoring Charges calculated in accordance with Schedule E;

(e) once the Counted MWh for the Contract Year equals the Maximum Annual MWh or the Counted Service Hours for the Contract Year equals the Maximum Annual Service Hours, a payment for each subsequent Billable MWh at the rate set out on Schedule G;

(f) once the Counted Start-ups for the Contract Year equals the Maximum Annual Start-ups, a payment for each additional Start-up calculated in accordance with Schedule G; and

(g) charges for services Delivered from Substitute Units pursuant to Section 5.1(c) and (d).

8.3 Determination of Billable MWh and Hybrid MWh

(a) "Billable MWh" shall be determined by application of the following rules:

(i) If a Unit under Condition 1 or Condition 2 Delivers MWh only in Nonmarket Transactions during a Settlement Period, the Billable MWh shall be the lesser of (A) the Hourly Metered Total Net Generation or (B) the Requested MWh plus the Ramping Energy.

(ii) If a Unit under Condition 1 delivers MWh in both Market and Nonmarket Transactions during a Settlement Period:

(A) If the Hourly Metered Total Net Generation during the Settlement Period is equal to or greater than the sum of Requested MWh plus Ramping Energy applicable to the Settlement Period, the Billable MWh shall be (1) the Requested MWh plus (2) the Ramping Energy minus (3) the Hybrid MWh, but shall never be less than zero.

(B) If the Hourly Metered Total Net Generation during the Settlement Period is less than the sum of Requested MWh plus

Ramping Energy applicable to the Settlement Period, the Billable MWh shall be (1) Hourly Metered Total Net Generation minus (2) the Hybrid MWh, but shall never be less than zero.

(iii) If a Unit is under Condition 2, the Billable MWh shall be the lesser of (A) the Hourly Metered Total Net Generation or (B) the sum of (1) Requested MWh, (2) Ramping Energy and (3) the amount, if any, by which the total MWh for which Owner's bids pursuant to Section 6.1 (b) cleared the market exceeds the sum of the Requested MWh and Ramping Energy.

(b) "Hybrid MWh" shall be the sum of the MWh scheduled in Market Transactions which were substituted for Requested MWh under Section 5.2 and the MWh scheduled in Market Transactions for which ISO issued a Dispatch Notice pursuant to Section 4.5 provided that Hybrid MWh shall never exceed the Hourly Metered Total Net Generation.

(c) Ramping Energy shall be calculated as follows:

(i) If a Unit is not providing Regulation under Schedule E during a given hour, "Ramping Energy" for that hour shall be the lesser of the (i) Actual Ramping Energy or (ii) the RMR Ramping Energy minus Market Ramping Energy.

(A) "Actual Ramping Energy" means the MWh calculated using the following formula:

$$ActualRampingEnergy = \frac{(Output\ 2 - Output\ 1)^2}{(2xRRx60)}$$

Where:
Output1 is the Hourly Metered Total Net Generation for the hour for which Ramping Energy is being calculated ("Calculation Hour");

Output2 is (i) the Hourly Metered Total Net Generation in the prior hour if the Hourly Metered Total Net Generation in the prior hour was greater than the Hourly Metered Total Net Generation in the Calculation Hour and (ii) the Hourly Metered Total Net Generation in the succeeding hour if the Hourly Metered Total Net Generation in the succeeding hour was greater than the Hourly Metered Total Net Generation in the Calculation Hour. If both clauses (i) and (ii) apply during a Calculation Hour, the Actual Ramping Energy for that hour shall be the sum of the Actual Ramping Energy calculated using clause (i) and the Actual Ramping Energy calculated using clause (ii);

RR is the Unit's Ramp Rate as stated in Section 8 of Schedule A applicable to the operating range at which the Unit was operating at the end of the Calculation Hour.

(B) "RMR Ramping Energy" means the MWh calculated using the following formula:

$$RMRRampinEnergy = \frac{(RMRMW2 - RMRMW1)^2}{(2xRRx60)}$$

Where:
RMRMW1 is the Requested MW for the Calculation Hour;

RMRMW2 is (i) the Requested MWh in the prior hour if the Requested MWh in the prior hour was greater than the Requested MWh in the Calculation Hour or (ii) the Requested MWh in the succeeding hour if the Requested MWh in the succeeding hour was greater than the Requested MWh in the Calculation Hour. If both clauses (i) and (ii) apply during a Calculation Hour, the RMR Ramping Energy for that hour shall be the sum of the RMR

Ramping Energy calculated using clause (i) and the RMR Ramping Energy calculated using clause (ii).

RR is the Unit's Ramp Rate as stated in Section 8 of Schedule A applicable to the operating range at which the Unit was operating at the end of the Calculation Hour.

(C) "Market Ramping Energy" means the MWh calculated using the following formula:

$$MarketRampingEnergy = \frac{(MKTMW2 - MKTMW1)^2}{(2xRRx60)}$$

Where:

MKTMW1 is the total MWh scheduled for delivery during the Calculation Hour in day-ahead or hour ahead Market Transactions ("Market Schedule");

MKTMW2 is (i) the Market Schedule during the prior hour if the Market Schedule in the prior hour was greater than the Market Schedule in the Calculation Hour or (ii) the Market Schedule in the succeeding hour if the Market Schedule in the succeeding hour was greater than the Market Schedule in the Calculation Hour. If both clauses (i) and (ii) apply during a Calculation Hour, the Market Ramping Energy for that hour shall be the sum of the Market Ramping Energy calculated using clause (i) and the Market Ramping Energy calculated using clause (ii).

RR is the Unit's Ramp Rate as stated in Section 8 of Schedule A applicable to the operating range at which the Unit was operating at the end of the Calculation Hour.

(ii) For Units which are providing Regulation under Schedule E, "Ramping Energy" for the last hour in which the Unit provides Regulation shall be calculated using the following formula but shall never be less than zero:

$$RampingEnergy = \frac{(Output - MKTMW)^2}{(2xRRx60)}$$

Where:

Output is the Hourly Metered Total Net Generation for the Calculation Hour;

MKTMW is the Market Schedule during the Calculation Hour;

RR is the Unit's Ramp Rate as stated in Section8 of Schedule A applicable to the operating range at which the Unit was operating at the end of the Calculation Hour.

(iii) Ramping Energy and RMR Ramping Energy shall be zero in any hour that Requested MWh are equal to or less than the Market Schedule for that hour. Ramping Energy and RMR Ramping Energy shall also be zero if (i) the Unit's Hourly Metered Total Net Generation is less than the Hourly Metered Total Net Generation for the succeeding hour and the Requested MWh in the succeeding hour are equal to or less than the Market Schedule for such succeeding hour or (ii) the Unit's Hourly Metered Total Net Generation is greater than the Hourly Metered Total Net Generation for the succeeding hour and the Requested MWh in the prior hour are equal to or less than Market Schedule for such prior hour.

(iv) Ramping Energy shall never be less than zero.

8.4 Determination of Prepaid Start-ups

Prepaid Start-ups for Condition 1 shall be the Maximum Annual Start-ups. There shall be no Prepaid Start-ups for Condition 2.

8.5 Non-Performance Penalty

(a) If a Unit fails to comply fully with a Dispatch Notice and such failure is not due to a Force Majeure Event under this Agreement, the Unit shall be subject to a Non-Performance Penalty computed in accordance with this Section 8.5.

(b) The Non-Performance Penalty shall be calculated for each hour of the Penalty Period in which Owner is not deemed to be in full compliance with a Dispatch Notice and is not excused from performance. The Non-Performance Penalty shall be the sum of the amounts calculated for each Settlement Period in the Month by multiplying (i) the Availability Deficiency Factor for the Settlement Period by (ii) the sum of the Hourly Penalty Rate and the Hourly Surcharge Penalty Rate for the Unit as set forth on Schedule B; provided that the Non-Performance Penalty for any Month shall not exceed the sum of the Condition 1 Availability Payment and Condition 1 Surcharge Payment (for Units on Condition 1), or the sum of the Condition 2 Availability Payment and Condition 2 Surcharge Payment (for Units on Condition 2) for the Month. For purposes of this calculation:

(i) an Availability Deficiency Factor shall be calculated for each hour of the Penalty Period as one minus the number determined by dividing (a) the Delivered MWh for the hour in question by (b) the product of the Unit Availability Limit and the percentage of the hour (up to 100%) that the Unit was subject to a Dispatch Notice;

(ii) the Penalty Period shall be the 72 hour period beginning at the time Owner fails to comply fully with a Dispatch Notice, provided that if Owner in accordance with Section 7.2(a) had scheduled an outage to begin during the 72 hour period, the Penalty Period will terminate at the time the outage was scheduled to begin.

(iii) the Unit Availability Limit shall be the Unit Availability Limit as it existed at the time ISO issued the Dispatch Notice with which Owner failed to comply but reduced to eliminate the effect of any Force Majeure Event affecting deliveries during the Penalty Period.

(c) For purposes of this Section 8.5 and Section 4.9(a)(i), a Unit shall be deemed to be in full compliance with a Dispatch Notice if the Unit Delivers (i) at least 97 percent of the Requested MW or (ii) not more than 2 MW less than the Requested MW.

8.6 Long-term Planned Outage Adjustment

Not later than 60 days after the end of each Contract Year, Owner shall submit to ISO a statement showing the Long-term Planned Outage Adjustment for the Contract Year. The Long-term Planned Outage Adjustment shall equal (a) the Hourly Availability Charge *plus* each Hourly Capital Item Charge, as shown in Schedule B, *multiplied by* (b) the difference, if positive, of (i) the hours scheduled for performance of Long-term Planned Outages *minus* (ii) the actual hours spent performing Long-term Planned Outages during the Contract Year. Owner shall credit any Long-term Planned Outage Adjustment on the next invoice or, if this Agreement has terminated, shall pay any Long-term Planned Outage Adjustment to the ISO upon submission of the Final Invoice. The Long-term Planned Outage Adjustment for the Contract Year ending December 31, 1999, shall be computed by including, in addition to scheduled and actual hours for Long-term Planned

Outages after the Effective Date, the hours scheduled for performance of Long-term Planned Outages during the period from January 1, 1999 through the Effective Date and the actual hours spent performing such Long-term Planned Outages during such period as if the Agreement had become effective on January 1, 1999.

ARTICLE 9

STATEMENTS AND PAYMENTS

9.1 Invoicing

(a) The billing, invoicing and payment of charges under this Agreement shall be as specified in this Article 9, Schedule O to this Agreement and Annex 1 to ISO's Settlement and Billing Protocol. ISO shall not modify any provision of Section 5.2.7 of the ISO Tariff or Annex 1 to the Settlement and Billing Protocol as they apply to this Agreement without Owner's consent, provided that Owner's consent shall not be required for a change of allocations of RMR costs among market participants under the ISO Tariff.

(b) Owner will submit to ISO RMR Invoices for each Month during the term of this Agreement, which are defined in this Section 9.1(b) as follows: (i) Estimated RMR Invoice; (ii) Revised Estimated RMR Invoice; (iii) Adjusted RMR Invoice; and (iv) Revised Adjusted RMR Invoice. In the event there are no revisions to the Estimated RMR Invoice or the Adjusted RMR Invoice, Owner shall submit an e-mail to ISO with a copy to the Responsible Utility indicating that the Estimated RMR Invoice or the Adjusted RMR Invoice shall be deemed to be the Revised Estimated RMR Invoice or the Revised Adjusted RMR Invoice.

(i) Within 14 days after the end of each Month during the term of this Agreement (and, if this Agreement does not expire or terminate at the end of a Month, within 14 days after the end of the Month in which the Agreement expires or terminates), Owner shall submit an estimated invoice ("Estimated RMR Invoice") to ISO for all charges and credits due under this Agreement for the Month ("Billing Month"). Each Estimated

RMR Invoice shall reflect actual data for the Billing Month to the extent actual data is available and shall otherwise reflect estimated data.

(ii) By the date specified on the RMR Payments Calendar, Owner shall submit a revised estimated invoice ("Revised Estimated RMR Invoice") to ISO, which will include appropriate revisions based on the ISO's validation of the Estimated RMR Invoice. The Due Date of the Revised Estimated RMR Invoice shall be the 30th day after the date on which Owner submitted the Estimated RMR Invoice to ISO, or if such date is not a Business Day, the Due Date shall be the next Business Day.

(iii) By the date specified on the RMR Payments Calendar, ISO shall submit an invoice ("ISO Invoice") to the Responsible Utility, with an e-mail notification to Owner and the Responsible Utility, which specifies the payment due from the Responsible Utility to ISO and from ISO to Owner on the basis of the Revised Estimated RMR Invoice. However, in the event the payment is due from Owner to ISO and from ISO to the Responsible Utility, then ISO shall submit the ISO Invoice to Owner with an e-mail notification to Owner and the Responsible Utility.

(iv) Within 7 days of receipt by Owner of the Final Settlement Statement for the last day of the Billing Month, Owner shall submit an adjusted invoice ("Adjusted RMR Invoice") to ISO, reflecting actual data for the Billing Month.

(v) By the date specified on the RMR Payments Calendar, Owner shall submit to ISO an invoice reflecting actual data for the Billing Month and including appropriate revisions based on the ISO's validation of the Adjusted RMR Invoice ("Revised Adjusted RMR Invoice"). The Due

Date of the Revised Adjusted RMR Invoice shall be the 30th day after the date on which Owner submitted the Adjusted RMR Invoice to ISO, or if such date is not a Business Day, the Due Date shall be the next Business Day.

(vi) By the date specified on the RMR Payments Calendar, ISO shall submit an ISO Invoice to the Responsible Utility, with an e-mail notification to Owner and the Responsible Utility, which specifies the payment due from the Responsible Utility to ISO and from ISO to Owner on the basis of the Revised Adjusted RMR Invoice. However, in the event the payment is due from Owner to ISO and from ISO to the Responsible Utility, then ISO shall submit the ISO Invoice to Owner with an e-mail notification to Owner and the Responsible Utility.

(c) If the day on which any RMR Invoice is due to be issued is not a Business Day, such RMR Invoice shall be issued on the next succeeding Business Day.

(d) Each RMR Invoice shall use the template posted on the ISO Home Page in accordance with Schedule O ("RMR Invoice Template"). Each RMR Invoice shall set out detailed calculations and breakdowns of the amounts due, shall identify the source of each input used in the calculations, and shall identify all relationships among data in different invoice levels.

(e) This section 9.1(e) applies to all Condition 1 Units. Any amounts received by or due to Owner's Scheduling Coordinator for Billable MWh and Ancillary Services Delivered in Nonmarket Transactions during the Billing Month shall be subtracted from the amount otherwise due under each RMR Invoice. If subtraction of the Energy and any Ancillary Service amounts for a Unit under Condition 1 results in a credit to ISO on an RMR Invoice, the credit shall be carried forward ("Credit

Carryforward") to the RMR Invoices for each succeeding Billing Month in that Contract Year until extinguished; *provided* that Owner shall not be required to carry any such credit into a later Contract Year or to pay any part of such credit to ISO.

(f) This section 9.1(f) applies to all Condition 2 Units. All amounts received by or due to Owner's Scheduling Coordinator in connection with Market Transactions and Nonmarket Transactions during the Billing Month ("Scheduling Coordinator Revenues") shall be subtracted from the amount otherwise due under each RMR Invoice. If subtracting the Scheduling Coordinator Revenues results in a credit to ISO on an RMR Invoice, the credit shall be carried forward ("Credit Carryforward") to the appropriate RMR Invoices for each succeeding Billing Month in that Contract Year until extinguished. If there is an unextinguished credit balance remaining at the end of the Contract Year, Owner shall refund to ISO an amount equal to the lesser of (i) the remaining balance of Scheduling Coordinator Revenues or (ii) the total amounts due Owner pursuant to Section 8.2 for the Contract Year minus all Scheduling Coordinator Revenues previously credited to Owner during such Contract Year. Such refund amount will be included on December's Adjusted RMR Invoice, or the Final Invoice if the Agreement is terminated.

(g) In the event any corrections, surcharges, credits, refunds or other adjustments pertaining to a Billing Month are discovered after the Revised Adjusted RMR Invoice for such Billing Month has been issued ("Prior Period Changes"), then such Prior Period Changes shall be included in a worksheet for the prior period ("Prior Period Change Worksheet") and submitted for payment in the next allowed Billing Month for Prior Period Changes. The allowed Billing Months for

Prior Period Changes are as follows. Any Prior Period Changes pertaining to the months of January through June of a Contract Year which are discovered prior to the submission of the December Estimated RMR Invoice for such Contract Year shall be included in a Prior Period Change Worksheet submitted with the December Estimated RMR Invoice. Any Prior Period Changes pertaining to the months of July through December of a Contract year which are discovered prior to the submission of the May Estimated RMR Invoice for the subsequent Contract year shall be included, subject to Section 9.8, in a Prior Period Change Worksheet submitted with the May Estimated RMR Invoice for the subsequent Contract Year. Any Prior Period Changes pertaining to a Billing Month for a prior Contract Year which are discovered after the first opportunity to submit a Prior Period Change Worksheet has passed, shall be included in a Prior Period Change Worksheet submitted with the Estimated RMR Invoice for the next December or May Billing Month, whichever comes first. Any Prior Period Changes pertaining to the time when the Facilities were under a superseded rate schedule using Conditions of Must Run Agreement A, B, and C, shall be calculated through a separate process and not included on RMR Invoices issued under this Agreement unless the Prior Period Changes result from the Revenue Requirements Settlements outlined in the Stipulation and Agreement approved on May 28, 1999, in FERC Docket No. ER98-441-000, *et al.*

(h) Owner shall send a copy of each RMR Invoice and any Prior Period Change Worksheet(s) to the Responsible Utility at the time it sends such invoices to ISO.

(i) Owner shall provide supporting detail with the Prior Period Change Worksheets to identify the relevant Contract Year and provide clear calculations by Facility, by Billing Month, and such other detail as necessary to support the Prior Period

Change(s). This level of detail shall be consistent with the level of detail originally required to perform the computation(s) that are being corrected in the Prior Period Change Worksheet. Prior Period Change Worksheets, when required, shall include all identified Prior Period Changes for each applicable prior Contract Year, and shall be computed as specified in section 9.1(j).

(j) A Prior Period Change Worksheet shall contain the following information and calculations for each Billing Month in the relevant Contract Year(s), commencing with the Billing Month pertaining to the Prior Period Change(s):

(i) The Revised Adjusted RMR Invoice for the Billing Month or, if such Billing Month has previously been submitted on a Prior Period Change Worksheet, the most recent revision of such RMR Invoice.

(ii) A revision of the RMR Invoice specified in paragraph (1) above which shows the RMR Invoice revised to incorporate the Prior Period Change(s) as if such Prior Period Change(s) had been invoiced in the Billing Month which gave rise to the Prior Period Change(s). Such revision shall incorporate the impact of the Prior Period Change(s) on RMR payments, including any impact resulting from the Credit Carry forward calculation for the current or previous Billing Months in the Contract Year. For Condition 2 Units, such calculation shall include a recalculation of the refund described in Section 9.1(f).

(iii) The difference between the amounts calculated under paragraph (2) above and paragraph (1) above. The amount due to or from Owner as a result of this calculation shall be clearly specified, with interest shown separately from any other amount due. Interest shall be calculated at the Interest Rate from the Due Date of the Revised Estimated RMR Invoice for the Billing Month to the date payment of the amount due is made.

Owner shall total for all Billing Months which are included on the Prior Period Change Worksheet, the amount due as a result of the calculation in paragraph (3) above for each Billing Month. Owner shall also total for all Billing Months which are included on the Prior Period Change Worksheet, the interest due as a result of the calculation in paragraph (3) above for each Billing Month. The total amount due and interest due shall be transferred from the Prior Period Change Worksheet to the appropriate Estimated RMR Invoice, and such amounts shall be due as specified on the Estimated RMR Invoice.

(k) Any time a Unit switches from Condition 1 to Condition 2 or Condition 2 to Condition 1 during a Contract Year, the provisions of Section 9.1(e) shall apply to the months when the unit was on Condition 1 and the provisions of Section 9.1(g) shall apply to the months when the unit was on Condition 2.

(l) ISO shall separately post on the ISO Home Page examples ("Prior Period Change Examples") developed and agreed to by the RMR Invoice Task Force created under Schedule O of the calculations described in sections 9.1(e), 9.1 (f), 9.1(g) and 9.1(j) to provide guidance on the correct treatment of Prior Period Changes and to show the correct preparation of the Prior Period Change Worksheet and transfer of amount due to the appropriate Estimated RMR Invoice. Additionally, the RMR Invoice Task Force shall develop and agree to, and ISO shall post on the ISO Home Page, guidelines ("Prior Period Change Guidelines") underlying the calculations described in sections 9.1(e), 9.1(f), 9.1(g) and 9.1(j). The Prior Period Change Worksheet shall be prepared, and the amount due shall be calculated and transferred to the Estimated RMR Invoice, in accordance with the

RMR Invoice Template, the Prior Period Change Examples, and the Prior Period Change Guidelines posted on the ISO Home Page. In the event of a dispute regarding the treatment of Prior Period Changes, all Parties to such dispute shall refer to the Prior Period Change Examples and Prior Period Change Guidelines posted on the ISO Home Page for guidance.

9.2 Facility Trust Accounts

ISO shall establish two segregated commercial bank accounts under the "Facility Trust Account" referred to in Annex 1 to ISO's Settlement and Billing Protocol and Section 5.2.7 of the ISO Tariff for each Responsible Utility. One commercial bank account, the "RMR Owner Facility Trust Account", shall be held in trust by ISO for Owner. The other commercial bank account, the "Responsible Utility Facility Trust Account", shall be held in trust by ISO for the Responsible Utility. Payments received by ISO from a Responsible Utility in connection with this Agreement, including payments following termination of this Agreement, will be deposited into the RMR Owner Facility Trust Account and payments from ISO to Owner will be withdrawn from such Account, all in accordance with Section 5.2.7 of the ISO Tariff, Annex 1 to ISO's Settlement and Billing Protocol and this Article 9. Any payments received by ISO from Owner in connection with this Agreement, including payments following termination of this Agreement, will be deposited into the Responsible Utility Facility Trust Account. Any payments to a Responsible Utility of funds received from Owner under this Agreement will be withdrawn from the Responsible Utility Facility Trust Account, all in accordance with Section 5.2.7 of the ISO Tariff, Annex 1 to ISO's Settlement and Billing Protocol and this Agreement. Neither the RMR Owner Facility Trust Account nor the Responsible Utility Facility Trust Account shall have other funds commingled in it at any time.

9.3 Payment

(a) ISO shall pay Owner all invoiced amounts due on Revised Estimated RMR Invoices, Revised Adjusted RMR Invoices, and Final Invoices whether or not disputed by ISO or the Responsible Utility except to the extent that ISO (i) is entitled to a refund on a Revised Estimated or Revised Adjusted RMR Invoice or Final Invoice against such payment under this Agreement or (ii) is entitled to deduct an amount under Section 9.6. All payments shall be made from the RMR Owner Facility Trust Account on or before the Due Date by wire transfer in accordance with instructions from Owner. If Owner is also the Responsible Utility, at the discretion of Owner payments to it may be made by memorandum account instead of wire transfer. Owner shall establish and maintain a settlement account at a commercial bank located in the United States and reasonably acceptable to ISO which can effect money transfers via Fed-Wire where payments to and from the Facility Trust Accounts shall be made in accordance with Section 9.2 and Annex 1 of the ISO Tariff. Owner shall notify ISO of its settlement account details prior to the Effective Date. Owner may from time to time change its settlement account details, provided that, Owner shall give ISO 15 days notice before making changes. In the event there is a refund amount due to ISO, Owner shall refund the amount due ISO in accordance with Section 9.2 and Annex 1 of the ISO Tariff.

(b) If a Revised Adjusted RMR Invoice is less than the amount paid by ISO on the Revised Estimated RMR Invoice, the difference shall be paid by Owner to ISO with interest at the Interest Rate from the Due Date of the Revised Estimated RMR Invoice to the Due Date of the Revised Adjusted RMR Invoice, or, if the Agreement is terminated, shall be paid to ISO on submission of the Final Invoice.

If a Revised Adjusted RMR Invoice is greater than the amount paid by ISO under the Revised Estimated RMR Invoice, ISO shall pay Owner the difference with interest at the Interest Rate from the Due Date of the Revised Estimated RMR Invoice to the Due Date of the Revised Adjusted RMR Invoice by ISO.

9.4 Payment Default

(a) Except as provided in Section 9.4 (b), Owner, in addition to any other remedy it may have, may pursue all claims against ISO and the Collateral, as defined in Section 9.7 below, if ISO fails to pay any invoice in full by the Due Date as required under Section 9.3. ISO, in addition to any other remedy it may have, may pursue all claims against Owner if Owner fails to pay any invoice in full by the Due Date as required under Section 9.3. The parties' remedies shall be subject to the limitations set forth in Article 11.

(b) If the amounts ISO has not paid have been invoiced by ISO to the Responsible Utility and the Responsible Utility has not paid such amounts to ISO, Owner shall cause execution to issue against, and shall collect solely from the Collateral or the Responsible Utility, and not ISO, if all of the following conditions have been satisfied:

(i) The Responsible Utility is SDGE.

(ii) ISO has invoiced via the ISO Invoice SDGE for costs (net of any applicable credits, all as shown on the Revised Estimated or Revised Adjusted RMR Invoice) after deducting only amounts permitted to be deducted under Section 9.6 .

(iii) The ISO Tariff expressly requires SDGE to pay all amounts shown on the ISO Invoices without offset, recoupment or deduction (except to the extent that Section 5.2.7 of the ISO Tariff permits deduction of amounts that are due the Responsible Utility after resolution of a dispute) and, to the extent that SDGE disputes any amounts due under the ISO Invoices, to pay the disputed amounts under protest and subject to refund with interest; and

(iv) SDGE fails to pay all or a portion of the amounts due under the ISO Invoices and did not have the right to have such amount deducted under Section 5.2.7 of the ISO Tariff.

(c) Notwithstanding the provisions of Section 9.4 (b), Owner may cause execution to issue against, and collect from, ISO, the Responsible Utility, the Collateral or insurance maintained by ISO pursuant to Section 12.1(a), if notwithstanding the requirement to pay ISO Invoices without offset, recoupment or deduction (except to the extent that Section 5.2.7 of the ISO Tariff permits deduction of amounts that are due the Responsible Utility after resolution of a dispute), a Responsible Utility nonetheless offsets amounts unrelated to this Agreement or withholds amounts based on a breach or default by ISO of any of its obligations to the Responsible Utility.

(d) The ISO Invoices shall separately show the amounts due for services from each Facility. If the Responsible Utility withholds any portion of the amount due under the ISO Invoices, ISO shall inform Owner of the specific Facility and time periods for which the Responsible Utility withheld payments.

(e) As a condition for Owner's agreement not to seek to recover amounts from ISO under Section 9.4(b), ISO agrees to include and retain in the ISO Tariff provisions expressly recognizing that Owner is a third party beneficiary of, and has all rights that ISO has under the ISO Tariff, at law, in equity or otherwise, to enforce the Responsible Utility's obligation to pay all sums invoiced to it in the ISO Invoices but not paid by the Responsible Utility, to the extent that, as a result of the

Responsible Utility's failure to pay, ISO does not pay Owner on a timely basis amounts due under this Agreement. Owner recognizes that its rights as a third party beneficiary are (i) no greater than ISO's rights against the Responsible Utility, and (ii) subject to Section 13 of the ISO Tariff regarding dispute resolution. Either ISO or Owner (but not both) will be entitled to enforce any claim arising from unpaid ISO Invoices, and only one party will be a "disputing party" under Section 13 of the ISO Tariff with respect to such claim so that the Responsible Utility will not be subject to duplicate claims or recoveries. Owner shall have the right to control the disposition of claims against the Responsible Utility for non-payments which result in payment defaults by ISO under this Agreement. To that end, ISO agrees that in the event of nonpayment by the Responsible Utility of amounts due under the ISO Invoices, ISO will not take any action to enforce its rights against the Responsible Utility unless ISO is requested to do so by Owner. ISO shall cooperate with Owner in a timely manner as necessary or appropriate to most fully effectuate Owner's rights related to such enforcement, including using its best efforts to enforce the Responsible Utility's payment obligations if, as, to the extent, and within the time frame, requested by Owner. ISO shall intervene and participate where procedurally necessary to the assertion of a claim by Owner.

(f) If a Responsibility Utility was not the Responsible Utility on April 1, 1998 (a "New Responsible Utility") and if:

(i) The senior unsecured debt of the New Responsible Utility is rated or becomes rated at less than A- from Standard & Poors ("S&P") or A3 from Moody's Investment Services ("Moody's), and

(ii) Such ratings do not improve to A- or better from S&P or A3 or better from Moody's within 60 days,

ISO shall then require the New Responsible Utility to issue and confirm to ISO an irrevocable and unconditional letter of credit in an amount equal to three times the highest monthly payment invoiced by ISO to the New Responsible Utility (or the prior Responsible Utility) in connection with services provided under this Agreement during the last 3 months for which invoices have been issued. The letter of credit must be issued by a bank or other financial institution whose senior unsecured debt rating is not less than A from S&P and A2 from Moody's. The letter of credit shall authorize ISO or Owner to draw on the letter of credit for deposit solely into the RMR Owner Facility Trust Account in an amount equal to any amount due and not paid by the Responsible Utility under the ISO Invoices.

9.5 Interest

If ISO or Owner fails to make any payment by the Due Date, the amount due but not paid shall accrue interest at the Interest Rate from the Due Date until the amount is paid.

9.6 Disputed Amounts

(a) If ISO or the Responsible Utility disputes a Revised Estimated or Revised Adjusted RMR Invoice or Final Invoice or part thereof submitted by Owner under this Agreement, or if the Responsible Utility disputes an ISO Invoice or part thereof that relates to an RMR Invoice or Final Invoice submitted by Owner to ISO under this Agreement, and if such dispute is based in whole or part on an alleged error or breach or default of Owner's obligations to ISO under this Agreement, then ISO promptly shall give written notice to Owner of the reasons for the dispute and the amount in dispute. ISO shall pay Owner the disputed amount without offset, recoupment or reduction of any kind or nature. Such payment may, however, be made by ISO under protest with reservation of the right to seek a refund with interest at the Interest Rate from the date of the disputed payment to the date of repayment. If ISO notifies Owner that ISO or the Responsible Utility disputes any amount of Owner's RMR Invoice or Final Invoice, Owner shall at its own cost provide ISO with all information and assistance ISO reasonably requires to resolve the dispute and shall join with ISO in any discussions and negotiations with the Responsible Utility to resolve the dispute. The dispute shall be subject to ADR provided that in such ADR proceeding only one entity (ISO or Responsible Utility) will be the disputing party with respect to such claim. Owner shall be obligated to refund to ISO as a result of resolution of such dispute only if, and to the extent, the resolution determines the amount invoiced by Owner exceeded the amounts due Owner under this Agreement for the period covered by the RMR Invoices(s) and/or Final Invoice. Any amount agreed or determined to be owed by Owner to ISO under this Section 9.6 (a) shall be refunded by Owner to ISO with interest, by Owner's inclusion of such refund (including interest) in a Prior Period Change Worksheet included with the next appropriate May or December Estimated RMR Invoice as specified in Sections 9.1(g) through 9.1(l) of this Agreement. If Owner does not include such refund (including interest) in the appropriate RMR Invoice, then such refund shall be made by ISO's deduction of such amount from the next Revised Estimated and Revised Adjusted RMR Invoice(s) and Final Invoice submitted by Owner to ISO under this Agreement until such amount is extinguished, or, if this Agreement has terminated, by paying such amount to ISO. Interest shall be at the Interest Rate unless it is determined through ADR that the amount invoiced by Owner was submitted without a good faith basis in fact or law, in which case interest shall be at twice the Interest Rate.

(b) It is expressly understood that the Responsible Utility shall, to the extent set forth herein, be a third party beneficiary of, and shall have all rights that ISO has under this Agreement, at law, in equity and otherwise, to dispute an RMR Invoice or Final Invoice submitted to ISO by Owner under this Agreement and to enforce Owner's obligation to make any required payment to ISO under this Agreement to the extent ISO does not make a related deposit into the Responsible Utility Facility Trust Account as a result of Owner's failure to make the required payment. The rights of the Responsible Utility as third party beneficiary shall be no greater than ISO's rights against Owner and shall be subject to the ADR provisions of this Agreement. Either ISO or the Responsible Utility, but not both, will be entitled to enforce any claim arising from a related set of facts, and only one such entity will be a disputing party under Article 11 of this Agreement with respect to any such claim so that Owner shall not be subject to duplicate claims or recoveries. If the Responsible Utility is not the Owner, the Responsible Utility shall control the disposition of all claims against Owner for non-payment described in this Section 9.6, including the choice of disputing party. The ISO shall have the right to intervene for the purpose of participating in the proceeding even if it is not the disputing party. ISO shall cooperate with the Responsible Utility in a timely manner as necessary or appropriate to most fully effectuate the Responsible Utility rights related to such enforcement, including using its best efforts to enforce Owner's payment obligations if, as, to the extent, and within the time frame, requested by Responsible Utility. Subject to the foregoing, ISO shall intervene and participate where procedurally necessary to the assertion of a claim by the Responsible Utility.

9.7 Payment Security

To secure all of ISO's payment obligations to Owner under this Agreement, ISO agrees to grant Owner a security interest and lien in the following collateral (collectively, the "Collateral"): (a) all past, present and future accounts and other amounts Responsible Utility owes ISO at any time pursuant to Section 5.2.7 of the ISO Tariff attributable to invoices submitted by Owner under this Agreement (collectively, the "Accounts"), (b) the RMR Owner Facility Trust Account, all funds in the RMR Owner Facility Trust Account at any time, and all funds paid on account of any Accounts, (c) all proceeds of the Collateral, if any, and (d) all of ISO's right, title and interest in the Collateral. ISO represents and warrants to Owner that (a) ISO has the authority to grant such security interest, (b) ISO will have good, marketable and exclusive title to all of the Collateral, (c) such security interest and lien will at all times be a valid, enforceable and first-priority lien on the Collateral, and (d) such security interest will be duly perfected by the filing of a financing statement under the California Uniform Commercial Code describing the Collateral in the office of the Secretary of State of California and the delivery of a written notice of Owner's security interest to the bank with which the RMR Owner Facility Trust Account is maintained. If ISO defaults on its obligation to pay under this Agreement, Owner shall be entitled to enforce such security interest, to exercise its rights in the Collateral, to collect the Accounts from Responsible Utility, to collect all funds in the RMR Owner Facility Trust Account, and to exercise all other rights and remedies under the California Uniform Commercial Code. ISO agrees to promptly execute and deliver all financing statements and other documents Owner reasonably requests, including but not limited to a written notice of Owner's security interest in the Collateral to the bank with which the RMR Owner Facility Trust Account is maintained, in order to maintain, perfect and enforce such security interest.

9.8 Errors

If a Party discovers an error in the amount of an invoice or payment under this Agreement and notifies the other Party within 60 days after discovering the error, the error shall be corrected as specified in Sections 9.1(g) through 9.1(l) of this Agreement; *provided* that a Party shall not be entitled to have an error corrected unless the Party notifies the other Party within 12 months after the date of the applicable Revised Adjusted RMR Invoice or Final Invoice, or within 60 days after issuance of the final report with respect to an audit pursuant to Section 12.2(g), whichever is later.

9.9 Payment of Termination Fee

(a) Within 14 days after the end of each Month during the period in which any Termination Fee is payable under Section 2.5, Owner shall submit an invoice ("Termination Fee Invoice") to ISO and a copy to the Responsible Utility for all Termination Fee amounts due for the Month. Each Termination Fee Invoice shall: (i) be broken down by Unit and (ii) clearly identify the source of each input used.

(b) ISO shall pay Owner amounts invoiced under this Section 9.9 in accordance with Sections 9.3 through 9.8. If ISO or, if applicable, the Responsible Utility, has disputed the amount of a Termination Fee stated in a Termination Fee Invoice, then neither ISO nor the Responsible Utility shall be required to give notice of the same disputed amount as to subsequent Termination Fee Invoices.

9.10 Payment of Final Invoice

(a) Within 7 days of receipt by Owner of the Final Settlement Statement for market transactions for the effective date of termination of this Agreement, Owner shall submit an invoice ("Final Invoice") to ISO and a copy to the Responsible Utility for all charges and other amounts then due under this Agreement. Amounts then due shall include: (i) charges for all Billable MWh and Ancillary Services provided under this Agreement and not previously invoiced; (ii) the Long-term Planned Outage Adjustment under Section 8.6. and (iii) refunds described in section 9.1(f) for Condition 2 Units. Calculation of the Long-term Planned Outage Adjustment shall be made by deeming the effective date of termination to be the end of the Contract Year, and by assuming that all Long-term Planned Outages scheduled to occur after the termination date occur as scheduled. The Final Invoice shall not include remaining Monthly payments of a Termination Fee under Section 2.5, which shall continue to be paid monthly until the obligation is extinguished.

(b) ISO shall pay Owner the amount stated in the Final Invoice in accordance with Section 9.3 through 9.8.

ARTICLE 10

FORCE MAJEURE EVENTS

10.1 Notice of Force Majeure Events

If either Party is unable to perform its obligations under this Agreement due to a Force Majeure Event, the Party unable to perform shall notify the other Party of the Force Majeure Event promptly after the occurrence thereof. The Party's notice may be given orally but shall promptly be confirmed in writing or electronically.

10.2 Effect of Force Majeure Event

(a) If a Force Majeure Event prevents a Party from performing, in whole or in part, its obligations under this Agreement, such Party's obligations, other than obligations to pay money (unless the means of transferring funds is affected), shall be suspended and such Party shall have no liability with respect to such obligations; provided, that the suspension of the Party's obligations is of no greater scope and of no longer duration than is required by the Force Majeure Event.

(b) If a Force Majeure Event (other than a flood, storm or drought affecting a hydroelectric Unit) reduces the Availability of a Unit, the Availability shall be determined as if the Unit were available up to the Unit Availability Limit in effect prior to the Force Majeure Event through the earlier of the 120th day following the Force Majeure Event or until the Unit's Availability is restored, whichever occurs first. If a flood or storm Force Majeure Event reduces the Availability of a hydroelectric Unit, the Availability shall be determined as if the Unit were available up to its Unit Availability Limit in effect prior to the Force Majeure Event through the earlier of the 120th day following the Force Majeure Event or until the Unit's Availability is restored, and as if the Unit were available up to one-half of such Unit Availability Limit from the 120th day through the earlier of the 240th day or the date on which the Unit's Availability is restored. If a drought Force Majeure Event reduces the Availability of a hydroelectric Unit, the Availability shall be determined as if the Unit were available up to its Unit Availability Limit in effect prior to the Force Majeure Event until the Unit's Availability is restored following the end of the drought Force Majeure Event.

10.3 Remedial Efforts

The Party that is unable to perform by reason of a Force Majeure Event shall use commercially reasonable efforts to remedy its inability to perform and to mitigate the consequences of the Force Majeure Event as soon as reasonably practicable; provided, that no Party shall be required to obtain replacement power or to settle any strike or other labor dispute on terms which, in the Party's sole discretion, are contrary to its interest and, except to the extent that the Unit's primary fuel is distillate fuel oil or Schedule H expressly requires Owner to maintain fuel oil capability for the Unit, Owner shall not be required to obtain or use fuel oil to operate a Unit. The Party unable to perform shall advise the other Party of its efforts to remedy its inability to perform and to mitigate the consequences of the Force Majeure Event, and shall advise the other Party of when it believes it will be able to resume performance of its obligations under this Agreement.

ARTICLE 11

REMEDIES

11.1 Dispute Resolution

The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. Unless this Agreement expressly provides that a particular type of dispute is not subject to ADR, the Parties shall use ADR procedures to resolve all disputes which are not otherwise settled. Owner and ISO will promptly join with all other owners of Reliability Must-Run Units and all Responsible Utilities to jointly develop ADR procedures to be used in connection with such disputes. Following unanimous agreement of Owner, ISO and Responsible Utilities to the ADR procedures, such procedures shall be posted on ISO's Home Page. Until there is unanimous agreement on such procedures, the Parties shall use the ADR procedures contained in Schedule K.

11.2 Waiver of Damages

(a) Except for the obligations set forth in Section 11.4 (Termination for Default) and Section 12.6 (Indemnity), neither Party shall be liable to the other Party for any claim, loss or damage of any nature arising out of or relating to the performance or breach of this Agreement including replacement power costs, loss of revenue, loss of anticipated profits or loss of use of, or damage to, plant or other property, personal injury, or death; provided, however, that this waiver of liability shall not include or cover any claim, damage or loss arising out of the willful misconduct of either Party. Amounts that are specifically payable or reimbursable by the other Party under the terms of this Agreement shall not be considered "claims, losses or damages" for purposes of this Section.

(b) Neither Party shall be liable to the other for any special, indirect, incidental or consequential damages suffered by the other Party or by third parties arising out of, or relating to, this Agreement or the performance of, or breach of any obligation under, this Agreement, or the negligence of any Party. This limitation shall apply even if the Party is advised of the possibility of these damages.

(c) Except for the obligations to make or adjust payments or pay penalties expressly provided in Section 2.5 (Termination Fee), Section 7.4 (Planned Capital Items), Section 7.5 (Unplanned Repairs), Section 7.6 (Unplanned Capital Items), Section 7.8 (Upgrades of Generating Units), Article 8 (Rates and Charges) and Article 9 (Statements and Payments), of this Agreement, either Party's maximum aggregate liability for any and all claims arising out of or relating to performance or breach of this Agreement during the Contract Year, whether based upon contract, tort (regardless of degree of fault or negligence), strict liability, warranty, or otherwise, including any liability for Owner's failure to Deliver Requested MWh or Requested Ancillary Services shall not exceed $20 million.

11.3 Injunctive Relief

In addition to any other remedy to which a Party may be entitled by reason of the other Party's breach of this Agreement, the Party not in default shall be entitled to seek temporary, preliminary and permanent injunctive relief from any court of competent jurisdiction restraining the other Party from committing or continuing any breach of this Agreement.

11.4 Termination For Default

(a) If either Party shall fail to perform any material obligation imposed on it by this Agreement and that obligation has not been suspended pursuant to Section 10, the other Party, at its option, may terminate this Agreement by giving the Party in default notice setting out specifically the circumstances constituting the default and declaring its intention to terminate this Agreement. If the Party receiving the notice disputes the notice, it shall notify the other Party within 14 days after receipt of the notice setting out specifically the grounds of such disputes. Time is of the essence in remedying a default. If the Party receiving the notice does not, within 30 days after receiving the notice, remedy the default or refer the dispute to ADR, the Party not in default shall be entitled by a further notice to terminate this Agreement. The Party not in default shall have a duty to mitigate damages.

(b) Termination of this Agreement pursuant to this Section 11.4 shall be without prejudice to the right of Owner or ISO to collect any amounts due to it prior to the time of termination. If ISO terminates this Agreement as to any Unit(s) due to Owner's default, Owner shall reimburse to ISO the amount, if any, by which costs incurred by ISO as a direct result of the termination through the end of the then current Contract Year exceed the costs which ISO would have incurred absent such termination.

11.5 Cumulative and Nonexclusive

Except as provided in Section 5.4(b), each remedy provided for in this Agreement shall be cumulative and not exclusive.

11.6 Beneficiaries

Except as is specifically set forth in this Agreement, nothing in this Agreement, whether express or implied, confers any rights or remedies under, or by reason of, this Agreement on any persons other than the Parties and their respective successors and assigns, nor is anything in this Agreement intended to relieve or discharge the obligations or liability of any third party, nor give any third person any rights of subrogation or action against any

Party. The owner of title to a Unit that is leased to Owner is an intended beneficiary of Section 2.2(e).

ARTICLE 12

COVENANTS OF THE PARTIES

12.1 Insurance

(a) At all times prior to January 1, 2002, ISO shall maintain (i) an errors and omissions insurance policy and (ii) director and officer insurance, with combined aggregate coverage of at least $150 million under the two policies and an operating reserve of at least $15 million. Effective on or after January 1, 2002, ISO may reduce the level of insurance coverage, but may not do so unless it provides Owner at least 90 days notice of its intent to reduce the insurance coverage. At Owner's request, ISO shall provide Owner with evidence of the insurance coverage it has in place. This Section 12.1 shall not be construed to require ISO to maintain any level of coverage for any period after termination of the Agreement.

(b) Owner and ISO will secure and maintain in effect during the term of this Agreement the insurance required by Schedule I. Self-insurance may be utilized by mutual agreement. Owner shall name ISO as an additional insured on its general commercial liability insurance policies. ISO shall name Owner as an additional insured on its errors and omissions insurance policies. Owner and ISO will each certify or cause its respective insurance agent to certify that it is insured under a major risk management program, including self-insured retentions, and except for policies covered by Section 12.1 (a), such insurance will remain in effect in amounts meeting the requirements of Schedule I.

12.2 Books And Records

(a) For a period of 36 months from creation of the records, Owner shall maintain and make available for audit by ISO complete operations records for each Unit. Such records shall include:

(i) information for each Settlement Period on the Availability of the Units, Delivered MWh and Delivered Ancillary Services,

(ii) outages,

(iii) Facility licenses and permits,

(iv) copies of operating and maintenance agreements for the Unit,

(v) a list of citations filed against the Unit by any environmental, air quality, health and safety, or other regulatory agency in the last 36 months,

(vi) a list of any resolved and unresolved WSCC log items from the last 36 months pertaining to the Unit,

(vii) maintenance, overhauls and inspections performed, and

(viii) books, accounts and all documents required to support Owner's statements, invoices, charges and computations made pursuant to this Agreement.

ISO may audit Owner's books, accounts and documents relating to invoices, statements, charges and computations no more frequently than once each Contract Year, and only one time following expiration or termination of this Agreement.

(b) The Responsible Utility shall have the right to participate jointly with ISO in auditing books, accounts, documents and operating records of the Facilities to the extent required to verify the accuracy and correctness of all Owner's statements, invoices, and computations underlying all Owner charges passed through by ISO to the Responsible Utility in connection with services rendered by Owner under this Agreement.

(c) For a period of 36 months from the creation of the records, ISO shall maintain and make available for audit by Owner all operations records required to permit Owner to verify that ISO has complied with its obligations to Owner under this Agreement.

(d) In addition to the audit rights under Section 12.2 (a) and (b), if Owner's rates are determined pursuant to the formula contained in Schedule F, representatives of ISO and the Responsible Utility shall have the right jointly to audit the records, accounts and supporting documents of Owner to verify (i) the accuracy of any arithmetic calculation and (ii) application of the formula.

(e) If Owner's rates are determined pursuant to the formula contained in Schedule F, the California Agency shall have the right to audit the records, accounts and supporting documents of Owner or ISO to verify the accuracy of any arithmetic calculation and application of the formula, including the accuracy of allocation to accounts under the FERC Uniform System of Accounts, 18 C.F.R. Part 101. If there is more than one California Agency, only one audit shall be conducted by the California Agencies and such audit shall be binding on all the California Agencies.

(f) Any entity exercising its right to audit under this Section 12.2 shall give the audited entity not less than 30 days prior written notice of the audit. Books or records requested in any audit shall be available for inspection by the auditing entity at the offices of the entity being audited between 9:00 A.M. and 5:00 P.M. on Business Days. Any audit under this Section 12.2 shall be completed not more than 36 months after the records were created. Any audit right herein shall be limited to the books and accounts of Owner or ISO and shall not extend to the books and accounts of the parent or any other affiliate of Owner or ISO. The expense of any audit shall be borne solely by the auditing Party or entity.

(g) No adjustments to payments shall be required as a result of an audit unless, and then only to the extent that, ISO, Owner, or another entity making such an audit under this Section 12.2 takes written exception to the books and accounts and makes a claim upon Owner or ISO for any discrepancies disclosed by such audit within 60 days following issuance of the final audit report.

(h) All information provided during the course of an audit shall be treated as Confidential Information in accordance with Section 12.5.

(i) Nothing in this Agreement shall override any obligation Owner or ISO may have under applicable law to maintain books and records for periods longer than 36 months nor shall this Agreement override any obligation Owner or ISO may have to make books and records available for audit by FERC or any other entity. Nothing in this Agreement is intended to limit in any manner (i) the authority of FERC to audit the books and records of Owner or ISO or the manner in which such audit is noticed or conducted or (ii) ISO's right to audit market participants (including Owner) under the ISO Tariff.

12.3 Representations And Warranties

(a) ISO represents and warrants to Owner as follows:

(i) ISO is a validly existing corporation with full authority to enter into this Agreement.

(ii) ISO has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement shall be a legally binding obligation of ISO.

(b) Owner represents and warrants to ISO as follows:

(i) Owner is a validly existing limited liability company with full authority to enter into this Agreement.

(ii) Owner has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery this Agreement shall be a legally binding obligation of Owner.

12.4 Responsibilities

Each Party shall be responsible for protecting its facilities from possible damage by reason of electrical disturbances or faults caused by the operation, faulty operation, or non-operation of the other Party's facilities. The other Party shall not be liable for any damages so caused.

12.5 Confidentiality

(a) Except as may otherwise be required by applicable law, all information and data provided by the Parties to one another pursuant to this Agreement and marked "Confidential" or otherwise identified with specificity in writing as confidential at the time of disclosure ("Confidential Information") shall be treated as confidential and proprietary material of the providing Party and will be kept confidential by the receiving Party and used solely for purposes of this Agreement. Confidential Information will not include information that is or becomes available to the public through no breach of this Agreement, information that was previously known by the receiving Party without any obligation to hold it in confidence, information that the receiving Party receives from a third party who may disclose that information without breach of law or agreement, information that the receiving Party develops independently without using the Confidential Information, and information that the disclosing Party approves for release in writing. The receiving Party shall keep such information confidential and shall limit the disclosure of any such Confidential Information to only those personnel within its organization with responsibility for using such information in connection with this Agreement. The receiving Party shall assure that personnel within its organization read and comply with the provisions of this Section 12.5 and any Confidentiality Agreement implementing this Section 12.5. The Parties shall use all reasonable efforts to maintain the confidentiality of the Confidential Information in any litigation, shall promptly notify the providing Party of any attempt by a third party to obtain the Confidential Information through legal process or otherwise. A Party or third party beneficiary under Article 9 which has received Confidential Information may use that information in litigation or regulatory proceedings related to this Agreement but only after notice to the other Party and affording the other Party an opportunity to obtain a protective order or other relief to prevent or limit disclosure of the Confidential Information.

(b) The Parties may provide any Confidential Information (i) to the Responsible Utility pursuant to provisions of this Agreement under which information is to be provided to that Responsible Utility and as required for settlement and billing; (ii) to any entity with audit rights under Section 12.2 or review rights specified in other provisions of this Agreement, (iii) on a need-to-know basis, to Owner's Scheduling Coordinator, financial institutions, agents, lessors of the Unit and potential purchasers of interests in a Unit; and, (iv) as required for settlement and billing, to Scheduling Coordinators responsible for paying for services provided under this Agreement. As a condition to receiving any Confidential Information under this Section 12.5, the recipient shall execute a Confidentiality Agreement in the applicable form contained in Schedule N and thereby agree to be subject to the non-disclosure and other obligations contained in this Section 12.5.

(c) The obligation to provide confidential treatment to Confidential Information shall not be affected by the inadvertent disclosure of Confidential Information by either Party.

12.6 Indemnity

Subject to the limitations in Section 11.2 (b), each Party shall indemnify, defend and hold harmless the other Party and its officers, directors, employees, agents, contractors and sub-contractors, from and against all third party claims, judgments, losses, liabilities, costs, expenses (including reasonable attorneys' fees) and damages for personal injury, death or property damage, caused by the negligence or willful misconduct related to this Agreement or breach of this Agreement of the indemnifying Party, its officers, directors, agents, employees, contractors or sub-contractors, *provided* that this indemnification shall be only to the extent such personal injury, death or property damage is not attributable to the negligence or willful misconduct related to this Agreement or breach of this Agreement of the Party seeking indemnification, its officers, directors, agents, employees, contractors or sub-contractors. This indemnification shall not include or cover any claim covered by any workers' compensation law. This indemnification shall be for an amount not exceeding the deductible of the indemnifying Party's commercial general liability insurance in the case of Owner and errors and omission insurance in the case of ISO. The indemnified Party shall give the other Party prompt notice of any such claim. The indemnifying Party shall have the right to choose competent counsel, control the conduct of any litigation or other proceeding, and settle any claim. The indemnified Party shall provide all documents and assistance reasonably requested by the indemnifying Party. Section 14.3 of the ISO Tariff shall not apply to this Agreement.

12.7 Owner Financial Requirements

(a) Through the term of the Agreement, Owner shall maintain an investment grade rating by Moody's or Standard and Poor's or provide documentation from a financial institution or corporate owner acceptable to the ISO that there is an equity position described below. The ISO shall not unreasonably withhold acceptance of the documentation.

(i) An equity to debt ratio of at least 30%, or

(ii) An equity to total asset ratio of at least 30% or

(iii) Demonstrate to the ISO's reasonable satisfaction that other factors, including, without limitations, commercial financing arrangements, and working capital positions, mitigate the risk of Owner failing to meet the performance requirements under this Agreement.

(b) If the Owner does not possess and maintain an investment grade rating, an equity position or make other arrangements as described in Section 12.7 (a), then it must provide one of the following:

(i) Proof of insurance to cover the financial exposure to the ISO for one year of Capital Items, Repairs, fuel and any other operating expenses; or

(ii) Security to cover the financial exposure to the ISO for one year of Capital Items, Repairs, fuel and any other operating expenses in one of the following forms:

(A) standby letter of credit;

(B) corporate guarantee;

(C) cash deposit; or

(D) security bond.

ARTICLE 13

ASSIGNMENT

13.1 Assignment Rights and Procedures

Neither Party shall assign its rights or delegate its duties under this Agreement without the prior written consent of the other Party, which shall not be unreasonably withheld. ISO shall be entitled to deny consent to a proposed assignment by Owner only if the assignee does not meet the financial criteria set out in Section 13.2 (a) or the technical criteria set out in Section 13.2 (b). Notwithstanding the foregoing, if FERC approves an assignment, then the non-assigning Party shall be deemed to have consented to the assignment, subject to the non-assigning Party's right to seek judicial review of a FERC decision. Each Party shall give the other Party prompt notice of any proposed assignment or delegation, together with such information as the other Party may reasonably request with respect to the proposed assignment or assignee. Each Party shall be deemed to consent to the assignment or delegation unless it submits a written objection to the assignment or delegation within 14 days of receiving the notice and all financial and technical information as required in Sections 13.2(a) and 13.2(b). In the event of an assignment of this Agreement pursuant to a Financing Agreement, ISO will execute for the benefit of the bank, financial institution or other entity with an interest in the Financing Agreement, a consent to such assignment reasonably acceptable to ISO and Owner. An assignment of this Agreement by Owner in connection with the sale of a Unit shall terminate Owner's rights and obligations under this Agreement prospectively from the effective date of the assignment.

13.2 Limitation on Right to Withhold Consent

(a) ISO shall not withhold consent to assignment of this Agreement on financial grounds if the assignee meets the financial requirements in Section 12.7(a) or provides financial security pursuant to Section 12.7(b).

(b) ISO shall not withhold consent to an assignment on grounds that the assignee is not technically qualified if the assignee was an Owner of a Reliability Must-Run Unit as of May 1, 1999 or the assignee submits appropriate documentation to the ISO to establish that it has sufficient resources and expertise to be able to:

(i) Secure the necessary fuel and transportation for the fuel for the Facility;

(ii) Secure all necessary support services, including water supply, communications, waste disposal, etc. for the Facility;

(iii) Provide service from the Facility in compliance with the terms of this Agreement;

(iv) Provide the engineering and other technical services required to support operation and maintenance of the Facility;

(v) Obtain as necessary, and comply with all permits or licenses required to operate or maintain the Facility; and

(vi) Provide environmental services required for the operation and maintenance of the Facility.

(c) The proposed assignee shall provide the last two years' annual audited financial statements and quarterly financial statements (unaudited) prior to the proposed date of purchase. If the proposed assignee is a new company and there are no historical financial statements, then a financial institution or corporate owner must provide pro forma financial statements in a form acceptable to the ISO.

13.3 Transfer of Conditions Following Assignment

If this Agreement is assigned to a new Owner pursuant to Section 13.1, the new Owner may transfer one or more Units to a different Condition by giving ISO at least seven days prior notice provided that such notice is given not later than 30 days after the effective date of the assignment. The transfer shall become effective on the first day of month following the later of (i) seven days after the effective date of the assignment or (ii) seven days after the date ISO receives the new Owner's transfer notice. This section shall not apply to assignment to a new Owner which is an affiliate of Owner as defined in 18 C.F.R. Section 161.2.

ARTICLE 14

MISCELLANEOUS PROVISIONS

14.1 Notices

Except as otherwise expressly provided in this Agreement or required by law, all notices, consents, requests, demands, approvals, authorizations and other communications provided for in this Agreement shall be in writing and shall be sent by personal delivery, certified mail, return receipt requested, facsimile transmission or by recognized overnight courier service, to the intended Party at such Party's address set forth in Schedule J. Any notices which may be given orally and are given orally shall be confirmed in writing. All such notices shall be deemed to have been duly given and to have become effective: (a) upon receipt if delivered in person or by facsimile; (b) two days after having been delivered to an air courier for overnight delivery; or (c) seven days after having been deposited in the United States mail as certified or registered mail, return receipt requested, all fees pre-paid, addressed to the applicable address(es) set forth in Schedule J.

14.2 Effect of Invalidation

Each covenant, condition, restriction and other term of this Agreement is intended to be, and shall be construed as, independent and severable from each other covenant, condition, restriction and other term. If any covenant, condition, restriction or other term of this Agreement is held to be invalid by any court or regulatory body having jurisdiction, the invalidity of such covenant, condition, restriction or other term shall not affect the validity of the remaining covenants, conditions, restrictions or other terms hereof unless the invalidity has a material impact upon the rights and obligations of the Parties. If an invalidity has a material impact on the rights and obligations of the Parties, the Parties shall make a good faith effort to renegotiate and restore the benefits and burdens of this Agreement as they existed prior to the determination of an invalidity.

14.3 Amendments

(a) Any amendments or modifications of this Agreement shall be made only in writing and, except for changes authorized by the FERC under Sections 205 or 206 of the Federal Power Act, shall be duly executed by both Parties. To the extent that any amendments or modifications are subject to FERC approval, such amendments or modifications shall become effective when permitted to be effective by FERC. For purposes of this Agreement, transfer of any Unit from one condition to the other condition or termination of the Agreement as to less than all Units shall not constitute a modification or amendment to this Agreement.

(b) Where Owner's rates are not subject to FERC jurisdiction, either ISO or Owner may, not later than 90 days prior to the end of each Contract Year, serve a notice on the other Party and the Responsible Utility stating that it requires a review of the terms of this Agreement, including any rates, prices and charges contained therein ("Review Notice").

(i) The Review Notice shall, as a minimum requirement, set forth the following:

(A) the precise nature of the proposed revisions (indicating, where possible, the relevant Article, Section and Schedule); and

(B) justification for each proposed revision.

(ii) The Party in receipt of the Review Notice shall respond to such notice within 30 days of its receipt by issuing a notice in response ("Response Notice"). The Response Notice shall, as a minimum requirement, set forth the following:

(A) those revisions set forth in the Review Notice that are accepted as proposed;

(B) those revisions set out in the Review Notice that are not accepted;

(C) alternative proposals (if any) to the proposed revisions set out in the Review Notice;

(D) any revisions required by the responding party not covered by (A) through (C) above; and

(E) its justification for any of the matters raised under Sections 14.3 (b) (ii) (B) (C) or (D).

(iii) Any Party failing to respond to a Review Notice shall be deemed to have accepted the revisions set out in the Review Notice.

(iv) Following receipt of the Response Notice the duly authorized representatives of the Parties shall meet to negotiate in good faith any revisions to this Agreement.

(v) In the event that the Parties are unable to reach agreement on the revisions to be made to this Agreement within 60 days of the date of the Review Notice, either Party may refer the matter for resolution through ADR. The arbitrator shall determine the revisions, if any, to the Agreement on the basis that:

(A) the purpose of the Agreement is to maintain the reliability of ISO Controlled Grid; and

(B) costs and charges payable by ISO should reflect the costs of providing services to the ISO.

(vi) In the event that the Parties agree to the revisions, or such matters are determined through ADR, or a Party fails to respond to a Review Notice, the agreed, determined or deemed accepted revisions shall take effect and the rights and obligations of the Parties shall be amended as from the beginning of the ensuing Contract Year or from such other date and time agreed between the Parties or determined through ADR, and following such time the Parties shall act in accordance with the terms and conditions of this Agreement as amended.

14.4 Filings Under Sections 205 or 206 of the Federal Power Act

Nothing contained in this Agreement shall be construed as affecting the right of Owner unilaterally to make application to FERC for a change in rates, terms and conditions under Section 205 of the Federal Power Act and pursuant to FERC rules and regulations promulgated thereunder. ISO may challenge such application or may submit complaints concerning Owner's rates, terms and conditions under Section 206 of the Federal Power Act and pursuant to FERC rules and regulations promulgated thereunder.

14.5 Construction

The language in all parts of this Agreement shall in all cases be construed as a whole and in accordance with its fair meaning, and shall not be construed strictly for or against either of the Parties.

14.6 Governing Law

This Agreement shall be interpreted and construed under and pursuant to the laws of the State of California, without regard to conflicts of laws principles.

14.7 Parties' Representatives

Both Parties shall ensure that throughout the term of this Agreement, a duly appointed Representative is available for communications between the Parties. The Representatives shall have full authority to deal with all day-to-day matters arising under this Agreement. If a Party's Representative becomes unavailable, the Party shall promptly appoint another

Representative. Acts and omissions of Representatives shall be deemed to be acts and omissions of the Party. Owner and ISO shall be entitled to assume that the Representative of the other Party is at all times acting within the limits of the authority given by the Representative's Party. Owner's Representatives and ISO's Representatives shall be identified on Schedule J.

14.8 Merger

This Agreement and the Stipulation and Agreement filed April 2, 1999 in Docket Nos. ER98-441-000 *et al.* constitute the full agreement of the Parties with respect to the subject matter hereto and supersede all prior agreements, whether written or oral, with respect to such subject matter.

14.9 Independent Contractors

Nothing contained in this Agreement shall create any joint venture, partnership or principal/agent relationship between the Parties. Neither Party shall have any right, power or authority to enter into any agreement or commitment, act on behalf of, or otherwise bind the other Party in any way.

14.10 Conflict with ISO Tariff

The ISO Tariff shall govern matters relating to the subject matter of this Agreement which are not set forth in this Agreement. In all other circumstances, this Agreement shall govern. In the event of a conflict between the terms and conditions of this Agreement and any terms and conditions set forth in the ISO Tariff the terms and conditions of this Agreement shall prevail. Provided however, if the ISO Tariff is revised after September 30, 1999, in accordance with the Stipulation and Agreement dated April 2, 1999 in FERC Docket Nos. ER98-441-000 *et al.* to permit ISO to issue Dispatch Notices before establishment of the "final schedule" (as defined in the ISO Tariff) for the day-ahead market, such revision is an exception to the precedence of this Agreement over the ISO Tariff.

14.11 Waiver

The failure to exercise any remedy or to enforce any right provided in this Agreement shall not constitute a waiver of such remedy or right or of any other remedy or right provided herein. A Party shall be considered to have waived any remedies or rights hereunder only if such waiver is in writing.

14.12 Assistance

During the term of this Agreement, each Party shall provide such reasonable assistance and cooperation as the other Party may require in connection with performance of the duties and obligations of each Party under this Agreement, including, but not limited to, assistance in securing any necessary regulatory approvals and in facilitating necessary financing.

14.13 Headings

Article and section headings used in this Agreement are inserted for convenience only and are not intended to be a part hereof or in any way to define, limit, describe or to otherwise be used in interpreting the scope and intent of the particular provisions to which they refer.

IN WITNESS WHEREOF, this Agreement has been executed as of the date first above written.

Dynegy South Bay, LLC

By: ______________________________

Name:
Title:

The California Independent System Operator Corporation

By: ______________________________
Name:
Title:

FERC
RELIABILITY MUST-RUN SCHEDULES

Schedule A Unit Characteristics , Limitations and Owner Commitments

Schedule B Monthly Option Payment

Schedule C Variable Cost Payment

Part 1 for Thermal Units
Part 2 for Geothermal Units
Part 3 for Conventional Hydro Units
Part 4 for Pumped Storage Hydro Units

Schedule D Start-up Payment

Part 1 for Condition 1 Units
Part 2 for Condition 2 Units

Schedule E Ancillary Services Payment

Part 1 for Condition 1
Part 2 for Condition 2
Part 3 for Black Start Services

Schedule F Determination of Annual Revenue Requirements of Must-Run Generating Units

Schedule G Charges for Service in Excess of Contract Service Limits

Schedule H Fuel Oil Service

Schedule I Insurance Requirements

Schedule J Notices

Schedule A

Unit Characteristics, Limitations and Owner Commitments

1. Description of Facility

Provide the following information for all units at the Facility, regardless of their RMR designation status. Information regarding units not designated as Reliability Must-Run Units is required only if and to the extent that the information is used to allocate Facility costs between Reliability Must-Run Units and other units.

Unit	RMR (Y/N)	Maximum Net Dependable Capacity (includes ISO-paid Upgrade capacity)*	Fuel Type
SY1	Y	145	Nat. Gas/Residual
SY2	Y	149	Nat. Gas/Residual
SY3	Y	174	Nat. Gas/Residual
SY4	Y	221	Nat. Gas/Residual
SYCT	Y	13 / 15*	Jet Fuel – JP5 only

*Summer/Winter values shown for the CT

For this Facility, the Owner will use MW in Schedule B to allocate Annual Fixed Revenue Requirements to and among Units. This election shall be applicable to all Facilities containing Reliability Must Run Units subject to any "RMR contract" as defined in the ISO Tariff executed by Owner or any of its affiliates as defined in 18 CFR § 161.2.

* Maximum Net Dependable Capacity shall reflect any transformer or line loss to the Delivery Point.

2. Description of RMR Units

The South Bay Facility is located at 990 Bay Boulevard, Chula Vista, CA 91911.

	Unit 1	Unit 2	Unit 3	Unit 4	CT
Type (fossil, combustion turbine, etc.)	Fossil	Fossil	Fossil	Fossil	CT
Synchronous Condenser Capability (Y/N)	N	N	N	N	N
Power Factor Range (lead to lag)	0.97-0.98	0.97-0.98	0.92-0.99	0.93-0.99	0.93-1.00
Maximum Reactive Power Leading MVar	37	37	76	89	5
Maximum Reactive Power Lagging, MVar	-30	-30	-30	-30	-1
Load at Maximum MVar Lagging, MW	145	149	174	221	13/15*
Load at Maximum MVar Leading MW	145	149	174	221	13/15*
Black Start Capable (Y/N)	N	N	N	N	Y
Automatic Start or Ramp (Y/N)	N	N	N	N	N
Upgrade Capacity Paid by ISO, MW					

*Summer / Winter

* <u>If "Y", describe the conditions under which the Unit will start or ramp automatically</u>.

3. Operational and Regulatory Limitations of RMR Units:

NOx

Air emissions from the steam boilers at the South Bay Generating Facility are regulated by the San Diego Air Pollution Control District (SDAPCD) under Rule 68 and 69 and by unit-specific SDAPCD permits. Rule 68 requires each boiler at these facilities to operate at or below a NOx concentration limit of 125 ppm where natural gas is used as a fuel and 225 ppm where oil (liquid fuel) is used as a fuel and applies special emissions limits for specific operating conditions, such as start up, fuel changes, low load operations and overhaul testing as set forth in Rule 68 Table 1: Exemption Limits.

Rule 69 establishes a unit-specific NOx emission limit for each steam boiler at the South Bay Power Plant of 0.15 and 0.40 lbs of NOx per gross megawatt-hour on gas and oil fuels, respectively. These unit-specific limits went into effect on January 1, 2001.

Rule 69 also sets limits as to when the generating facilities can burn oil fuel for economic reasons, specifically prohibiting economic oil burn on predicted ozone non-attainment days. Economic oil burns were prohibited after December 31, 2000, except for certain regulatory and operational testing, pursuant to conditions specified in the permits to operate. This may place operational limitations on generation.

NOx – Combustion Turbines

SDAPCD Rule 69.3.1 limits NOx emissions from the South Bay combustion turbine. Historically, the combustion turbine has been operated as a peaking unit. Under Rule 69.3.1 (adopted December 16, 1998), peaking units operated less than 877 hours annually must meet NOx emission concentration limits of 42 ppm @ 15% O2 when utilizing natural gas and 65 ppm @ 15% O2 when utilizing oil, which NOx concentration limits have not otherwise restricted operations. Operation of the combustion turbine in excess of 877 hours annually or operation as other than peaking units triggers the more restrictive NOx limitations prescribed by the formula set forth in Rule 6.9.3.1(d). Generation may be limited where the more restrictive formula emission limits apply, unless feasible pollution control equipment can be and is installed.

SO2

South Bay boiler sulfur dioxide emissions are regulated under the federal Clean Air Act, Title IV Acid Rain Program. Essentially, Title IV prohibits the South Bay power plant units from independently emitting more SO2 during an emission year then the quantity of SO2 allowances held by the owner of operator of such units as of January 31 following such emission year. Each SO2 allowance has a value of 1 ton of SO2 emissions. SO2 allowances may be allocated by EPA under Title IV and/or acquired in the SO2 allowance marketplace. The number of SO2 allowances available to the owners and the operators of the South Bay power plant units are sufficient to allow continued operation along recent historical patterns. SO2 emission regulations could limit generation, particularly if the use of the oil fuel increases, where sufficient SO2 allowances are not available through the EPA's allocation of allowances or through the allowance marketplace.

Ammonia
The SDAPCD permit for South Bay Unit 1 limits the concentration of ammonia emissions generated through the operation of SCR NOx control to 10 ppm when natural gas isutilized and 10 ppm when oil is utilized. Local Rules 69, 1200, and 51 also limit ammonia emissions by requiring the "lowest emission rate achievable" taking into consideration cost effectiveness and public health factors, requiring the protection of public health, and requiring protection against noxious odors. Thus the hourly and/or total annual generation from the South Bay Facility may be limited due to the ammonia limits.

Particulates
Particulates for the South Bay generating units and the combustion turbine are limited by Rule 53. Specifically, emissions of sulfur dioxides and combustion particulates shall be limited to a concentration of 0.05% and 0.10 grains per cubic foot. As additional particulate controls, the South Bay generating unit permits limit startup to the utilization of natural gas fuel and require maintenance of stack pH when burning oil fuel. None of these requirements/limits limit generation.

Other Criteria Pollutant and Toxic Emissions
Other criteria pollutant and toxic emission limits do not limit generation.

Source Testing
The South Bay steam generating units are source tested annually. SDAPCD has approved Duke Energy South Bay's plan to source test the combustion turbines on a three year testing cycle. This will require one third of the Combustion Turbines to be tested each year. This revised testing was allowed on the basis of each CT operating less than 100 hours per year. The District retains the authority to return to annual source testing regardless of operating hours. Any CT operating above 100 hours per year is subject to annual source testing unless arrangements are made otherwise with the SDAPCD. The source testing requirements do not limit generation.

The San Diego Air Pollution Control District is located at 9150 Chesapeake Drive, San Diego, CA 92123.

Monthly Reserved MWh for Air Emission Limitations
Schedule P will not be applicable for Contract Year 2004.

Month	Reserved MWh	Month	Reserved MWh
January		July	
February		August	
March		September	
April		October	
May		November	
June		December	

Operating Limits related to Ambient Temperatures

Ambient Temperature Correction Factors for Availability Test

Maximum Net Dependable Capacity of the combustion turbine is reduced from the winter rating by 0.5% for every 1 Deg F change in compressor inlet temperature above 80 Deg F.

Other Limits (e.g., cooling water discharge)

The South Bay Facility uses San Diego Bay water as the cooling medium for the steam turbine condensers. The use of this water is regulated by the plant's National Pollutant Discharge Elimination System (NPDES) permit. This permit may place operational limitations on the instantaneous and average loads of the Units.

4. Delivery Point

Unit	Transmission Node (Station Name)	Voltage
SY1	South Bay Power Plant Substation	69 KV
SY2	South Bay Power Plant Substation	138 KV
SY3	South Bay Power Plant Substation	138 KV
SY4	South Bay Power Plant Substation	138 KV
SYCT	South Bay Power Plant Substation	69 KV

5. Metering and Related Arrangements

Unit	Meter Location	Meter (Manufacturer & Model No.)
South Bay Unit 1 Main Power Transformer	Unit 1 & 2 Battery Room	Process Systems, Inc., Quad 4 Plus model
South Bay Unit 1-2B Auxillary Transformer	Unit 1 & 2 Battery Room	Process Systems, Inc., Quad 4 Plus model
South Bay Unit 2 Main Power Transformer	Unit 1 & 2 Battery Room	Process Systems, Inc. Quad 4 Plus model
South Bay Unit 3 Main Power Transformer	Unit 3, North Wall	Process Systems, Inc. Quad 4 Plus model
South Bay Unit 3-4B Auxillary Transformer	Unit 4, North Wall	Process Systems, Inc. Quad 4 Plus model
South Bay Unit 4 Main Power Transformer	Unit 4, North Wall	Process Systems, Inc. Quad 4 Plus model
South Bay Gas Turbine Power Transformer	Gas Turbine	Process Systems, Inc., Quad 4 Plus model

6. Start-up Lead Times

Unit	Start-up Segment Number	Generating Unit Down Time (Minutes)*	Generating Unit Start-up Time (Minutes)
SY1	1	0	0
SY1	2	240	240
SY1	3	600	241
SY1	4	840	481
SY1	5	2880	840
SY2	1	0	0
SY2	2	240	240
SY2	3	420	241
SY2	4	600	480
SY2	5	840	840
SY3	1	0	0
SY3	2	240	240
SY3	3	600	241
SY3	4	840	480
SY3	5	2880	840
SY4	1	0	0
SY4	2	180	180
SY4	3	360	181
SY4	4	480	240
SY4	5	600	600
SYCT	1	0	0
SYCT	2	60	15

"X_{max}" used in Schedules C and D shall be equal to or less than the hours in the heading of this column.

The Start-up Lead Time shall be the Startup Time as defined and submitted by the Owner through the process outlined in the ISO Tariff.

7. Ramping Constraint

Duration in hours from Synchronization to Unrestricted AGC Capability when the Unit is started from a initial start-up condition of hot, warm or cold:

None

8. Ramp Rate

Unit	Ramp Rate Point Number	Output of Point Range (MW)	Minimum Ramp Rate (MW/Minute)	Maximum Ramp Rate (MW/Minute)
SY1	1	30	1	4
SY1	2	146	1	4
SY2	1	30	1	4
SY2	2	149.6	1	4
SY3	1	30	1	4
SY3	2	175	1	4
SY4	1	45	1	4.5
SY4	2	222	1	4.5
SYCT	1	10	1	3.57
SYCT	2	15	1	3.57

Separate Ramp Rates will be shown for each load range and will describe any special restrictions affecting Ramp Rates at various load points, e.g., feed pumps.

The ISO Master File values shall be set equal to the values in this section and the Ramp Rate used in the ISO systems shall be the Operational Ramp Rate submitted by the Owner through the process outlined in the ISO Tariff.

9. Minimum Load

Unit	Minimum Operating Level (PMIN) (MW)	Minimum Dispatchable Level (MDL) (should be > or = PMIN) (MW)
SY1	30	30
SY2	30	30
SY3	30	30
SY4	45	45
SYCT	10	15

The Minimum Load for dispatch and settlement shall be the Minimum Operating Level in the ISO Master File or as modified by the Owner through the process outlined in the ISO Tariff via an ISO provided reporting system for any approved change in physical constraints.

The Minimum Operating Level for dispatch purposes is defined as the level at which the Unit can operate on a sustained basis. The Minimum Dispatchable Level shall define the minimum level to be used when the Unit is required to readily respond to an ISO dispatch instruction.

The Minimum Operating Level value(s) listed in the table above shall be used to determine the B coefficient for each respective Unit in Schedule D, Table D-1 for the calculation of Start-up Costs.

10. Minimum Run Time

Unit	Hours
SY1	8.0
SY2	6.0
SY3	8.0
SY4	4.0
SYCT	1.0

11. Minimum Off Time

Unit	Hours
SY1	48.0
SY2	7.0
SY3	48.0
SY4	6.0
SYCT	0.5

12. Contract Service Limits

Unit	Maximum Annual MWh	Maximum Annual Service Hrs	Maximum Annual Start-ups
SY1	388,098	5,603	11
SY2	375,019	5,648	21
SY3	356,054	5,058	16
SY4	148,191	1,961	14
SYCT	1,246	89	15

13. Owner's Repair Cost Obligation

Owners Repair Cost Obligation for the current Contract Year is $574,032.

14. Existing Contractual Limitations and Other Contract Restrictions on Market Transactions

15. Applicable UDC Tariff(s)

Schedule D- Schedule AL-TOU, General Service – Large – Time Metered, Transmission Service

Schedule B

Monthly Option Payment

The formulas and values used to compute the Monthly Option Payment in accordance with Section 8.1 and Section 8.2 for each Unit for each Month are set forth in Equation B-1 below:

Equation B-1

$$\text{Monthly Option Payment} = \text{Monthly Availability Payment} + \text{Monthly Surcharge Payment} - \text{Monthly Nonperformance Penalty}$$

The Monthly Option Payment can never be less than zero.

1. The Monthly Availability Payment is calculated in accordance with Equation B-2 below:

Equation B-2

$$\text{Monthly Availability Payment (\$)} = \text{lesser of } \text{Current Monthly Availability Payment (\$)} \text{ or } \text{100\% of AFRR minus Cumulative Monthly Availability Payments Excluding Current Monthly Availability Payment (\$)}$$

2. The Current Monthly Availability Payment is calculated in accordance with Equation B-3 below:

Equation B-3

$$\text{Current Monthly Availability Payment (\$)} = \text{Sum for all hours} \left[\text{Hourly Availability Charge (\$/hr)} * \frac{\text{Unit Availability Limit (MW)}}{\text{Maximum Net Dependable Capacity (MW)}} \right]$$

Where:

A. Hourly Availability Charge is calculated in accordance with Equation B-4 below:

Equation B-4

$$\text{Hourly Availability Charge} = \text{Hourly Availability Rate} * \text{Fixed Option Payment Factor}$$

Where:

Hourly Availability Rate is calculated in accordance with Equation B-5 below.

Equation B-5

$$\text{Hourly Availability Rate} = \frac{\text{Annual Fixed Revenue Requirement}}{\text{Target Available Hours}}$$

Annual Fixed Revenue Requirement is set forth in Section 7 below.

Target Available Hours are set forth in Section 6 below.

For Units under Condition 1, the Fixed Option Payment Factor is set forth in Table B-0 below:

Table B-0, Fixed Option Payment Factor

Unit	Fixed Option Payment Factor
SY1	0.0
SY2	0.0
SY3	0.0
SY4	0.0
SYCT	0.0

For Units under Condition 2, the Fixed Option Payment Factor is 1.

The Hourly Availability Charges for the Contract Year are set forth in Table B-1 below:

Table B-1, Hourly Availability Charges ($/Hr)

Unit	Condition 1	Condition 2
SY1	$0.00	$ 842.34
SY2	$0.00	$ 866.80
SY3	$0.00	$1,046.82
SY4	$0.00	$1,087.48
SYCT	$0.00	$ 81.34

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

3. The Monthly Surcharge Payment is calculated in accordance with Equation B-6 below:

Equation B-6

$$\text{Monthly Surcharge Payment (\$)} = \text{lesser of} \quad \text{Current Monthly Surcharge Payment (\$)} \quad \text{or} \quad \text{100\% of Sum of all Annual Capital Item Costs minus Cumulative Monthly Surcharge Payments Excluding Current Monthly Surcharge Payment (\$)}$$

4. The Current Monthly Surcharge Payment is calculated in accordance with Equation B-7 below:

Equation B-7

$$\text{Current Monthly Surcharge Payment (\$)} = \text{Sum for all hours} \left[\text{Sum of all Hourly Capital Item Charges (\$/hr)} * \frac{\text{Unit Availability Limit (MW)}}{\text{Maximum Net Dependable Capacity (MW)}} \right]$$

Where:

A. The Hourly Capital Item Charge for each Capital Item approved pursuant to Sections 7.4 or 7.6 is calculated in accordance with Equation B-8 below:

Equation B-8

$$\text{Hourly Capital Item Charge} = \text{Hourly Capital Item Rate} * \text{Surcharge Payment Factor}$$

Where:

Hourly Capital Item Rate is calculated in accordance with Equation B-9 below:

Equation B-9

$$\text{Hourly Capital Item Rate} = \frac{\text{Annual Capital Item Cost}}{\text{Target Available Hours}}$$

- Annual Capital Item Cost is the amount recoverable by Owner under this Agreement in a Contract Year for each Capital Item approved pursuant to Section 7.4 or Section 7.6.

- Target Available Hours are shown in Section 6 below.

- For Units under Condition 1, the Surcharge Payment Factor for all Capital Items covered by the Small Project Budget shall be the Fixed Option Payment Factor. For all other Capital Items, the Surcharge Payment Factor shall be as agreed to by Owner and ISO. If the Owner and ISO do not agree on the Surcharge Payment Factor, the Surcharge Payment Factor shall equal the Fixed Option Payment Factor, unless the Owner demonstrates in ADR that it would not have installed the proposed Capital Item in accordance with Good Industry Practice but for its obligations to the ISO under this Agreement, in which case the Surcharge Payment Factor shall be as determined in ADR.

For Units under Condition 2, the Surcharge Payment Factor is 1.

The Hourly Capital Item Charges for the Contract Year are set forth in Table B-2 below:

Table B-2

Unit	Capital Item Project No.	Annual Capital Item Cost	Condition 1 Surcharge Payment Factor	Condition 1 Hourly Capital Item Charge	Condition 2 Hourly Capital Item Charge
SY2	2001-1	$837,678.90	0.00	$0.00	$ 99.29
SY3	2001-2	$1,477,692.14	0.00	$0.00	$182.16
SYCT	2003-1	$189,753.81	0.00	$0.00	$22.21

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

5. The Monthly Nonperformance Penalty is calculated pursuant to Section 8.5 using the following variables:

A. Hourly Penalty Rate

A Unit's Hourly Penalty Rate for each Contract Year is the lesser of (a) the Unit's Hourly Availability Rate for the Contract Year (calculated pursuant to Item 2.A above), or (b) three times the Unit's Hourly Availability Charge for the Contract Year (as shown in Table B-1 above).

The Hourly Penalty Rates for the Contract Year are set forth in Table B-3 below:

Table B-3, Hourly Penalty Rate

Unit	Condition 1	Condition 2
SY1	$0.00	$ 842.34
SY2	$0.00	$ 866.80
SY3	$0.00	$1,046.82
SY4	$0.00	$1,087.48
SYCT	$0.00	$ 81.34

B. <u>Hourly Surcharge Penalty Rate</u>

A Unit's Hourly Surcharge Penalty Rate for each Capital Item for each Contract Year is the lesser of (a) the corresponding Hourly Capital Item Rate for the Contract Year (calculated pursuant to Item 4.A above), or (b) three times the applicable Hourly Capital Item Charge for the Contract Year (as shown in Table B-2 above). The Hourly Surcharge Penalty Rates for the Contract Year are set forth in Table B-4 below:

Table B-4

Unit	Capital Item Project No.	Hourly Capital Item Rate	Condition 1 Hourly Surcharge Penalty Rate	Condition 2 Hourly Surcharge Penalty Rate
SY2	2001-1	$ 99.29	$0.00	$99.29
SY3	2001-2	$182.16	$0.00	$182.16
SYCT	2003-1	$22.21	$0.00	$22.21

6. <u>Target Available Hours</u>

A Unit's Target Available Hours for each Contract Year are calculated in accordance with the Equation B-10 below:

Equation B-10

Target Available Hours (TAH) = Hours in the Calendar Year – (Average Other Outage Hours + Long-Term Planned Outage Hours)

Average Other Outage Hours means the average annual Other Outage Hours for the Unit during the 60-month period ending June 30 of the previous calendar year.

Long-term Planned Outage Hours means the Long-term Planned Outage Hours for the Contract Year scheduled with ISO pursuant to Section 7.2(a). For periods prior to December 31, 1998, Other Outage Hours shall exclude a planned interruption, in whole or in part, in the electrical output of a Unit to permit Owner to perform a major equipment overhaul or inspection or for new construction work, but only if the outage lasted 21 or more consecutive days.

Long-term Planned Outage Hours scheduled for a Contract Year shall be subject to the Long-term Scheduled Outage Adjustment pursuant to Section 8.6 of the Agreement.

The Average Other Outage Hours, Long-term Planned Outage Hours and Target Available Hours for each Unit for the Contract Year are shown in Table B-5 below:

Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH
SY1	365	None	8,395
SY2	323	None	8,437
SY3	648	None	8,112
SY4	527	None	8,233
SYCT	215	None	8,545

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.

7. Annual Fixed Revenue Requirement (AFRR)

The Annual Fixed Revenue Requirement for each Unit is set forth in Table B-6 below. For any Contract Year commencing on or after January 1, 2002, the Annual Fixed Revenue Requirement shall be determined by the Formula Rate set forth in Schedule F, unless Owner files a superseding rate schedule under Section 205 of the Federal Power Act.

Table B-6, Annual Fixed Revenue Requirement

Unit	Annual Fixed Revenue Requirement
SY1	$7,071,465
SY2	$7,313,225
SY3	$8,491,802
SY4	$8,953,245
SYCT	$ 695,059

8. <u>Limited Section 205 Filing for an Extension of Contract Term</u>

If ISO has extended the term of this Agreement pursuant to Section 2.1(b), then not later than October 31 of the expiring Contract Year, Owner shall make a filing with FERC under Section 205 of the Federal Power Act containing the values in Tables B-1 through B-6 for the ensuing Contract Year.

In the event that a Long-term Planned Outage that is scheduled for the last quarter of the expiring Contract Year is postponed or rescheduled after October 31 of such year to the ensuing Contract Year, Owner shall make an additional Section 205 filing to revise the values in Tables B-1 through B-5 to reflect such rescheduled Long-term Planned Outage Hours.

SCHEDULE C

Variable Cost Payment
Part 1 for Thermal Units

The Variable Cost Payment for each Unit for the Billing Month shall be the amount calculated in accordance with the following formula:

Variable Cost Payment =
A. ISO Unit Monthly Billed Fuel Cost +
B. ISO Unit Monthly Fuel Imbalance Charge +
C. ISO Monthly Other Fuel Related Cost +
D. ISO Monthly Emissions Cost +
E. ISO Monthly Variable O&M Cost +
F. ISO Scheduling Coordinator Charge +
G ISO ACA Charge

Each component of the Variable Cost Payment for thermal Units will be calculated as described below:

A. ISO Unit Monthly Billed Fuel Cost

The ISO Unit Monthly Billed Fuel Cost is calculated in accordance with Equation C1-0.

Equation C1-0

$$\text{ISO Unit Monthly Billed Fuel Cost (\$)} = \frac{\text{Monthly sum of the ISO Unit Hourly Cap Heat Input for this Unit (MMBtu)}}{\text{Monthly sum of the ISO Unit Hourly Cap Heat Input for all Units at Facility (MMBtu)}} \times \text{ISO Facility Monthly Billed Fuel Cost}$$

Where:

- ISO Unit Hourly Cap Heat Input for each Unit is calculated in accordance with Equation C1-6;
- The ISO Facility Monthly Billed Fuel Cost is calculated in accordance with Equation C1-1.

1. The ISO Facility Monthly Billed Fuel Cost

The ISO Facility Monthly Billed Fuel Cost is calculated in accordance with Equation C1-1.

Equation C1-1

$$\begin{pmatrix}\text{ISO Facility}\\ \text{Monthly}\\ \text{Billed}\\ \text{Fuel Cost}\\ (\$)\end{pmatrix} = \text{Lesser of} \begin{pmatrix}\text{ISO Facility}\\ \text{Cumulative}\\ \text{Actual}\\ \text{Fuel Cost}\\ (\$)\end{pmatrix} \text{ or } \begin{pmatrix}\text{ISO Facility}\\ \text{Cumulative}\\ \text{Cap}\\ \text{Fuel Cost}\\ (\$)\end{pmatrix} - \begin{pmatrix}\text{ISO Facility}\\ \text{Cumulative}\\ \text{Billed}\\ \text{Fuel Cost}\\ (\$)\end{pmatrix}$$

Where:

- The ISO Facility Cumulative Actual Fuel Cost is the sum of all ISO Unit Monthly Actual Fuel Costs for all Units at the Facility since the start of the Contract Year, including the current Month. ISO Unit Monthly Actual Fuel Costs for each Unit is calculated in accordance with Equation C1-2.
- The ISO Facility Cumulative Cap Fuel Cost is the sum of all ISO Unit Monthly Cap Fuel Costs for all Units at the Facility since the start of the Contract Year, including the current Month. ISO Unit Monthly Cap Fuel Costs is the sum of the ISO Unit Hourly Cap Fuel Cost (calculated pursuant to Equation C1-5) for each hour of the Month for each Unit.
- The ISO Facility Cumulative Billed Fuel Cost is the sum of all ISO Unit Monthly Billed Fuel Costs for all Units at the Facility since the start of the Contract Year, excluding the current Month. ISO Unit Monthly Billed Fuel Cost for each Unit is calculated in accordance with Equation C1-0.

2. ISO Unit Monthly Actual Fuel Cost

The ISO Unit Monthly Actual Fuel Cost is calculated in accordance with Equation C1-2.

Equation C1-2

$$\begin{pmatrix}\text{ISO Unit}\\ \text{Monthly}\\ \text{Actual}\\ \text{Fuel Cost}\\ (\$)\end{pmatrix} = \frac{\begin{matrix}\text{Monthly sum of the ISO}\\ \text{Unit Hourly Cap Heat Input}\\ \text{for the Unit}\\ \text{(MMBtu)}\end{matrix}}{\begin{matrix}\text{Monthly sum of the}\\ \text{Unit Hourly Cap Heat Inputs}\\ \text{for all units at the Facility}\\ \text{metered by the Fuel Meter}\\ \text{(MMBtu)}\end{matrix}} \times \left[\begin{pmatrix}\text{Monthly}\\ \text{Metered}\\ \text{Fuel}\\ \text{(MMBtu)}\end{pmatrix} \times \begin{pmatrix}\text{ISO}\\ \text{Monthly}\\ \text{Fuel}\\ \text{Price}\\ (\$/\text{MMBtu})\end{pmatrix} - \begin{pmatrix}\text{Monthly}\\ \text{Start-up}\\ \text{Fuel Cost}\\ (\$)\end{pmatrix}\right]$$

Where:

- ISO Unit Hourly Cap Heat Input is calculated in accordance with Equation C1-6.

- Unit Hourly Cap Heat Input is calculated in accordance with either Equation C1-7a or C1-7b.

- Monthly Metered Fuel is the non-duplicative sum of the quantities of fuel for the Month as measured by all gas metering systems or fuel oil measuring systems, as applicable ("Fuel Meters"), for the Unit.

(a) If the fuel is natural gas, the Owner may select from one of three options for the Fuel Meter:

(i) the revenue meter used by the entity providing natural gas to measure gas delivered to one or more Units ("Fuel Custody Meter");

(i) a gas metering system installed at the Facility to measure gas used in one or more Units that meets the measurement accuracy standard in the tariff of the local gas distribution company in whose service area the Facility is located and the measurement accuracy standards set forth below, and is subject to an annual accuracy test performed under the ISO's direction, as described below; or

(iii) a gas metering system installed at the Facility by the local gas distribution company in whose service area the Facility is located and maintained by the local gas distribution company to the same standards as revenue meters of the local gas distribution company.

For the selected Fuel Meter option, the Owner shall provide the required information for all Units, both RMR and non-RMR, connected to the specific Fuel Custody Meter.

If the Owner selects option (ii), the Owner shall assure the overall accuracy of the gas metering systems[1] in use for the Units are within acceptable industry and regulatory standards.[2] Gas metering systems shall be designed, installed, calibrated and maintained according to standards set forth by the American Gas Association (AGA), the American National Standards Institute (ANSI) and the California Public Utilities Commission (CPUC). An audit trail of all calibration records and measurement parameters used in volume and heating-value calculations as recorded electronically by the flow computer shall be maintained and all data shall be in no-longer-than-hourly intervals. All equations and calculations performed by the flow computer may be reviewed for accuracy and completeness, including compressibility, volumetric

---

[1] The gas metering system includes the primary measurement element (orifice, turbine meter, etc.); secondary elements such as pressure, temperature and heating-value measurement devices; the gas chromatograph, the flow computer or other data-collection and storage device; and the communication or output system.

[2] The American Gas Association (AGA) and the American National Standards Institute (ANSI) publish industry standards that gas utilities and gas transportation companies use for gas metering. Applicable standards include: AGA Report No. 3, Orifice Metering of Natural Gas; AGA Report No. 7, Measurement of Gas by Turbine Meters, AGA Report No. 8, Compressibility Factors of Natural Gas; AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters; ANSI B109.2, Diaphragm Type Gas Displacement Meters; and ANSI B109.3 Rotary Type Gas Displacement Meters. Also, CPUC General Order 58-A requires customer meters to register accurately to within –2% to 1%.

flow and energy flow, by the ISO or its agent. A consistent base pressure (14.73 psi) and base temperature (60° F) shall be used at all times. If the Facility has multiple sources of fuel gas, a gas chromatograph ("GC") shall be installed which analyzes all constituents of the blended gas, with the sampling point downstream of the individual supplies such that proper mixing occurs prior to sampling. The GC speed loop shall permit analysis of the gas in "real time".

In order to ensure the accuracy of a gas metering system selected under option (ii), an initial acceptance test shall be conducted by Owner and shall be witnessed by the ISO or its agent to assure the installation meets applicable industry standards. Such a test shall be conducted at five load points (maximum load, minimum load, and three evenly spaced load points), under steady state conditions (i.e., off Automatic Generation Control), and for a minimum of one hour at each load point. Analysis of the test results shall consist of a side-by-side comparison of volumetric flow, energy flow, gas-specific gravity and mole percents, and other factors mutually agreed to by the ISO and Owner for the Fuel Custody Meter and the meter installed at the Facility under option (ii). The gas metering system installed under option (ii) shall be deemed acceptable if the side-by-side energy flow comparison for the period shall be within +1 percent to –2 percent. The gas-metering system shall meet the required accuracy throughout the entire operating range of the RMR Unit. Following ISO acceptance, an annual routine test shall be conducted at a time chosen by the ISO to verify and confirm the performance of Owner's gas-metering system. With the exception that the test shall be conducted at one load point specified by the ISO, such a test shall be conducted in a similar fashion to the initial acceptance test and shall include inspection of the primary flow element; instrument end-to-end calibration; confirmation of integrity of sensing lines (meaning there shall be no leaks); confirmation of proper GC operation; and proper flow-computer operation and data handling. All systems and sub-systems utilized during the initial acceptance test, including, but not limited to, (a) all primary devices, including the differential producing device of the gas metering system, the GC, and differential pressure ("dP") and temperature instruments; (b) all secondary devices and circuits, including dP and temperature transmitters and circuits, sensing lines, GC sampling line and secondary circuits; and (c) all electronic devices, flow computers and devices, shall be sealed with an ISO-certified seal and no maintenance work or modifications and changes, including making any changes to flow computer programming, shall be permitted without prior approval by the ISO.

If any part of the option (ii) gas-metering system requires either routine or emergency maintenance, the Owner shall notify the ISO immediately by telephone or other means specified by the ISO. The Owner shall inform the ISO of the time period during which such maintenance is expected to occur. The ISO may, at its discretion, require gas-metering systems which are changed or modified during maintenance or repair to undergo re-certification, including acceptance testing. If the maintenance activity is necessary due to concerns that the gas-metering system is not operating in accordance with the required accuracy standards, such maintenance work shall be completed within 2 business days from the time when the concern was first noted.
A V-cone meter may not be used under option (ii), unless the meter was installed prior to January 1, 1997.

If, as a result of a change in the use of fuel gas from a supplier other than the local distribution company, the properties of the fuel gas change materially (Higher Heating Value (HHV) or Specific Gravity (SG) varies more than –3 percent to +3 percent due to the addition of new gas constituents) following the installation of a gas metering system under option (ii) or option (iii), Owner shall notify the ISO within twenty-four (24) hours. Acceptance testing shall be conducted to verify the metering accuracy due to the change in fuel gas supply and to test whether Owner's gas metering system meets the technical requirements of this specification. Owner shall be obligated to install any equipment necessary to bring its gas metering system into compliance. Owner shall not enter into any third-party agreements for non-pipeline grade fuel gas without the prior approval of the ISO. Such approval shall not be granted until the ISO has evaluated Owner's gas metering system, including the effect of the non-pipeline grade fuel gas on metering accuracy.

If an Owner selects option (iii) and the Facility has multiple sources of fuel gas, the local gas distribution company shall install a GC which analyzes all constituents of the blended gas, with the sampling point downstream of the individual supplies such that proper mixing occurs prior to sampling. The GC speed loop should permit analysis of the gas in "real time".

(b) If the fuel is other than natural gas, the Fuel Meter value shall be determined monthly by measuring the fuel oil consumed during the month using, at Owner's one-time election, either (i) a metering process which is acceptable to the Owner and ISO or (ii) a calculation acceptable to the Owner and ISO based on a tank-volume measurement process performed on the day immediately prior to the beginning of the Month and the last day of the Month and fuel oil deliveries during the Month. The metering or measurement process adopted shall comply with, or be comparable to, one or more applicable American Petroleum Institute ("API") Manual of Petroleum Measurement Standards.[3] If Owner and ISO cannot agree on an acceptable process, it shall be determined through ADR pursuant to Schedule K to this Agreement. Owner shall be permitted to change its election between metering as described in (i) above or tank volume measurement described in (ii) above only to reflect changes in the physical circumstances of the Unit or a change in the type of fuel burned at the Unit.

During any period in which the Fuel Meter fails to accurately measure gas flow, the Owner shall provide information to the ISO sufficient to estimate the gas flow during such failure. This information may include unit electric-generating history, accurate recorded gas flow based on another meter and heat input characteristics of all Units served by the failed meter. This information will be used to estimate the gas flow during the failure period to the mutual satisfaction of the ISO, the Responsible Utility and the Owner.

If a Fuel Meter serves RMR Units as well as other units, the heat input characteristics of the other units will be included in Table C1-7a or C1-7b, as applicable, and the Monthly sum of the Unit Hourly Cap Heat Inputs for all units at the Facility metered by

---

[3] The applicable API Manual of Petroleum Measurement Standards are: Chapter 2.2A (Measurement and Calibration of Upright Cylindrical Tanks by the Manual Strapping Method); Chapter 3.1B (Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging); Chapter 3.3 (Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging); Chapter 5.2 (Measurement of Liquid Hydrocarbons by Displacement Meters); and Chapter 5.3 (Measurement of Liquid Hydrocarbons by Turbine Meters).

the Fuel Meter used in Equation C1-2 will include Hourly Cap Heat Inputs for such other units calculated using Equation C1-7a or C1-7b, whichever is applicable.

- ISO Monthly Fuel Price is calculated in accordance with Equation C1-3.

- Monthly Start-Up Fuel Cost is the sum of the Start-Up Fuel Costs for all Start-ups (for Market and Nonmarket Transactions) in the Month for all units metered by the Fuel Meter with the Start-up Fuel Costs for each Unit calculated in accordance with Equations D-1a or D-1b in Schedule D, as applicable. If a Start-up is initiated but is not successfully completed, the Start-up Fuel Costs shall be adjusted in accordance with Equation C1-2a:

Equation C1-2a

$$\text{Adjusted Start-up Fuel Cost for Canceled Starts (\$)} = \frac{\text{Number of hours committed to the Start-up}}{\text{Applicable Start-up Lead Time in hours shown in Section 6 of Schedule A}} \times \text{Start-up Fuel Costs (\$)}$$

Where:

- The "number of hours committed to the Start-up" is the lesser of (a) time elapsed between the initiation of the Start-up and the cancellation or (b) the Applicable Start-up Lead Time as shown in Section 6 of Schedule A.

3. ISO Monthly Fuel Price

The ISO Monthly Fuel Price is calculated in accordance with Equation C1-3.

Equation C1-3

$$\text{ISO Monthly Fuel Price (\$/MMBtu)} = \frac{\text{Monthly sum of ISO Unit Hourly Cap Fuel Cost (\$)}}{\text{Monthly sum of ISO Unit Hourly Cap Heat Input (MMBtu)}}$$

Where:

- ISO Unit Hourly Cap Fuel Cost ($) is calculated in accordance with Equation C1-5;

- ISO Unit Hourly Cap Heat Input (MMBtu) is calculated in accordance with Equation C1-6.

4. Intentionally Omitted (There is no Equation C1-4.)

5. ISO Unit Hourly Cap Fuel Cost

For each hour, the ISO Unit Hourly Cap Fuel Cost is calculated in accordance with Equation C1-5.

Equation C1-5

ISO Unit Hourly Cap Fuel Cost ($) = ISO Unit Hourly Cap Heat Input (MMBtu) * Hourly Fuel Price ($/MMBtu)

Where:

- The Hourly Fuel Price is calculated in accordance with Equation C1-8;
- The ISO Unit Hourly Cap Heat Input (MMBtu) is calculated in accordance with Equation C1-6.

6. ISO Unit Hourly Cap Heat Input

For each hour, the ISO Unit Hourly Cap Heat Input is calculated in accordance with Equation C1-6.

Equation C1-6

$$\text{ISO Unit Hourly Cap Heat Input} = \text{Unit Hourly Cap Heat Input (MMBtu)} * \frac{\text{Billable MWh}}{\text{Hourly Metered Total Net Generation (MWh)}}$$

Where:

- Unit Hourly Cap Heat Input is calculated in accordance with either Equation C1-7a or C1-7b.

7. Unit Hourly Cap Heat Input (MMBtu)

The Unit Hourly Cap Heat Input to a Unit for any load is given by the following equations and shall be determined either by a polynomial equation (C1-7a) or exponential equation (C1-7b):

Equation C1-7a

$$\text{Unit Hourly Cap Heat Input} = 1.02 * (AX^3 + BX^2 + CX + D) * E$$

Equation C1-7b

$$\text{Unit Hourly Cap Heat Input} = 1.02 * (A * (B + CX + De^{FX})) * E$$

Where:

- X is Unit's Hourly Metered Total Net Generation, MWh;
- e is the base of natural logarithms;
- A, B, C, D are coefficients given for Equation C1-7a in Table C1-7a and given for Equation C1-7b in Table C1-7b;
- The coefficient E is applicable only when burning fuel oil. At all other times, it shall be set to 1.0.
- F is a coefficient given in Table C1-7b.

Table C1-7a

Unit	A	B	C	D	E
Coefficients					
SY1	-1.6900E-04	4.8108E-02	5.32025	195.82605	.954
SY2	-3.5900E-05	1.1695E-02	8.2045	119.8935	.954
SY3	-1.8400E-04	6.2385E-02	3.79015	286.0515	.954
Sy4	1.22273E-05	5.18492E-07	11.1475	114.736	.954
SYCT (Jet Fuel)	1.3707E-03	1.4520E-04	9.6409	62.9260	

Table C1-7b

A	B	C	D	E	F

8. Hourly Fuel Price

The Hourly Fuel Price for Units shall be the same for each hour of a given day and is calculated in accordance with Equation C1-8.

Equation C1-8 (Gas)

Hourly Fuel Price ($/MMBtu) = Commodity Price ($/MMBtu) + Intrastate Transportation Rate ($/MMBtu)

Equation C1-8 (Oil)

Hourly Fuel Price ($/MMBtu) = Commodity Price ($/MMBtu) + Transportation Rate ($/MMBtu)

Commodity Price for Natural Gas

For the Facilities within the service area of SCE or SDG&E, the Commodity Price shall be the product of 1.02 and the simple average of the following indices:

Gas Daily, SoCal Gas, Large Packages index (midpoint)
BTU Daily Gas Wire, SoCal Border index, Topock
NGI Daily Gas Price Index, Southern California Border (average)

For the Facilities within the service territory of PG&E, the Commodity Price shall be the product of 1.02 and the simple average of the following indices:

Gas Daily, PG&E Citygate index (midpoint)
NGI Daily Gas Price Index, PG&E Citygate (average)

The indices to be used for each Settlement Period in a given day are shown in Table C1-8. Where more than one day's index is shown for a Trading Day, the average of the two daily indices should be used. If an applicable index for a day, which is used to compute the index's average for a Trading Day, is not published, then that index will not be used to compute the Commodity Price for that trading day. If no index for a day is published, then the average of applicable indices on the Index Publication Date preceding and the Index Publication Date following such day will be substituted for the Index Publication Date index for that day in Table C1-8. In the event that an index ceases to be published, Parties shall agree on a replacement index.

Table C1-8
Natural Gas Price Indices

	Index Publication Date*		
Trading Day	Gas Daily **	Btu Daily ** Gas Wire	NGI Daily ** Price Index
Tuesday	Tuesday/ Wednesday	Monday/ Tuesday	Tuesday/ Wednesday
Wednesday	Wednesday/ Thursday	Tuesday/ Wednesday	Wednesday/ Thursday
Thursday	Thursday/ Friday	Wednesday/ Thursday	Thursday/ Friday

Friday	Friday/ Monday	Thursday/ Friday	Friday/ Monday
Saturday	Monday/ Tuesday	Friday/ Monday	Monday/ Tuesday
Sunday	Monday/ Tuesday	Friday/ Monday	Monday/ Tuesday
Monday	Monday/ Tuesday	Friday/ Monday	Monday/ Tuesday

Where:

. The Index Publication Date is the date on which the publication is published.

* *The Index Publication Date is the date of the publication which contains the prices for the applicable Trading Day.*

** *Where more than one day's index is shown for a Trading Day, the average of the two daily indices should be used.*

Gas Daily: The "Flow Date(s)" column should match the Trading Day.

Btu Daily: The Index Publication Date should be the day prior to the Trading Date in the Table above, except for Sunday and Monday, where Friday should be used as the Index Publication Date.

NGI Daily: The Index Publication Date should be the same as the Trading Date in the tables above, except for Saturday and Sunday, where Monday should be used as the Index Publication Date.

Commodity Price for Distillate Fuel Oil

The Commodity Price for Distillate Fuel Oil shall be the simple average of the midpoint of the ranges for CARB No. 2 Diesel and for Jet as published in Platt's Oilgram United States West Coast Product Assessments (page 22). If the Unit can burn only Jet, the Commodity Price shall be the midpoint of the range for Jet.

In an event the index ceases to be published, the Parties shall agree on a replacement index.

For distillate fuel, the index will be for the last day prior to the RMR Transaction Day.

Commodity Price for No. 6 Residual Fuel Oil

The fuel price shall be the prudent actual replacement cost of the fuel consumed, or, if the fuel is consumed and not replaced, then the fuel price will be "last-in-first-out" (LIFO) inventory price of the fuel consumed.

Where conversion from barrels of Fuel to MMBtu is required, the following conversion coefficients shall be used:

- No. 1 Distillate Fuel Oil - 5.754 MMBtu per barrel;

- No. 2 Distillate Fuel Oil - 5.796 MMBtu per barrel;
- Jet Fuel - 5.650 MMBtu per barrel;
- No. 6 Residual Fuel Oil - 6.258 MMBtu per barrel.

Intrastate Transportation Rate for Gas

The Intrastate Transportation Rate for Gas shall be the applicable intrastate transportation rate determined as follows:

Units served by SDG&E: The Southern California Gas Company intrastate transportation rate (currently GT-SD) plus the volumetric component of the SDG&E gas transportation rate for electric generation service, including the ITCS[4] (currently GTUEG – SD), or any successor rate for electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.

Units served by Southern California Gas: The Southern California Gas Company intrastate transportation rate for firm electric generation service, including the ITCS (GT-F) plus the G-ITC Wheeler Ridge Interconnection Access fee, if applicable, or any successor rate for firm electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.

Units served by PG&E: The PG&E intrastate transportation charge stated in Rate Schedule G-EG, or any successor rate for electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.[5]

Transportation Rate for Distillate Fuel Oil

The Transportation Rate for Distillate Fuel Oil shall be $0.025 per gallon. There shall be no Transportation Rate for No. 6 Residual Fuel Oil.

B. ISO Monthly Fuel Imbalance Charge

Levels of Responsibility

Each month, the Owner is responsible for all Nonmarket fuel imbalance charges incurred up to and including 2.25 percent of the ISO Facility Monthly Billed Fuel Cost.

The Monthly Fuel Imbalance Charge is equal to 75% of 1st Tier Imbalance plus 100% of 2nd Tier Imbalances;

---

[4] ITCS means Interstate Transition Cost Surcharges.

[5] If the Facility does not qualify for service under Rate Schedule G-EG, the applicable rate shall be given by Rate Schedule G-NT.

Where:

The **1st Tier Imbalances** is that portion of the Monthly Sum of Daily Imbalance Charges which exceeds 2.25 percent of the ISO Facility Monthly Billed Fuel Cost for the Month and is less than or equal to 10.0 percent of the ISO Facility Monthly Billed Fuel Cost for the Month.

The **2nd Tier Imbalances** is that portion of the Monthly Sum of Daily Imbalance Charges which is greater than 10.0 percent of the ISO Facility Monthly Billed Fuel Cost for the Month.

The Monthly Sum of Daily Imbalance Charges is the sum for all days in the month of imbalance charges and similar fees and penalties imposed on Owner (or its fuel supplier and paid by Owner) by transportation providers delivering gas to the Units because deliveries were in excess of or less than scheduled for a given day, but only to the extent that (i) the imbalance was caused by Owner compliance with a Dispatch Notice issued after (or less than 30 minutes prior) to the Transporter's deadline for scheduling transportation, and (ii) Owner issued a notice to the ISO as soon as possible after the Owner became aware it might incur imbalance charges advising ISO of such possible charges.

In any month in which Owner incurs a 1^{st} Tier or 2^{nd} Tier Imbalance charge, Owner will provide the ISO with a report showing the allocation of the imbalance charges between Market Transactions and Nonmarket Transactions. If ISO or the Responsible Utility disagree on allocation, the dispute will be resolved through ADR.

To receive payment for a 2nd Tier Imbalance, Owner must document in an informational filing with FERC that the charges were appropriately allocated to Nonmarket Transactions and it was commercially reasonable to incur them. As used in this context and for purposes of calculating imbalance charges, "commercially reasonable" does not mean that Owner is required to acquire storage to avoid imbalances. If either the ISO or Responsible Utility disagree with the imbalance charges, desires a formal review and gives such notice to the Owner within 30 days of the informational filing, the Owner must file under Section 205 of the Federal Power Act to collect any 2^{nd} Tier Imbalance charges.

Pursuant to the above, the Monthly Fuel Imbalance Charge is calculated in accordance with Equation C1-9.

Equation C1-9

$$\text{Monthly Fuel Imbalance Charge} = 0.75 \text{ X } \left[\text{Monthly Sum of Daily Imbalance Charges} - 0.0225 \text{ X } \text{ISO Facility Monthly Billed Fuel Cost} \right] + 0.25 \text{ X } \left[\text{Monthly Sum Of Daily Imbalance Charges} - .10 \text{ X } \text{ISO Facility Monthly Billed Fuel Cost} \right]$$

Note that if either of the two bracketed portions of the equation yields a value less than or equal to zero, then that portion of the equation is set to zero.

C. ISO Monthly Other Fuel Related Cost

The ISO Monthly Other Fuel Related Cost is calculated in accordance with Equation C1-10.

Equation C1-10

$$\text{ISO Monthly Other Fuel Related Cost} = \frac{\text{Monthly sum of Billable MWh}}{\text{Monthly sum of Total Hourly Metered Net Generation}} * \left[\text{Other Gas Tariff Charges} + \text{Applicable Taxes} \right]$$

Where:

- Other Gas Tariff Charges are those intrastate gas transportation tariff charges not included in Transportation Rate Charges set forth in Section A.8 of this Schedule listed below:

  GTUEG – SD Demand Charge

- Applicable taxes and fees are:

  1. State Regulatory Fee (Schedule G-PUC) $0.0076/mmbtu, if applicable.
  2. Franchise Fee Surcharge (Schedule GP-SUR), if applicable.
  3. Utility User Tax (City of Chula Vista) $0.0919/mmbtu, if applicable.

All other fuel related taxes and fees are intended to be covered by the two percent adder in Hourly Fuel Cost and are the Owner's responsibility.

D. ISO Monthly Emissions Cost

Part 1 for SCAQMD-Jurisdictional Thermal Units

The ISO Monthly Emissions Cost for each Unit shall be the sum, for all hours in the month, of the ISO Hourly Emissions Cost. These costs apply to a Facility within the South Coast Air Quality Management District (SCAQMD).

The ISO Hourly Emissions Cost shall be calculated in accordance with Equation C1-11.

Equation C1-11

ISO Hourly Emissions Cost ($/hr) =
a. ISO Hourly RECLAIM Trading Credit Cost ($/hr) +
b. ISO Hourly NOx Emissions Cost ($/hr) +

c. ISO Hourly Organic Gases Emissions Cost ($/hr) +
d. ISO Hourly Sulfur Oxides Emissions Cost ($/hr) +
e. ISO Hourly Particulate Matter Emissions Cost ($/hr)+
f. ISO Hourly Carbon Monoxide Emissions Cost ($/hr) +
g. ISO Hourly Sulfur Dioxides Trading Credit Costs ($/hr)

a. <u>ISO Hourly RECLAIM Trading Credit Cost</u>

For each hour, the ISO Hourly RECLAIM Trading Credit ("RTC") Cost for NOx emissions required for the Unit to generate the Billable MWh is calculated in accordance with Equation C1-12.

Equation C1-12

$$\text{ISO Hourly RECLAIM Trading Credit Cost (\$/hr)} = \text{Hourly } NO_x \text{ Emissions (lbs/hr)} * \text{RECLAIM } NO_x \text{ Trading Credit Rate (\$/lb)} * \frac{\text{Billable MWh}}{\text{Hourly Metered Total Net Generation}}$$

Where:

- Hourly NOx Emissions is calculated in accordance with Equation C1-13.

Equation C1-13

$$\text{Hourly NOx Emissions (lbs/hr)} = AX^2 + BX + C$$

<u>Where</u>:

- X is the Hourly Metered Total Net Generation for the hour.
- Coefficients A, B, and C are given in Table C1-13 for each Unit.

Table C1-13

Description of Unit	**A**	**B**	**C**

The RECLAIM NOx Trading Credit Rate ($/lb) will be equal to the 13-week sales-weighted average sales price for RTCs calculated as of the last day of the Month from sales records available from the SCAQMD for all actual sales in the SCAQMD during the thirteen preceding weeks, including the Settlement Period.

b. ISO Hourly NOx Emissions Cost

For each hour, the ISO Hourly NOx Emissions Cost for the Billable MWh is calculated in accordance with Equation C1-14.

Equation C1-14

$$\text{ISO Hourly NOx Emissions Cost (\$/hr)} = (5 * 10^{-4}) * \text{Hourly NOx Emissions (lbs/hr)} * \text{NOx Emissions Fee (\$/ton)} * \frac{\text{Billable MWh}}{\text{Hourly Metered Total Net Generation}}$$

Where:

- $(5 * 10^{-4})$ is the conversion factor from lbs to tons.
- Hourly NOx Emissions is calculated in accordance with Equation C1-13.
- NOx Emissions Fee is obtained from Table III of SCAQMD Rule 301(e). The fee is dependent upon the Cumulative Tons of Pollutant (NOx), which is calculated in accordance with Equation C1-15. The Cumulative Tons of Pollutant is reset to zero each July 1st.

Equation C1-15

$$\text{Cumulative Tons of Pollutant (tons/hr)} = \text{Tons of Pollutant From the prior July 1}^{st}\text{ to the Previous Hour} + \text{Tons of Pollutant For Current Hour}$$

Where:

- Tons of Pollutant for Current Hour is in accordance with Equation C1-16.

Equation C1-16

$$\text{Tons of Pollutant for Current Hour (tons/hr)} = (4.76 * 10^{-7}) * (AX^3 + BX^2 + CX + D) * \text{Pollutant Emissions Amount for Natural Gas}$$

Where:

- $(4.76 * 10^{-7})$ is the conversion factor from lbs. to tons (1 ton/2000 lbs.) and from mmcf to MMBtu (1 mmcf/1050 MMBtu).
- X is the Hourly Metered Total Net Generation, MWh.
- Coefficients A, B, C, and D are the coefficients of the hourly heat rate curve given in

Table C1-16 for each Unit.

Table C1-16

Description of Unit	A	B	C	D

Pollutant Emissions Amount For Natural Gas is the applicable pollutant from SCAQMD General Instruction Book (for the latest year), Annual Emissions Reporting Program, Appendix A - Common Emission Factors For Combustion Equipment, Table 1 - Common Emission Factors For Combustion Equipment for Forms B1 and B1U.

c. - f. <u>ISO Hourly Organic Gases Emissions Cost, ISO Hourly Sulfur Oxides Emissions Cost, ISO Hourly Particulate Matter Emissions Cost, and ISO Hourly Carbon Monoxide Emissions Cost</u>

The ISO Hourly Organic Gases (OG) Emissions Cost, ISO Hourly Sulfur Oxides (SOx) Emissions Cost, ISO Hourly Particulate Matter (PM) Emissions Cost, and ISO Hourly Carbon Monoxide (CO) Emissions Cost are each calculated in accordance with Equation C1-17.

Equation C1-17

$$\begin{array}{c} \text{ISO Hourly} \\ \text{Applicable} \\ \text{Emissions Cost} \\ (\$/\text{hr}) \end{array} = (4.76 * 10^{-7}) * \begin{array}{c} \text{ISO Unit Hourly} \\ \text{Cap Heat Input} \\ (\text{MMBtu/hr}) \end{array} * \begin{array}{c} \text{Associated} \\ \text{Emissions Factor} \\ (\text{lbs/mmcf}) \end{array} * \begin{array}{c} \text{Associated} \\ \text{Emissions Fee} \\ (\$/\text{ton}) \end{array}$$

Where:

- ISO Hourly Applicable Emissions Cost is the ISO Hourly OG Emissions Cost, ISO Hourly SOx Emissions Cost, ISO Hourly PM Emissions Cost, or ISO Hourly CO Emissions Cost.
- $(4.76 * 10^{-7})$ is the conversion factor from lbs. to tons (1 ton/2000 lbs.) and from mmcf to MMBtu (1 mmcf/1050 MMBtu).
- Associated Emissions Factor is the associated OG Emissions Factor, SOx Emissions Factor, PM Emissions Factor or CO Emissions Factor from Table 1 from General Instruction Book for the SCAQMD (for the latest year) Annual Emissions Reporting Program.
- Associated Emissions Fee is the associated OG Emissions Fee, SOx Emissions Fee, PM Emissions Fee, or CO Emissions Fee from Table III of SCAQMD Rule 301(e), and is dependent upon the Cumulative Tons of Pollutant pursuant to Equation C1-15.

g. **ISO Hourly Sulfur Dioxides Trading Credit Costs**

Beginning in the year 2000, certain Units will be subject to Title IV of the Federal Clean Air Act for providing SO_2 Allowances to cover related trading costs. Prior to 2000, the ISO Hourly Sulfur Dioxides Trading Credit Cost will be zero. The Owner may make a filing under Section 205 of the Federal Power Act limited to recovering applicable ISO Hourly Sulfur Dioxides Trading Credit Costs when such costs are incurred.

Part 2 for Ventura County Air Pollution Control District[6]

Beginning in the year 2000, certain Units will be subject to Title IV of the Federal Clean Air Act for providing SO_2 Allowances to cover related trading costs. Prior to 2000, the ISO Hourly Sulfur Dioxides Trading Credit Cost will be zero. The Owner may make a filing under Section 205 of the Federal Power Act limited to recovering applicable ISO Hourly Sulfur Dioxides Trading Credit Costs when such costs are incurred.

E. **ISO Monthly Variable O&M Cost**

The ISO Monthly Variable O&M Cost for each Unit shall be the product of the Unit's Billable MWh for the Billing Month and the Unit's Variable O&M Rate. Variable O&M Rate for each Unit shall be:

Table C1-18

Unit	Variable O&M Rate ($/MWh)
SY1	1.11
SY2	1.10
SY3	1.04
SY4	0.70
SYCT	0

F. **ISO Scheduling Coordinator Charge**

The ISO Scheduling Coordinator Charge for each Unit shall be the product of PX Administration Charge as charged under the PX Tariff and the Unit's Billable MWh for the Billing Month.

G. **ISO ACA Charge**

The ISO ACA Charge is the product of the Unit's Billable MWh for the Billing Month and the applicable annual charge for short-term sales under 18 CFR Section 382.201 of the FERC Regulations.

6 Ventura County APCD, where Mandalay Generating Station is located, does not require payment of emissions fees, but rather permit renewal fees. The permit renewal fees are included in the fixed O&M costs.

SCHEDULE C

Variable Cost Payment for All Conditions

Part 2 for Geothermal Units

NOT APPLICABLE

SCHEDULE C

Variable Cost Payment for All Conditions

Part 3 for Conventional Hydro Units

NOT APPLICABLE

SCHEDULE C

Variable Cost Payment for All Conditions

Part 4 for Pumped Storage Hydro Units

NOT APPLICABLE

SCHEDULE D

Part 1

Start-up Payment for Condition 1 Units

1. **Prepaid Start-up Charge**

Prepaid Start-up Charge for each Unit operating under Condition 1 for each Contract Year will be calculated as the Prepaid Start-up Cost times the number of Prepaid Start-ups. The number of Prepaid Start-up equals the Maximum Annual Start-ups per Unit. The Prepaid Start-up Cost will be calculated in accordance with Equation D-1 for Start-up Cost with the following assumptions:

a) Hourly Fuel Price: For the initial Contract Year the Hourly Fuel Price shall be the simple average of the applicable index prices from Table C1-8 of Schedule C for the period beginning on the later of the initial publication date of such indices or January 1, 1998 and ending December 31, 1998, plus the applicable Transportation Rate under Equation C1-8 as in effect on April 1, 1999. For each subsequent Contract Year, the Hourly Fuel Price shall be agreed upon by ISO and Owner; if there is no agreement, the Hourly Fuel Price shall be the simple average of the Hourly Fuel Prices for the twelve months ending the prior June 30 as calculated in accordance with Equation C1-8 of Schedule C;

b) Energy Price shall be based on the Applicable UDC Tariff rate, including applicable demand charges, provided that the Applicable UDC Tariff rate shall only be the energy charge rate at those Facilities where Units have the capability to use Energy from other units at the same Facility to effect Start-ups or where generation from other units is otherwise permitted under the ISO Tariff to be netted against auxiliary power needed to effect Start-up of the Unit. For the initial Contract Year, the Energy Price shall be calculated as the total auxiliary power (including Energy for Start-ups) costs charged to the Facility by its supplier of end-use Energy for the six-month period ending December 31, 1998 divided by the auxiliary power (including Energy for Start-ups) consumed at the Facility for that same time period. For Facilities that have not been charged for auxiliary power for the six-month period ending December 31, 1998, the Energy Price for the Initial Contract Year shall be the simple average of the prices for Energy for varying times of day shown in the Applicable UDC Tariff. For each subsequent Contract Year, the Energy Price shall be calculated as the total auxiliary power (including Energy for Start-ups) costs charged to the Facility by its supplier of end-use Energy for the twelve months ending the prior June 30 divided by the auxiliary power (including Energy for Start-ups) consumed at the Facility for that same twelve-month period;

c) All Start-ups are assumed to be from maximum time off line as shown by value X_{Max} in Table D-1, and

d) Other Start-up Costs shall be zero ($0) for non-hydroelectric Units; for hydroelectric Units, other Start-up costs shall be the cost shown in Table D-2 for Normal Work Hours.

THIS PAGE INTENTIONALLY LEFT BLANK

The Prepaid Start-up Cost and Prepaid Start-up Charge for the current Contract Year are set forth in Table D-0:

Table D-0

Unit	Number of Prepaid Start-ups	Prepaid Start-up Cost ($/start)	Prepaid Start-up Charge ($)
SY1	11	$15,108.56	$166,194.16
SY2	21	$14,381.71	$302,015.91
SY3	16	$17,367.22	$277,875.52
SY4	14	$18,389.00	$257,446.00
SYCT	15	$ 528.00	$ 7,920.00

2. **Start-up Cost**

The cost for a Start-up shall be calculated in accordance with Equation D-1:

Equation D-1

$$\underset{(\$)}{\text{Start-up Cost}} = \underset{(\$)}{\text{Start-up Fuel Cost}} + \underset{(\$)}{\text{Start-up Power Cost}} + \underset{(\$)}{\text{Other Start-up Costs}} + \underset{(\$)}{\text{Shutdown Power Cost}}$$

Each component of the Start-up Cost in Equation D-1 is set forth below.

a. **Start-up Fuel Costs**

The Start-up Fuel Cost shall be calculated in accordance with Equation D-1a:

Equation D-1a

$$\underset{(\$)}{\text{Start-up Fuel Cost}} = \left[\left(\underset{(\text{MMBtu/hr})}{A} * \underset{(\text{hrs})}{x} \right) + \underset{(\text{MMBtu})}{B} \right] * \underset{(\$\text{MMBtu})}{\text{Hourly Fuel Price}}$$

Where:

- "x" equals the number of hours since the Unit ceased operation and cannot exceed "x_{Max}".
- The Hourly Fuel Price is calculated pursuant to Schedule C Equation C1-8 for the hour in which the Start-up began.
- The values A, B and x_{Max} for each Unit are given in Table D-1 below.

b. **Start-up Power Costs**

The Start-up Power Cost shall be calculated in accordance with Equation D-1b:

Equation D-1b

$$\underset{(\$)}{\text{Start-up Power Cost}} = \left(\left[\underset{(MWh/hr)}{C} * \underset{(hrs)}{x}\right] + \underset{(MWh)}{D}\right) * \underset{(\$/MWh)}{\text{Energy Price}}$$

Where:

- "x" is equal to the hours since the Unit ceased operation and cannot exceed "x_{Max}".
- The Energy Price shall be equal to the total auxiliary power (including Energy for Start-ups) costs charged to the Facility by its supplier of end-use Energy for the billing cycle in which the Start-up was initiated divided by the total auxiliary power (including Energy for Start-ups) consumed at the Facility during such billing cycle.
- The values C, D and x_{Max} are given in Table D-1 below.

c. **Shutdown Power Costs**

The Shutdown Power Cost shall be calculated in accordance with Equation D-1c:

Equation D-1c

$$\underset{(\$)}{\text{Shutdown Power Cost}} = \underset{(MWh)}{\text{Shutdown Power Requirement}} * \underset{(\$/MWh)}{\text{Energy Price}}$$

The Energy Price shall be equal to the total auxiliary power (including Energy for Shutdowns) costs charged to the Facility by its supplier of end-use Energy for the billing cycle in which the Shutdown was initiated divided by the total auxiliary power (including Energy for Shutdowns) consumed at the Facility during such billing cycle. The Shutdown Power Requirement is given in Table D-1 below.

d. **Other Start-up Costs for Hydroelectric Only**

Other Start-up Costs are the cost of labor to start hydroelectric Units that require an operator to manually parallel, and reflect the labor costs to travel to the site. If the Start-up of a hydroelectric Unit occurs outside normal work hours, the Start-up Costs include the minimum work hours and labor rates as set by the applicable collective bargaining agreement(s).

The Other Start-up Costs shall be calculated in accordance with Equation D1-d. The values for E are provided in Table D-2 for normal work hour and outside of normal work hour situations

Equation D-1d

Other Start-up Costs ($) = E

Once a Unit has been given a Dispatch Notice to Start-up, other Start-up Costs are incurred.

Table D-1, Start-Up Costs

Unit	Xmax (Hrs)	A (mmBtu)/hr	B[7]	C	D	E	Shutdown Power Requirement (MWh)
SY1	62	16.14	39.49	0.33	0.0	0	12.60
SY2	60	16.77	42.46	0.27	0.0	0	12.60
SY3	63	18.32	42.22	0.34	0.0	0	16.55
SY4	63	22.50	46.90	0.25	0.0	0	15.44
SYCT	0	0	25.00	0	0.0	0	0.0

Table D-2, Other Start-Up Costs – Hydroelectric Units

Unit	E (Normal Work Hours)	E (Outside Normal Work Hours)
	($)	($)

3. Monthly Start-up Adjustment

For each Start-up successfully completed in compliance with a Dispatch Notice during the Billing Month, and each Start-up initiated in compliance with a Dispatch Notice but not successfully completed because it is canceled or rescinded by ISO, until the total Counted Start-ups for the Contract Year equals the number of Prepaid Start-ups for the Contract Year, the Monthly Start-up Adjustment, which shall be a credit or payment, is the sum of Prepaid Start-up Adjustments, and Prepaid Start-up Adjustments for Canceled Start-ups calculated in accordance with Equations D-2 and D-3:

Equation D-2

Prepaid Start-up Adjustment = Prepaid Start-up Cost calculated in accordance with Section 1 minus the actual Start-up Cost calculated in accordance with Equation D-1.

[7] Includes fuel consumed from the time Unit reaches Synchronization to the time Unit reaches Minimum Load.

Equation D-3

$$\text{Prepaid Start-up Adjustment for Canceled Start-up} = \frac{\text{Number of hours committed to the Start-up}}{\text{applicable Start-up Lead Time (hrs) as shown in Schedule A, Section 6}} * \text{Prepaid Start-up Adjustment calculated in accordance with Equation D-2}$$

Where:

The "number of hours committed to the Start-up" is the lesser of (a) time elapsed between the initiation of the Start-up and the cancellation and (b) the applicable Start-up Lead Time.

SCHEDULE D

Part 2

Start-up Payment for Condition 2 Units

1. Start-up Payment

The Start-up Payment for each Start-up successfully completed for each Unit operating under Condition 2 equals the Start-up Cost calculated using Equation D-1.

2. Payment for Canceled Start-up

If Start-up is initiated under a Dispatch Notice but is not successfully completed because it is canceled or rescinded by the ISO, the Start-up Payment is calculated in accordance with Equation D-4:

Equation D-4

$$\text{Start-up Payment for Canceled Start-up (\$)} = \frac{\text{Number of hours committed to the Start-up}}{\text{applicable Start-up Lead Time (hrs) as shown in Schedule A, Section 6}} * \text{Start-up Cost calculated in accordance with Equation D-1 (\$)}$$

The "number of hours committed to the Start-up" is the lesser of (a) time elapsed between the initiation of the Start-up and the cancellation or (b) the applicable Start-up Lead Time.

Schedule E

Ancillary Services
Part 1 for Condition 1

The ISO may call upon the Unit to provide the following Ancillary Services as defined in the ISO Tariff:

Regulation
Spinning Reserve
Nonspinning Reserve
Replacement Reserve
Voltage Support (including synchronous condenser operation)
Black Start

If the Unit is otherwise generating, the Owner shall be required to operate the Unit within the Power Factor range of the Unit specified in Schedule A to provide Ancillary Services without additional compensation.

Certain Units (hydroelectric and synchronous condensers) can provide Ancillary Services without generating Energy. Under this Condition, Owner will be compensated for Motoring Charges if the Unit is providing Ancillary Services while synchronized without generating Energy.

Motoring Charge

When Units are operated as synchronous condensers (i.e., motored using electric power) to provide Ancillary Services, if applicable, the payment for that service is given by the following formula:

Motoring Charge = (Power consumption rate (MWh/hr)) * (hours operated) * (Energy Price)

Where the Power consumption rate is given by the following table:

Unit	Power consumption rate (MWh/hour)

The Energy Price shall be equal to the total power costs charged to the Facility by its supplier of end-use Energy under the Applicable UDC Tariff for the billing cycle in which the Motoring Charge was incurred divided by the total power consumed at the Facility under such tariff during such billing cycle.

Pre-empted Dispatch Payment

If the ISO issues a Dispatch Notice to:

(i) decrease a Unit's scheduled output of Energy in a Market Transaction to provide

Ancillary Services;

(ii) decrease a Unit's scheduled provision of Ancillary Services capacity in a Market Transaction in order to provide Regulation, Spinning Reserve, Nonspinning Reserve, or Replacement Reserve pursuant to a Dispatch Notice,

(iii) decrease a Unit's scheduled provision of Ancillary Service capacity in a Market Transaction in order to provide Energy pursuant to a Dispatch Notice, the ISO shall pay the appropriate Pre-empted Dispatch Payment described below. The Pre-empted Dispatch Payments are intended to make an Owner whole with respect to the original Market Transaction.

A. <u>For Pre-empted Energy Market Transactions</u>:

Pre-empted Dispatch Payment = Imbalance Energy Charge – Cost Savings

- Imbalance Energy Charge = $(X_o - X_n)$ ✱ Penalty Price
- Penalty Price = Unrestricted Imbalance Energy Price + additional penalties (per MWh) imposed by the ISO for failure to comply with Market Schedules due to compliance with Dispatch Notice.
- Cost Savings = Fuel Cost Savings + Emissions Savings + Other Savings

Where:

- X_o = Original Total Schedule in Market and Nonmarket Transactions;
- X_n = New Total Schedule in Market and Nonmarket Transactions;

<u>For fossil fuel Units, the Fuel Cost Savings is calculated as follows</u>:

- Fuel Cost Savings = Fuel Savings x Hourly Fuel Price
- Fuel Savings = $((AX_o^3+BX_o^2+CX_o+D) - (AX_n^3+BX_n^2+CX_n+D))$ ✱ E

or

- Fuel Savings = $[(A * (B + CX_o + De^{FX_o})) - (A * (B + CX_n + De^{FX_n}))]$ ✱ E
- A, B, C, D, E and F are the coefficients from Table C1-7a or C1-7b, as applicable;
- Hourly Fuel Price is calculated in Equation C1-8.

<u>For geothermal Units, the Fuel Cost Savings is calculated by the following formula</u>:

Fuel Cost Savings = $(X_o - X_n)$ ✱ Hourly Fuel Price

Where:

- Hourly Fuel Price is the Steam Price identified in Equation C2-1 in Schedule C. However, for purposes of this Pre-empted Dispatch Payment calculation, the value for the Steam Price will be set to zero for Geysers Main Units until the cumulative Hourly

Metered Total Net Generation for the Contract Year from all Units exceeds the Minimum Annual Generation given in Equation C2-2.

For pumped storage hydroelectric Units, the Fuel Cost Savings is calculated by the following formula:

$$\text{Fuel Cost Savings} = (X_o - X_n) * \text{Hourly Fuel Price}$$

Where:

- Hourly Fuel Price is YTD Pumping Cost / YTD Energy Produced; and YTD Pumping Cost and YTD Energy Produced are as defined in Equation C4-2.

For conventional hydroelectric Units, the Fuel Cost Savings is zero.

Other Savings = $((X_o\text{-}X_n)$ x (Variable O&M Rate + applicable annual charge for short-term sales under 18 CFR 382.201 of the FERC Regulations + PX Administration Charge as charged under the PX Tariff))

Emissions Savings = RECLAIM Savings + NOx Emissions Fee Savings + Organic Gases Fee Savings + Sulfur Oxides Fee Savings + Particulate Matter Savings + Carbon Monoxide Fee Savings

$$\text{RECLAIM Savings} = ((AX_o^2+BX_o+C) - (AX_n^2+BX_n+C)) * \text{RECLAIM NOx Trading Credit Rate}$$

Where:

- A, B and C are the coefficients from Table C1-13;
- X_o = Original Total Schedule in Market and Nonmarket Transactions;
- X_n = New Total Schedule in Market and Nonmarket Transactions;

$$\text{NOx Emissions Fee Savings} = \frac{((AX_o^2+BX_o+C) - (AX_n^2+BX_n+C))}{2000} * NO_x \text{ Emissions Fee;}$$

Where:

- A, B and C are the coefficients from Table C1-13;
- X_o = Original Total Schedule in Market and Nonmarket Transactions;
- X_n = New Total Schedule in Market and Nonmarket Transactions;

Organic Gases Fee Savings =

4.76×10^{-7} * Gas Fuel Savings * Associated Emission Factor for Organic Gases * Associated Emissions Fee for Organic Gases

Sulfur Oxides Fee Savings =

> 4.76×10^{-7} ✱ Gas Fuel Savings ✱ Associated Emission Factor for Sulfur Oxides ✱ Associated Emissions Fee for Sulfur Oxides

Particulate Matter Oxides Fee Savings =

> 4.76×10^{-7} ✱ Gas Fuel Savings ✱ Associated Emission Factor for Particulate Matter ✱ Associated Emission Fee for Particulate Matter

Carbon Monoxide Fee Savings =

> 4.76×10^{-7} ✱ Gas Fuel Savings ✱ Associated Emission Factor for Carbon Monoxide ✱ Associated Emission Fee for Carbon Monoxide

All Emissions Fees and Emission Factors are determined in accordance with Schedule C.

[If applicable, insert emission cost savings formula for fuel other than natural gas.]

The Owner will be entitled to retain all payments received from the Owner's Scheduling Coordinator for the Unit's scheduled output.

B. <u>For Pre-empted Ancillary Services Market Transactions</u>:

ISO shall pay Owner the product of (i) the difference between the MW of the Ancillary Service Owner had scheduled to provide in a Market Transaction and the MW of Ancillary Services Owner is able to provide after complying with the Dispatch Notice and (ii) the Market Clearing Price the Owner pays to buy back its commitment to deliver the preempted MW of Ancillary Services (if the Owner actually incurs such a cost), or the penalty the Owner pays for failure to deliver the preempted MW of Ancillary Services (if the Owner actually incurs such a cost) for the applicable Ancillary Service, market, and hour. In addition, if compliance with the Dispatch Notice causes reduction of a market regulation transaction, the ISO shall also pay the Owner the product of the Regulation Energy Payment Adjustment (REPA) amount, if applicable, and the MW of Regulation which Owner had scheduled but is unable to provide because of its compliance with the Dispatch Notice.

Schedule E

Ancillary Services
Part 2 for Condition 2

The ISO may call upon the Unit to provide the following Ancillary Services as defined in the ISO Tariff:

Regulation
Spinning Reserve
Nonspinning Reserve
Replacement Reserve
Voltage Support (including synchronous condenser operation)
Black Start

The Owner shall be required to operate the Unit within the Power Factor range of the Unit specified in Schedule A to provide Voltage Support without additional compensation.

The Owner shall receive no payment for any Ancillary Services Capacity provided. However, operation of a Unit in synchronous condenser mode will be compensated as shown below.

Motoring Charge

When Units are operated as synchronous condensers (i.e., motored using electric power) to provide Ancillary Services, if applicable, the payment for that service is given by the following formula:

Motoring Charge = (Power consumption rate (MWh/hr)) * (hours operated) * (Energy Price)

Where the Power consumption rate is given by the following table:

Unit	Power consumption rate (MWh/hour)

The Energy Price shall be equal to the total power costs charged to the Facility by its supplier of end-use Energy under the Applicable UDC Tariff for the billing cycle in which the Motoring Charge was incurred divided by the total power consumed at the Facility under such tariff during such billing cycle.

Schedule E

Ancillary Services
Part 3 for Black Start Services

For those Units with Black Start capability, the cost of maintaining such capability is included in this Agreement and no additional costs shall be charged to the ISO for maintaining such capability. The ISO will pay for Black Start service, including for a Black Start Test Dispatch Notice, at the rates and prices in this Agreement for Start-Ups and Delivery of Energy in connection with the Black Start service. Owner shall maintain the Black Start capability of the Unit and the Facility and provide Black Starts in accordance with the ISO Ancillary Services Requirements Protocol and the ISO Dispatch Protocol, which shall be deemed incorporated by reference into this Agreement.

When the ISO first gives written notice to the Owner that it has obtained adequate Black Start service through an auction or a separate agreement with Owner or other Generators and Black Start service under this Agreement is no longer required, the ISO shall not be entitled to call upon this Unit to provide Black Start service. Once the ISO has given this notice, the Owner may remove Black Start service from this Agreement by filing unilaterally a change in rate schedule with FERC. Such filing shall not be required to include any reduction in rate or revenue solely because Black Start service is removed. The ISO shall not oppose the absence of any rate or revenue reduction that results solely from removing such service.

Schedule F

Determination of Annual Revenue Requirements of Must-Run Generating Units

Table of Contents

Article I. Purpose and General Procedures

Part A. Determination of Rates and Charges

This Schedule F establishes the procedures and methodology for determining the Annual Fixed Revenue Requirements (in dollars) and Variable O&M Rates (in \$/MWh) for facilities designated for must-run service for purposes of calculating certain charges for such service under the RMR Contract.

The Annual Fixed Revenue Requirements and the Variable O&M Rate for each designated must-run generating facility shall be determined annually. The Annual Fixed Revenue Requirements and the Variable O&M Rate for each such facility that shall be used for calculating charges to the ISO during each calendar year shall be determined by application of the Formula set forth in Article II hereof to the Owner's costs incurred during the twelve-month period ended on June 30 of the prior calendar year. Each twelve-month period ending on June 30 of each year is hereinafter referred to as the "Cost Year" relating to the rates and charges that are effective during the succeeding calendar year.

Part B. Informational Filings

In connection with the determination of rates and charges for each calendar year, reflecting costs incurred during the June 30 Cost Year as described in the foregoing Part A of this Article I, the Owner shall provide to the ISO an Information Package detailing and supporting all calculations involved in such determination. A single Information Package may contain all such informational materials pertaining to all of the Owner's designated must-run facilities. On or before October 1, 2001, the Owner shall provide to the ISO the Information Package relating to the rates and charges to become effective on January 1, 2002. Thereafter, on November 1 of each year, the Owner shall provide to the ISO the Information Package relating to the rates and charges to be effective during the calendar year beginning on the following January 1.

Each such Information Package shall be in a clear and readable format and shall contain:

1. detailed workpapers showing the derivation of costs under the Formula for the relevant Cost Year along with supporting schedules showing the data used in applying the formula, presented in a format consistent with the presentation of information in the FERC Form No. 1;

2. a clear identification of the depreciation rates reflected in claimed costs for the Cost Year and the rate of return and every other stated item (*i.e.*, any item which appears as a numerical value in the Formula and which only may be changed by a filing with the FERC);

3. a comparison of the major components of the resulting revenue requirements for the relevant Cost Year with the corresponding components of the revenue requirements that result from the application of the Formula using costs from the Owner's FERC Form No. 1 relating to the preceding calendar year;

4. such additional documentation as to specific items of costs required by the Formula.

The Owner shall provide each Information Package to the ISO in printed form and a suitable electronic format. The ISO shall post the Information Package on its web site. A suitable electronic format shall be any format that the FERC permits for electronic filings.

Coincident with providing each such Information Package to the ISO, the Owner shall also submit the Information Package to the FERC in an informational filing so as to allow for review of the related rates and charges by the FERC staff and affected parties. As to the informational filing relating to rates and charges to be effective during calendar year 2002, (i) discovery requests by the FERC staff and affected parties shall be made within 45 days of the filing, with responses by the Owner due within 60 days of the filing, and (ii) protests, if any, by affected parties shall be filed with the FERC within 75 days of the filing. As to each subsequent informational filing, (i) discovery requests by the FERC staff and affected parties shall be made within 20 days of the filing, with responses by the Owner due within 35 days of the filing, and (ii) protests, if any, by affected parties shall be filed with the FERC within 45 days of the filing. In the event that the need arises during the discovery process for the nondisclosure or confidentiality of information, the Owner and affected parties, other than FERC Staff and state regulatory agencies, shall utilize the procedures contained in Schedules N-1 and N-2 of the RMR Contract. If the Owner seeks the confidentiality or nondisclosure of information provided to FERC or state regulatory agencies, it shall follow the applicable rules, regulations and statutory provisions of those agencies.

Protests to the Information Package challenging arithmetic calculations or conformity to the Rate Formula, not resolved by summary disposition of the FERC, shall be resolved by the use of the Alternative Dispute Resolution procedures in Schedule K of the RMR contract. In such a proceeding, the Owner will bear the burden of proof as in a proceeding under Section 205 of the Federal Power Act (FPA). If it is found that an erroneous calculation or non-conforming formula element has been used, refunds shall be ordered. The amount of refunds shall restore the parties to the positions they would have occupied had the erroneous calculations or non-conforming formula elements not been used, with interest calculated pursuant to Section 35.19a of the Commission's regulations, 18 C.F.R. Section 35.19a.

If a matter is set for hearing, additional discovery shall be permitted in accordance with the Commission's Rules of Practice and Procedure. Under hearings established pursuant to this provision, refund rights will be as in a proceeding under Section 205 of the FPA. Any refunds due as the result of a final Commission order will be credited or paid to the ISO with interest in accordance with 18 C.F.R. 35.19a.

In addition to the discovery provided above, affected parties shall have the ability to audit the Owner's books and records as provided in Section 12.2 of the RMR Contract. To the extent that an audit discloses that the formula was not correctly applied for a particular year, the affected prior billings shall be corrected, and appropriate refunds or credits shall be provided to the ISO, with interest determined in accordance with 18 C.F.R. 35.19a.

Notwithstanding the above procedures, all parties retain full rights to make filings at any time under Sections 205 and 206 of the FPA, as appropriate.

Article II. Formula for Determination of Annual Revenue Requirements

Part A. Purpose and Overview

The purpose of this Formula For Determination of Annual Revenue Requirements ("Formula") is to specify the method for determining the Annual Revenue Requirements, and certain components thereof, of particular must-run generating units for each Cost Year.

Part B of this Formula contains the specifications for the components of costs that may be included in the Annual Revenue Requirements of individual designated must-run generating units (*i.e.*, for each "Subject Resource").

Part C of this Formula sets forth (i) general instructions for the use and application of the Formula, and (ii) certain general definitions of terms used herein.

Part B. Determination of Annual Revenue Requirements

Section 1. Annual Fixed Revenue Requirements and Variable O&M Rate

(A) Annual Fixed Revenue Requirements

The "Annual Fixed Revenue Requirements" for the Subject Resource is the amount determined as the following difference:

1. Total Annual Revenue Requirements, as defined below; less

2. Total Annual Variable Costs, as defined below.

(B) Variable O&M Rate

The "Variable O&M Rate" for the Subject Resource is the rate (in $/MWh) determined as the follows:

Variable O&M Rate = [Annual Variable O&M Expenses]/[Annual Net Generation]

where "Annual Variable O&M Expenses" is defined hereinbelow, and "Annual Net Generation" is the net generation (in MWh) of the Subject Resource during the Cost Year.

Notwithstanding the foregoing, whenever the Annual Net Generation of the Subject Resource is zero or negative, the Variable O&M Rate shall be deemed to be zero.

(C) Total Annual Revenue Requirements

The "Total Annual Revenue Requirements" for the Subject Resource is the amount that is the sum of the following amounts:

1. Operating Expenses, determined pursuant to Section 2 below; and

2. Return and Income Tax Allowance, determined pursuant to Section 3 below.

Section 2. Operating Expenses

"Operating Expenses" for the Subject Resource is the quantity that is the sum of the following amounts:

1. Total O&M Expenses, as defined below;

2. Depreciation Expenses, as defined below;

3. Taxes Other Than Income Taxes, as defined below; and

4. Revenue Credits, as defined below.

(A) Total O&M Expenses

"Total O&M Expenses" is the amount of expenses arising from the operation and maintenance of the Subject Resource, including Production O&M Expenses, Transmission O&M Expenses, Distribution O&M Expenses, and Administrative & General Expenses, all as defined below.

(1) **Production O&M Expenses:** Expenses incurred directly in operating and maintaining the Subject Resource:

(a) **Steam Production O&M:** For steam units only, amounts properly recorded in Accounts 500-515.

(b) **Hydro Production O&M:** For hydro units only, amounts properly recorded in Accounts 535-545.

(c) **Other Power Generation O&M:** For other types of units, amounts properly recorded in Accounts 546-554.

(d) **Other Power Supply Expenses:** Amounts properly recorded in Accounts 555-557, if any, that are reasonably assignable or allocable to the Subject Resource.

(2) **Transmission O&M Expenses:** Expenses incurred directly in operating and maintaining the transmission facilities associated with the Subject Resource, as properly recorded in Accounts 560-573 and reasonably assignable or allocable to the Subject Resource.

(3) **Distribution O&M Expenses:** Expenses incurred directly in operating and maintaining the distribution facilities associated with the Subject Resource, as properly recorded in Accounts 580-598 and reasonably assignable or allocable to the Subject Resource.

(4) **Administrative and General (A&G) Expenses:** Those portions, if any, of administrative and general expenses, as properly recorded in Accounts 920-935, that are reasonably related to the operation of the Subject Resource, determined from appropriate direct assignment or reasonable allocation. Such expenses shall exclude (i) franchise fees related solely to the Owner's retail sales, (ii) retail regulatory expenses, (iii) assessments under 18 CFR Section 382.201 of the FERC Regulations, (iv) association dues, and (v) general advertising expenses.

Notwithstanding the foregoing, O&M Expenses hereunder shall exclude all PX Administration charges as charged under the PX Tariff, irrespective of in which Account or Accounts such charges are included.

(B) Depreciation Expenses

"Depreciation Expenses" are provisions for depreciation and amortization for the Subject Resource, as properly recorded in Accounts 403, 404, 405, 406, and 407, including only:

(1) **Production Plant Depreciation:** Depreciation and amortization, if any, of investment in the Subject Resource;

(2) **Transmission Plant Depreciation:** Depreciation and amortization, if any, of investment in the transmission facilities associated with the Subject Resource, as reasonably assignable or allocable to the Subject Resource;

(3) **Distribution Plant Depreciation:** Depreciation and amortization, if any, of investment in the distribution facilities associated with the Subject Resource, as reasonably assignable or allocable to the Subject Resource;

(4) **General and Intangible Plant Depreciation:** Depreciation and amortization, if any, of general and intangible plant investments that are reasonably assignable or allocable to the Subject Resource.

Notwithstanding the foregoing, costs recorded in Accounts 405, 406 and 407 shall be included hereunder only if, and to the extent that, FERC shall have permitted the inclusion of such costs for ratemaking purposes for the Owner under the RMR Contract.

(C) Taxes Other Than Income Taxes

"Taxes Other Than Income Taxes" are taxes other than income and revenue taxes, as properly recorded in Account 408.1, that are reasonably assignable and allocable to the Subject Resource, including for example:

1. Property and Property-Related Taxes;
2. Payroll and Labor-Related Taxes;
3. Other Taxes, if any, identifiable as reasonably assignable or allocable to the Subject Resource.

Taxes Other Than Income Taxes assignable and allocable to the Subject Resource shall not include any taxes related solely to, or arising solely from, the Owner's retail sales.

(D) Revenue Credits

"Revenue Credits" are those revenues, if any, that are (i) properly recorded in Account 451 (Miscellaneous Service Revenues), Account 453 (Sales of Water and Water Power), Account 454 (Rent From Electric Property), Account 455 (Interdepartmental Sales), and Account 456 (Other Electric Revenues), and (ii) directly related to, or reasonably allocable to, the Subject Resource. Such Revenue Credits shall be treated as negative values hereunder.

(E) Treatment of Capital Leases

The foregoing components of Operating Expenses may include expenses associated with capital leases as approved by the Commission, as set forth more fully under Article II, Part B, Section 4(A) of this Formula.

Section 3. Return and Income Tax Allowance

"Return and Income Tax Allowance" is the quantity that is the sum of:

1. the product of:

   a. Allowable Pre-Tax Rate of Return, and

   b. Net Investment,

   as both such quantities are hereinafter defined; and

2. the quantity equal to:

   [ITC Amortization]/(1-t)

   where:

   a. "t" is the effective, combined state and federal income tax rate.

   b. "ITC Amortization," is amortization, if any, of investment tax credits, as properly recorded in Account 411.4, that are reasonably assignable or allocable to the Subject Resource and to those portions of general and intangible plant investments that are reasonably assignable or allocable to the Subject Resource. Notwithstanding the foregoing, this term shall include only those amounts of amortization of investment tax credits which the Owner shall have elected to receive under Section 46(f)(1) of the Internal Revenue Code. ITC Amortization amounts that reduce net income shall be treated as negative values hereunder, while ITC Amortization amounts, if any, that increase net income shall be treated as positive values hereunder.

Section 4. Net Investment

"Net Investment" is the quantity that is determined as follows:

Net Investment = Gross Plant Investment - Depreciation Reserve + CWIP + PHFU - ADIT + Working Capital

where the quantities appearing in the foregoing equation are defined hereinafter below.

In determining Net Investment hereunder, each component thereof, other than Cash Allowance, shall be determined as the end-of-year balances in the Accounts specified for the relevant Cost Year.

(A) Gross Plant Investment

"Gross Plant Investment" is gross original cost plant investment as properly recorded in Accounts 101, 102, 106, and 114, including only the following amounts:

(1) **Production Plant Investment:** investment in the generating unit itself and in common facilities associated with the unit, as recorded in Accounts 310-316, 330-336, or 340-346, 106 and 114;

(2) **Transmission Plant Investment:** investment in transmission facilities associated with the Subject Resource, as properly recorded in Accounts 350-359, 106, and 114, and reasonably assignable or allocable to the Subject Resource;

(3) **Distribution Plant Investment:** investment in distribution facilities associated with the Subject Resource, as properly recorded in Accounts 360-373, 106, and 114, and reasonably assignable or allocable to the Subject Resource; and

(4) **General and Intangible Plant Investment:** reasonably assignable and allocable portions, if any, of general and intangible plant investment, recorded in Accounts 389-399 and 301-303, 106 and 114.

Subject to the limitations detailed in this paragraph, when the Owner has a capital lease in lieu of gross plant investment, it may include Account 101.1 hereunder. A lease may be capitalized and the costs included for ratemaking purposes if the Owner demonstrates that the lease qualifies as a capital lease under 18 C.F.R. Part 101, General Instruction No. 19 (1998), and the Owner has obtained, prior to the informational filing, approval to include such costs for ratemaking purposes from the FERC under the FPA. Capital leases shall be accounted for in accordance with 18 C.F.R. Part 101, General Instruction No. 20 (1998).

(B) Depreciation Reserve

"Depreciation Reserve" is accumulated provision for depreciation and amortization, as properly recorded in Accounts 108, 111, and 115, related to the Subject Resource, including the following amounts:

(1) **Production Plant Depreciation Reserve:** amounts of Depreciation Reserve for the investment in the unit itself and in common facilities associated with the unit;

(2) **Transmission Plant Depreciation Reserve:** amounts of Depreciation Reserve for the investment in transmission facilities associated with the Subject Resource, as reasonably assignable or allocable to the Subject Resource;

(3) **Distribution Plant Depreciation Reserve:** amounts of Depreciation Reserve for the investment in distribution facilities associated with the Subject Resource, as reasonably assignable or allocable to the Subject Resource;

(4) **General and Intangible Plant Reserve:** amounts of Depreciation Reserve for the portions, if any, of general and intangible plant investments reasonably assignable and allocable to the Subject Resource.

Credit balances in the aforementioned accounts shall be treated as positive values hereunder, and debit balances in such accounts shall be treated as negative values.

(C) CWIP

"CWIP" is the amount of construction work in progress, as properly recorded in Account 107 for construction projects associated with the Subject Resource related solely and directly to pollution control for the Subject Resource.

(D) PHFU

"PHFU" is the cost of plant held for future use, as properly recorded in Account 105 that is reasonably assignable or allocable to the Subject Resource.

(E) ADIT

"ADIT" is accumulated provision for deferred income taxes, as properly recorded in Accounts 190, 281, 282, 283, and 255, that are reasonably assignable or allocable to the investment in, or operation of, the Subject Resource, including the following amounts:

(1) **Production Plant ADIT:** amounts of ADIT arising directly from the investment in, or operation of, the Subject Resource itself and common facilities associated with the Subject Resource;

(2) **Transmission Plant ADIT:** amounts of ADIT arising directly from the investment in, or operation of, the transmission facilities, if any, associated with the Subject Resource;

(3) **Distribution Plant ADIT:** amounts of ADIT arising directly from the investment in, or operation of, distribution facilities, if any, associated with the Subject Resource; and

(4) **General and Intangible Plant ADIT:** amounts of ADIT arising from the portions, if any, of general and intangible plant investments reasonably assignable and allocable to the Subject Resource.

For purposes of this Formula, ADIT means accumulated provision for deferred income taxes, as properly recorded in the aforementioned Accounts, *including* amounts previously recorded in such accounts and reclassified as a result of the adoption of SFAS No. 109, but *excluding* amounts recorded in such accounts as a result of the adoption of SFAS No. 109, such that the required adoption of SFAS No. 109 will have no effect on the costs determined hereunder.

Notwithstanding the foregoing, as to Account 255, ADIT hereunder shall include only those amounts, if any, related to investment tax credits which the Owner shall have elected to receive under Section 46(f)(2) of the Internal Revenue Code.

ADIT balances that are credit balances shall be treated as positive values hereunder, while ADIT balances that are debit balances shall be treated as negative values hereunder.

Owner shall support all amounts of ADIT included and not included hereunder in the manner described in sections 35.13(h)(6) and (7) of the Commission's regulations (Statements AF and AG, respectively), except that the time period for the relevant data for the informational package will be consistent with the requirements of this formula, rather than the "Periods" referenced in those regulations.

(F) Working Capital

"Working Capital" is the sum of the portions, if any, of the following items that are reasonably assignable or allocable to the Subject Resource:

(1) **Fuel Stocks,** which is the amount of fossil fuel stock, if any, maintained for the Subject Resource, as properly recorded in Account 151;

(2) **Plant Materials and Supplies,** consisting of the value of plant materials and supplies reasonably assignable or allocable to the Subject Resource, as properly recorded in Accounts 154 and 163;

(3) **Prepayments,** consisting of the amount, if any, of prepayments reasonably assignable or allocable to the Subject Resource, as properly recorded in Account 165;

(4) **Working Cash Allowance,** which is one-eighth of O&M Expenses (as defined herein), less (a) Total Annual Fuel Costs (as defined hereinbelow), and (b) all amounts or portions, if any, of Account 555 (Purchased Power) that may be included in such O&M Expenses; and

Unamortized Deferred Costs, which shall be that portion, if any, of Account 186 directly related to, or reasonably allocable to, the Subject Resource.

Section 5. Allowable Pre-Tax Rate of Return

The Allowable Pre-Tax Rate of Return shall be the sum of:

(a) 12.25%, and

(b) 30% of the amount, if any, by which (a) the latest available 6-month average of yields on 10-year U.S. Treasury Bonds, as of the date of the first Informational Filing, exceeds (b) the latest available 6-month average of yields on 10-year U.S. Treasury Bonds as of *[the effective date of the settlement]*.

Notwithstanding the foregoing, the Owner may make application to the FERC, prior to or in conjunction with the first Informational Filing, in a limited proceeding to seek to establish a different Allowable Pre-Tax Rate of Return under Section 205 of the Federal Power Act.

Section 6. Additional Quantities

(A) Annual Variable O&M Expenses

"Annual Variable O&M Expenses" is the sum of the following quantities:

(1) **Variable Production O&M Expenses:** those portions of Production O&M

Expenses, as defined above, other than fuel expenses, that are reasonably determined to be variable expenses, in the sense that they are incurred as a result of, or otherwise are reasonably associated with, the production of energy by the Subject Resource.

(2) **Variable A&G Expenses:** that portion of A&G Expenses that is related or allocable to the foregoing Variable Production O&M Expenses.

Notwithstanding the foregoing, starting with the first information filing hereunder and continuing until the Owner elects to use a different method to determine its Annual Variable O&M Expenses, the Owner may compute Annual Variable O&M Expenses as the amount equal to the product of (a) the Initial Variable O&M Rate, in $/MWh, for the Subject Resource, as set forth in Exhibit A hereto (Exhibit A can be found in Appendix B to the Stipulation and Agreement), times (b) the Net Generation of the Subject Resource (as defined hereinabove). Whenever the Owner does not compute Annual Variable O&M Expenses based on the Initial Variable O&M Rate in the foregoing manner, the Owner shall include in each of Informational Package a detailed explanation of the method or methods used to classify O&M expenses as between fixed (*i.e.*, capacity-related) expenses and variable (*i.e.*, energy-related) expenses and the reason(s) such method results in just and reasonable rates.

(B) Annual Fixed O&M Expenses

"Annual Fixed O&M Expenses" is the quantity that is equal to the following:

(1) Total O&M Expenses, as defined hereinabove, less

(2) the sum of:

a. Annual Variable O&M Expenses, as defined hereinabove, and

b. Annual Variable Fuel Costs, as defined hereinbelow,

c. Annual Emissions Costs, as defined hereinbelow, and

d. Annual Non-Fuel Start-Up Costs, as defined hereinbelow.

(C) Fuel Expenses

(1) Total Annual Fuel Costs

"Total Annual Fuel Costs" is the total fuel expense for the Subject Resource for the Cost Year properly recorded in Account 501 or Account 547, as appropriate depending on the nature of the Subject Resource.

(2) Annual Fixed Fuel Costs

"Annual Fixed Fuel Costs" is that portion, if any, of Total Annual Fuel Costs related to fuel handling and administration of fuel planning, procurement and transportation which do not vary with the amount of fuel purchased.

(3) Annual Variable Fuel Costs

"Annual Variable Fuel Costs" is the quantity that is the following difference:

1. Total Annual Fuel Costs, less
2. Annual Fixed Fuel Costs.

(D) Annual Emissions Costs

"Annual Emissions Costs" is the total emissions costs that are related to the operation of the Subject Resource during the Cost Year.

(E) Annual Non-Fuel Start-Up Costs

"Annual Non-Fuel Start-Up Costs" is the aggregate sum of costs, other than fuel costs, attributable to start-ups of the Subject Resource during the Cost Year, consisting of start-up power costs, shut-down power costs, and other non-fuel start-up costs, all as determined pursuant to the applicable sections of Schedule D of the RMR Contract, as applied to all start-ups of the Subject Resource during the Cost Year.

(F) Total Annual Variable Costs

"Total Annual Variable Costs" is the sum of:

1. Annual Variable O&M Expenses,
2. Annual Variable Fuel Costs, and
3. Annual Emissions Costs.

Part C. General Instructions and Explanatory Notes

Section 1. General Instructions

In applying this Formula to a Subject Resource, the following instructions and explanations shall be followed:

(A) No Duplicative Charges

The costs determined and referenced by this Formula shall exclude costs that are recoverable, or that are actually recovered, elsewhere under the applicable contract or agreement between the Owner and the ISO. There shall be no double counting of costs hereunder.

(B) Determination of Depreciation Expenses

Depreciation Expenses, Depreciation Reserve, and Deferred Income Taxes reflected in the revenue requirements determined pursuant to this Formula shall be computed using either fixed depreciation rates or depreciation rates determined annually from fixed mortality characteristics (i.e., service lives, net salvage ratios, etc.). Such depreciation rates and/or mortality characteristics, which may differ for particular assets or groups of assets comprising, or related to, the Subject Resource, are set forth on Exhibit B, which is attached hereto and made a part hereof. Such depreciation rates and/or mortality characteristics may not be changed except pursuant to Section 205 or Section 206 of the FPA. Nothing herein shall be construed as affecting any requirements of the FERC regarding the use by the Owner of depreciation rates for financial reporting purposes.

(C) Costs in Excess of Original Cost

The components of rate base and the costs reflected under the Formula shall not include an acquisition adjustment or costs associated with an acquisition adjustment unless the Owner shall have obtained approval from the FERC to include under the Formula such an adjustment or such costs for ratemaking purposes under the FPA. The effective date for the inclusion of such costs shall be as set forth in the FERC order.

(D) Use of FERC Accounting

The costs determined and referenced by this Formula shall reflect only FERC-basis accounting, and shall not reflect any accounting for costs approved by any state regulatory commission or other body if not approved or accepted by the FERC for use in connection with the RMR Contract. Except as otherwise provided herein, the accounting for costs for purposes of applying this Formula shall be consistent with the requirements of the Uniform System of Accounts.

(E) Accounting Methods

The costs determined and referenced by this Formula shall reflect only such accounting methods prescribed by such authorities as AICPA and FASB that shall have been approved or accepted by the FERC for use in connection with the RMR Contract. The Owner shall be required to seek and gain such approval or acceptance from the FERC prior to reflecting any changed accounting methods in the determination of costs in connection with this Formula.

The Owner shall carry the burden of demonstrating that its accounting methods and entries reflected in the costs determined and referenced by this Formula produce just, reasonable, and nondiscriminatory rates for its customers.

(F) Out-of-Period Adjustments

The costs determined and referenced by this Formula shall not reflect any accounting entries the purpose of which is to adjust or correct for accounting entries in years other than the Cost Year if such adjusting or correcting entries would have an unjust, unreasonable, or discriminatory effect on the ISO.

(G) Extraordinary Costs

Extraordinary costs included in the costs determined and referenced by this Formula shall be subject to amortization over a reasonable period of time. In determining how costs should be amortized, the parties shall also determine how the costs being amortized should be recovered in the event that the plant closes and does not reopen.

As used herein, "extraordinary costs" mean costs arising from events and transactions that are of an unusual nature and infrequent occurrence, the effects of which are abnormal and significantly different from the ordinary and typical activities of the Owner, and would not reasonably be expected to recur in the foreseeable future. In determining significance, items should be considered individually and not in the aggregate. However, the effects of a series of related transactions arising from a single specific and identifiable event or plan of action should be considered in the aggregate. An item can be extraordinary even if it is less than five (5) percent of income computed before the extraordinary item. In its annual Information Package, the Owner shall identify and provide explanations for all extraordinary costs which it seeks to include in the rates and charges determined pursuant to this Formula, and the Owner shall bear the burden of proof, as in a proceeding under Section 205 of the FPA, that its proposed treatment of extraordinary costs is just and reasonable.

(H) Imprudently Incurred Costs

The costs determined and referenced by this Formula shall not include any costs which have been determined by the FERC in a proceeding under Section 206 of the FPA to have been imprudently incurred by the Owner.

(I) Transmission Cost Assignments and Allocations

Costs of transmission facilities assigned and/or allocated to the Subject Resource hereunder are intended to include only those costs, if any, related to the step-up substation facilities and other transmission facilities directly connected to the Subject Resource and used to deliver the output of the Subject Resource to the transmission grid. In each annual Informational Package, the Owner shall clearly identify and fully describe all transmission facilities which it claims satisfy the foregoing criteria.

(J) Distribution Cost Assignments and Allocations

Costs of distribution facilities assigned and/or allocated to the Subject Resource hereunder are intended to include only those costs, if any, related to the step-up substation facilities and other distribution facilities directly connected to the Subject Resource and used to deliver the output of the Subject Resource to the transmission or distribution system. In each annual Informational Package, the Owner shall clearly identify and fully describe all distribution facilities which it claims satisfy the foregoing criteria.

(K) Inclusion of Certain Costs

The Owner shall include in its annual Informational Package detailed workpapers and explanations supporting the reasonableness of including in the revenue requirements determined pursuant to this formula any amounts recorded in Accounts 501, 547, 555, 561, 927, 105, and 186. The Owner shall bear the burden of proof, as in a proceeding under Section 205 of the FPA, to affirmatively demonstrate that all such included amounts are directly related to the provisions of service under the RMR

Contract and are reasonably assignable or allocable to the Subject Resource. As to Account 105, the requirement for a definitive plan required by the description of Account 105 in the Uniform System of Accounts, and the affirmative demonstration required by this paragraph, shall be deemed to be met upon a showing that the ISO has approved, in accordance with the provisions of Section 7.4 of the RMR Contract, a plan for the future use of the property.

(L) Direct Assignments and Allocations

Where Part B of this Formula provides for the identification and/or assignment of costs incurred directly in connection with a particular facility or facilities (including a Subject Resource), or directly related to such a facility or facilities, the Owner shall bear the burden of demonstrating the reasonableness of each such identification and/or assignment, and each failure to make such an identification and/or assignment. Notwithstanding the foregoing, where this Formula provides for such a direct identification or assignment of costs, the Owner may use an allocation method to apportion such costs among particular facilities; provided, however, that (i) the Owner shall in its Informational Package clearly identify and describe such allocation method and the basis for it, and (ii) the Owner shall bear the burden of demonstrating the reasonableness of the method. It is recognized that such allocation methods may, for example, be appropriate for apportioning certain types of costs between individual generating units at a multi-unit generating station. Such allocations of costs between individual generating units at a plant site shall be consistent with the requirements for such allocations, if any, provided in the RMR Contract.

(M) No Adverse Distinction

In applying this Formula and in maintaining its books and records insofar as they affect the results of applying this Formula, the Owner shall not make an adverse distinction between the Subject Resource and any other facility or facilities owned or operated by the Owner; *e.g.*, the Owner shall assign certain costs directly to the Subject Resource only if, and to the extent that, the Owner directly assigns such costs to other, similar facilities.

Section 2. General Definitions

Except as may be expressly stated otherwise, the following terms have the followings meanings as used herein:

(A) Account

"Account" refers to a particular account for "major" utilities as prescribed by the Uniform System of Accounts.

(B) FERC

"FERC" means the Federal Energy Regulatory Commission or its successor.

(C) Uniform System of Accounts

"Uniform System of Accounts" means the FERC's "Uniform System of Accounts Prescribed For Public Utilities and Licensees Subject to the Provisions of the Federal

Power Act," as such uniform system of accounts was in effect as of the first effective date of the RMR Contract.

(D) RMR Contract

"RMR Contract" means the contract to which this Formula is attached and made a part thereof.

(E) Subject Resource

"Subject Resource" means any particular generating unit to which this Formula is applied for purposes of determining the annual costs thereof.

(F) Cost Year

"Cost Year" means the twelve-month period ended June 30 to which this Formula is applied to determine the Annual Fixed Revenue Requirements and Variable O&M Rate for a Subject Resource to be applicable during the next succeeding calendar year.

(G) Owner

"Owner" means the entity, other than the ISO, that is a party to the RMR Contract.

(H) ISO

The "ISO" means the California Independent System Operator Corporation.

Exhibit A - Initial Variable O&M Rates[1]

Line	RMR Facility	Unit	Initial Variable O&M Rate ($/MWh)
1	South Bay	Unit 1	1.11
2	South Bay	Unit 2	1.10
3	South Bay	Unit 3	1.04
4	South Bay	Unit 4	0.70
5	South Bay	Ct	0.00

[1] Exhibit A for each owner is filed in Appendix to the Stipulation and Agreement.

Exhibit B - Depreciation Rate and Mortality Characteristics [2] [3]

Line	RMR Facility	Unit	Plant Account	Depreciation Rate (%)	Mortality Characteristics			
					Retire-ment Date	Average Service Life	Salvage Value or Rate	Interim Retire-ments Rate
1	South Bay	All	Land	n/a	n/a	n/a	n/a	n/a
2	South Bay	Steam	Steam	5.66%	2006	36	-29.00%	n/a
3	South Bay	CT	Other Production	5.54%	2006	36	-29.00%	n/a
4	South Bay	All	Transmission	3.07%	2006	36	-29.00%	n/a
5	South Bay	All	General	5.43%	2006	36	-29.00%	n/a

2 Exhibit B for each owner is filed in Appendix B to the Stipulation and Agreement.

3 Effective as of the effective date of the Settlement.

Exhibit C - 1998 Cost Information

Pursuant to Article IV.E of the Stipulation and Agreement filed with the FERC on April 2, 1999, the Owner shall file with the FERC in Docket No. ER98-441-000, et. al., a superceding Exhibit C, setting forth the following information for each unit for the period ending December 31, 1998:

(1) Name of the facility and unit;

(2) Gross Plant In Service, *i.e.* the original cost plus plant additions minus retirements, by major plant function (*i.e.* production, transmission, distribution and general);

(3) Net Plant In Service Gross Plant, *i.e.* gross plant minus depreciation reserve, by major plant function;

(4) Rate Base, *i.e.* net plant and other components of Net Investment as defined in the Formula, such as working capital, Accumulated Deferred Income Taxes (ADIT), etc.

This Exhibit C shall be for informational purposes only and shall be initially filed with FERC by June 1, 1999.

Schedule G

Charge for Service in Excess of Contract Service Limits

Payment for service in excess of the Maximum Annual MWh, Maximum Annual Service Hours or Maximum Annual Start-ups shall be determined in accordance with Option A or Option B. Payment for service from hydroelectric Units in excess of the Maximum Monthly MWh shall be determined in accordance with Option A only. Owner shall make a one-time election between Option A or Option B. Owner must choose Option A for both Billable MWh and Start-ups or Option B for both Billable MWh and Start-ups. This election shall be applicable to all of the Owner's Units under this Agreement and all other Reliability Must-Run Units subject to a "reliability must-run contract" as defined in the ISO Tariff with Owner or any of its affiliates as defined in 18 C.F.R. Section 161.2.

1. Option A

A. For all Billable MWh Delivered after the Counted MWh for the Contract Year equals the Maximum Annual MWh, the Counted Service Hours equals the Maximum Annual Service Hours or, for hydroelectric Units, the Counted MWh for the Month equals the Maximum Monthly MWh ("Schedule G Billable MWh"):

Fossil Fuel Units

In addition to the Variable Cost Payment computed in accordance with Schedule C, the ISO shall pay the Option A Variable Cost Payment, which shall be calculated in accordance with Equation G-1:

Equation G-1

$$\text{Option A Variable Cost Payment} = \frac{0.5 * (\text{Variable Cost Payment for the Billing Month})}{\text{Billable MWh for the Billing Month}} * \text{Schedule G Billable MWh}$$

Pumped Storage Hydroelectric Facilities

In addition to the Variable Cost Payment computed in accordance with Schedule C, ISO shall pay the product of (a) the Schedule G Billable MWh, (b) 0.5, and (c) YTD Pumping Costs divided by YTD Energy Produced as computed in accordance with Equation C4-2 in Schedule C.

Conventional Hydroelectric Facilities

In addition to the Variable Cost Payment computed in accordance with Schedule C, ISO shall pay the sum of the products for each hour in the Billing Month of (a) the Hourly Fuel Price for natural gas for the hour calculated in accordance with Equation C1-8 of Schedule C, (b) 12,000 Btu/kWh, (c) the Schedule G Billable MWh for that hour, and (d) 0.5.

B. For all Service Hours provided after the Counted Service Hours for the Contract Year equals the Maximum Annual Service Hours.

Synchronous Condensers

In addition to the Motoring Charge computed in accordance with Schedule E, ISO shall pay the product of (a) the Motoring Charges calculated in accordance with Schedule E, and (b) 0.5.

C. For all Start-ups required to comply with a Dispatch Notice after the Counted Start-ups for the Unit equals the Maximum Annual Start-ups ("Schedule G Start-ups"), the ISO shall pay :

Fossil Fuel Units and Geothermal Units

Two times (a) the Start-up Payment computed in accordance with Equation D-1 in Schedule D, or (b) if the Schedule G Start-up is initiated under a Dispatch Notice but is not successfully completed because it is canceled or rescinded by the ISO, the Start-up Payment for Canceled Start-up is computed in accordance with Equation D-4 in Schedule D.

Conventional Hydroelectric Facilities and Units Capable Only of Synchronous Condenser Operation

The Start-up Payment computed in accordance with Schedule D, plus (a) (0.00338) * the Unit's Annual Fixed Revenue Requirement stated in Section 7 of Schedule B, divided by (b) the Unit's Maximum Annual Start-ups.

Pumped Storage Hydroelectric Facilities

The Start-up Payment computed in accordance with Equation D-1 in Schedule D, plus (a) 0.00167 * the Unit's Annual Fixed Revenue Requirement stated in Section 7 of Schedule B), divided by (b) the Unit's Maximum Annual Start-ups.

2. Option B

A. For all Schedule G Billable MWh Delivered in the Billing Month, the ISO shall pay the Variable Cost Payment computed in accordance with Schedule C. Since Schedule G Billable MWh are included in calculating the Variable Cost Payment for Billable MWh for the Billing Month under Schedule C, there is no additional payment for Schedule G Billable MWh under Option B.

B. For all Service Hours provided after the Counted Service Hours for the Contract Year equals the Maximum Annual Service Hours:

Synchronous Condensers

In addition to the Motoring Charge computed in accordance with Schedule E, ISO shall pay the product of (a) the Motoring Charges calculated in accordance with Schedule E, and (b) 0.5.

C. For all Schedule G Start-ups in the Billing Month, the ISO pay:

Units Capable Only of Synchronous Condenser Operation

The Start-up Payment computed in accordance with Schedule D, plus (a) (0.00338) * the Unit's Annual Fixed Revenue Requirement stated in Section 7 of Schedule B, divided by (b) the Unit's Maximum Annual Start-ups.

Fossil Fuel Units and Geothermal Units

Three times (a) the Start-up Payment computed in accordance with Equation D-1 in Schedule D, or (b) if the Schedule G Start-up is initiated under a Dispatch Notice but is not successfully completed because it is canceled or rescinded by the ISO, the Start-up Payment for Canceled Start-up is computed in accordance with Equation D-4 in Schedule D.

3. Owner's Election

Option A __x__

Option B _____

Schedule H

Fuel Oil Service

1. Owner's Obligations: With respect to South Bay Units 1, 2, 3, and 4, Owner is required to (1) maintain, in accordance with Good Industry Practice, residual fuel-oil[4] burning capability, residual fuel-oil inventories, and permits to burn residual fuel-oil and (2) burn residual fuel-oil in response to a Dispatch Notice during periods of natural gas curtailment by the Owner's natural gas supplier.

(a) Environmental Liability Obligation - As between Owner and the ISO: Owner shall be liable for all costs associated with the clean-up and/or mitigation of any release into the environment of the fuel-oil maintained by Owner pursuant to the terms of this Agreement, including but not limited to all penalties assessed by regulatory agencies as a result of any such release, and all amounts paid to compensate third parties for damages resulting from any such release. In addition to insurance obtained in accordance with section 12.1 and Schedule I of this Agreement, Owner will secure and maintain in effect environmental liability insurance to indemnify it in the event of any such release so long as this Agreement requires Owner to maintain residual fuel-oil burning capability, residual fuel-oil inventories, and permits to burn residual fuel-oil. Owner shall name ISO as an additional insured on such insurance. The coverage will be no less than the coverage required pursuant to Title 14, California Code of Regulations, Section 791.7(e)(2)(B). The reasonable costs to Owner of such environmental liability insurance will be a fixed operating expense that Owner is entitled to include in its Schedule F filings for any AFRR effective after December 31, 2002. Should Owner ever obtain environmental liability insurance that is incrementally priced based on the amount of fuel-oil in its tanks, Owner shall pro-rate the cost of such insurance and include in its annual AFRR filing only those insurance costs corresponding to the amounts necessary to insure 100,000 barrels of useable fuel-oil.

2. Minimum Oil Inventory for non Market Transactions: Owner shall use best efforts to maintain at all times a minimum useable[5] fuel-oil inventory for South Bay of 50,000 barrels, beyond "heel"[6] inventory levels, for local reliability purposes unless the ISO requests or directs Owner to acquire additional volumes. Owner shall not reduce the useable fuel-oil inventory for South Bay below 50,000 barrels except in response to a Dispatch Notice by the ISO during a period of natural gas curtailment by the Owner's natural gas supplier. Moreover, as soon as Owner becomes aware that the useable fuel-oil inventory for South Bay will be reduced below 50,000 barrels, Owner shall immediately notify the ISO and use best efforts to promptly replenish its fuel-oil inventory to restore the useable

---

4 Residual Fuel-Oil, for the purpose of this document shall be considered the fuel-oil product capable of 6.258 MMBtu output per barrel.

5 "Useable" oil is that oil that is readily available for use in power generation (i.e., oil that is liquid, above tank suction points, and otherwise capable of being used.).

6 "Heel" inventory is the oil at the tank bottom that may contain sediment and water and/or is beyond the reach of the suction pipe(s).

fuel-oil inventory for South Bay to no less than 50,000 barrels. Owner shall promptly notify the ISO upon replenishment. The minimum useable fuel-oil inventory for South Bay of 50,000 barrels represents approximately five days' fuel requirement for the RMR units at South Bay,[7] and shall be maintained in such a manner as to be readily available for use in the boilers.

3. Cost Recovery:

(a) Variable Cost: Recovery of commodity and transportation costs for fuel-oil shall be in accordance with Equation C1-8 of Schedule C. Section 8 of Schedule C provides as to the Commodity Price for No. 6 Residual Fuel-Oil that the "fuel price shall be the prudent actual replacement cost of the fuel consumed, or, if the fuel is consumed and not replaced, then the fuel price will be 'last-in-first-out' (LIFO) inventory price of the fuel consumed." Section 8 of Schedule C provides also that there shall be no Transportation Rate for No. 6 Residual Fuel-Oil. The actual cost of transportation may be included in the prudent actual replacement cost of the fuel consumed or the LIFO inventory price of the fuel consumed (whichever is applicable), except that such cost of transportation shall not exceed $1.50 per barrel.

(b) AFRR: Owner shall not, in filings to take effect after December 31, 2002, pursuant to Schedule F of the Agreement or otherwise, include the costs relating to an inventory of more than 100,000 barrels of usable fuel-oil at South Bay unless the ISO requests or directs Owner to acquire such additional volumes. In any filing to take effect after December 31, 2002, pursuant to Schedule F or otherwise, the inventory cost of the fuel-oil chargeable to the ISO shall be based on the quantity of useable fuel-oil at South Bay on the June 30 immediately preceding the annual filing. If the inventory of fuel-oil at South Bay does exceed 100,000 useable barrels, for purposes of calculating the fuel-oil inventory component of AFRR, the costs of such inventory shall be multiplied by a fraction the numerator of which is 100,000 and the denominator of which is the total number of barrels of useable fuel-oil. The fuel-oil transportation cost included in the fuel-oil inventory shall not exceed $1.50 per barrel for AFRR.

(c) Cost of "heel" inventory**:** If the entire fuel-oil inventory (usable and "heel") must be removed from a tank, Owner may include 30% of the costs associated with replacing the "heel" inventory in the ISO invoice for the month during which the replacement occurred.

4. Owner's Utilization of the Fuel-Oil**:** Subject to Section 2 above, Owner may use residual fuel-oil for: 1) purposes of Market Transactions and may retain all profits from those Market Transactions as allowed in Section 9.1 of the Agreement, and 2) non-RMR units for Market Transactions, provided that there are no additional costs to the ISO associated with such usage.

---

[7] See Dual Fuel Capability Requirements Report to the ISO Governing Board dated August 19, 1999, Attachment C, Attachment 7, "Value to Customers of Increased Reliability".

Schedule I

Insurance Requirements

Owner - Obtained Insurance

Commercial General Liability
Commercial general liability insurance covering personal injury and property damage to third parties in connection with the activities at the Facility. The coverage will have a limit of not less than $35 million per occurrence, and will include coverage for sudden and accidental pollution losses. The ISO will be added as an additional insured under the terms of this coverage to the per-occurrence limit above.

Property
Property Insurance for direct physical loss or damage to the Facility, in an amount not less than the probable maximum loss at the Facility.

ISO – Obtained Insurance

Errors and Omissions Insurance and Directors & Officers Insurance
Errors and omissions insurance and directors and officers insurance coverage will have a combined limit of not less than $150 million for the shorter of (i) until the termination of this Agreement or (ii) until January 1, 2002.

Schedule J
Notices

OWNER

Name:	Randall J. Hickok
Title:	Managing Director, Asset Management West Dynegy Inc.
Address:	4140 Dublin Blvd, Suite 100, Dublin, CA 94568
Telephone:	(925) 803-5104
Facsimile:	(925) 829-9406
E-mail:	randy.hickok@dynegy.com

With a copy to:

Name:	James M. Hinrichs
Title:	Senior Director Asset Management Dynegy Inc.
Address:	1210 Savoy St., San Diego, CA 92107
Telephone:	(619) 224-4747
Facsimile:	(619) 224-6564
E-mail:	jim.hinrichs@dynegy.com
Name:	Joseph M. Paul
Title:	Sr. Corporate Counsel Dynegy Inc.
Address:	4140 Dublin Blvd, Suite 100, Dublin, CA 94568
Telephone:	(925) 803-5105
Facsimile:	(713) 356-2007
E-mail:	joe.paul@dynegy.com
Name:	Daniel P. Thompson
Title:	Vice President Western Fleet Operations Dynegy Inc.
Address:	4140 Dublin Blvd., Dublin, CA 94568
Telephone:	(845) 664-0178
Facsimile:	(925) 829-9406
E-mail:	daniel.p.thompson@dynegy.com
Name:	R. Alan Padgett
Title:	Managing Director West Commercial Operations Dynegy Inc.
Address:	1000 Louisiana St., Suite 5800, Houston, TX 77002
Telephone:	(713) 767-0480
Facsimile:	(713) 507-6536
E-mail:	alan.padgett@dynegy.com
Name:	Barbara Walsh
Title:	Consultant
Address:	282 Ocean Palm Drive, Unit 6, Flagler Beach, FL 32136
Telephone:	(386) 793-1560
Facsimile:	None
E-mail:	bwalsh3429@aol.com

Schedule J
Notices (continued)

ISO: Nancy Traweek
Director, Operations Support
California ISO Corporation
151 Blue Ravine Road
Folsom, CA 95630
Telephone: (916) 351-2213
Facsimile: (916) 351-2487
E-mail: ntraweek@caiso.com

With a copy to:

Sidney Mannheim Davies
Assistant General Counsel
Tariff and Tariff Compliance
Counsel and Vice President
California ISO Corp.
151 Blue Ravine Road
Folsom, CA 95630
Telephone: (916) 608-7144
Facsimile: (916) 608-7222
E-mail: sdavies@caiso.com

SCHEDULE K

DISPUTE RESOLUTION

Applicability

1.1 General Applicability.

Except as limited below or otherwise as limited by law (including the rights of any party to file a complaint with FERC under the relevant provisions of the Federal Power Act (FPA)), these ADR Procedures shall apply to (a) all disputes between parties which arise under this Agreement and (b) disputes between ISO and a Responsible Utility relating to a Responsible Utility Invoice, "Final Estimated RMR Invoice, Final Adjusted RMR Invoice" as defined in the ISO Tariff, or RMR Charge or RMR Refund as defined in Annex 1 of the Settlement and Billing Protocol in the ISO Tariff. The foregoing shall not impair the applicability of the ISO Tariff ADR procedures to other disputes between the parties that do not arise under this Agreement. All alternative dispute resolution proceedings hereunder shall be administered by the American Arbitration Association ("AAA"). The Owner, Responsible Utility and the ISO shall enter into such arrangements with the AAA as are necessary to provide for AAA administration of this Schedule K.

1.1.1 This Schedule K shall not apply to disputes as to whether rates and charges under the Agreement are just and reasonable under the Federal Power Act except as provided in Schedule F. Nothing herein shall limit the right of the FERC to initiate or adjudicate complaints or other proceedings in accordance with applicable statutes or regulations or to compel FERC to exceed its statutory authority as defined by any applicable federal statutes, regulations or orders lawfully promulgated thereunder.

1.2 Disputes Involving Government Agencies.

If a party to a dispute is a government agency the procedures herein which provide for the resolution of claims and arbitration of disputes are subject to any limitations imposed on the agency by law, including but not limited to the authority of the agency to effect a remedy. If the governmental agency is a federal entity, the procedures herein shall not apply to disputes involving issues arising under the United States Constitution.

1.3 Injunctive and Declaratory Relief.

Where the court having jurisdiction so determines, use of the ADR Procedures shall not be a condition precedent to a court action for injunctive relief nor shall the provisions of California Code of Civil Procedure sections 1281 *et seq.* apply to such court actions.

1.4 Negotiation and Mediation.

1.4.1 Negotiation.

ISO, Responsible Utility and Owner ("Parties") shall make good-faith efforts to negotiate and resolve any dispute between them arising under this Agreement prior to invoking the ADR Procedures herein. Each Party shall designate an individual with authority to negotiate the matter in dispute to participate in such negotiations. The

Responsible Utility may participate in the ADR proceedings arising under this Agreement to the extent the dispute involves billing or payment obligations, in which case ISO or the Responsible Utility, but not both shall be the disputing party. In addition, to the extent Article 7 or other provisions of this Agreement provide the Responsible Utility third-party beneficiary rights, the Responsible Utility may also participate in the ADR as a Party.

The Owner may participate in the ADR proceedings relating to a Responsible Utility Invoice, "Final Estimated RMR Invoice, Final Adjusted RMR Invoice" as defined in the ISO Tariff or RMR Charge or RMR Refund as defined in Annex 1 of the Settlement and Billing Protocol, in which case, ISO or the Owner, but not both, shall be the disputing party. In addition, to the extent the ISO Tariff provides the Owner third-party beneficiary rights, the Owner may also participate in the ADR as a Party.

1.4.2 Statement of Claim.

In the event a dispute is not resolved through such good-faith negotiations, any party may submit a statement of claim, in writing, to each other disputing party, which submission shall commence the ADR Procedures. The statement of claim shall set forth in reasonable detail (i) each claim, (ii) the relief sought, including the proposed award, if applicable, (iii) a summary of the grounds for such relief and the basis for each claim, (iv) the parties to the dispute, and (v) the individuals having knowledge of each claim. The other parties to the dispute shall similarly submit their respective statements of claim within 14 days of the date of the initial statement of claim or such longer period as the AAA may permit following an application by the responding party. If any responding party wishes to submit a counterclaim in response to the statement of claim, it shall be included in such party's responsive statement of claim. No party shall be considered as having received notice of a claim decided or relief granted by a decision made under these procedures unless the statement of claim includes such claim or relief.

1.4.3 Selection of Mediator.

After submission of the statements of claim, the parties may request mediation, if the disputing parties so agree. If the parties agree to mediate, the AAA shall distribute to the parties by facsimile or other electronic means a list containing the names of at least seven prospective mediators with mediation experience, or with technical or business experience in the electric power industry, or both, as he or she shall deem appropriate to the dispute. The parties shall either agree upon a mediator from the list provided or from any alternative source, or alternate in striking names from the list with the last name on the list becoming the mediator. The first party to strike off a name from the list shall be determined by lot. The parties shall have seven days from the date of receipt of the AAA's list of prospective mediators to complete the mediator selection process and appoint the mediator, unless the time is extended by mutual agreement. The mediator shall comply with the requirements of Section 1.5.2.

1.4.4 Mediation.

The mediator and representatives of the disputing parties, with authority to settle the dispute, shall within 14 days after the mediator's date of appointment schedule a date to mediate the dispute. Matters discussed during the mediation shall be confidential and shall not be referred to in any subsequent proceeding. With the consent of all disputing parties, a resolution may include referring the dispute directly to a technical body (such as a WSCC technical advisory panel) for resolution or an advisory opinion, or referring the dispute directly to FERC.

1.4.5 Demand for Arbitration.

If the disputing parties have not succeeded in negotiating a resolution of the dispute within 30 days of the initial statement of claim or, if within that period the parties agreed to mediate, within 30 days of the parties' first meeting with the mediator, such parties shall be deemed to be at impasse and any such disputing party may then commence the arbitration process, unless the parties by mutual agreement agree to extend the time. A party seeking arbitration shall provide notice of its demand for arbitration to the other disputing parties~~.~~

1.5 Arbitration.

1.5.1 Selection of Arbitrator.

1.5.1.1 Disputes Under $1,000,000. Where the total amount of claims and counterclaims in controversy is less than $1,000,000 (exclusive of costs and interest), the disputing parties shall select an arbitrator from a list containing the names of at least 10 qualified individuals supplied by AAA, within 14 days following submission of the demand for arbitration. If the disputing parties cannot agree upon an arbitrator within the stated time, they shall take turns striking names from the list of proposed arbitrators. The first party to strike off a name shall be determined by lot. This process shall be repeated until one name remains on the list, and that individual shall be the designated arbitrator.

1.5.1.2 Disputes of $1,000,000 or Over. Where the total amount of claims and counterclaims in controversy is $1,000,000 or more (exclusive of interest and costs), the disputing parties may agree on any person to serve as a single arbitrator, or shall endeavor in good faith to agree on a single arbitrator from a list of ten qualified individuals provided by the AAA, 14 days following submission of the demand for arbitration. If the disputing parties are unable to agree on a single arbitrator within the stated time, the party or parties demanding arbitration, and the party or parties responding to the demand for arbitration, shall each designate an arbitrator. Each designation shall be from the AAA list of arbitrators, as applicable, no later than the tenth day thereafter. The two arbitrators so chosen shall then choose a third arbitrator.

1.5.2 Disclosures Required of Arbitrators.

The designated arbitrator(s) shall be required to disclose to the parties any circumstances that might preclude him or her from rendering an objective and impartial determination. Each designated arbitrator shall disclose:

1.5.2.1 Any direct financial or personal interest in the outcome of the arbitration;

1.5.2.2 Any information required to be disclosed by California Code of Civil Procedure Section 1281.9.; and

1.5.2.3 Any existing or past financial, business, professional, or personal interest that are likely to affect impartiality or might reasonably create an appearance of partiality or bias. The designated arbitrator shall disclose any such relationships that he or she personally has with any party or its counsel, or with any individual whom they have been told will be a witness. They should also disclose any such relationship involving members of their families or their current employers, partners, or business associates. All designated arbitrators shall make a reasonable effort to inform themselves of any interests or relationships described above. The obligation to disclose interests, relationships, or circumstances that might preclude an arbitrator from rendering an objective and impartial determination is a continuing duty that requires the arbitrator to disclose, at any stage of the arbitration, any such interests, relationships, or circumstances that arise, or are recalled or discovered.

1.5.2.4 If, as a result of the continuing disclosure duty, an arbitrator makes a disclosure which is likely to affect his or her partiality, or might reasonably create an appearance of partiality or bias or if a party independently discovers the existence of such circumstances, a party wishing to object to the continuing use of the arbitrator must provide written notice of its objection to the other parties within ten days of receipt of the arbitrator's disclosure or the date of a party's discovery of the circumstances giving rise to that party's objection. Failure to provide such notice shall be deemed a waiver of such objection. If a party timely provides a notice of objection to the continuing use of the arbitrator the parties shall attempt to agree whether the arbitrator should be dismissed and replaced in the manner described in Section 1.5.1. If within ten days of a party's objection notice the parties have not agreed how to proceed the matter shall be referred to the AAA for resolution.

1.5.3 Arbitration Procedures.

The AAA shall compile and make available to the arbitrator and the parties standard procedures for the arbitration of disputes, which procedures (i) shall conform to the requirements specified herein~~,~~ and (ii) may be modified or adopted for use in a particular proceeding as the arbitrator deems appropriate, in accordance with Section 1.5.4 The procedures shall be based on the latest edition of the American Arbitration Association Commercial Arbitration Rules, to the extent such rules are not inconsistent with this Schedule K. Except as provided herein, all parties shall be bound by such procedures.

1.5.4 Modification of Arbitration Procedures.

In determining whether to modify the standard procedures for use in the pending matter, the arbitrator shall consider (i) the complexity of the dispute, (ii) the extent to which facts are disputed, (iii) the extent to which the credibility of witnesses is relevant to a resolution, (iv) the amount in controversy, and (v) any representations made by the parties. Alternatively, the parties may, by mutual agreement, modify the standard procedures. In the event of a disagreement between the arbitrator and the agreement of the parties regarding arbitration procedures to be utilized, the parties' agreement shall prevail.

1.5.5 Remedies.

1.5.5.1 Arbitrator's Discretion. The arbitrator shall have the discretion to grant the relief sought by a party~~,~~ or determine such other remedy as is appropriate, unless the parties agree to conduct the arbitration "baseball" style. Unless otherwise expressly limited herein, the arbitrator shall have the authority to award any remedy or relief available from FERC, or any court of competent jurisdiction. Where this Agreement leaves any matter to be agreed between the parties at some future time and provides that in default of agreement the matter shall be referred to the ADR, the arbitrator shall have authority to decide upon the terms of the agreement which, in the arbitrator's opinion, it is reasonable that the parties should reach, having regard to the other terms this Agreement concerned and the arbitrator's opinion as to what is fair and reasonable in all the circumstances.

1.5.5.2 "Baseball" Arbitration. If the parties agree to conduct the arbitration "baseball" style, the parties shall submit to the arbitrator and exchange with each other their last best offers in the form of the award they consider the arbitrator should make, not less than seven days in advance of the date fixed for the hearing, or such later date as the arbitrator may decide. If a party fails to submit its last best offer in accordance with this Section, that party shall be deemed to have accepted the offer proposed by the other party. The arbitrator shall be limited to awarding only one of the proposed offers, and may not determine an alternative or compromise remedy.

1.5.6 Summary Disposition.

The procedures for arbitration of a dispute shall provide a means for summary disposition of a demand for arbitration, or a response to a demand for arbitration, that in the reasoned opinion of the arbitrator does not have a good faith basis in either law or fact. If the arbitrator determines that a demand for arbitration or response to a demand for arbitration does not have a good faith basis in either law or fact, the arbitrator shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator to the prevailing party. A determination made under this Section is subject to appeal pursuant to Section 1.6.

1.5.7 Discovery Procedures.

The procedures for the arbitration of a dispute shall include adequate provision for the discovery of relevant facts, including the taking of testimony under oath, production of documents and other things, the presentation of evidence, the taking of samples, conducting of tests, and inspection of land and tangible items. The nature and extent of such discovery shall be determined as provided herein and shall take into account (i) the complexity of the dispute, (ii) the extent to which facts are disputed, (iii) the extent to which the credibility of witnesses is relevant to a resolution, and (iv) the amount in controversy. The forms and methods for taking such discovery shall be as described in the Federal Rules of Civil Procedure, except as modified pursuant to Section 1.5.4.

1.5.8 Evidentiary Hearing.

The arbitration procedures shall provide for an evidentiary hearing, with provision for the cross-examination of witnesses, unless all parties consent to the resolution of the matter on the basis of a written record. The forms and methods for taking evidence shall be determined by the arbitrator(s) and modified pursuant to Section 1.5.4. The arbitrator may require such written or other submissions from the parties as he or she may deem appropriate, including submission of direct and rebuttal testimony of witnesses in written form. The arbitrator may exclude any evidence that is irrelevant, immaterial, unduly repetitious or prejudicial, or privileged. The arbitrator shall compile a complete evidentiary record of the arbitration that shall be available to the parties on its completion upon request.

1.5.9 Confidentiality.

Subject to the other provisions of this Agreement, any party may claim that information contained in a document otherwise subject to discovery is "Confidential" if such information would be so characterized under the Federal Rules of Evidence or the provisions of the Agreement. The party making such claim shall provide to the arbitrator in writing the basis for its assertion. If the claim of confidentiality is confirmed by the arbitrator, he or she shall establish requirements for the protection of such documents or other information designated as "Confidential" as may be reasonable and necessary to protect the confidentiality and commercial value of such information. Any party disclosing information in violation of these provisions or requirements established by the arbitrator, unless such disclosure is required by federal or state law or by a court order, shall thereby waive any right to introduce or otherwise use such information in any judicial, regulatory, or other legal or dispute resolution proceeding, including the proceeding in which the information was obtained.

1.5.10 Timetable.

Promptly after the appointment of the arbitrator, the arbitrator shall set a date for the issuance of the arbitration decision, which shall be no later than six months (or such earlier date as the parties and the arbitrator may agree) from the date of the appointment of the arbitrator, with other dates, including the dates for an evidentiary hearing or other final submissions of evidence, set in light of this date. The date for the evidentiary hearing or other final submission of evidence shall not be changed, absent extraordinary circumstances. The arbitrator shall have the power to impose sanctions, including dismissal of the proceeding, for dilatory tactics or undue delay in completing the arbitration proceedings.

1.5.11 Decision.

1.5.11.1 Except as provided below with respect to "baseball" style arbitration, the arbitrator shall issue a written decision granting the relief requested by one of the parties, or such other remedy as is appropriate, if any, and shall include findings of fact and law. The arbitration decision shall be based on (i) the evidence in the record, (ii) the terms of this Agreement and to the extent relevant, the ISO Tariff and Protocols, (iii) applicable United States federal law, including the Federal Power Act and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) applicable state law. Additionally, the arbitrator may consider relevant decisions in previous arbitration proceedings involving this Agreement. To the extent it may do so without violating confidentiality requirements, a summary of the disputed matter and the arbitrator's decision may be published in an ISO newsletter on ISO's Home Page.

1.5.11.2 In arbitration conducted "baseball" style, the arbitrator shall issue a written decision adopting one of the awards proposed by the parties, and shall include findings of fact and law. The arbitration decision shall be based on (i) the evidence in

the record, (ii) the terms of this Agreement and to the extent relevant, the ISO Tariff and Protocols, (iii) applicable United States federal law, including the Federal Power Act and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) applicable state law. If the arbitrator concludes that no proposed award is consistent with the factors enumerated in (i) through (iv) above, or addresses all of the issues in dispute, the arbitrator shall specify how each proposed award is deficient and direct that the parties submit new proposed awards that cure the identified deficiencies. To the extent it may do so without violating confidentiality requirements, a summary of the disputed matter and the arbitrator's decision may be published in an ISO newsletter on ISO's Home Page.

1.5.11.3 Where a panel of arbitrators is appointed pursuant to Section 1.5.1.2, a majority of the arbitrators must agree on the decision. An award shall not be deemed to be precedent except in so far as a future dispute between the parties involves the same issue.

1.5.12 Compliance.

Unless the arbitrator's decision is appealed under Section 1.6, the disputing parties shall, upon receipt of the decision, immediately take whatever action is required to comply with the award to the extent the award does not require regulatory action. An award that is not appealed shall be deemed to have the same force and effect as an order entered by FERC or any court of competent jurisdiction.

1.5.13 Enforcement.

Following the expiration of the time for appeal of an award pursuant to Section 1.6.3, any party may apply to FERC or any court of competent jurisdiction for entry and enforcement of judgment based on the award.

1.5.14 Costs.

The costs of the time, expenses, and other charges of the arbitrator shall be borne by the parties to the dispute, with each side on an arbitrated issue bearing its pro-rata share of such costs, and each party to an arbitration proceeding bearing its own costs and fees. If the arbitrator determines that a demand for arbitration or response to a demand for arbitration was made in bad faith, the arbitrator shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator to the prevailing party.

1.6 Appeal of Award.

1.6.1 Basis for Appeal.

A party may apply to the FERC or any court of competent jurisdiction to hear an appeal of an arbitration decision only upon the grounds that the decision is contrary to or beyond the scope of this Agreement and to the extent relevant, the ISO Tariff and Protocols, United States federal law, including, without limitation, the Federal Power Act, and any applicable FERC regulations and decisions, or state law. Appeals shall, unless otherwise ordered by FERC or the court of competent jurisdiction, conform to the procedural limitations set forth in this Section 1.6.

1.6.2 Appellate Record.

The parties intend that FERC or a court of competent jurisdiction should afford substantial deference to the factual findings of the arbitrator. No party shall seek to expand the record before FERC or a court of competent jurisdiction beyond that assembled by the arbitrator, except (i) by making reference to legal authority which did not exist at the time of the arbitrator's decision, or (ii) if such party contends the decision was based upon or affected by fraud, collusion, corruption, misconduct or misrepresentation.

1.6.3 Procedures for Appeals.

1.6.3.1 If a party to an arbitration desires to appeal a decision, it shall provide a notice of appeal to all parties and the arbitrator(s) within 14 days following the date of the decision. Within ten days of the filing of the notice of appeal, the appealing party must file an appropriate application, petition or motion with FERC for review under the Federal Power Act or with a court of competent jurisdiction. Such filing shall state that the subject matter has been the subject of an arbitration pursuant to this Agreement and, to the extent relevant, the ISO Tariff and protocols.

1.6.3.2 Within 30 days of filing the notice of appeal (or such period as FERC or the court of competent jurisdiction may specify) the appellant shall file the complete evidentiary record of the arbitration and a copy of the decision with FERC or with the court. The appellant shall serve on all parties to the arbitration copies of a description of all materials included in the submitted evidentiary record.

1.6.4 Award Implementation.

Implementation of the decision shall be deemed stayed pending an appeal unless and until, at the request of a party, FERC or the court of competent jurisdiction with which an appeal has been filed, issues an order dissolving, shortening, or extending such stay.

A summary of each appeal shall be published in an ISO newsletter on the ISO Home Page.

1.6.5 Judicial Review of FERC Orders.

FERC orders resulting from appeals shall be subject to judicial review pursuant to the Federal Power Act.

SCHEDULE L-1

REQUEST FOR APPROVAL OF CAPITAL ITEMS OR REPAIRS

This form should be used to request ISO approval of Planned Capital Items, Unplanned Repairs or Unplanned Capital Items pursuant to Sections 7.4, 7.5 or 7.6 of the Agreement.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR
RELIABILITY MUST-RUN UNIT
CAPITAL ITEM AND REPAIR PROJECT REQUEST

Date: **CA ISO Project Number:**

Facility: **Unit:**

Owner: **Location:**

This request covers:

( ) Capital Items for the next Contract Year (preliminary)
( ) Capital Items for the next Contract Year (final)
( ) Unplanned Repairs
( ) Unplanned Capital Items

If this request covers Capital Items for the next Contract Year, provide:

Small Project Estimate (reliability)

Small Project Estimate (other)

Identify separately each Capital Item included in a small project estimate projected to cost more than $50,000.

If this request covers Unplanned Repairs, or Capital Items projected to cost more than $500,000, provide the information in the remainder of this form for each project.

Project Description: (describe the project and its major scope items – materials, new systems, modifications to existing systems, etc.)

If the project is required because of loss or damage to a Unit, describe the cause and nature of

the loss or damage and all repairs performed or required for all Units during the year:

Project Budget:

Year	Labor	Material	Contract	Int Svc	Other	Material	Over head AEGE	Total Cost	AD VAL TAX	Total Expenditures	Total Financial Costs

Describe any work or repairs performed relating to this project in the last five years:

As applicable, state the proposed depreciation life, Annual Capital Item Cost, Surcharge Payment Factor or Repair Payment Factor (percentage owed by ISO) of the Capital Item or Repair:

Describe why this project is required (justification):

Is this project required to comply with any laws, regulations or permits? If so, please list them and explain requirement.

Provide a cost/benefit analysis summary for this project:

Include all assumptions including changes to unit performance [efficiency, aux. power loads, etc.], impact on Maximum Net Dependable Capacity, grid interconnection/metering impacts, etc.

Describe the impacts on the Unit's ability to perform its obligations under this Agreement if this project is not approved:

Describe alternatives to this project that were evaluated and the projected costs of those alternatives:

Describe alternatives along with their major scope items. Also, compare the projected cost of these alternatives with the selected alternative, and compare the unit performance impacts (efficiency, auxiliary power demands, Maximum Net Dependable Capacity effects, etc.) of these alternatives against the chosen alternative.

List any proceeds received or expected to be received by Owner from insurers or other third parties pursuant to applicable insurance, warranties and other contracts in connection with the project.

Provide the schedule for implementing this project:

Event	Begin	Complete

Describe any outages required to implement this project:

Other comments:

SCHEDULE L-2

CAPITAL ITEM AND REPAIR PROGRESS REPORT

CALIFORNIA INDEPENDENT SYSTEM OPERATOR
RELIABILITY MUST-RUN UNIT
CAPITAL ITEM AND REPAIR PROGRESS REPORT

Date:

CA ISO Project Number:

Facility:

Unit:

Owner:

Location:

Capital Item or Repair:

Original In-Service Date:

Current In-Service Date:

If Current In-Service Date has changed, describe the reason why:

Describe any additional costs or savings resulting from the change in the Current In-Service Date:

Describe what portion of any additional costs Owner is requesting ISO to pay, and why Owner believes that ISO should be obligated to pay those additional costs:

SCHEDULE M

Mandatory Market Bid for Condition 2 Units When Dispatched by the ISO

Energy Bid

The bid the Owner of a Condition 2 Fossil Fuel Unit must submit into Energy markets when dispatched by the ISO is given in Equation M-1a (for Units with input/output data in polynomial form) or Equation M-1b (for Units with input/output data in exponential form):

Equation M-1a

$$\text{Energy Bid (\$/MWh)} = \frac{(AX^3 + BX^2 + CX + D)}{X} * P * E$$

+ [Variable O&M Rate + Emissions Rates + Scheduling Coordinator Charge + ACA Charge]

Equation M-1b

$$\text{Energy Bid (\$/MWh)} = \frac{A \times (B + CX + De^{FX})}{X} * P * E$$

+ [Variable O&M Rate + Emissions Rate + Scheduling Coordinator Charge + ACA Charge]

Where:

- for Equation M-1a, A, B, C, D and E are the coefficients given in Table C1-7a;
- for Equation M-1b, A, B, C, D, E and F are the coefficients given in Table C1-7b;
- X is the Unit Availability Limit, MW;
- P is the Hourly Fuel Price as calculated by Equation C1-8 in Schedule C using the Commodity Prices most recently published before the day the bid is submitted.
- Scheduling Coordinator Charge ($/MWh): The PX Administration Charge under the PX Tariff.
- ACA Charge ($/MWh): The applicable annual charge for short-term sales under 18 CFR Section 382.201 of the FERC Regulations.
- Variable O&M Rate ($/MWh): as shown on Table C1-18

For Units in the SCAQMD only

Emissions Rate (\$/MWh) = Emissions Cost / Unit Availability Limit

Emissions Cost = (a) RECLAIM Cost + (b) NOx Emissions Cost + (c) Organic Gases Cost + (d) Sulfur Oxides Cost + (e) Particulate Matter Cost + (f) Carbon Monoxide Cost

(a) RECLAIM Cost = $((AX^2+BX+C)$ * RECLAIM NOx Trading Credit Rate

(b) NOx Emissions Cost = $\frac{(AX^2+BX+C)}{2000}$ * NOx Emissions Fee

Where:

A, B and C are the coefficients from Table C1-13;

X = Unit Availability Limit;

(c) Organic Gases Cost =

4.76×10^{-7} * (Gas Fuel) * Associated Emission Factor for Organic Gases * Associated Emissions Fee for Organic Gases

(d) Sulfur Oxides Cost =

4.76×10^{-7} * (Gas Fuel) * Associated Emission Factor for Sulfur Oxides * Associated Emissions Fee for Sulfur Oxides

(e) Particulate Matter Oxides Cost =

4.76×10^{-7} * (Gas Fuel) * Associated Emission Factor for Particulate Matter * Associated Emission Fee for Particulate Matter

(f) Carbon Monoxide Cost =

4.76×10^{-7} * (Gas Fuel) * Associated Emission Factor for Carbon Monoxide * Associated Emission Fee for Carbon Monoxide

Where:

Gas Fuel = $AX^3 + BX^2 + CX + D$ or $A \times (B + CX + De^{FX})$, depending on the form of heat input the Owner is using

- A, B, C, D are the coefficients from C1-7a or C1-7b;
- F is the coefficient from C1-7b;
- X = Unit Availability Limit;
- Factors and Associated Emission fees are determined in Schedule C, Section D.3.

The bid the Owner of a geothermal Condition 2 Unit must submit into Energy markets when dispatched by the ISO is given in Equation M-2.

Equation M-2

Energy Bid ($/MWh) = Fuel Cost + [Variable O&M Rate + Scheduling Coordinator Charge + ACA Charge]

Where:

- The Fuel Cost is the Steam Price identified in Equation C2-1 in Schedule C. However, for purposes of this mandatory market bid, the value for the Steam Price will be zero for Geysers Main Units until the cumulative Hourly Metered Total Net Generation during the Contract Year from all Units exceeds the Minimum Annual Generation given in Equation C2-2.
- Variable O&M Cost ($/MWh): the cost shall be as shown on Table C2-1.
- Scheduling Coordinator Charge: The PX Administration Charge under the PX Tariff.
- ACA Charge ($/MWh): The applicable annual charge for short-term sales under 18 C.F.R. Section 382.201 of the FERC Regulations.

Ancillary Services Bid

The bid the Owner of a Condition 2 Unit must submit into Ancillary Service markets when dispatched by ISO is as follows:

$$\text{Ancillary Services Bid (\$/MW per hr)} = \frac{\left[\dfrac{\text{Annual Fixed Revenue Requirement (\$)}}{\left(\begin{array}{c}\text{30 minutes x Unit's}\\ \text{Highest Ramp Rate}\\ \text{from Schedule A,}\\ \text{MW/min}\end{array}\right) * \left(\begin{array}{c}\text{Target}\\ \text{Available}\\ \text{Hours}\end{array}\right)}\right] + \left[\dfrac{\text{Annual Fixed Revenue Requirement (\$)}}{\left(\begin{array}{c}\text{Maximum}\\ \text{Net}\\ \text{Dependable}\\ \text{Capacity}\end{array}\right) * \left(\begin{array}{c}\text{Target}\\ \text{Available}\\ \text{Hours}\end{array}\right)}\right]}{2}$$

Annual Fixed Revenue Requirement is shown in Schedule B.
Target Available Hours is shown in Schedule B.
The product of 30 minutes times the Unit's highest Ramp Rate in Schedule A shall not exceed the Unit's Maximum Net Dependable Capacity.

Schedule N-1

NON-DISCLOSURE and CONFIDENTIALITY AGREEMENT for RESPONSIBLE UTILITY

[Name of Responsible Utility] (the "Responsible Utility") acknowledges that **[Name of Owner]** ("Owner") and the California Independent System Operator Corporation ("ISO") (jointly, the "Providing Parties" and severally, the "Providing Party") have agreed to provide certain information to the Responsible Utility pursuant to certain provisions of the Must-Run Service Agreement ("MRSA") between Owner and ISO and as required for settlement and billing of charges under Article 9 of such Agreement. In order to permit the Responsible Utility to receive such Confidential Information from Owner or ISO pursuant to the above-referenced provisions of the MRSA, the Responsible Utility and the Providing Parties hereby agree as follows:

(1) For purposes of this Non-Disclosure and Confidentiality Agreement, the term "Confidential Information" shall have the same meaning it has in Section 12.5 of the MRSA, a copy of which is appended;

(2) The Providing Parties shall provide such Confidential Information pursuant to the terms of this Non-Disclosure and Confidentiality Agreement;

(3) The Responsible Utility shall keep such Confidential Information confidential, shall use it only for the purposes related to the MRSA, and shall limit the disclosure of any such Confidential Information to only those personnel within its organization with responsibility for using such information in connection with the MRSA. Such personnel may not include any person whose duties include (i) the marketing or sale of electric power or natural gas or gas transportation capacity at wholesale or retail, (ii) the purchase of electric power or natural gas or gas transportation capacity at wholesale or retail, (iii) the direct supervision of any employee with such responsibilities, or (iv) the provision of electricity or natural gas marketing consulting services to any employee with such responsibilities;

(4) The Responsible Utility shall assure that personnel within its organization read and comply with the provisions of this Non-Disclosure and Confidentiality Agreement;

(5) The Responsible Utility shall use all reasonable efforts to maintain the confidentiality of the Confidential Information in any litigation, and shall promptly notify the providing Party of any attempt by a third party to obtain the Confidential Information through legal process or otherwise;

(6) The Responsible Utility may use Confidential Information in litigation or regulatory proceedings related to the Must-Run Service Agreement between Owner and ISO but only after notice to the Providing Party and affording the Providing Party an opportunity to obtain a protective order or other relief to prevent or limit disclosure of the Confidential Information.

The Responsible Utility agrees to be bound by the terms of Section 12.5 of the MRSA in the same manner and to the same extent as the Providing Parties. The person signing on behalf of the Responsible Utility represents that he/she is authorized to bind the Responsible Utility to the terms of this Non-Disclosure and Confidentiality Agreement.

The undersigned signatory represents that he/she is authorized to bind the Responsible Utility, to the terms of this Non-Disclosure and Confidentiality Agreement.

Signature:______________________________
Name:______________________________
Title:______________________________
Responsible Utility:________________________
Address:______________________________

Telephone:______________________________

Signature:______________________________
Name:______________________________
Title:______________________________
Owner:______________________________
Address:______________________________

Telephone:______________________________

Signature:______________________________
Name:______________________________
Title:______________________________
California Independent System Operator Corporation
Address:______________________________

Telephone:______________________________

Schedule N-2

NON-DISCLOSURE and CONFIDENTIALITY AGREEMENT for PERSONS OTHER THAN THE RESPONSIBLE UTILITY

[Name of] (the "Receiving Party") acknowledges (a) that **[Name of Owner]** ("Owner") has agreed to provide Confidential Information to the California Agency pursuant to certain provisions of the Must-Run Service Agreement ("MRSA") between Owner and the California Independent System Operator Corporation ("ISO"), and (b) that Owner and ISO (jointly, the "Providing Parties" and severally, the "Providing Party") may provide Confidential Information on a need-to-know basis to Owner's Scheduling Coordinator, financial institutions, agents and potential purchasers of interests in a Unit; and, as required for settlement and billing, to Scheduling Coordinators responsible for paying for services provided under the MRSA between Owner and ISO. In order to permit the Receiving Party to receive such Confidential Information from Owner or ISO, the Receiving Party and the Providing Parties hereby agree as follows:

(1) For purposes of this Non-Disclosure and Confidentiality Agreement, the term "Confidential Information" shall have the same meaning it has in Section 12.5 of the MRSA between Owner and ISO, a copy of which is appended;

(2) The Providing Parties shall provide such Confidential Information pursuant to the terms of this Non-Disclosure and Confidentiality Agreement;

(3) The Receiving Party shall keep such Confidential Information confidential, shall use it only for the purposes related to the MRSA, and shall limit the disclosure of any such Confidential Information to only those personnel within its organization with responsibility for using such information in connection with the MRSA upon their execution of this Non-Disclosure and Confidentiality Agreement. Such personnel may not include any person whose duties include (i) the marketing or sale of electric power or natural gas or gas transportation capacity at wholesale or retail, (ii) the purchase of electric power or natural gas or gas transportation capacity at wholesale or retail, (iii) the direct supervision of any employee with such responsibilities, or (iv) the provision of electricity or natural gas marketing consulting services to any employee with such responsibilities;

(4) The Receiving Party shall assure that personnel within its organization authorized to receive Confidential Information read and comply with the provisions of this Non-Disclosure and Confidentiality Agreement;

(5) The Receiving Party shall use all reasonable efforts to maintain the confidentiality of the Confidential Information in any litigation, and shall promptly notify the providing Party of any attempt by a third party to obtain the Confidential Information through legal process or otherwise;

The Receiving Party agrees to be bound by the terms of Section 12.5 of the MRSA in the same manner and to the same extent as the Providing Parties. The person signing on behalf of the Receiving Party represents that he/she is authorized to bind the Receiving Party to the terms of this Non-Disclosure and Confidentiality Agreement.

Signature:____________________________
Name: ____________________________
Company:____________________________
Title: ____________________________
Receiving Party:____________________________

Address:____
____
____
Telephone:______________________________________

Signature:______________________________________
Name: ____
Owner: ____
Title: ____
Address:____
____
____
Telephone:______________________________________

Signature:______________________________________
Name: ____
California Independent System Operator Corporation
Title: ____
Address:____
____
____
Telephone:______________________________________

SCHEDULE O

RMR Owner's Invoice Process

The following principles and practices shall govern the submission of invoices to the ISO for Energy and Ancillary Services provided under this Agreement ("RMR services"):

1 Invoices submitted by Owner to the ISO for RMR services shall be clear, understandable and complete.

2. The ISO, all RMR Owners and Responsible Utilities shall agree on the RMR invoice template, which agreement shall not be unreasonably withheld, prior to its implementation. The ISO shall publish the current version of the RMR invoice template by including it on the ISO Home Page. The ISO will specifically tell each Owner and Responsible Utility where on the ISO Home Page this RMR invoice template can be found. Each Owner shall use the then current RMR invoice template for invoicing RMR services for each Facility. The RMR invoice template may change from time to time. The ISO shall notify the California Agency, all RMR Owners and Responsible Utilities when a new agreed upon RMR invoice template has been placed on the ISO Home Page.

3. Subject to the provisions of paragraph 4 below, a Completed RMR invoice based on the version of the RMR invoice template posted on the ISO's Home Page seven days prior to submission of the invoice shall be deemed to satisfy the requirements of this Agreement. As used herein, the term "Completed RMR invoice" means that: (a) all of the raw data required to calculate debits and credits have been included; (b) all calculations have been performed in accordance with the formulae in the current RMR invoice template, or in the event that Owner believes a conflict exists between one or more formula(s) in the RMR Owner's invoice and the corresponding formula in the RMR invoice template, such conflict has been identified and substitute equations have been documented and used at the appropriate location(s) in the invoice; (c) linkages between invoice levels are identified; (d) all billing and service assumptions, data inputs and formulae reasonably necessary to understand the derivation of each charge on the invoice has been included; and (e) the invoice has been provided to the ISO and the Responsible Utility.

4. The Estimated RMR invoice or the Adjusted RMR invoice timeline set forth in the ISO's RMR Payments Calendar (for the appropriate invoice) shall not commence, payments shall not be made and interest shall not begin to accrue until a Completed RMR invoice has been submitted to the ISO and Responsible Utility.

5. In the event of any conflict between the RMR invoice template and this Agreement, this Agreement shall govern. The Owner or Responsible Utility detecting the conflict shall promptly give notice to the ISO. The ISO shall notify all RMR Owners and all Responsible Utilities as soon as practicable after a conflict has been identified.

6. If Owner identifies a conflict, Owner shall identify the conflict in its letter transmitting its completed Estimated or Adjusted RMR invoice to the ISO and include therein Owner's revised formula, which will be effective until agreement has been reached among the ISO, Owner, the other RMR Owners and the Responsible Utilities on the correct formula, or a decision has been rendered through ADR from which no further appeal is possible.

7. An RMR Invoice Task Force has been formed with representatives from each of the RMR Owners, the Responsible Utilities and the ISO. When a conflict has been identified, the ISO, Owner, the other RMR Owners and the Responsible Utility will participate in meetings of the RMR Invoice Task Force to reach agreement on a revised RMR invoice template. The RMR Invoice Task Force shall meet at least monthly until all conflicts are resolved. Once all conflicts have been resolved, the RMR Invoice Task Force will meet approximately every six months to address

invoicing and payment issues.

8. The RMR Invoice Task Force also shall be responsible for simplifying the RMR invoices so that they are easier to process and less burdensome to prepare.

9. To the extent that the Owner, the ISO and the Responsible Utility have agreed, certain columns in the Owner's RMR invoice template shall be standard for the Facility and shall not change. The Owner shall not be required to complete such columns each month on its invoice for it to be considered a Completed RMR invoice, unless the underlying information requirements change.

10. Owner shall supply monthly RMR Level 0-3 invoice information in accordance with the RMR invoice template for each Responsible Utility service territory as follows:

    1. Level 0: the summary invoice for Owner's total amount invoiced to the ISO for all of Owner's Facilities;

    2. Level 1: the summary invoice for all RMR Units at a Facility;

    3. Level 2: the detailed calculated information for individual RMR Units at the Facility; and

    4. Level 3: the detailed hourly data for individual RMR Units at each Facility.

    Each invoice shall contain such other information as is necessary to perform the calculations, including indicated netted meter reads, ISO Dispatch Notice information (both day-ahead, real time, and adjustments), Owner's Availability Notice information and final market schedule information. No quantities shall be left blank. Each assumption made by the Owner to perform a calculation shall be listed and explained either in the appropriate Level 0-3 template under Notes or in a transmittal letter accompanying the invoice.

    The methods described shall be used to calculate quantities such as Hourly Fuel Price, Hourly Emissions Cost and Start-up calculations used as input data in the RMR invoice template.

    Owner shall indicate any data appearing on the invoice which it considers confidential. Responsible Utility may use the data in accordance with Section 12.5 and Schedule N of this Agreement.

SCHEDULE P

Reserved Energy for Air Emissions Limitations

This Schedule P applies only to Units located within the San Diego Air Quality Control Basin ("Basin").

1. For purposes of this Schedule P, the term Emission Limitation means present or future limitations on the discharge of air pollutants or contaminants into the atmosphere specified by any federal, state, regional or local law ("Clean Air Law"), by any regulation, air quality implementation plan, or permit condition promulgated or imposed by any agency authorized under any such Clean Air Law or by the judgment of any court of competent jurisdiction.

2. (a) Except as set out in Sections 2 (b) and (c), if a Facility is located in the Basin and is subject to an Emission Limitation that would limit the MWh that can be produced from the Facility during the Contract Year or part thereof (such Contract Year or part being referred to as the "Limitation Period"), Owner shall, so long as some or all of the Units at the Facility are operating under Condition 1, reserve for the Facility for each Month of the Limitation Period for dispatch under this Agreement, a quantity of MWh equal to the average monthly Requested MWh for the Facility for that Month in the 36 Months preceding the next Contract Year (the "Monthly Reserved MWh").

   (b) If there are less than 36 Months of Requested MWh preceding the next Contract Year, the Monthly Reserved MWh for the Limitation Period shall be determined by agreement between ISO and Owner. If Owner and ISO are unable to reach agreement by October 31 preceding the next Contract Year, Owner or ISO may refer the matter to ADR under a schedule (specified by the arbitrator if the participants cannot agree) requiring a decision within 30 days following appointment of the arbitrator.

   (c) (i) If the Monthly Reserved MWh has been determined in accordance with Section 2(a) and this Agreement terminates as to a Unit at the Facility, the Monthly Reserved MWh shall be adjusted downward to the average of the Requested MWh for the Units that remain subject to this Agreement for the same 36 Month period previously used to calculate the Monthly Reserved MWh.

   (ii) If the Monthly Reserved MWh has been determined in accordance with Section 2 (b) and the Agreement terminates as to a Unit at the Facility, the adjustment shall be determined by agreement of Owner and ISO. If the Parties are unable to reach agreement at least 45 days before the Agreement terminates as to the Unit, Owner or ISO may refer the matter to ADR under a schedule (specified by the arbitrator if the participants cannot agree) requiring a decision within 30 days following appointment of the arbitrator.

3. The Monthly Reserved MWh are set forth on Schedule A. No less than 15 days before the beginning of each Contract Year, Owner shall make a Section 205 filing limited to changing the terms of Schedule A to revise the Monthly Reserved MWh determined in accordance with Section 2. The revised Monthly Reserved MWh shall be effective from the first day of the Contract Year.

4. If the sum of the Billable MWh and Hybrid MWh during a Month is less than the Monthly Reserved MWH, ISO may:

   (a) carry forward into the following Months of the Limitation Period all unused Monthly Reserved MWh, provided the cumulative unused MWh that are carried forward into the following Months may not exceed 20% of the aggregate Monthly Reserved MWh for the remainder of the Limitation Period including the Monthly Reserved MWh for the Months into which unused Monthly Reserved MWh are to be carried forward, or

(b) carry forward less than all unused Monthly Reserved MWh and release to Owner the Monthly Unused Reserved MWh not carried forward.

ISO shall notify Owner of the amount of unused Monthly Reserved MWh to be carried forward within 3 Business Days after the beginning of the next Month.

5. ISO may elect to reduce the aggregate Monthly Reserved MWh for the remainder of the Limitation Period by notifying Owner not less than 5 days prior to the beginning of the Month in which the reduction is to be effective. Notwithstanding the foregoing, if ISO or Owner forecasts that usage will approach the Emission Limitation in the last Month of the Limitation Period, ISO and Owner shall closely coordinate to release any unused Monthly Reserved MWh as soon as possible.

6. If there are unused Monthly Reserved MWh for the Facility remaining at the end of the Limitation Period, ISO shall pay the Unused Emission Reserve Payment. The Unused Emission Reserve Payment shall be the product of (a) the Unused Monthly Reserved MWh Payment Rate and (b) the lesser of (i) the unused Monthly Reserved MWh carried forward by the ISO into the last Month of the Limitation Period and (ii) the unused Monthly Reserved MWh remaining at the end of the Limitation Period. The Unused Monthly Reserved MWh Payment Rate shall be $10 per MWh. The Unused Emission Reserve Payment shall be included in the invoice for the last Billing Month of the Limitation Period.

7. If the ISO determines that the Monthly Reserved MWh have become insufficient due to a Force Majeure Event at the Facility or at Reliability Must-Run Units at another facility or because of an outage on the ISO Controlled Grid or the Distribution Grid due to a Force Majeure Event, ISO may request Owner to undertake, and if so requested, Owner shall undertake all such necessary and commercially reasonable measures approved in advance by ISO and the Responsible Utility to (a) obtain, where possible, a modification or variance from applicable Emission Limitations, or (b) procure necessary emission reduction credits or allowances sufficient to offset emissions in excess of Emission Limitations to enable Owner to provide additional MWh dispatched by the ISO to meet reliability requirements arising by reason of such Force Majeure Event. ISO shall reimburse Owner for all reasonable costs of procuring such emission reduction credits or allowances.

8. If the ISO wishes to dispatch a Unit at a Facility that is within 5% of exceeding its Monthly Reserved MWh for the Limitation Period, the ISO shall first dispatch Units at other Facilities that are not within 5% of the Monthly Reserved MWh during the Limitation Period if the other Unit(s), in the ISO's sole judgment, provide equivalent reliability benefits.

9. If any Emission Limitation affecting the Facility materially changes, ISO and Owner promptly shall renegotiate this Schedule P to reflect such change. If ISO and Owner are unable to agree on revisions to this Schedule P, the Owner may file a revised Schedule P with FERC under Section 205 of the Federal Power Act for the limited purpose of taking such changes in the Emissions Limitation into account. Such filing may be with or without the concurrence of the ISO, but ISO reserves its right to protest any such filing.

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK