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January 26, 2009

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BY HAND DELIVERY

J. Mike Monasmith
Siting Project Manager
California Energy Commission
1516 Ninth Street MS-15
Sacramento, CA 95814

DOCKET
07-AFC-6
DATE JAN 26 2009
RECD. JAN 26 2009

**Re: Carlsbad Energy Center Project (07-AFC-6)
Responses to Center for Biological Diversity's Data Responses**

Dear Mr. Monasmith:

Pursuant to the Committee's December 26, 2008 ruling regarding intervenor Center for Biological Diversity's ("CBD") petition to compel data responses, Applicant Carlsbad Energy Center LLC timely submits the enclosed responses to CBD's data requests related to the Carlsbad Energy Center Project. Please note that the response to data request F1 has a corresponding several-hundred page attachment. While the attachment is contained on the disc provided to all parties, should any party wish to also receive a paper copy of Attachment DRF1-2, the Applicant will gladly provide it.

Should you have questions related to this submittal, please contact John McKinsey at (916) 447-0700.

Respectfully submitted,

Stoel Rives LLP

Kimberly J. Hellwig
Senior Paralegal

KJH:kjh
Enclosure
cc: See Proof of Service

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA

APPLICATION FOR CERTIFICATION FOR THE *CARLSBAD ENERGY CENTER PROJECT*	**Docket No. 07-AFC-6 PROOF OF SERVICE (As of 1/12/2009)**

Applicants Responses to Intervenor Center for Biological Diversity's Date Requests

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 07-AFC-6
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DECLARATION OF SERVICE

I, Denise M. Morison, declare that on January 26, 2009, I deposited copies of **Applicant's Responses to Intervenor Center for Biological Diversity's Data Requests** in the United States mail at Sacramento, California, with first-class postage thereon fully prepaid and addressed to those identified on the Proof of Service list above.

OR

Transmission via electronic mail consistent with the requirements of California Code of Regulations, title 20, sections 1209, 1209.5, and 1210. All electronic copies were sent to all those identified on the Proof of Service list above.

I declare under penalty of perjury that the foregoing is true and correct.

Denise M. Morison

Carlsbad Energy Center Project

(07-AFC-6)

Center for Biological Diversity Data Responses

(Response to Data Requests A1 through G1)

Submitted to

California Energy Commission
and
the Center for Biological Diversity

Submitted by

Carlsbad Energy Center LLC

January 2009

With Assistance from

CH2MHILL
2485 Natomas Park Drive
Suite 600
Sacramento, CA 95833

Shaw™ Stone & Webster, Inc.

Contents

Introduction

On September 26, 2008, the Center for Biological Diversity (CBD) submitted Data Requests A1 through G1 as an intervenor to the Carlsbad Energy Center Project (CECP) (07-AFC-6). On October 14, 2008, Carlsbad Energy Center LLC (Applicant) filed a letter with the California Energy Commission (CEC) objecting to each of the CBD data requests. On November 10, 2008, CBD filed a petition with the CEC requesting that CEC direct the Applicant to provide responses to CBD's Data Requests. CEC held a Carlsbad Siting Committee (Committee) hearing on December 15, 2008 to hear from the parties on CBD's Petition to Compel Data Responses. On December 26, 2008, the Committee adopted a ruling directing the Applicant to respond to certain of the Data Requests submitted by CBD. As directed, the Applicant hereby submits Data Responses to those Data Requests from CBD as so directed by the Committee.

The Applicant's Data Responses to the CBD's Data Requests numbers A1 through G1 are presented in the same order as the CBD presented them and are keyed to the Data Request numbers (A1 through G1) used by the CBD. To provide a clear record, each of CBD's Data Requests are included in this Data Response submittal, even those for which the Committee found that the Applicant was not required to submit a response. For those Data Requests for which a Data Response has not been required by the Committee, it is so noted in this submittal.

Tables, figures, or documents submitted in response to a Data Request (supporting data, stand-alone documents) are found at the end of this Data Response document and are not sequentially page-numbered consistently with the remainder of the document, though they may have their own internal page numbering system.

The Applicant looks forward to working cooperatively with CEC Staff and the CBD as the CECP proceeds through the CEC licensing process. We trust that these responses address the CBD's Data Requests.

Air Quality (CBD Data Requests)

A. Background

The California Global Warming Solutions Act of 2006 (AB 32) and related Executive Orders have set aggressive goals for the State to significantly reduce its greenhouse gas emissions over the next several decades. This includes attention to emissions generated outside the state by power that is ultimately used in California. Yet the Applicant only partially analyzed certain greenhouse gas emissions from the new project.

Data Request

A1. Please provide a full greenhouse gas inventory of direct and indirect emissions sources from the project, including building materials, construction emissions, operational energy use, vehicle trips, water supply, and waste disposal.

Response: The following are the responses to these data requests:

- Building Materials: There is insufficient detailed engineering information available at this time to calculate the greenhouse gas emissions associated with the manufacturing of building materials that will be used for the construction of the proposed project.
- Delivery of Building Materials: The following table (Table DRA1-1) summarizes the greenhouse gas emissions associated with both truck and rail delivery of construction materials. The detailed greenhouse gas emission calculations are included as Attachment DRA1-1.
- Onsite Construction Equipment: The greenhouse gas emissions associated with the use of onsite construction equipment were calculated by the CEC staff and summarized in the PSA (PSA, Appendix AIR-1, Table 2).
- Operational Energy: The greenhouse gas emissions associated with the operation of the proposed new units were included in the AFC (CECP AFC, Section 5.1.8.2). Since a portion of the power generated by the two new units will be used for onsite power, these operational greenhouse gas emissions include the emissions associated with power generation for use by the power plant. Approximately three percent of the gross annual power produced by the CECP units will be used for onsite power. Because power production is linked to fuel use, which in turn is linked to greenhouse gas emissions, approximately three percent of the annual greenhouse gas emissions shown in the AFC for the new units (equal to approximately 25,382 metric tonnes of CO2e) are associated with onsite power use.
- Vehicle Travel: Table DRA1-1 below summarizes the greenhouse gas emission associated with construction worker and power plant worker vehicle use. The detailed greenhouse gas emission calculations are included as Attachment DRA1-1.

- Water Supply: The estimated annual power use for the water supply system for the proposed CECP is approximately 2,575 MW-hr[1]. More then 97 percent of this will be provided by the power generated by the CECP gas turbine generators. Consequently, nearly all of the greenhouse gas emissions associated with the operation of the water supply system are included in the estimate of the greenhouse gas emissions shown in the AFC for the operation of the CECP gas turbine generators (CECP AFC, Section 5.1.8.2). The water supply system power provided by the CECP gas turbine generators will be approximately 2,500 MW-hr, which represents approximately 0.1 percent of the expected gross power generation of the proposed CECP. Since greenhouse gas emissions are based on fuel use, which in turn is based on the amount of power generated, the greenhouse gas emissions associated with generating 2,500 MW-hr are approximately 0.1 percent of the greenhouse gas emissions shown in the AFC for the operation of the CECP gas turbine generators. This corresponds to annual greenhouse gas emissions for the water supply system of approximately 846 metric tonnes CO_{2e}. The annual greenhouse gas emissions associated with providing the remaining 75 MW-hr of power for the water supply system are approximately 30 metric tonnes CO_{2e} using the California System Average GHG factor of approximately 0.400 metric tonnes CO_{2e}/MW-hr shown in the Preliminary Staff Assessment for CECP (PSA for CECP, Appendix AIR-1, page 4.1-104).
- Waste Disposal: The maximum waste disposal will occur during the demolition of the Encina Power Station fuel oil storage tanks. The greenhouse gas emissions associated with truck/rail transport of this waste material are shown in Table DRA1-1. The detailed greenhouse gas emission calculations for these activities are included as Attachment DRA1-1.

TABLE DRA1-1
Greenhouse Gas Emissions for Various Activities Associated with CECP

Activity	Annual Greenhouse Gas Emissions (metric tonnes CO_{2e})
Delivery of Building Materials (truck and rail)	521
Worker Vehicle Travel (Construction)	2,305
Worker Vehicle Travel (Operational)	175
Waste Disposal Transport	261

Data Request

A2. Please estimate the amount of HFC, PFC, and SF_6 that will be emitted by the CECP.

Response: The estimate of SF_6 emissions for the proposed project is discussed in Data Adequacy Supplement A, October 23, 2007, Response Number 3. Table DRA2-1 below lists the equipment at the proposed CECP that will use HFCs. As shown in this table, the total

[1] This includes the operation of a 50 hp water supply pump that will be powered by Encina Units 4 or 5.

charge of HFC associated with this equipment is expected to be approximately 121 pounds. While no leaks are expected, the emissions of HFC from this equipment are based on the maximum allowed expected equipment leak rate. Under the federal regulation that limits HFC emissions from equipment that uses refrigerants (40 CFR 82, Subpart F), the maximum allowable annual leak rate for equipment with refrigerant charges located at commercial and/or industrial facilities is 35 percent of the total charge. Based on this maximum allowable leak rate and the total refrigerant charge of 121 pounds, the maximum allowed annual HFC emission rate for this equipment is no more than approximately 42 pounds per year. Based on the California Air Resources Board's default Global Warming Potential (GWP) factor[2] of 11,700 for HFC-23 (the HFC with the highest listed GWP), this is equal to approximately 223 metric tonnes of CO_{2e} per year.

TABLE DRA2-1
CECP Equipment Using HFCs

Equipment Description	Quantity	Refrigerant Charge (lbs)	Total Refrigerant Charge (lbs)
Fuel Gas Enclosure	1	10	10
Plant Control Center	1	14	14
CEMS Shelter	2	11	22
Electrical Package Enclosure	2	9	18
Medium Voltage Switchgear Enclosure	2	14	28
Steam Turbine Power Control Center	2	9	18
Fire Water Pump Enclosure	1	11	11
Total			**121**

Data Request

A3. Please discuss mitigation measures to prevent the release of HFC, PFC, and SF_6.

Response: Per the CEC Committee ruling on this data request, the applicant will limit the response to identifying the project equipment that will be used to minimize the emissions of HFC, PFC, or SF_6. For the CECP, there is no equipment proposed for the control of HFC, PFC, or SF_6 emissions. As discussed in Response A2, the emissions of these pollutants are due to potential equipment leaks. If abnormal HFC, PFC, or SF_6 leak rates are discovered by plant operators, proper maintenance will be performed by qualified technicians in a timely manner to minimize these leaks.

[2] http://www.arb.ca.gov/regact/2007/ghg2007/frofinoal.pdf, Appendix A, Table 2.

B. Background

The San Diego Air Pollution Control District noted in its October 17, 2007 information request that, “It is likely that the project may be operated continuously or intermittently on natural gas derived from imported liquefied natural gas (LNG).” The processes necessary to convert and transport LNG are very energy intensive and could significantly increase California’s current emissions from domestic sources of natural gas.

Data Request

B1. Will the CECP use imported LNG?

Response: Requests B1 through B5 were denied by the Carlsbad AFC Committee on December 15, 2008 on the grounds that the Applicant lacks the information requested. Therefore, the Applicant has not provided a response to DR B1.

Data Request

B2. If so, please estimate the amount of LNG the CECP will use on an annual basis.

Response: Requests B1 through B5 were denied by the Carlsbad AFC Committee on December 15, 2008 on the grounds that the Applicant lacks the information requested. Therefore, the Applicant has not provided a response to DR B2.

Data Request

B3. What are the factors that will dictate “intermittent” or “continuous” use of LNG at the CECP?

Response: Requests B1 through B5 were denied by the Carlsbad AFC Committee on December 15, 2008 on the grounds that the Applicant lacks the information requested. Therefore, the Applicant has not provided a response to DR B3.

Data Request

B4. Please identify the LNG terminal or terminals that will provide gas for the CECP. Please list the county or countries of origin of the LNG to be shipped to these terminal(s). Estimate the relative amount of LNG that will transported from each country of origin.

Response: Requests B1 through B5 were denied by the Carlsbad AFC Committee on December 15, 2008 on the grounds that the Applicant lacks the information requested. Therefore, the Applicant has not provided a response to DR B4.

Data Request

B5. Please estimate the full lifecycle carbon footprint of the use of LNG, including the impacts of extraction, liquefaction, transportation, and regasification of the imported LNG to be used.

Response: Requests B1 through B5 were denied by the Carlsbad AFC Committee on December 15, 2008 on the grounds that the Applicant lacks the information requested. Therefore, the Applicant has not provided a response to DR B5.

C. Background

Section 5.1 of the Application for Certification ("AFC") calculates certain greenhouse gas emissions from specific elements of the project (the new equipment and the existing Units 1, 2, and 3). The calculations estimate that the CECP will emit 8.50 x 10^5 metric tons of carbon dioxide equivalent emissions. In City Data Response 50, the Applicant concludes that the project will only lead to "a net increase in GHG emissions of approximately 2.08 x 10^5 metric tons per year of carbon dioxide equivalent GHGs" based on assumptions about the benefits of shutting down Units 1, 2, and 3. However, this calculation neglects several potentially significant sources of greenhouse gases from the project and seriously underestimates the actual emissions that could result from this project, while potentially overestimating the benefits of retiring Units 1, 2, and 3. Table 5.1B-20 of the AFC estimates the greenhouse gases from the to-be-retired Units 1, 2, and 3 "based on maximum 2-year annual average with a 10-year look back period."

Data Request

C1. Since the AFC lists several conditions under which the CECP may operate once online (i.e., base load, load following, daily cycling, full shutdown), please confirm that the calculations of greenhouse gas emissions from the new equipment are based on the project's maximum potential to emit.

During the Committee hearing, CBD restated DR C1 to ask if the calculations of greenhouse gas emissions provided in the AFC were made with the same parameters as were used to calculate the emissions of criteria pollutants. As noted in the Committee's December 26, 2008 direction, the Committee has directed the Applicant to respond to DR C1 as restated.

Response: As shown in the detailed greenhouse gas emission calculations in the AFC (CECP AFC, Appendix 5.1B, Table 5.1B-16), the greenhouse gas emissions for the new equipment were based on operating a total of 4,100 hours per year per gas turbine and 50 hours per year for the firepump engine. This is consistent with the total of 4,100 operating hours per year per gas turbine and 50 hours per year for the emergency firepump engine shown in the AFC for the maximum potential to emit for criteria pollutants during a non-commissioning year (CECP AFC, Appendix 5.1B, Table 5.1B-4). The only difference between the greenhouse gas and criteria pollutant annual emission estimates is that for the greenhouse gas emission estimate it is assumed there are 4,100 operating hours per year at baseload conditions for each gas turbine, consistent with the approach used to estimate maximum SOx and PM emissions from the plant. The 4,100 baseload operating hours per year was used for the greenhouse gas emission estimates because this approach provides the maximum emissions for these pollutants by maximizing annual fuel use. The combination of baseload operating hours and gas turbine startup/shutdown hours was used to calculate the annual potential to emit for criteria pollutants because this approach provides the maximum emissions for criteria pollutants due to the elevated emissions that will occur during gas turbine startups/shutdowns.

Data Request

C2. Please provide the 2-year period relied upon to calculate emissions.

Response: The detailed greenhouse gas emission calculations for Units 1, 2, and 3 are shown in the AFC (CECP AFC, Appendix 5.1B, Table 5.1B-20). As noted on this table, the greenhouse gas emissions from Units 1, 2 and 3 are based on maximum 2-year average fuel use occurring over the past 10 years. This maximum 2-year period is from 2000 to 2001.

Data Request

C3. Please calculate greenhouse gases based on the most recent (current) 2-year average for each of these units, and for units 4 and 5. Please include the method used to calculate these emissions.

Response: The greenhouse gas emissions during the period from 2007 to 2008 for Encina Power Station Units 1-5 are shown in Table DRC3-1 below. Also included in this table are the operating hours and fuel use for each unit**.** The detailed greenhouse gas emission calculations are enclosed as Attachment DRA1-1.

TABLE DRC3-1
2007 to 2008 Annual Operating Data for Units 1-5
Encina Power Station

	GHG Emissions	Operating Hours	Natural Gas Use	Fuel Oil Use
Unit	**MT/year CO_2e**	**(hrs/yr)**	**(MMscf/yr)**	**(gals/yr)**
2007				
1	3.71E+04	1,328	685	18,542
2	2.83E+04	891	520	19,538
3	4.76E+04	1,753	879	21,533
4	1.41E+05	2,773	2,604	70,027
5	2.16E+05	3,483	3,989	87,402
2008				
1	4.77E+03	301	89	0
2	2.43E+04	886	450	0
3	4.00E+04	1,765	742	0
4	1.94E+05	3,902	3,599	0
5	3.89E+05	6,627	7,215	0

Data Request

C4. Please provide the breakdown of oil use versus natural gas use in these units over the past 2 years and the hours of use for each type of fuel. Also provide this information for units 4 and 5.

Response: The natural gas and fuel oil use and operating hours for Encina Power Station Units 1-5 for the period from 2007 to 2008 are shown in Table DRC3-1. Please note that the operating hours shown in Table DRC3-1 are the total annual operating hours for each unit regardless of fuel type. During 2007, fuel oil was combusted specifically for reliability testing required by the California Independent System Operator. The fuel oil reliability testing in 2007 occurred over an approximate three to four hour period for each unit. No fuel oil testing was required in 2008.

D. Background

Table 5.1B-12 of the AFC shows a significant decrease in NOx and SOx emissions from Units 1, 2, and 3 since 1995.

Data Request

D1. Please explain these decreases.

Response: At the hearing on the Petition, CBD withdrew DR D1; therefore, the Committee's direction of December 26, 2008 indicates that no response is required to DR D1.

E. Background

The anticipated life expectancy of the proposed CECP is 40 years. Existing Units 1, 2, and 3 are already more than 50 years old, and Units 4 and 5 are over 30 years old.

Data Request

E1. Please provide an estimate of the remaining useful life of Units 1, 2, and 3, as well as Units 4 and 5, if the CECP were not constructed.

Response: At the hearing on the Petition, the Committee determined that DR E1 was seeking information for which CBD could not form an opinion and that it was seeking the Applicant's opinion. The Committee agreed with the Applicant that such as estimate is speculative at best. The Committee determined that the Applicant was not required to respond to this data request. Therefore, no response to this data request is provided.

Data Request

E2. Would new permits be necessary in order to keep Units 1, 2, 3, 4, and 5 operating for this amount of time?

Response: In its December 26 ruling, the Committee directed the Applicant to respond to DR E2 in terms of existing permits and future requirements that the Applicant is aware of, but the Applicant need not speculate as to potential future permits. Encina Power Station routinely applies for permit renewals for its primary environmental operating permits including the Title V Operating Permit and NPDES discharge permit, which are issued in five year intervals. In December 2007, a renewal application for the existing Title V Operating Permit was submitted to the San Diego County APCD, which administratively extends the permit until acted on by the APCD. The existing NPDES permit for Encina does not expire until October 1, 2011 and a renewal application will be submitted at least 180 days prior to the expiration, as required. Encina also operates under a lease with the State Lands Commission, which was renewed beginning December 14, 2006, and which has a term of 20 years expiring on December 13, 2026.

E3. Please provide the annual hours of use for Units 1, 2, 3, 4, and 5 over each of the past 5 years (not the 5-year average). Also, please provide the annual capacity factor for each of the units over each of the past 5 years (not the 5-year average).

Response: In its December 26 order, the Committee directed that, to the extent the Applicant possesses the information requested in DR E3, the Applicant is directed to supply such information. The annual fuel use, operating hours, and annual capacity factor for Encina Power Station Units 1-5 during the 5-year baseline period discussed in the CECP AFC (2002 to 2006) are shown in Table DRE3-1 below.

TABLE DRE3-1
2002 to 2006 Annual Operating Data for Units 1 – 5
Encina Power Station

Year	Unit	Natural Gas Use (MMscf/yr)	Fuel Oil Use (gals/year)	Operating Hours (hrs/year)	Annual Fuel Use Factor* (%)
2002	1	1,640	0	3,250	18.8
	2	2,061	218,991	4,347	24.0
	3	2,146	0	3,775	22.1
	4	9,500	734,633	6,805	34.4
	5	10,893	650,230	7,837	36.8
2003	1	1,350	115,290	2,811	15.7
	2	1,675	74,466	3,268	19.4
	3	2,384	117,600	4,519	24.8
	4	9,919	0	7,309	35.6
	5	11,452	0	6,846	38.3
2004	1	1,963	0	3,520	22.5
	2	2,504	0	3,931	28.8
	3	3,891	0	6,023	40.1
	4	13,593	0	7,512	48.7
	5	12,711	0	6,905	42.5
2005	1	1,750	19,320	3,644	20.1
	2	1,900	19,320	3,684	21.9
	3	2,083	18,060	3,886	21.5
	4	9,145	0	7,239	32.8
	5	6,398	0	4,971	21.4

TABLE DRE3-1
2002 to 2006 Annual Operating Data for Units 1 – 5
Encina Power Station

Year	Unit	Natural Gas Use (MMscf/yr)	Fuel Oil Use (gals/year)	Operating Hours (hrs/year)	Annual Fuel Use Factor* (%)
2006	1	584	0	1,568	6.7
	2	1,093	20,412	2,448	12.6
	3	1,327	27,636	2,570	13.7
	4	5,895	73,500	5,881	21.2
	5	6,295	54,600	6,007	21.1

*An annual capacity factor based on actual annual fuel use versus maximum allowable annual fuel use based on equipment capacity (see Data Response Number 76 for CECP project for this capacity factor information).

F. Background

The AFC states that one of the goals of the project is “meeting the expanding need for new, highly efficient, reliable electrical generating resources located in the load center of the San Diego region.”

Data Request

F1. What is the reliability need of the area? (Please include a numerical answer that identifies the number of megawatts necessary to meet existing reliability).

Response: At the Committee hearing on December 15, the Applicant volunteered to provide the information requested in DR F1, therefore the Committee directed the Applicant to response to DR F1. The need for additional power generating capacity for the CECP project area is discussed in the enclosed copy (see Attachment DRF1-1) of the California Public Utilities Commission (CPUC) order on the long-term power procurement plans for the San Diego area (Decision Number 08-11-008). As shown on page 38 of this CPUC order, the San Diego Gas and Electric Company is authorized to procure up to 530 MW of new local generating capacity. The proposed CECP is ideally suited to fulfill part of this new generating need since the ne increase in generation from the 540 MWs from the CECP is 220 MWs, considering the retirement of 320 MWs from Existing Encina Units 1-3. With respect to CPUC decisions that specifically address the need for the proposed CECP, enclosed as Attachment DRF2-2 is a copy of the CPUC’s November 18, 2008 proposed decision on the Sunrise Powerlink Transmission project and which was the final decision adopted by the CPUC in December 2008. On page 61 of this document, the CPUC includes the CECP as part of the power generating baseline needed for reliability purposes for the San Diego area. These two documents clearly show the CPUC’s determination that additional new generating capacity is needed for the CECP project area.

Data Request

F2. If the CECP will provide more than the reliability needs of the region, please discuss the ways in which the excess capacity provided by the proposed project could foster economic or population growth, or the construction of additional housing, either directly or indirectly, in the surrounding environment and the impacts this growth may have on the environment including the potential increased emissions of greenhouse gases.

Response: At the hearing on the Petition, CBD withdrew DR F2; therefore, the Committee's direction of December 26, 2008 indicates that no response is required to DR F2.

G. Background

The AFC does not appear to include analysis of an alternative that could meet the region's reliability needs with a smaller facility.

CBD Data Request

G1. Please provide an analysis of this alternative including a calculation of the potential greenhouse gas emissions.

Response: At the hearing on the Petition, CBD withdrew DR G1; therefore, the Committee's direction of December 26, 2008 indicates that no response is required to DR G1.

ATTACHMENT DRA1-1

Detailed GHG Emission Calculations

Table A.1: Construction Building Material Truck Deliveries - GHG Emissions

Annual Truck Trips	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Year	GHG Emission Factors (lbs/mile) CO2[a]	CH4[b]	N20[b]	Global Warming Potential Factor[c] for CO2	Global Warming Potential Factor[c] for CH4	Global Warming Potential Factor[c] for N2O
3313	80	265,040	4.0	1.12E-05	1.06E-05	1	21	310

Global Warming Potential CO2 Emiss. as CO2 (lbs/year)	Global Warming Potential CH4 Emiss. as CO2 (lbs/year)	Global Warming Potential N2O Emiss. as CO2 (lbs/year)	Total CO2e (lbs/year)	Total CO2e (MT/year)
1,072,535	63	869	1,073,467	487

Notes:

a. Emfac2007 V2.3, San Diego County, all HHD Diesel models in the range from 1965 to 2008

b. CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, emission factors onroad vehicles, heavy Diesel trucks.

c. CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, global warming potential table.

Table A.2: Construction Building Material Rail Deliveries - GHG Emissions

Annual Fuel Use (gals/year)	GHG Emission Factors (lbs/gal) CO_2[a]	CH_4[a]	N20[a]	Global Warming Potential Factor[b] for CO_2	Global Warming Potential Factor[b] for CH_4	Global Warming Potential Factor[b] for N_2O
3,383	22.16	9.05E-04	1.81E-04	1	21	310

Global Warming Potential CO_2 Emiss. as CO_2 (lbs/year)	Global Warming Potential CH_4 Emiss. as CO_2 (lbs/year)	Global Warming Potential N_2O Emiss. as CO_2 (lbs/year)	Total CO_2e (lbs/year)	Total CO_2e (MT/year)
74,946	64	190	75,200	34

Notes:

a. CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, emission factors for Diesel combustion.

b. CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, global warming potential table.

Table A.3: Construction Worker Vehicle Travel - GHG Emissions

Annual Vehicle Trips	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Year	GHG Emission Factors (lbs/mile) $CO2^{a}$	$CH4^{b}$	$N20^{b}$	Global Warming Potential Factor[c] for CO2	Global Warming Potential Factor[c] for CH4	Global Warming Potential Factor[c] for N2O
67,140	80	5,371,200	0.9	3.92E-05	6.01E-05	1	21	310

Global Warming Potential CO2 Emiss. as CO2 (lbs/year)	Global Warming Potential CH4 Emiss. as CO2 (lbs/year)	Global Warming Potential N2O Emiss. as CO2 (lbs/year)	Total CO2e (lbs/year)	Total CO2e (MT/year)
4,977,577	4,422	100,124	5,082,124	2,305

Notes:
a. Emfac2007 V2.3, San Diego County, all light duty gasoline vehicle models in the range from 1965 to 2008
b. CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, emission factors onroad vehicles, gasoline light duty vehicles (2000 average model year).
c. CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, global warming potential table.

Table A.4: Tank Demolition Waste Material Truck Transport - GHG Emissions

Annual Truck Trips	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Year	GHG Emission Factors (lbs/mile) CO2[a]	CH4[b]	N20[b]	Global Warming Potential Factor[c] for CO2	Global Warming Potential Factor[c] for CH4	Global Warming Potential Factor[c] for N2O
1775	80	142,000	4.0	1.12E-05	1.06E-05	1	21	310

Global Warming Potential CO2 Emiss. as CO2 (lbs/year)	Global Warming Potential CH4 Emiss. as CO2 (lbs/year)	Global Warming Potential N2O Emiss. as CO2 (lbs/year)	Total CO2e (lbs/year)	Total CO2e (MT/year)
574,630	33	465	575,129	261

Notes:

a. Emfac2007 V2.3, San Diego County, all HHD Diesel models in the range from 1965 to 2008

b. CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, emission factors onroad vehicles, heavy Diesel trucks.

c. CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, global warming potential table.

Table A.5: Power Plant Worker Vehicle Travel - GHG Emissions								
Annual Vehicle Trips	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Year	GHG Emission Factors (lbs/mile) CO_2[a]	CH_4[b]	N20[b]	Global Warming Potential Factor[c] for CO_2	Global Warming Potential Factor[c] for CH_4	Global Warming Potential Factor[c] for N_2O
5,110	80	408,800	0.9	3.92E-05	6.01E-05	1	21	310

Global Warming Potential CO_2 Emiss. as CO_2 (lbs/year)	Global Warming Potential CH_4 Emiss. as CO_2 (lbs/year)	Global Warming Potential N_2O Emiss. as CO_2 (lbs/year)	Total CO_2e (lbs/year)	Total CO_2e (MT/year)
378,842	337	7,620	386,799	175

Notes:

a. Emfac2007 V2.3, San Diego County, all light duty gasoline vehicle models in the range from 1965 to 2008

b. CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, emission factors onroad vehicles, gasoline light duty vehicles (2000 average model year).

c. CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, global warming potential table.

Table A6 - Greenhouse Gas Emission Calculation for Units 1, 2, 3, 4, and 5 for 2007

Natural Gas HHV (Btu/scf) = 1,019

Encina Fuel 2007 Fuel Types	Boiler #1	Boiler #2	Boiler #3	Boiler #4	Boiler #5
Residual Oil (gallons)	18542.16	19538.4	21533.4	70026.6	87402
Nat. Gas (million ft3)	685.003	520.046	878.875	2603.5158	3988.81

Greenhouse Gas Emission Calculation for Units 1, 2, 3, 4, and 5 in 2007

Equipment	Annual Average Heat Input (MMBtu/year)	CO2 Emission Factor(1) (kg/MMBtu)	CH4 Emission Factor(2) (kg/MMBtu)	N2O Emission Factor(2) (kg/MMBtu)	CO2 Emission Rate (kg/year)	CH4 Emission Rate (kg/year)	N2O Emission Rate (kg/year)
Unit 1 - nat. gas	6.98E+05	52.87	9.00E-04	1.00E-04	3.69E+07	6.28E+02	6.98E+01
Unit 1 - oil	2.78E+03	73.10	3.00E-03	6.00E-04	2.03E+05	8.33E+00	1.67E+00
Unit 2 - nat. gas	5.30E+05	52.87	9.00E-04	1.00E-04	2.80E+07	4.77E+02	5.30E+01
Unit 2 - oil	2.92E+03	73.10	3.00E-03	6.00E-04	2.14E+05	8.77E+00	1.75E+00
Unit 3 - nat. gas	8.96E+05	52.87	9.00E-04	1.00E-04	4.73E+07	8.06E+02	8.96E+01
Unit 3 - oil	3.22E+03	73.10	3.00E-03	6.00E-04	2.36E+05	9.67E+00	1.93E+00
Unit 4 - nat. gas	2.65E+06	52.87	9.00E-04	1.00E-04	1.40E+08	2.39E+03	2.65E+02
Unit 4 - oil	1.05E+04	73.10	3.00E-03	6.00E-04	7.66E+05	3.14E+01	6.29E+00
Unit 5 - nat. gas	4.06E+06	52.87	9.00E-04	1.00E-04	2.15E+08	3.66E+03	4.06E+02
Unit 5 - oil	1.31E+04	73.10	3.00E-03	6.00E-04	9.56E+05	3.92E+01	7.85E+00

Equipment	Global Warming Potential Factor(3) for CO2	Global Warming Potential Factor(3) for CH4	Global Warming Potential Factor(3) for N2O	Global Warming Potential CO2 Emiss. as CO2 (kg/year)	Global Warming Potential CH4 Emiss. as CO2 (kg/year)	Global Warming Potential N2O Emiss. as CO2 (kg/year)	Global Warming Potential CO2 Emiss. as CO2 (MT/year)(4)	Global Warming Potential CH4 Emiss. as CO2 (MT/year)	Global Warming Potential N2O Emiss. as CO2 (MT/year)	Total (MT/year)
Unit 1 - nat. gas	1	23	310	3.69E+07	1.44E+04	2.16E+04	3.69E+04	1.44E+01	2.16E+01	3.69E+04
Unit 1 - oil	1	23	310	2.03E+05	1.92E+02	5.16E+02	2.03E+02	1.92E-01	5.16E-01	2.04E+02
Unit 2 - nat. gas	1	23	310	2.80E+07	1.10E+04	1.64E+04	2.80E+04	1.10E+01	1.64E+01	2.80E+04
Unit 2 - oil	1	23	310	2.14E+05	2.02E+02	5.44E+02	2.14E+02	2.02E-01	5.44E-01	2.15E+02
Unit 3 - nat. gas	1	23	310	4.73E+07	1.85E+04	2.78E+04	4.73E+04	1.85E+01	2.78E+01	4.74E+04
Unit 3 - oil	1	23	310	2.36E+05	2.22E+02	6.00E+02	2.36E+02	2.22E-01	6.00E-01	2.36E+02
Unit 4 - nat. gas	1	23	310	1.40E+08	5.49E+04	8.22E+04	1.40E+05	5.49E+01	8.22E+01	1.40E+05
Unit 4 - oil	1	23	310	7.66E+05	7.23E+02	1.95E+03	7.66E+02	7.23E-01	1.95E+00	7.69E+02
Unit 5 - nat. gas	1	23	310	2.15E+08	8.41E+04	1.26E+05	2.15E+05	8.41E+01	1.26E+02	2.15E+05
Unit 5 - oil	1	23	310	9.56E+05	9.03E+02	2.43E+03	9.56E+02	9.03E-01	2.43E+00	9.60E+02
									Total =	**4.70E+05**

Notes:

(1) CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, carbon dioxide emission factors stationary source combustion table - natural gas and resid. oil factors.

(2) CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, CH4 and N2O emission factors stationary source combustion table - natural gas and resid. oil factors.

(3) California Climate Action Registry, Appendix to the General Reporting Protocol: Power/Utility Reporting Protocol, Version 3.0, April 2008, Table C.1.

(4) MT/year stands for metric tonnes per year.

Table A7 - Greenhouse Gas Emission Calculation for Units 1, 2, 3, 4, and 5 for 2008

Encina Fuel 2008 Fuel Types	Boiler #1	Boiler #2	Boiler #3	Boiler #4	Boiler #5
Residual Oil (gallons)	0	0	0	0	0
Nat. Gas (million ft3)	88.46	450.351	741.779	3599.286	7214.643

Greenhouse Gas Emission Calculation for Units 1, 2, 3, 4, and 5 in 2008

Equipment	Annual Average Heat Input (MMBtu/year)	CO2 Emission Factor(1) (kg/MMBtu)	CH4 Emission Factor(2) (kg/MMBtu)	N2O Emission Factor(2) (kg/MMBtu)	CO2 Emission Rate (kg/year)	CH4 Emission Rate (kg/year)	N2O Emission Rate (kg/year)
Unit 1 - nat. gas	9.01E+04	52.87	9.00E-04	1.00E-04	4.77E+06	8.11E+01	9.01E+00
Unit 1 - oil	0.00E+00	73.10	3.00E-03	6.00E-04	0.00E+00	0.00E+00	0.00E+00
Unit 2 - nat. gas	4.59E+05	52.87	9.00E-04	1.00E-04	2.43E+07	4.13E+02	4.59E+01
Unit 2 - oil	0.00E+00	73.10	3.00E-03	6.00E-04	0.00E+00	0.00E+00	0.00E+00
Unit 3 - nat. gas	7.56E+05	52.87	9.00E-04	1.00E-04	4.00E+07	6.80E+02	7.56E+01
Unit 3 - oil	0.00E+00	73.10	3.00E-03	6.00E-04	0.00E+00	0.00E+00	0.00E+00
Unit 4 - nat. gas	3.67E+06	52.87	9.00E-04	1.00E-04	1.94E+08	3.30E+03	3.67E+02
Unit 4 - oil	0.00E+00	73.10	3.00E-03	6.00E-04	0.00E+00	0.00E+00	0.00E+00
Unit 5 - nat. gas	7.35E+06	52.87	9.00E-04	1.00E-04	3.89E+08	6.62E+03	7.35E+02
Unit 5 - oil	0.00E+00	73.10	3.00E-03	6.00E-04	0.00E+00	0.00E+00	0.00E+00

Equipment	Global Warming Potential Factor(3) for CO2	Global Warming Potential Factor(3) for CH4	Global Warming Potential Factor(3) for N2O	Global Warming Potential CO2 Emiss. as CO2 (kg/year)	Global Warming Potential CH4 Emiss. as CO2 (kg/year)	Global Warming Potential N2O Emiss. as CO2 (kg/year)	Global Warming Potential CO2 Emiss. as CO2 (MT/year)(4)	Global Warming Potential CH4 Emiss. as CO2 (MT/year)	Global Warming Potential N2O Emiss. as CO2 (MT/year)	Total (MT/year)
Unit 1 - nat. gas	1	23	310	4.77E+06	1.87E+03	2.79E+03	4.77E+03	1.87E+00	2.79E+00	4.77E+03
Unit 1 - oil	1	23	310	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Unit 2 - nat. gas	1	23	310	2.43E+07	9.50E+03	1.42E+04	2.43E+04	9.50E+00	1.42E+01	2.43E+04
Unit 2 - oil	1	23	310	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Unit 3 - nat. gas	1	23	310	4.00E+07	1.56E+04	2.34E+04	4.00E+04	1.56E+01	2.34E+01	4.00E+04
Unit 3 - oil	1	23	310	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Unit 4 - nat. gas	1	23	310	1.94E+08	7.59E+04	1.14E+05	1.94E+05	7.59E+01	1.14E+02	1.94E+05
Unit 4 - oil	1	23	310	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Unit 5 - nat. gas	1	23	310	3.89E+08	1.52E+05	2.28E+05	3.89E+05	1.52E+02	2.28E+02	3.89E+05
Unit 5 - oil	1	23	310	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
									Total =	**6.52E+05**

Notes:

(1) CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, carbon dioxide emission factors stationary source combustion table - natural gas and resid. oil factors.

(2) CARB Final Emission Factors for Mandatory Reporting Program, December 2, 2008, CH4 and N2O emission factors stationary source combustion table - natural gas and resid. oil factors.

(3) California Climate Action Registry, Appendix to the General Reporting Protocol: Power/Utility Reporting Protocol, Version 3.0, April 2008, Table C.1.

(4) MT/year stands for metric tonnes per year.

ATTACHMENT DRF1-1

Decision on Petitions for Modification of Decision 07-12-052

Decision 08-11-008 November 6, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans. (U 39 E)	Rulemaking 06-02-013 (Filed February 16, 2006)

DECISION ON PETITIONS FOR MODIFICATION OF DECISION 07-12-052

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DECISION ON PETITIONS FOR MODIFICATION OF DECISION 07-12-052

1. Summary

Following the Commission's issuance of Decision (D.) 07-12-052 on December 20, 2007, seven Petitions for Modification (PFM) were filed. This decision grants in part, and denies in part, the requested modifications and clarifies some inconsistencies.

D.07-12-052 reviewed, critiqued and adopted, with modifications, the long-term procurement plans (LTPPs) of Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company (SDG&E) for the 10-year period 2007-2016. More than 30 intervenors provided insight and dissection of the LTPPs and provided guidance for our evaluation. The decision covered the history and background of energy procurement and its integration into California's developing environmental policies, included forecasts, resources and need determinations for the utilities, developed guidelines for the procurement process, and discussed how each LTPP interfaced with state energy policies.

There were seven PFM for D.07-12-052 filed and the modifications granted are as follows:

1. We authorize the investor-owned utilities (IOU) to recognize the effects of debt equivalence when comparing power purchase agreements (PPA) against PPAs in their bid evaluations, but not when a utility-owned generation (UOG) project is being considered;

2. We delete the exception of allowing the IOUs to choose UOG projects outside of a competitive solicitation based solely on the synergies associated with expansion of existing facilities;

3. We clarify the circumstances under which engineering, procurement and construction bids may be considered;

4. We authorize SDG&E to procure up to the 530 megawatts (MW) of new local capacity that was conditionally authorized in D.07-12-052, clarifying that applications for this procurement should be supported by updates of the status and projected on-line date of the Sunrise Powerlink project; and

5. We modify the circumstances under which an IOU must retain the services of an independent evaluator (IE) for requests for offers (RFO) that seek products two years or greater in duration. However, we still require that an IE be utilized whenever an affiliate or utility bidder participates in the RFO, regardless of contract duration.

2. Petitions for Modification

The following PFMs of D.07-12-052 were filed:

1. Southern California Edison Company (SCE) and SDG&E: January 23, 2008;
2. Pacific Gas and Electric Company (PG&E): January 28, 2008;
3. Independent Energy Producers Association (IEP): February 6, 2008;
4. Competitive Market Advocates (CMA): February 13, 2008;
5. Calpine Corporation (Calpine): March 25, 2008;
6. SDG&E: June 9, 2008; and
7. PG&E and SDG&E, June 13, 2008.

3. Overview

The electricity market crisis of 2000-2001 shifted the paradigm from the competitive process envisioned under the 1996 electricity restructuring system to a hybrid market that includes both regulated IOUs, as well as independent power producers (IPP). The Commission has signaled in numerous decisions its commitment to pursue policies and goals that promote competition and customer choice, while maintaining a viable and workable electricity generation sector that assures reliable service at just and reasonable rates for bundled utility customers.

Maintaining a balance among the interests of the bundled ratepayers, the ratepayer funded IOUs, and the competitive market participants continues to be a challenging endeavor. We recently effectuated the appropriate balance in the most recent LTPP decision (D.07-12-052).

Not all parties agree with our outcomes, and many of the PFMs involve issues that are particularly germane to the hybrid market. In particular, some PFMs addressed how to ensure competitive solicitations, others focused on whether IOUs can submit utility-built projects into the solicitations and if so, how are they compared with those from IPPs, and other PFMs questioned whether and how the IOUs should propose resources identified outside of a competitive solicitation. This decision resolves all of the PFMs received to date for D.07-12-052. We believe that these modifications represent the best approach to resolving – in this same spirit of striking a fair balance amongst stakeholders in the hybrid market environment – the concerns raised.

4. Petitions for Modification of D.07-12-052

4.1. SCE and SDG&E's January 23, 2008 and PG&E's January 28, 2008 Petitions for Modification

The PFMs filed by SCE and SDG&E on January, 23, 2008 and PG&E on January, 28, 2008, address the treatment of debt equivalence (DE) in the evaluation of competitive bids in their solicitations. D.07-12-052 broke with the Commission's decision in the 2004 LTPP, D.04-12-048, and eliminated DE as a factor the IOUs could use in evaluating bids. The IOUs strongly urge the Commission to re-institute it as a bid evaluation factor.

SCE and SDG&E raise four points in support of their PFM. First, SCE and SDG&E suggest that DE is a real economic cost to the IOUs that should be considered in the bid evaluation process to avoid sub-optimal procurement contracting decisions. Furthermore, they argue that elimination of the use of DE adders in solicitations that include UOG bids does not address the identified problem with head-to-head competition. Their third point is that failure to consider DE in the contract selection process could potentially lead to a deterioration of an IOU's creditworthiness. Finally, they suggest that failure to consider DE with respect to the evaluation of replacement or repower contracts may violate state law [specifically, Pub. Util. Code § 454.5(c)].

PG&E raises three main points in its PFM in support of re-instituting DE as a bid evaluation tool: without the DE adder, there will be disparity in the bid evaluation process; eliminating consideration of DE violates Pub. Util. Code § 454.5(c); and there is no factual support for reversing past Commission decisions.

Two parties [IEP and the Cogeneration Association of California and the Energy Producers and Users Coalition (CAC-EPUC)] filed responses opposing SCE and SDG&E's PFM. Three parties filed responses opposing PG&E's PFM [IEP, the Western Power Trading Forum (WPTF) and CAC-EPUC], and SCE filed a response in support of PG&E's PFM.

Replies were filed by SCE and SDG&E and PG&E to the responses to their respective PFMs.

On May 20, 2008, the Administrative Law Judge (ALJ) issued a ruling requesting additional briefs and reply briefs to address five assumptions and six questions specifically related to DE. Opening briefs were filed June 20, 2008, and reply briefs were due July 18, 2008.

4.2. Independent Energy Producers Association's Petition for Modification

IEP's proposed modifications to D.07-12-052 seek to clarify the decision's discussion of UOG participation in head-to-head competition with privately-owned projects. IEP sees an inherent conflict in the IOU's "dual role of primary purchaser and potential supplier of electricity."[1] However, IEP offers some suggestions to improve the hybrid market and prevent abuses where the IOU is both a supplier and a procurer of electricity in the same solicitation.

To begin, IEP discusses the fact that the Commission does not allow UOG projects to participate in competitive solicitations because the Commission has not developed "a fair, publicly-vetted comparison methodology."[2] IEP then finds it inconsistent that the Decision does allow purchase and sales agreements (PSA) and EPCs to compete against IPP PPAs. IEP recommends that the Decision be modified to remove these inconsistencies. In addition, IEP finds that allowing EPCs and PSAs to compete against PPAs does not promote a hybrid market between the IOUs and the IPPs. IPPs are in the business of building, owning and operating power plants. However, under PSA and EPC models, outside companies build the plants, but then the IOU owns and operates the facilities. IEP questions whether the competitive solicitation process, when PSAs and EPCs are allowed to bid against PPAs, is merely a mechanism to select the construction contractor for IOU power plants.

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1 IEP's PTM, February 6, 2008, p. 2.

2 IEP, p. 4.

IEP proposes removing the exception that allows for EPC contracts and PSA agreements. IEP offers to work with the Commission to develop a fair, publicly-vetted comparison methodology for making evaluations between IPP bids and UOG proposals (which from IEP's perspective includes PSAs and EPCs).

4.3. Competitive Market Advocates' Petition for Modification

CMA is concerned with the development of a competitive wholesale market structure for electricity. The focus of CMA's PFM is on modifying the decision so that new ratepayer funded UOG projects do not fill all of the IOUs' resource needs and unnecessarily complicate the transition to a competitive market. CMA suggests changing the following three conclusions in the decision regarding UOG projects:

1. The decision allows for head-to-head competition between bids for PPAs and bids for PSA or engineering, procurement and construction (EPC) contracts without fully explaining how a fair evaluation and comparison of bids for privately-owned and utility-owned resources can be made;

2. The decision allows for UOG projects outside of a solicitation if the utility believes the project is needed for reliability, but CMA is concerned that this could compromise the integrity of the resource adequacy (RA) requirements; and

3. The decision allows for UOG projects outside of a solicitation if the UOG project would expand an existing facility.

In summary, CMA fears that if these conclusions remain in the LTPP decision, IPPs will not have any interest in investing in California's generation resources and only the utilities, with ratepayer funding, will invest in new generation projects. According to CMA, that could be the end of the competitive market. To cure this deficiency, CMA asks the Commission to do the following:

1. Either eliminate the IOUs' ability to solicit any UOG (including PSAs and EPCs) in their solicitations[3] or develop transparent evaluation criteria for comparing UOG and PPA bids; and

2. Eliminate the two new categories of circumstances under which the utilities may propose UOG projects, reliability and facility expansion, or clarify that these exceptions are only permitted in extraordinary circumstances.

SCE filed a response to CMA's PFM addressing the request to eliminate the two new categories for proposing UOG projects. SCE states that the authorization to the utilities to submit applications for approval of UOG projects, outside of a head-to-head solicitation, to address reliability concerns or to expand on existing facilities is well-reasoned, supported by the record, and good public policy for California. Specifically, SCE argues that allowing applications for UOG projects that address unique reliability issues is not a blank check to subvert the Commission's RA policies, and allowing applications for projects that expand existing facilities may promote the state putting forth innovative proposals that encourage reliability and protect the environment. In fact, SCE reminds parties that the decision requires the IOU to file an application for a UOG project, justify in the application why a competitive solicitation is not feasible and support the unique circumstances that justify this request. All interested parties have an opportunity to raise opposition to the application and

[3] Joint Response to CMA's PTM, March 14, 2008, p. 2.

to urge the Commission to deny the application if the new resource is not in the ratepayer and/or public interest.

PG&E, SDG&E, Division of Ratepayer Advocates (DRA) and The Utility Reform Network (TURN) (Joint Parties) filed a joint response to both CMA's PFM and IEP's PFM. In regards to CMA's request to eliminate PSAs and EPCs from competing in solicitations, Joint Parties argue that to grant this would be a complete reversal of the Commission's policy of encouraging a hybrid market until there is a competitive market. From the Joint Parties perspective, if CMA's requests were granted and UOG alternatives were eliminated from future solicitations, PPAs would be competing just against one another, without the "discipline that utility-owned cost-of-service-based projects can exert in such solicitations." Joint Parties believe that more competition, not less, will bring new resources and benefit ratepayers. As the Joint Parties suggest, there is no evidence that the hybrid market as currently designed is failing. In fact, Joint Parties reference the recent PG&E and SDG&E solicitations and discuss how many PPAs bid into the solicitations, creating a "robust" competitive process.

Code of Conduct

Both CMA and IEP discuss a "code of conduct" referenced in the Decision that would govern the relationships among employees within the utility as a precondition for the participation of UOG in competitive solicitations. CMA suggests that eliminating the IOUs ability to consider any type of UOG bid in their solicitations, including PSAs and EPCs, would remove any problems or inconsistencies with the code of conduct.

IEP, on the other hand, suggests developing the code of conduct in a public process subject to Commission approval. IEP notes that while the code of conduct is discussed in the decision, it is not included in the Findings of Fact

(FOF), Conclusions of Law (COL) or Ordering Paragraphs (OP). IEP suggests in its PFM that this omission be addressed.

Joint Parties urge the Commission to defer the topic to the 2008 LTPP, R.08-02-007, and not "bog down the development of a code of conduct with additional process or to reopen the issue of the code of conduct now. . ."[4] SCE urges the Commission to outright reject IEP's suggestions vis-à-vis a code of conduct, especially the suggestion that there could be a "one size fits all" code for all three utilities.[5] SCE paraphrases the language from the Decision, and clarifies that the intent was that if a utility should choose to conduct a head-to-head solicitation, prior to launching it, the utility must develop an internal procedure for complying with the requirement that the utility not share information between employees involved with the development of the bid and the choosing of the bids.

SCE argues that there is no need for a uniform code of conduct universal to all IOUs, especially since (1) some utilities may not choose to allow head-to-head competition between UOG and IPP bids in their solicitations, and (2) some utilities already have their own code in place. Furthermore, SCE argues that if a code is needed, it would need to be tailored to each utility, and waiting until a code of conduct was in place could delay the process, to the disadvantage of ratepayers. Finally, even if a code was developed, SCE questions whether a public forum is the best way to accomplish the goal.

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[4] Joint Parties Response, March 14, 2008, p. 2.

[5] SCE Response, March 7, 2008, p. 2.

In summary, SCE asks the Commission to reject any amendments to D.07-12-052 on the code of conduct issue since (1) the utilities are not government entities subject to public review of their internal processes; (2) D.07-12-052 did not improperly delegate to the Energy Division (ED) review of the utilities internal processes; and (3) Rulemaking (R.) 08-02-007 has already signaled that it will give all interested parties an opportunity to propose refinements to the bid evaluation process.

4.4. Calpine Corporation's Petition for Modification

Calpine's PFM focuses on modifying and clarifying the language of D.07-12-052 to emphasize that the IOUs are not to exclude existing generation resources from IOU resource solicitations.

SDG&E and the Joint Parties [PG&E, TURN, SCE and DRA] filed responses. SDG&E argues that Calpine's PFM should be denied for the following reasons: the IOUs need new generation in their service territories and the utilities need flexibility in their RFOs to meet this need; the RA proceeding is addressing Calpine's concerns for just and reasonable compensation for existing energy and capacity; there is no compelling reason to ask the Commission to deviate from its current policy that allows the IOUs to tailor their RFOs; and D.07-12-052 provides safeguards to ensure that RFOs are fairly designed and conducted properly.

Joint Parties also urge the Commission to deny Calpine's PFM on the following grounds: the utilities need flexibility in designing their RFOs to meet specific needs; Calpine has made the same arguments before that the Commission rejected; there are procedural safeguards in place to ensure that the RFOs are properly designed; and generators will have ample opportunity to contract with utilities for energy and capacity and to be compensated. Joint Parties do not want the Commission to require that existing generation be allowed to participate in all RFOs.

4.5. SDG&E's June 9th, 2008 Petition for Modification

SDG&E's June 9th, 2008 PFM requests clarification of two issues: (1) what is the timing on SDG&E's authorization to procure additional local capacity resources (LCR) to address any local area reliability shortfalls between the time when the Sunrise Powerlink project (Sunrise) is approved (if it is approved) and when it is operational, and (2) whether an Independent Evaluator (IE) is required for short-term solicitations for RA capacity.

D.07-12-052 authorizes 530 MW of new local capacity, that includes 130 MW of already approved peakers, with the remaining 400 MW conditioned upon whether Sunrise is approved or not. If Sunrise is approved, D.07-12-052 found that SDG&E does not need the additional 400 MW. However, given the lag time between when a project is approved and the date it becomes operational, SDG&E is concerned that it may face a shortage of local area capacity in that time period that was unaccounted for in D.07-12-052.

Therefore, in this PFM, SDG&E requests authorization for up to 322 additional MWs (the amount of local capacity needed without Sunrise) beyond the 130 MW already approved to meet local reliability needs during the period between approval and the on-line date of Sunrise. SDG&E further states that any long-term contracts signed to meet this need will come before the Commission, thus the Commission will be able to ensure that only needed new capacity is being added.

SDG&E also requests clarification on the use of an IE for short-term RA capacity solicitations when an affiliate may be present among the bidders. D.07-12-052 requires that an IE be retained for all RFOs seeking products of more than three months in duration. SDG&E states that short-term RA capacity solicitations involve "standard local or system RA products where only a very limited set of factors is involved (local or system RA, amount, location and price),[6] thus, minimal negotiation is involved and is based mostly upon these standard factors. Furthermore, all transactions are reported in the quarterly compliance filings, and if an affiliate is selected, the deal would be evaluated under affiliate transaction reporting. SDG&E therefore requests that short-term (from one month to one year) RA capacity transactions be exempt from the IE requirement even if an affiliate submits a bid.

There were no responses filed on SDG&E's PFM.

4.6. PG&E and SDG&E's June 13th, 2008 Joint Petition for Modification

PG&E and SDG&E request in their joint PFM that the IE requirements in D.07-12-052 be changed from requiring the retention of an IE for all RFOs that seek products greater than three months duration to all RFOs that seek products of two years or more in duration, using the definition of duration adopted in D.07-12-052. In solicitations where affiliate, IOU-built or IOU-turnkey bidders are present, an IE would be required regardless of the length of the contract term.

PG&E and SDG&E state that while the Commission's goal of ensuring an impartial bidding process is appreciated, the administrative burden and excess

[6] SDG&E June 9, 2008 PFM of D.07-12-052.

costs associated with retaining an IE for all products greater than three months, regardless of the presence of affiliate, IOU-built or IOU-turnkey bidders, is disadvantageous to the ratepayer. Furthermore, all RFOs with a product term greater than three months are reviewed by the procurement review group (PRG) and are reported in the quarterly compliance filings, thus non-market participants and Commission Staff have the opportunity to ensure the transparency and impartiality of the selection process.

SCE and WPTF filed responses. SCE generally supports PG&E and SDG&E's PFM; however, SCE offers two additional refinements: (1) SCE suggests that an IE requirement should be eliminated for all RFOs, regardless of product duration, if no affiliate products are sought, and (2) for RFOs that seek products of less than two years' duration, an IE should not be required unless and until the IE receives notice that an affiliate intends to participate.

WPTF opposes adoption of the PFM on the following grounds: (1) the PFM ignores the intent of the Commission to ensure a fair, competitive procurement process free of real or perceived conflicts of interest, (2) much of utility procurement, including summer peaking procurement, falls into the three month to two year category, and the use of an IE is likely to reduce processing time, including litigation, and (3) the proposal is premature given that all parties have not had sufficient time utilizing the new standards to draw definitive conclusions about price increases and time delays caused by the retention of an IE for shorter-term solicitations.

5. Discussion

5.1. Debt Equivalence

Debt Equivalence (DE) is the term used by credit rating agencies for long-term fixed obligations, such as PPAs, that are included in their financial risk analyses for the IOUs. We have been considering the appropriate role for DE in the LTPP process since the 2004 LTPP proceeding.

D.04-12-048 found that the costs associated with rebalancing an IOU's portfolio to counter the effects of DE should be considered in an IOU's cost of capital (COC) proceeding, but not in the LTPP proceeding. D.04-12-048 also found that IOUs may impute a DE of 20% to the fixed cost component of PPA bids as an evaluation tool in comparing bids in a competitive solicitation. However, that decision also indicated that DE was a "subjective factor based on the credit agencies' perceived risk associated with PPAs, that the credit agencies' views are "not static and can change with respect to a particular PPA during the term of the PPA," and that "the imputed costs for existing PPAs will be reduced as the regulatory climate in California improves."[7]

In the 2006 LTPP proceeding, the IPP trade associations urged us to eliminate DE as a bid evaluation tool for the IOUs. In D.07-12-052, we reviewed and reanalyzed the use of DE in the evaluation of bids and found that while the cumulative impact of DE associated with the PPAs in an IOU's portfolio could potentially impact its credit rating, the IOU's COC proceeding is the appropriate forum to address this potential impact. Consequently, D.07-12-052 determined that the IOUs could no longer use the DE adder for the evaluation of individual bids in RFOs.

PG&E, SCE and SDG&E all filed PFMs asking us to revisit this finding, and in response we issued a ruling on May 20, 2008, asking parties to respond to several assumptions and questions related to the DE issue. The arguments set

[7] D.04-12-048, pp. 129-133.

forth in the initial PFMs, the responses and replies to the PFMs, and the additional requested briefs and reply briefs have provided a wealth of additional information for our consideration on this topic. Following careful deliberation of the competing positions we revise our opinion in several areas, as described below.

5.1.1. The DE Adder as a Bid Evaluation Criterion

Because the DE associated with a PPA is a factor considered by rating agencies and is a factor the Commission evaluates when it determines an IOU's return on equity in the IOU's COC proceeding, we find it is appropriate in some cases for the IOUs to recognize the effects of DE in their bid evaluation processes.

Specifically, we find that it is appropriate to consider DE in cases in which the bids included in the solicitation are sufficiently similar that a comparison of relative DE-effects would not in turn suggest the need to consider other, potentially countervailing risk-related effects of selecting one bid over another. Consequently, we will allow the use of the 20% DE adder in head-to-head competition between PPAs where no UOG projects (including EPC or PSA bids) are being considered. We empower the utilities to develop in their bid evaluation protocols, in consultation with their IEs and PRGs, to ensure that in head-to-head competition, the use of the DE adder does not disadvantage bids for renewable and innovative low-carbon resources that may have higher capital costs than traditional gas-fired generation.

As pointed out by IEP, though, there are a number of both risk-creating and risk-mitigating effects associated with an IOU signing a PPA rather than building UOG, as indicated by the following lists compiled by a Standard and Poor's representative:

Benefits of PPAs

- Construction risk is borne by the supplier
- Operating risk is typically shifted to the supplier if certain threshold availability and/or heat rate targets are not met
- Recovery of costs may be simplified through the use of a power cost adjustment mechanism
- Avoid taking a long view of the market
- Asset diversity
- Temper exposure to technology risk

Risks of PPAs

- Forego rate base treatment and the opportunity to earn a return
- Debt imputation is viewed as increasing operating leverage for analytical purposes, which can erode the financial metrics used to measure creditworthiness
- Potential need to provide collateral to the supplier[8]

The complexity of the risk-related pros and cons associated with PPA versus UOG ownership suggested by these two lists (and the fact that, presumably, neither list is exhaustive) suggests that it would be inappropriate to single out and consider only one specific risk-related effect (i.e., the risk associated with the additional DE within a particular regulatory framework) of a PPA bid on the potential impact to an IOU's credit ratings when comparing PPA and UOG bids. Consequently, we will continue to prohibit the use of the DE adder in solicitations that include both PPA and UOG (including PSA or EPC) bids.

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[8] David Bodek, "Standard & Poor's Imputed Debt Calculations for Power Purchase Agreements," Society of Utility and Regulatory Financial Analysts, April 19, 2007, Slides 5 and 6. This slide presentation is available at <http://www.surfa.com/ppres.php> under "2007 Forum Presentations." (Cited in IEP's Opening Brief on Debt Equivalence Issues, June 20, 2008, p. 7.)

5.1.2. The DE Adder and Pub. Util. Code § 454.6

The IOUs also requested reconsideration of the DE adder issue in solicitations that include contracts for repowering in order to ensure that they could adhere to the requirements of Public Utilities (Pub. Util.) Code Section 454.6. Pub.Util. Code § 454.6 states that a contract for a repowering or replacement that meets the criteria established in Pub. Util. Code § 454.5(b) shall be recoverable in rates, "taking into account any…debt equivalence associated with the contract…." In the event that an IOU submits an application for a replacement or repowering project that requires Pub. Util. Code § 454.6 rate recovery treatment, the IOU should certainly include the DE associated with this contract in its COC proceeding filings such that the Commission can include this DE in its consideration regarding adjustments to the IOU's debt/equity ratio and/or return on equity. Nothing in D.07-12-052 or this decision should be construed to suggest otherwise. We find no merit, though, in the IOUs' position that Pub. Util. Code § 454.6 requires that DE costs also be taken into account in the IOUs' bid evaluation process for these repower projects.

5.2. Head-to-Head Competition Between PPAs and UOG

In the 2006 LTPP proceeding, IEP and CMA raised some important and valid concerns regarding the challenges associated with IOU solicitations that include UOG and IPP bids, and in response to their arguments:

- D.07-12-052 placed a ban on direct utility bids in IOU RFOs; and
- R.08-02-007, the 2008 LTPP, will consider whether and how a level playing field can be achieved (or approached) for head-to-head competition between all types of UOG and PPA bids.

IEP and CMA are still concerned that allowing PPAs to compete against PSAs, and in some circumstances EPCs, will interfere with moving towards a truly competitive market, and their PFM asks us to make further modifications to D.07-12-052 related to UOG bids. As discussed below, we are not persuaded to make any modifications to D.07-12-052 on this topic.

As noted in D.07-12-052, we initially proposed in the proposed decision (PD) a complete ban on UOG bids. However, in their comments on the PD, DRA and TURN so cogently argued in favor of permitting head-to-head competition, that we changed the final decision and elected to continue to permit head-to-head competition between PPA and PSA (and under appropriate circumstance EPC) bids under the current hybrid market paradigm, while we await the development of a more complete record on this issue in the 2008 LTPP proceeding. Nothing in CMA or IEP's PFMs leads us to modify our conclusions on this interim compromise. We are still gathering data on various aspects of this process, and allowing one more round of RFOs with PSA and PPA bids will be useful and instructive in our assessment of head-to-head competition evaluation methodologies in the 2008 LTPP. We also note that in continuing to allow this limited head-to-head competition, we are not "limiting competition to construction," as IEP's PFM states, since PPAs are still in the RFO mix.

One point raised by the Petitioners in this context that requires additional clarification is D.07-12-052's inclusion of EPC bids "under appropriate circumstances." The purpose of allowing EPC bids is in no way intended to provide the IOUs with a broad loophole that allows for what are essentially direct utility build projects, as suggested by the Petitioners. The purpose of this inclusion is to acknowledge that certain extraordinary circumstances that are unpredictable in advance may necessitate utility ownership of generation at a particular site. The point we are making in including EPCs in the head-to-head competition discussion is that even under these circumstances, our preference is for an open solicitation by the IOU for the contract for this project, rather than the selection of a construction contractor by the IOU via an internal, less transparent process.

While extraordinary circumstances are by definition difficult to identify a priori, our intention is to set a high bar for an "appropriate circumstance" for an IOU to circumvent the potential for private ownership by soliciting EPC bids. Simply owning land on which generation could be built does not meet this test. Requesting EPC bids in general in an RFO as an alternative to PSAs and PPAs certainly does not satisfy this requirement either.

5.3. Exceptions to RFO Solicitations

The Commission has repeatedly stated its desire to develop a functional competitive energy market in California, and as explained in the Decision, we are in the process of implementing a number of programs and safety mechanisms in support of this end state. In the interim, we are operating in an evolving "hybrid market," and the issue of whether and under what circumstances an IOU can propose utility owned generation outside of a competitive solicitation represents one of the challenges posed by such a market. As we stated in the Decision, we continue to believe in a "competitive market first" approach. As such we believe that all long-term procurement should occur via competitive procurements, rather than through preemptive actions by the IOU, except in truly extraordinary circumstances.

However, as noted by several parties throughout this proceeding, unique circumstances could arise that dictate a need for UOG outside of a competitive RFO. D.07-12-052 divided the unique circumstances warranting some form of utility ownership into five categories and noted that the categories were not to be considered permanent but that they may change based on continued experience with procurement processes.[9] We repeat the five unique circumstances here for purposes of addressing the PFM:

- Market Power Mitigation – the IOU must make a strong showing that as a result of some attribute of the desired resource, a private owner would have the ability to exert significant influence over the price of its development or of the price and quantity of its output (energy, capacity, or ancillary services);

- Preferred Resources – while we continue to rely on markets to deliver efficiently priced products for ratepayers, we see no reason to limit our options and intend to continue to deploy all resources available to us, including utility development and ownership, to meet California's vital environmental policy objectives;

- Expansion of Existing Facilities – we can envision certain unique circumstances in which ratepayers would benefit from development on or expansion of an existing IOU asset that would not lend itself to the PPA project structure, but the IOU would need to make a strong showing that such development were clearly preferable to a resource that could be obtained via a competitive solicitation that would not necessarily result in utility ownership;

- Unique Opportunity – an attractively priced resource resulting from a settlement or bankruptcy proceeding (we anticipate that these opportunities will diminish over time); and

[9] In addition, D.07-12-052 stated that the IOU must demonstrate, as part of its application that holding an RFO is infeasible.

- Reliability - resources needed to meet specific, unique reliability issues (particularly under circumstances in which it becomes evident that reliability may be compromised if new resources are not developed, and the only means of developing new resources in sufficient time is via UOG.

CMA argues in its PFM that the exception for reliability could be considered redundant, since the Commission has the authority to order UOG for "emergency reliability" purposes. CMA is, in fact, correct. The Commission has the authority to execute a number of decisions in order to ensure reliability. CMA also argues that this exception could "undermine the effectiveness of the planning metrics used to develop RA requirements." We disagree with CMA's assertions. Allowing a certain exception to the RFO requirement is in no way intended to impact or alter the RA requirements – including load forecasting conventions, the planning reserve margin, or resource counting conventions. The RA requirements are not the subject of this proceeding and they remain squarely in a separate proceeding.[10] This exception merely provides clarity surrounding how procurement to address reliability issues - as dictated by the RA requirements - may occur. We find that the exception for reliability is well founded and should remain in D.07-12-052. We continue to identify this exception for purposes of clarity, transparency and completeness.

We do, however, agree that D.07-12-052 should be modified to eliminate the "Expansion of Existing Facilities" exception. The arguments presented by CMA and IEP on the due process issue are compelling, and that alone is sufficient to support the modification. We also agree that the language used in

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[10] R.05-12-013, or its successor; R.08-01-025, or its successor; R.08-04-012, or its successor.

the decision may create some uncertainty, and for this reason also modify the Decision. We note that in removing this exception based on due process concerns, we do so without prejudice, and we do not preclude the expansion of existing facilities for UOG projects approved via one of the remaining four exceptions to the competitive RFO requirement.

We continue to look unfavorably upon any procurement option selected outside of a competitive solicitation but we also realize that in certain instances this may be the optimal method for meeting the needs of California's ratepayers.

5.4. Code of Conduct

IEP presents strong arguments supporting the development of a code of conduct for ensuring that when a utility is competing head-to-head as a seller of a product with other sellers, and the utility is the buyer, that there are bans on preferential access to information within the divisions of the utility. We agree, and in fact, language in D.07-12-052 addressed that very point. What we are not prepared to do at this time, however, is to develop, in a public forum, a universal code of conduct for all three utilities to be used in all solicitations where there is head-to-head competition. D.07-12-052 only permits bids that result in utility ownership that are developed by independent parties – direct utility-build bids are prohibited – and given this limitation we conclude that the current system whereby each utility develops its own code of conduct, in consultation with its IE, PRG and the ED staff, adequately protects ratepayers and ensures the integrity of the solicitation process.

However, we recognize that the procedure, as established, does not provide potential RFO participants (i.e., the bidders) any certainty that a code of conduct exists. Therefore, we shall require that any RFO that seeks any form of utility ownership options must include this code of conduct in the RFO bid documents when they are issued.

Phase II of the 2008 LTPP, R.08-02-007 is scoped to evaluate "whether and how refinements can be made to the bid evaluation process to ensure fair competition between power purchase agreements and utility-owned generation bids and alternatives to the competitive market approach where competition cannot be used to reach equitable and efficient outcomes."[11] Therefore, we are not going to adopt changes requested in the PFMs to modify D.07-12-052 but rather will focus the Commission's attention on the 2008 Rulemaking and make changes and modifications to the process, as warranted, in the next LTPP decision.

5.5. Solicitations and Existing Generation

Calpine's request to modify D.07-12-052 to require the IOUs to request bids from existing generation in all RFOs is denied. Existing generation is assumed by the utilities and the regulators to be available to IOUs when their net-short positions are calculated. Therefore, recontracting with these resources is not sufficient to meet new generation requirements.

The Decision allowed IOUs the ability to tailor RFOs to meet specific requirements (i.e., address system reliability needs and therefore limit the solicitation to new or repowered generation or RA requirements – system, zonal, or local). In support of this position, the Commission agreed with the IOUs that all parties benefit from this practice. The Commission believes that IPPs actually

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[11] OIR, February 14, 2008, p. 11.

benefit from this practice in that they are properly discouraged from utilizing their resources to develop bids for products not needed by the IOU.

We continue to expect RFO product descriptions to be based on each utility's operational needs and not create false barriers to participation or otherwise limit the competitive process.

5.6. SDG&E's Need Authorization

In its PFM, SDG&E asks the Commission for procurement authority to meet its anticipated need in the time between the Commission's anticipated approval of Sunrise and the point in time when the new line is operational. In D.07-12-052, we bifurcated SDG&E's procurement authority into 530 MW [130 MW already approved peakers plus 400 MW of additional power] if Sunrise was not approved, and 130 MW [0 MW of additional power] if it was approved. SDG&E is concerned that even if Sunrise is approved, in the time period between approval and operation, SDG&E will face a shortage of local area capacity.

Whether or not to approve the SDG&E's application for a certificate of public convenience and necessity for the Sunrise Powerlink transmission project is the subject of Application 06-08-010 and we do not prejudge that matter here. The Commission's goal in conditioning the need authorization on the outcome of the Sunrise project was to minimize the amount of local area resources SDG&E procures in the event that the Sunrise project is approved and obviates the need for some or all of these resources at this time. However, history has taught us that there is a significant degree of uncertainty surrounding the approval and timing of transmission projects. Adding to this the recent challenges and delays a number of local generation resources have faced in SDG&E's territory, we share SDG&E's concerns regarding the potential for significant local area capacity shortfalls and do not find it prudent to attempt to "finesse" the timing of this procurement.

Consequently, we authorize SDG&E to procure up to the 530 MWs of new local capacity authorized in D.07-12-052, with the stipulation that applications for this procurement should be supported by updates of the status and projected on-line date of the Sunrise Powerlink project. Subtracting the 133 MWs of resources already approved by the Commission, this results in an additional 400 MWs of authorization for local area resources through 2015.

All of the requirements associated with the types of resources and process requirements identified in D.07-12-052 remain in full force.

5.7. Independent Evaluator

In D.07-12-052, the Commission required the use of an IE for all RFOs seeking products greater than three months duration. The intent behind this directive was to ensure a transparent and fair bid selection process that was beneficial to ratepayers, especially in cases where affiliates or utilities are bidding into the solicitation. Our requirement that the utilities utilize IEs for short- and medium-term products, rather than just long-term (greater than five years), is to ensure that RFOs where affiliate or utility bids may be present are conducted in an impartial and transparent manner regardless of contract duration while also addressing the fact that an IOU may not know whether an affiliate would bid into the solicitation prior to bid evaluation and selection. However, the Commission recognizes that there are RFOs for many different types of products, including standard and non-standard products, and RFOs may happen in a matter of hours or days, making the selection and retention of an IE in some cases burdensome, costly, and ultimately unnecessary. While we appreciate WPTF's point that sufficient time has not lapsed to make such a call, we seek to adequately balance the realities of procurement and the cost of the IE program with the need for fairness and impartiality. Given that solicitations for products of three months or more in duration require consultation with the PRG, of which DRA and ED staff are members, we believe that robust systems are in place to ensure impartiality without unnecessarily impeding the procurement process.

With the goal of protecting the interests of ratepayers, the logical demarcation for retention of an IE [in addition to when an affiliate or a utility is a bidder in the solicitation] would depend upon the complexity of the product sought (e.g., standard products would be considered non-complex products and therefore may not require the use of an IE); however, the record does not establish a clear breaking point for complex versus non-complex products. Given that product complexity is often directly correlated with product duration, we find it prudent to adopt the Joint Parties' PFM allowing for the retention of an IE for products greater than two years duration.

We uphold the requirement that IOUs employ an IE whenever an affiliate or utility bidder is present, regardless of contract duration. To ensure that an IE is retained in such cases, we require that an IOU address the possibility of affiliate or utility bids by designating at the outset of an RFO whether such bidders are allowed to participate. If the IOU does not wish to make such a determination up front, the IOU could require that all parties that intend to participate in an RFO submit a notice of intent early in the RFO process such that an IE can be retained before bids are received. However, the IOU assumes a risk in adopting this approach. One of the requirements of the IE is to ensure that an RFO has not been designed in a manner that unfairly favors some bidders over others. Consequently, if an affiliate bids into an RFO for which no IE was contracted a priori, the IOU runs the risk of having its RFO nullified in the middle of the process if an IE makes a finding of this kind.

Further, we do not adopt SCE's suggestion that an IE only be retained for solicitations where an affiliate bidder is present, regardless of contract duration. While the initial intent of the IE was to ensure fairness of RFOs where an affiliate may be among the bidders, our experience has shown us that sources of bias, or perceived sources of bias, whether intentional or not, may become present during complex solicitations with or without affiliate participation. We maintain that the ultimate goal of the IE is to ensure a fair and competitive solicitation process, and retaining an IE for more complex solicitations is a prudent step toward achieving this objective.

The portion of SDG&E's June 9th, 2008 PFM requesting that short-term (from one month to one year) RA capacity transactions be exempt from the IE requirement is denied. While short-term RA capacity RFOs may involve a somewhat standard evaluation process, no such formal standard RA products are currently in place; thus the possibility for additional evaluation criteria beyond standard criteria could be necessary. Therefore, the Commission requires, as stated above, that an IE be retained for all RFOs where an affiliate or utility bidder participates into the solicitation. At such time as the California Independent System Operator designates standard RA products, this requirement could be revisited. As stated in D.04-12-048 and upheld in D.07-12-052, the IE process may be changed or updated in a later proceeding based upon experience and lessons learned under the current rules and regulations.

5.8. Conclusions

The Commission understands that the hybrid market, by its very nature, presents many challenges to establishing a fair and open solicitation process in which all participants compete on a level playing field. Until there is a different model for developing new resources, however, we will continue to function under the IOU/IPP hybrid-model and take all reasonable steps to ensure that the integrity of the solicitation process is not compromised and that ratepayers are protected. To that end, we find that only the following requested modifications to D.07-12-052 are granted;

1. We authorize the IOUs to recognize the effects of DE when comparing PPAs against PPAs in their bid evaluations but not when a UOG project is being considered;

2. We grant the request to delete the exception of allowing IOUs to chose UOG projects outside of a competitive solicitation based solely on the synergies associated with the expansion of existing facilities;

3. We clarify the circumstances under which EPC bids may be considered;

4. We authorize SDG&E to procure up to the 530 MW of new local capacity that was conditionally authorized in D.07-12-052, clarifying that applications for this procurement should be supported by updates of the status and projected on-line date of the Sunrise Powerlink project;

5. We modify the circumstances under which an IOU must retain the services of an IE to RFOs that seek products two years or greater in duration. However, we still require that an IE be utilized whenever an affiliate or utility bidder participates in the RFO, regardless of contract duration.

The other changes requested in the PFMs are denied.

5.9. Further Modifications to D.07-12-052

For clarification, we made the following changes to D.07-12-052, to incorporate the modifications we grant today and to correct typographical errors:

- Conclusion of Law 30 contains an extraneous word "for" after evaluating, we remove the word "for."

- Eliminating bias in the RFO process: we replace the word "impartiality" with "bias" on page 208 of the Decision.

- Page 140, we clarify that an IE must be utilized for all competitive RFOs that seek products of two years or more in duration. We specify that the contract duration clock begins: (1) at the time the contract resources begin delivery or the product is made available, if delivery or availability of the product occurs within one year of contract execution; or (2) at the time of contract execution if delivery or availability does not begin within one year of contract execution.

- Pages 207-208, we clarify that we are allowing four [not five] categories of unique circumstances, and we are deleting the following: "Expansion of Existing Facilities – we envision certain unique circumstances in which ratepayers would benefit from development on or expansion of an existing IOU asset that would not lend itself to the PPA project structure, but the IOU would need to make a strong showing that such development was clearly preferable to a resource that could be obtained via a competitive solicitation that would not necessarily result in utility ownership."

- Finding of Fact 62, we change "greater than three months in length" to "two years or more in duration." In addition, we add that the contract duration clock begins: (1) at the time the contract resources begin delivery or the product is made available, if delivery or availability of the product occurs within one year of contract execution; or (2) at the time of contract execution if delivery or availability does not begin within one year of contract execution.

- Finding of Fact 96, we delete "expansion of existing facilities."

- Ordering Paragraph 9, we change "greater than three months in length" to "two years or more in duration." We add that the contract duration clock begins: (1) at the time the contract resources begin delivery or the product is made available, if delivery or availability of the product occurs within one year of contract execution; or (2) at the time of contract execution if delivery or availability does not begin within one year of contract execution.

- Ordering Paragraph 31, we delete "expansion of existing facilities."

- Ordering Paragraph 13, we modify to read as follows: Such costs, if any, shall not exceed a total annual amount of $400,000, and the total shall be paid by PG&E, SCE and SDG&E on a pro rata basis (i.e., 33.3% to each IOU) unless the contractor(s) perform work related to only a specific utility.

6. Comments on Proposed Decision

Comments on the proposed decision (PD) were received from Calpine, CMA, DRA, IEP, NRG, Energy (NRG), PG&E, SCE, SDG&E and TURN. Reply comments were received from IEP and PG&E.

SCE generally supports the PD, but asks for some clarifying language on the modification that deletes the exception allowing IOUs to choose UOG projects outside of a competitive solicitation for expansion of existing facilities. SCE requests that we specify in the decision that this deletion is without prejudice and that a utility is not precluded from seeking authorization for a UOG project that happens to involve the expansion of an existing facility. We agree with SCE and incorporate these suggestions in the decision. TURN also asks for similar consideration in its comments to the PD and in particular argues that expansion of an existing IOU asset does not lend itself to a PPA project structure. TURN asks the Commission to clarify the PD so that parties know a solicitation of EPC bids for the expansion of existing facilities is permissible in a competitive RFO that also seeks PPAs and PSAs. As discussed above, this assumption is subsumed in our discussion that a utility may tailor its RFO to meet its needs and our preference is for all resources to be chosen via competitive solicitations.

SDG&E again requests that it be granted additional resources, and NRG and IEP support this request. We have reconsidered our findings in the PD and revised the decision to increase SDG&E's need for new resources up to 530 MW and we ask SDG&E to update the status of the Sunrise project in any application for new procurement. SDG&E also argues that we should keep the expansion of existing facilities exception and not try to limit the circumstances for a utility to solicit an EPC bid. We did qualify the exception for existing facility expansion as discussed above, and are not going to further address the EPC bid issue in this decision. NRG's comments focus on giving SDG&E the additional authority to procure local area capacity, and we granted SDG&E's request.

Calpine asks the Commission to prohibit the IOUs from excluding existing generation from their long-term RFOs since without the long-term contracts, these facilities can not recover the full cost of their equity investment. IEP also argues in favor of the same modification. We have considered this request and we again decline to establish such an edict. The PD includes a discussion and analysis of our findings on this topic.

DE continues to be a contentious topic. PG&E specifically urges the Commission to allow the IOUs to consider DE in all RFOs that include PPAs, including those that also have UOG resources. PG&E states that DE is a real cost and a utility should consider all real costs in evaluating bids in a RFO. IEP opposes this suggestion and argues that DE is not a cost, but an element of financial risk that must be balanced with other risks and benefits in determining a utility's cost of capital. Most certainly, IEP argues that DE should not be used in solicitations that compare UOG and PPAs. In the alternative, IEP asks that we remove the endorsement of use of a 20% DE adder when there is no UOG participating in the RFO or to at least reduce the DE to no more than 16.7%. This proposal merits consideration in a future LTPP, but has not been fully vetted enough for us to address in this decision.

IEP also raised an issue in its comments that was not addressed in the PD and that is that allowing the use of DE could overstate the cost of PPA capacity payments and could conflict with other policy objectives, such as promoting renewables. As IEP states, RPS-eligible renewable generation facilities are frequently characterized by high capital costs and low variable costs, whereas gas-fired resources can be the opposite. Therefore, using a DE adder in PPA competition could favor fossil-fuel technologies, and disfavor renewables or other technologies likely to reduce GHG emissions. IEP asks us to modify the PD so as to address this disparity in technologies. We considered IEP's arguments and modified the PD to ensure that we are promoting the state's policy directives towards renewables and reduced GHG emissions. We made the following change to the text of the decision:

> We empower the utilities to develop in their bid evaluation protocols, in consultation with their IEs and PRGs, to ensure that in head-to-head competition, the

> use of the DE adder does not disadvantage bids for renewable and innovative low-carbon resources that may have higher capital costs than traditional gas-fired generation.

We decline to make any other modifications to the DE section of the decision, but may want to consider DE again in the next LTPP proceeding. As we have mentioned, it is the Commission's intent to move towards a competitive market, and as we make further inroads in that direction, we may better understand how to ensure that utilities and independent power producers are competing on a level field in solicitations for new resources.

IEP also requests in its comments a number of other changes to the PD including imposing limits on PSAs bidding into RFOs, requiring the development of a code of conduct for the IOUs, affirming that the IOUs should not exclude existing generation from bidding into RFOs, and granting SDG&E the additional generation it requested. DRA argues in its comments against the PSA limitations, the code of conduct and no limits on existing generation. We grant SDG&E the additional generation, but are not making the other requested changes to the PD since they are issues we carefully considered in drafting the PD and we are not convinced that the changes are warranted at this time.

7. Assignment of Proceeding

President Michael R. Peevey is the assigned Commissioner and Carol A. Brown is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Petitions for Modification of D.07-12-052 were filed by SCE and SDG&E; PG&E; IEP; CMA; Calpine; SDG&E; and PG&E and SDG&E.

2. The requested modifications to D.07-12-052 are granted in part, and denied in part.

3. The modifications adopted by the Commission are set forth herein and as set forth below:

a. We authorize the IOUs to recognize the effects of DE when comparing PPAs against PPAs in their bid evaluations, but not when a UOG project is being considered.

b. We delete the exception of allowing the IOUs to chose UOG projects outside of a competitive solicitation for expansion of existing facilities.

c. We clarify the circumstances under which EPC bids may be considered.

d. We authorize SDG&E to procure up to the 530 MW of new local capacity that was conditionally authorized in D.07-12-052, and require that applications for this procurement be supported by updates of the status and projected on-line date of the Sunrise Powerlink project.

e. We modify the circumstances under which an IOU must retain the services of an IE to RFOs that seek products two years or greater in duration. However, we still require that an IE be utilized whenever an affiliate or utility bidder is present, regardless of contract duration.

4. We also make the following clarifications to D.07-12-052:

a. Conclusion of Law 30, contains an extraneous word "for" after evaluating, we are removing the word "for."

b. Eliminating bias in the RFO process: we are replacing the word "impartiality" with "bias" on page 208 of the Decision.

c. Page 140, we clarify that an IE must be utilized for all competitive RFOs that seek products of two years or more in duration. We specify that the contract duration clock begins: (1) at the time the contract resources begin delivery or the product is made available, if delivery or availability of the product occurs within one year of contract execution; or (2) at the time of contract execution if delivery or availability does not begin within one year of contract execution.

d. Pages 207-208, we clarify that we are allowing four [not five] categories of unique circumstances, and we are deleting the following: Expansion of Existing Facilities – we envision certain unique circumstances in which ratepayers would benefit from development on or expansion of an existing IOU asset that would not lend itself to the PPA project structure, but the IOU would need to make a strong showing that such development was clearly preferable to a resource that could be obtained via a competitive solicitation that would not necessarily result in utility ownership.

e. Finding of Fact 62, we change "greater than three months in length" to " two years or more in duration." We add that the contract duration clock begins: (1) at the time the contract resources begin delivery or the product is made available, if delivery or availability of the product occurs within one year of contract execution; or (2) at the time of contract execution if delivery or availability does not begin within one year of contract execution.

f. Finding of Fact 96, we delete "expansion of existing facilities."

g. Ordering Paragraph 9, we change "greater than three months in length" to " two years or more in duration." We add that the contract duration clock begins: (1) at the time the contract resources begin delivery or the product is made available, if delivery or availability of the product occurs within one year of contract execution; or (2) at the time of contract execution if delivery or availability does not begin within one year of contract execution.

h. Ordering Paragraph 31, we delete "expansion of existing facilities."

i. Ordering Paragraph 13, we modify to read as follows: Such costs, if any, shall not exceed a total annual amount of $400,000, and the total shall be paid by PG&E, SCE and SDG&E on a pro rata basis (i.e., 33.3% to each IOU) unless the contractor(s) perform work related to only a specific utility.

5. Requests for capital structure adjustments related to PPAs are appropriate in a utility's COC proceeding, not in an advice letter/application for the PPA.

Conclusions of Law

1. As set forth herein, it is reasonable to grant in part, and deny in part, the modifications requested to D.07-12-052.

2. All other requested changes or modifications requested in the PFM that have not been explicitly granted are deemed denied.

O R D E R

IT IS ORDERED that:

1. The following modifications requested in the Petitions for Modification (PFM) to Decision (D.) 07-12-052 are granted:

   a. We authorize the investor-owned utilities (IOUs) to recognize the effects of debt equivalence (DE) when comparing power purchase agreements (PPA) against PPAs in their bid evaluations, but not when a utility-owned generation (UOG) project is being considered.

   b. We grant the request to delete the exception of allowing IOUs to chose UOG projects outside of a competitive solicitation for expansion of existing facilities.

   c. We specify the circumstances under which engineering, procuring and construction (EPC) bids are appropriate as follows:
   (1) The purpose of allowing EPC bids is in no way intended to provide the IOUs with a broad loophole that allows for what are essentially direct utility build projects, as suggested by the Petitioners – the purpose is simply to acknowledge that certain extraordinary circumstances that are unpredictable in advance may necessitate utility ownership of generation at a particular site; (2) While extraordinary circumstances are by definition difficult to identify a priori, our intention is to set a high bar for an "appropriate circumstance" for an IOU to circumvent the potential for private ownership by soliciting EPC bids. (3) Simply owning land on which generation could be built or requesting EPC bids in general in an RFO as an alternative to PSAs and PPAs does not satisfy this requirement.

   d. We authorize San Diego Gas & Electric Company (SDG&E) to procure a total of up to 530 megawatts (MW) of new local capacity that was conditionally authorized in D.07-12-052 and require that applications for this procurement be supported by updates of the status and projected on-line date of the Sunrise Powerlink project.

e. We modify the circumstances under which an IOU must retain the services of an Independent Evaluator (IE) to requests for offers (RFO) that seek products two years or greater in duration is granted. However, we still require that an IE be utilized whenever an affiliate or utility bidder participates in the RFO, regardless of contract duration.

2. We also make the following clarifications to D.07-12-052:

- Conclusion of Law 30, contains an extraneous word "for" after evaluating, we are removing the word "for."

- On page 208 of the Decision in the section on eliminating bias in the RFO process, we are replacing the word "impartiality" with "bias."

- On page 140, we clarify that an IE must be utilized for all competitive RFOs that seek products of two years or more in duration. We specify that the contract duration clock begins: (1) at the time the contract resources begin delivery or the product is made available, if delivery or availability of the product occurs within one year of contract execution; or (2) at the time of contract execution if delivery or availability does not begin within one year of contract execution.

- On pages 207-208, we clarify that we are allowing four [not five] categories of unique circumstances, and we are deleting the following: "Expansion of Existing Facilities – we envision certain unique circumstances in which ratepayers would benefit from development on or expansion of an existing IOU asset that would not lend itself to the power purchase agreement (PPA) project structure, but the IOU would need to make a strong showing that such development were clearly preferable to a resource that could be obtained via a competitive solicitation that would not necessarily result in utility ownership."

- Finding of Fact 62, we change "greater than three months in length" to " two years or more in duration." We also add that the contract duration clock begins: (1) at the time the contract resources begin delivery or the product is made available, if delivery or availability of the product occurs within one year of contract execution; or (2) at the time of contract execution if delivery or availability does not begin within one year of contract execution.

- For Finding of Fact 96, we delete "expansion of existing facilities."

- For Ordering Paragraph 9, we change "greater than three months in length" to " two years or more in duration." We also add that the contract duration clock begins: (1) at the time the contract resources begin delivery or the product is made available, if delivery or availability of the product occurs within one year of contract execution; or (2) at the time of contract execution if delivery or availability does not begin within one year of contract execution.

- For Ordering Paragraph 31, we delete "expansion of existing facilities."

- We modify Ordering Paragraph 13 to read as follows: Such costs, if any, shall not exceed a total annual amount of $400,000, and the total shall be paid by Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company on a pro rata basis (i.e., 33.3% to each IOU) unless the contractor(s) perform work related to only a specific utility.

3. All other requested changes or modifications requested in the PFM that have not been explicitly granted are denied.

4. In all other respects, D.07-12-052 remains unchanged or modified.
5. Rulemaking 06-02-013 is closed.

This order is effective today.

Dated November 6, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

ATTACHMENT DRF1-2

The CPUC's 11/18/08 Proposed Decision on the Sunrise Powerlink Transmission Project

STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3298

FILED
11-18-08
12:55 PM

November 18, 2008

Agenda ID #8136
Alternate to Agenda ID #8065
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 06-08-010

Enclosed is the Alternate Proposed Decision of President Peevey to the Proposed Decision of Administrative Law Judge Vieth previously mailed to you. This cover letter explains the comment and review period and provides a digest of the alternate decision.

When the Commission acts on this agenda item, it may adopt all or part of the decision as written, amend or modify it, or set them aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Pub. Util. Code § 311(e) requires that the alternate item be accompanied by a digest that clearly explains the substantive revisions to the proposed decision. The digest of the alternate proposed decision is attached.

This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Upon the request of any Commissioner, a Ratesetting Deliberative Meeting (RDM) may be held. If that occurs, the Commission will prepare and publish an agenda for the RDM 10 days beforehand. When an RDM is held, there is a related ex parte communications prohibition period. (See Rule 8.2(c)(4).)

Parties to the proceeding may file comments on the proposed decision and alternate proposed decision as provided in Pub. Util. Code §§ 311(d) and 311(e) and in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3(b), the page limit for opening comments is extended to 25 pages.

As further provided by Rule 14.3(b): "Comments shall include a subject index listing the recommended changes to the proposed or alternate decision, a table of authorities and an appendix setting forth proposed findings of fact and conclusions of law. The subject index, table of authorities, and appendix do not count against the page limit." **The Commission does not accept redlined versions of proposed decisions or alternate decisions** and any **comments that include redlined versions of those documents will be rejected** by the Commission's Docket Office.

As provided by Rule 14.3(c): "Comments shall focus on factual, legal or technical errors in the proposed or alternate decision and in citing such errors shall make specific references to the record. Comments which merely reargue positions taken in briefs will be accorded no weight. Comments proposing specific changes to the proposed or alternate decision shall include supporting findings of fact and conclusions of law."

As provided by Rule 14.3(d): "Replies to comments may be filed within five days after the last day for filing comments and shall be limited to identifying misrepresentations of law, fact or condition of the record contained in the comments of other parties. Replies shall not exceed five pages in length."

Comments must be filed either electronically pursuant to Resolution ALJ-188 or with the Commission's Docket Office. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ Vieth at xjv@cpuc.ca.gov and President Peevey's advisor Matthew Deal at mjd@cpuc.ca.gov. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:tcg

Attachment

ATTACHMENT

DIGEST OF SUBSTANTIVE DIFFERENCES BETWEEN PROPOSED DECISION AND ALTERNATIVE MAILED OCTOBER 31, 2008 AND ALTERNATE DECISION MAILED NOVEMBER 18, 2008

A.06-08-010: Application of San Diego Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project

This digest is prepared pursuant to Pub. Util. Code Sec. 311(e). It describes the substantive differences between the Proposed Decision and the Alternative Proposed Decision of Commissioner Grueneich (Grueneich Alternate), both mailed October 31, 2008, and between the Grueneich Alternate and the alternative proposed decision of President Peevey (Peevey Alternate), mailed November 18, 2008.

The differences between the Proposed Decision and the Grueneich Alternate are as follows:

The Proposed Decision denies San Diego Gas & Electric Company's (SDG&E) application for a certificate of public convenience and necessity (CPCN) to build the Sunrise Powerlink Transmission Project (Sunrise) for the following reasons:

- It is not needed to meet SDG&E's renewable portfolio standard (RPS) obligation of 20% by 2010;
- Assuming a 20% RPS, it is not economic and will potentially generate significant ratepayer costs;
- It will have many significant and unmitigable impacts on the environment; and
- Other alternatives will meet SDG&E's eventual reliability needs more economically and with fewer significant and unmitigable impacts on the environment.

The Grueneich Alternate conditionally approves SDG&E's CPCN application to build Sunrise along the Final Environmentally Superior Southern Route based on Commission approval of an SDG&E compliance plan to ensure that substantial amounts of Imperial Valley renewable resources will be delivered over Sunrise.

The Grueneich Alternate deviates from the proposed decision by assuming higher combustion turbine prices and focusing on the economic results assuming renewable procurement at 33% RPS levels. Under these assumptions, the Grueneich Alternate finds:

- Sunrise will generate over $100 million per year in ratepayer benefits, significantly more than the other alternatives;
- This Commission is committed to achieving GHG reductions in the energy sector through, in part, renewable procurement at 33% RPS levels;
- The other environmentally preferred alternatives are infeasible for meeting these broader policy goals; and
- Sunrise – in the form of the Final Environmentally Superior Southern Route – is the highest ranked Alternative that will facilitate Commission policy to achieve GHG reductions through renewable procurement at 33% RPS levels in the shortest time possible with the greatest economic benefits.

The differences between the Peevey Alternate and the Grueneich Alternate are as follows:

The Peevey Alternate generally adopts the changes to the Proposed Decision in the Grueneich Alternate and, as described below, makes additional changes that lead to different conclusions.

The Peevey Alternate adopts the Grueneich Alternate's assumptions regarding combustion turbine costs and focuses on the 33% RPS level. It shares the following findings with the Grueneich Alternate:

- This Commission is committed to achieving GHG reductions in the energy sector through, in part, renewable procurement at 33% RPS levels;
- The other environmentally preferred alternatives are infeasible for meeting these broader policy goals.

The Peevey Alternate deviates from the Grueneich Alternate by adopting SDG&E's and CAISO's Phase 2 estimates of the project's operating and maintenance costs and by consistently applying CAISO's assumption that RPS compliance savings cannot be negative. It also provides a thorough analysis of the applicability of Section 399.25 to Sunrise given its interpretation in prior Commission decisions. In addition, the Peevey Alternate provides broader context on California's renewable energy and greenhouse gas reduction policies, CPUC procurement policies, and implementation of the Renewable Portfolio Standard by the CPUC.

As a result of these changes and additions, the Peevey Alternate modifies these findings of the Grueneich Alternate:

- Annual ratepayer benefits from Sunrise increase to over $125 million per year;
- The Peevey Alternate qualifies that Sunrise – in the form of the Final Environmentally Superior Southern Route – is the highest ranked *environmentally acceptable* Alternative that will facilitate Commission policy to achieve GHG reductions through renewable procurement at 33% RPS levels in the shortest time possible with the greatest economic benefits.

Also based upon these changes and additions, the Peevey Alternate further deviates from the Grueneich Alternate by reaching the following additional findings:

- Sunrise is vital because it will deliver renewable generation that would otherwise remain unavailable; the cost of Sunrise is appropriately balanced against the certainty of the line's contribution to economically rational RPS compliance.
- The Commission currently has sufficient methods through which it can monitor, evaluate, influence and enforce IOU compliance with its policies. There is no need to add an additional compliance requirement in order to guarantee that renewable generation is delivered via Sunrise.
- Sunrise affords SDG&E the best opportunity for SDG&E to plan for the current and future reliability needs throughout its service territory. Sunrise will also provide a number of desirable, but unquantifiable, reliability benefits – a more robust southern California transmission system, and provide insurance against

unexpected high load growth in SDG&E's service area, among other things.

The Peevey Alternate, therefore, approves SDG&E's CPCN application to build Sunrise along the Final Environmentally Superior Southern Route without the condition of a compliance plan, as required under the Grueneich Alternate.

(END OF ATTACHMENT)

Decision **ALTERNATE PROPOSED DECISION OF PRESIDENT PEEVEY**
(Mailed 11/18/2008)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902 E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project.	Application 06-08-010 (Filed August 4, 2006)

(See Appendix F for List of Appearances.)

DECISION GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE SUNRISE POWERLINK TRANSMISSION PROJECT

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DECISION GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE SUNRISE POWERLINK TRANSMISSION PROJECT

1. Executive Summary

This decision grants the application of San Diego Gas & Electric Company (SDG&E) for a Certificate of Public Convenience and Necessity (CPCN) to construct the Sunrise Powerlink Transmission Project (Sunrise) using the Final Environmentally Superior Southern Route.[1]

SDG&E's initial construction proposal, referred to as the Proposed Project, contemplates a new 500/230 kV transmission line running approximately 150 miles from the El Centro area of Imperial County to northwestern San Diego County.[2] The 500 kV portion of the line would travel the length of Anza-Borrego Desert State Park (Anza Borrego), a distance of approximately 25 miles. We find all of the routes that go through Anza-Borrego to be environmentally unacceptable and infeasible.

Assuming renewable procurement at 33% Renewable Portfolio Standard (RPS) levels, we estimate that the Final Environmentally Superior Southern Route will generate net benefits of over $125 million per year,[3] and we find that it is the second highest ranked Alternative that will facilitate our policy to achieve greenhouse gas (GHG) reductions through renewable procurement at 33% RPS levels in the shortest time possible.[4]

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[1] Appendix A contains a list of acronyms and other naming conventions we use in this decision.

[2] The Proposed Project includes construction of 91 miles of 500 kilovolt (kV) line and 59 miles of 230 kV transmission line, replacement of transmission cable for several other lines, a new substation, and modification of several other substations.

[3] See Table 13, Section 11.4.1.

[4] See Section 17.11.

A statutory framework governs our review of this application and we highlight its major components. Pursuant to Public Utilities Code Section 1001,[5] before granting a CPCN we must find a need for the Proposed Project or an alternative evaluated in this proceeding. Section 1002(a) requires that we consider four additional factors: community values; recreational and park areas; historical and aesthetic values; and influence on the environment. SDG&E claims that Sunrise is needed to maintain reliability, promote renewable energy, and reduce energy costs and projects that construction of the line will provide economic benefits to its ratepayers. The CPCN portion of our proceeding has been the forum for economic review and this decision evaluates each of SDG&E's claims.

The review process established by the California Environmental Quality Act (CEQA)[6] has been the primary focus for environmental review. As lead agency pursuant to CEQA, we have evaluated the environmental impacts of the Proposed Project, seven alternatives (two of them solely generation based, "non-wires" alternatives and the rest, transmission based, "wires" alternatives), and a No Project Alternative. CEQA requires a lead agency to identify and study feasible alternatives and mitigation measures to reduce a project's significant environmental impacts.

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[5] Unless otherwise expressly stated, all references to statutes are to the California Public Utilities Code.

[6] Pub. Resources Code § 21000, *et seq.* CEQA and its federal counterpart, the National Environmental Policy Act (NEPA, 42 USC § 4321, *et seq*.) require the preparation, respectively, of an environmental impact report (EIR) and an environmental impact statement (EIS) to identify alternatives to the proposed project, the potentially significant effects on the environment of the proposed project and its alternatives, and to indicate the manner in which those significant environmental effects can be mitigated or avoided.

This proceeding has been heavily-contested, involving lengthy evidentiary hearings and dozens of public meetings. In addition to voluminous testimony, documentary evidence, and two rounds of briefs in connection with the evidentiary hearings, there have been eleven opportunities for public comment, both written and oral, including Public Participation Hearings at five different locations. The Final Environmental Impact Report/Environmental Impact Statement (Final EIR/EIS)[7] prepared jointly by this Commission and the United States Bureau of Land Management (BLM) is over 11,000 pages long. Today's decision certifies the Final EIR, which is the CEQA portion of the Final EIR/EIS.

A significant portion of the environmental review focuses on the environmental impacts the Proposed Project and other Northern Routes would have on Anza-Borrego. SDG&E proposes to build the Proposed Project, with steel towers standing over 150 feet high, through wilderness lands in the heart of Anza-Borrego. Many members of the public have referred to Anza-Borrego as the crown jewel[8] of the State Parks system. The Vision Statement in Anza-Borrego's General Plan states:

> Anza-Borrego is a place of awe, inspiration, and refuge. The vast desert landscape and scenery are preserved in a pristine condition. The full array of natural and cultural resources are

[7] The Final EIR/EIS comprises not only the set of documents with that name but also the two prior sets of documents, the Draft EIR/EIS and the Recirculated Draft EIR/Supplemental Draft EIS. Unless specific reference to one of these set of documents is required, the decision refers generically to the EIR/EIS.

[8] Written comment from the public and numerous speakers at public meetings refer to Anza-Borrego this way. For example, Monica Argandona, the Desert Program Director for the California Wilderness Coalition, used this term at the February 26, 2008 Public Participation Hearing in Borrego Springs. At that same meeting, another speaker, Mr. Rasmusson, stated that "while this park doesn't assume the majesty of a Hetch-Hetchy or Yosemite, it still remains a jewel nonetheless." RT 2977:2-4.

> cared for so as to perpetuate them for all time while supporting those seeking enjoyment from these resources ...[9]

The Final EIR/EIS finds that SDG&E's Proposed Project has 52 significant, unmitigable environmental impacts that would require de-designation of approximately 50 acres of state wilderness in Anza-Borrego. SDG&E subsequently proposed to build entirely within a 100-foot corridor in Anza-Borrego. However, the Final EIR/EIS concludes that this "Enhanced" Northern Route only increases the potential for significant, adverse impacts. Further, the status of legal right-of-way within that 100-foot corridor is heavily contested. Consequently, we find that all routes that would traverse Anza-Borrego are unacceptable.

The Final EIR/EIS ranks three alternatives as environmentally superior to the Final Environmentally Superior Southern Route – the All-Source Generation Alternative, the In-Area Renewable Alternative, and the LEAPS Transmission-Only Alternative.[10] We find these three alternatives to be infeasible for, among other things, meeting California's broader policy goals.

Modeling performed by the CAISO demonstrates total projected reliability benefits of Sunrise to be $237 million per year in addition to a number of desirable, but unquantifiable, reliability benefits. Among other things, Sunrise will create a more robust southern California transmission system, and provide insurance against unexpected high load growth in SDG&E's service area. A transmission solution affords SDG&E the best opportunity to plan for the current

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[9] State Parks Foundation Exhibit P-1, Reference #2 (Anza-Borrego Final General Plan & EIR, page 3-8).

[10] These alternatives are described in detail in Sections 6.14.4, 15, and 17.

and future reliability needs throughout its service territory. The generation alternatives will not provide these benefits.

A major issue in the proceeding is whether Sunrise is needed to meet 20% RPS and, if not, a higher RPS. The record shows that assuming a 20% RPS,[11] Sunrise does not result in RPS compliance savings. The lack of RPS compliance savings does not mean that Sunrise is not needed for SDG&E to meet its RPS goals. Sunrise is vital to SDG&E meeting its RPS goals because it will deliver renewable generation that would otherwise remain unavailable. Further, the cost of Sunrise is appropriately balanced against the certainty of the line's contribution to economically rational RPS compliance. Additionally, Sunrise generates significant RPS compliance savings assuming a 33% RPS.

AB 32 requires that California reduce its GHG emissions to 1990 levels by 2020.[12] The energy sector is expected to contribute a significant amount to those reduction goals. Our recent GHG decision[13] making recommendations to the California Air Resources Board (CARB) on its Draft Assembly Bill 32 Scoping Plan[14] commits this Commission to achieving renewable procurement at 33% RPS levels, assuming certain safeguards. Thus, this Commission is committed to

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[11] Senate Bill (SB) 1078 (Stats.2002, c.516) established an RPS of 20% by 2017. SB 107 (Stats.2006, c.464) accelerates the RPS goal to 20% by 2010. The RPS Program, including its procurement targets, is codified at § 399.11 et seq.

[12] AB 32 (Stats. 2006, c 598), codified at Health & Saf. Code § 38500 et seq.

[13] *Greenhouse Gas Regulatory Strategies*, Decision (D.) 08-10-037.

[14] Climate Change Draft Scoping Plan, a framework for change, June 2008 Discussion Draft Pursuant to AB 32 the California Global Warming Solutions Act of 2006 Prepared by the California Air Resources Board for the State of California, June 26, 2008, available at http://www.arb.ca.gov/cc/scopingplan/document/draftscopingplan.pdf. The Air Resources Board released its Proposed Scoping Plan on October 15, 2008 and it is available at http://www.arb.ca.gov/cc/scopingplan/document/psp.pdf.

achieving GHG reductions in the energy sector, in part, through renewable procurement at 33% RPS levels.

Under renewable procurement at 33% RPS levels, the Final Environmentally Superior Southern Route is the second highest ranking alternative that will facilitate our renewable energy development and GHG emission reduction goals for the energy sector. The higher ranking alternative is environmentally unacceptable and therefore infeasible. We estimate that the Final Environmentally Superior Southern Route will facilitate development of over 2,800 megawatts (MW) of Imperial Valley renewables by 2015, and that more than half of that development will be of high capacity geothermal resources. In contrast, the higher ranked alternatives are not estimated to facilitate even half that amount of renewable development.

We do not take our decision to approve the Final Environmentally Superior Southern Route lightly. The Final EIR/EIS describes the risk of wildfires created by electric distribution and transmission lines. It also describes the increased risk of power outages as a result of wildfires. We find that while there are likely to be increased dual line power outages, the fire risk posed by the Final Environmentally Superior Southern Route is minimized given that the route is comprised of 230 kV and 500 kV lines placed on tall, steel structures. We also require SDG&E to take significant mitigation measures to prevent fire ignition in both the construction and operation of the line.

We acknowledge that there has been significant public opposition to Sunrise. Of the more than 400 individuals who have commented on Sunrise during our Public Participation Hearings, the vast majority oppose one or more of the Sunrise alternatives because of impacts on community values, the environment, and the other factors we consider pursuant to § 1002(a). Our consideration of these factors is reflected in the Sunrise route we approve as set forth in this decision.

2. Background

2.1. Procedural History

This proceeding commenced on December 14, 2005, when SDG&E filed Application (A.) 05-12-014, its initial request for a CPCN for authority to construct Sunrise (2005 Application). Because of critical deficiencies in the 2005 Application, including failure to identify the route for Sunrise or to include a Proponent's Environmental Assessment (PEA), SDG&E filed an entirely new set of documents on August 4, 2006. Though at times SDG&E's 2006 filing has been referred to, informally, as an "amendment" to the 2005 filing, we designated the 2006 filing as a new application and assigned a new proceeding number, A.06-08-010 (2006 Application). The Chief Administrative Law Judge (ALJ) consolidated the dockets for the 2005 and 2006 Applications and subsequently, in D.07-11-008, we affirmed the consolidation and then closed the 2005 Application.

On September 6, 2006, responding to requests from the Commission's Energy Division, SDG&E filed a multiple volume supplement to the 2006 Application. On September 13, 2006, the assigned ALJ held a Prehearing Conference in Ramona, California. During this period the Commission continued to receive protests and ultimately more than a dozen were filed.[15] A

[15] The following persons and entities filed protests to the 2005 Application, the 2006 Application, or both: California State Parks Foundation (State Parks Foundation); Carmel Country Highland Owners; the Cities of Hemet, Murrieta and Temecula; Community Alliance for Sensible Energy; the Center for Biological Diversity and the Sierra Club, San Diego Chapter (Conservation Groups); Division of Ratepayer Advocates (DRA); Imperial Irrigation District; Mussey Grade Road Alliance (Mussey Grade); Nevada Hydro Company (Nevada Hydro); Ramona Alliance Against Sunrise Powerlink; Ratepayers For Affordable Clean Energy Coalition; Starlight Mountain

Scoping Memo issued after the Prehearing Conference, as required by statute.[16] The Scoping Memo established the scope of this proceeding and the schedule, coordinating the CPCN review with the timeline for the concurrent, parallel track CEQA/NEPA review. The Scoping Memo also designated ALJ Steven Weissman as the presiding officer and set two hearing phases, focusing Phase 1 on all issues that could be examined prior to issuance of the Draft EIR/EIS, and Phase 2 on issues tied to the Draft EIR/EIS. In Section 2.2 below, we discuss the Scoping Memo in greater detail. On October 2, 2006, SDG&E supplemented the 2006 Application to include and rank four alternative routings which, unlike its initial route, would not pass through Anza-Borrego. On January 19, 2007, SDG&E filed corrections to certain cost/benefit assumptions in the 2006 Application.

The NEPA and CEQA scoping processes commenced, respectively, on August 31, 2006 with BLM's publication in the Federal Register of a Notice of Intent to prepare an EIS; and on September 15, 2006 with the issuance by Commission Energy Division staff of a Notice of Preparation of an EIR. BLM and Commission staff, together with their environmental consultants, jointly held seven public scoping meetings in October 2006. By November 2006, the Commission had received over 300 comments on the Notice of Preparation from public, private, and tribal agencies and from members of the public. In February 2007, following preliminary identification of the alternatives to analyze in the EIR/EIS, BLM and Commission staff, and their consultants, held eight more

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Estates Owners; West Chase Homeowners Association; and Utility Consumers' Action Network (UCAN).

[16] *Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling (Scoping Memo)*, November 1, 2006.

public scoping meetings to gain further input. The subsequent CEQA/NEPA review proceeded with additional public notice and input at milestone intervals, consistent with those environmental laws.

Though we originally expected to release the Draft EIR/EIS on August 3, 2007, issuance of the document was delayed by five months when, in the course of Phase 1 hearings, SDG&E disclosed new information critical to the Commission's environmental review.[17] The Commission and BLM released the Draft EIR/EIR on January 4, 2008. Between January 28 and February 1, 2008, BLM and Commission staff, and their consultants, held a series of nine workshops to present the Draft EIR/EIS to the public, to explain the ensuing public review process, and to accept written comments brought to the workshops. In late February 2008, the ALJ and the assigned Commissioner held five Public Participation Hearings where they took both written and oral statements. On July 11, 2008, the lead agencies released a Recirculated Draft EIR/Supplemental Draft EIS for additional public comment. After considering all additional comments, the lead agencies released the Final EIR/EIS on October 14, 2008.

Review of this application has included four Prehearing Conferences held over the course of this consolidated proceeding, several workshops, public input at Public Participation Hearings in Borrego Springs (three times, including one session attended by four commissioners and another attended by three), Ramona (three times, including comments received at two Prehearing Conferences), San Diego, Julian and Pine Valley, and 37 days of evidentiary hearings, approximately half in San Diego and half in San Francisco. Assigned

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[17] *Assigned Commissioner's Ruling Addressing Newly Disclosed Environmental Information*, July 24, 2007.

Commissioner Dian M. Grueneich attended every Prehearing Conference and Public Participation Hearing. We received a round of Opening and Reply Briefs following Phase 1 hearings and a second round after Phase 2.[18] Shortly thereafter, a Revised Scoping Memo directed CAISO to do additional modeling runs needed to complete the record and provide them as Exhibit Compliance -1 (Compliance Exhibit), authorized parties to file a round of comments, and addressed other outstanding matters.[19]

This abbreviated procedural history does not include the many discovery conferences and modeling workshops held in connection with our review of Sunrise. These were necessitated by the complexity of the issues before us, the number of parties, and in particular, by the importance of detailed computer

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[18] The following parties filed briefs: (1) Phase 1 Opening Briefs (on or about November 9, 2007): Cabrillo Power I LLC (Cabrillo Power), California Independent System Operator (CAISO); Conservation Groups, California Department of Parks and Recreation (State Parks), California Farm Bureau Foundation (Farm Bureau), DRA, Imperial Irrigation District, Mussey Grade, Nevada Hydro, Rancho Peñasquitos Concerned Citizens (Rancho Peñasquitos), SDG&E, South Bay Replacement Project (South Bay), and UCAN; (2) Phase 1 Reply Briefs (on or about November 30, 2007): CAISO; Conservation Groups, DRA, Imperial Irrigation District, Mussey Grade, Nevada Hydro, Rancho Peñasquitos, SDG&E, South Bay, State Parks and UCAN; (3) Phase 2 Opening Briefs (on or about May 30, 2008): CAISO, City of Santee, Conservation Groups, DRA, Farm Bureau, Imperial Irrigation District, Jacqueline Ayer, Mussey Grade, Nevada Hydro, Powers Engineering, Rancho Peñasquitos, SDG&E, South Bay, State Parks, and UCAN; (4) Phase 2 Reply Briefs (on or about June 13, 2008): CAISO; City of Santee; Conservation Groups, DRA; Farm Bureau, Imperial Irrigation District, Jacqueline Ayer, Mussey Grade; Nevada Hydro; Rancho Peñasquitos; SDG&E; State Parks, and UCAN.

[19] *Revised Scoping Memo and Ruling of the Assigned Commissioner and Administrative Law Judge (Revised Scoping Memo), June 20, 2008.* A subsequent ruling revised the dates for comment. *Administrative Law Judge's Ruling Memorializing Dates for Comments on Exhibit Compiance-1,* August 28, 2008. The following parties filed comments/briefs: (1) Opening (on September 5, 2008): CAISO, DRA, Nevada Hydro, Rancho Peñasquitos, SDG&E, and UCAN; and (2) Reply (on September 10, 2008): CAISO, DRA, Jacqueline Ayer, and SDG&E.

modeling in analyzing SDG&E's effort to demonstrate the need for the Proposed Project, especially in comparison to the other alternatives.

2.2. Scoping Memo

As required by §1701.1, the Scoping Memo articulated the scope for this proceeding, established the preliminary schedule, and addressed various other procedural issues, such as discovery and the service of prepared testimony and pleadings.

The Scoping Memo identified the scope of this application as including "the proposed project using SDG&E's preferred route and configuration, alternative routes and configurations, the no project alternative, and non-wires alternatives." It also articulated the legal framework for review, including these over-arching elements: assessment of "need for and cost-effectiveness of the project" under § 1001, consideration of the four factors listed in § 1002(a) -- community values, recreational and park areas, historical and aesthetic values, and influence on the environment, the environmental analysis required by CEQA, and compliance with other law discussed in Section 4 and elsewhere in this decision. Finally, the Scoping Memo provided specific direction to the parties regarding additional modeling and related activities.

The Revised Scoping Memo, which issued after the Phase 2 hearings, acknowledged the need to recirculate the Draft EIR/EIS, set out the basic modeling assumptions to be used by CAISO in the preparation of the Compliance Exhibit, and adjusted the schedule of the proceeding accordingly.

3. Project Objectives and Description

3.1. Project Objectives

SDG&E's PEA states that Sunrise was designed to address eight objectives.[20] Under CEQA and NEPA, lead agencies must identify the project objectives to be considered for CEQA/NEPA purposes, and those objectives may or may not mirror an applicant's suggestion. After thorough consideration, Commission and BLM staff distilled SDG&E's eight PEA objectives to three Basic Project Objectives which we have used in our review of Sunrise:

- **Basic Project Objective 1**: to maintain reliability in the delivery of power to the San Diego region;

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[20] Section 3.1 of SDG&E's PEA sets forth the eight objectives, which we paraphrase as follows:

1) Ensure that SDG&E's transmission system satisfies reliability criteria.
2) Provide transmission facilities with a voltage level and transfer capability that (a) allows for prudent system expandability to meet both anticipated short-term (2010) and long-term (2015 and beyond) load growth and (b) supports regional expansion of the electric grid.
3) Provide transmission capability for Imperial Valley renewable resources for SDG&E customers to assist in meeting or exceeding California's 20% renewable energy source mandate by 2010 and the Governor's proposed goal of 33% by 2020.
4) Reduce the above-market costs associated with maintaining reliability in the San Diego area while mitigating the potential exercise of local market power, particularly the costs associated with older generators such as the South Bay and Encina Power Plants.
5) Improve regional transmission system infrastructure.
6) Obtain electricity generated by diverse fuel sources and decrease the dependence on increasingly scarce and costly natural gas.
7) Avoid, to the extent feasible, the taking and relocation of homes, businesses or industries, in the siting of the transmission line, substation and associated facilities.
8) Minimize the need for new or expanded transmission line right-of-way.

- **Basic Project Objective 2**: to reduce the cost of energy in the region; and
- **Basic Project Objective 3**: to accommodate the delivery of renewable energy to meet state and federal renewable energy goals from geothermal and solar resources in the Imperial Valley and wind and other sources in San Diego County.[21]

3.2. Description of the Northern Routes

SDG&E's Proposed Project and its subsequent routing variations through Anza-Borrego have become known during the course of this proceeding as the "Northern Route Alternatives" or "Northern Routes"; today's decision uses these terms, or as appropriate, "Northern Route."

3.2.1. The Proposed Project

The Proposed Project consists of a 150-mile transmission line between Southern California's Imperial and San Diego counties.[22] The major project components comprise:

- A new 91-mile, single-circuit 500 kV overhead electric transmission line linking SDG&E's existing Imperial Valley Substation (in Imperial County near the City of El Centro) with a new 500/230 kV Central East Substation to be constructed in the San Felipe area of central San Diego County, southwest of the intersection of County Highway S22 and S2;
- A new 59-mile 230 kV double-circuit and single-circuit transmission line, running partly overhead and partly underground through San Diego County from the proposed new 500/230 kV Central East Substation to SDG&E's existing Peñasquitos Substation (in the City of San Diego); and
- Other upgrades, in particular the addition of a 230 kV shunt capacitor at SDG&E's San Luis Rey Substation, the addition of a

[21] Draft EIR/EIS, ES-3.2.

[22] See Draft EIR/EIS, Sec. B.2 and B.3 for a more complete description of the Proposed Project.

69 kV shunt capacitor at SDG&E's South Bay Substation, and replacement of the conductors on an existing 8.2 mile, 69 kV transmission line that runs from SDG&E's existing Sycamore Canyon Substation to its existing Elliott Substation.

The project's two transmission components (the 91-mile 500 kV component and the 59-mile double and single circuit 230 kV components) consist of five separate segments or "links":

- The Imperial Valley Link - 60.9 miles of 500 kV line from Imperial Valley Substation (west of El Centro) to the eastern boundary of Anza-Borrego;
- The Anza-Borrego Link - 22.6 miles of 500 kV line entirely within the boundaries of Anza-Borrego;
- The Central Link (Central San Diego County) - 27.3 miles (7.4 miles of 500 kV line; 19.9 miles of 230 kV line) in the communities of Ranchita and San Felipe;
- The Inland Valley Link (West-Central San Diego County) - 25.5 miles of 230 kV through the communities of Santa Ysabel and Ramona, and through Marine Corps Air Station Miramar; and
- The Coastal Link (Western San Diego County) - 13.6 miles of 230 kV line with new towers in communities of Rancho Peñasquitos and Torrey Hill (City of San Diego).

The Proposed Project also requires the relocation of several segments of existing transmission lines, as follows.

- Move nine miles of an existing 69 kV transmission line to parallel the proposed new 230 kV line at a point between the junction of State Route 76 and State Route 79, near the existing Santa Ysabel Substation; and
- Move existing 69 kV and 92 kV transmission lines located between the eastern boundary of Anza-Borrego and a point near the proposed new Central East Substation by undergrounding portions in the adjacent State Route

78 roadway and placing portions on the new 500 kV towers sited within Anza-Borrego.

3.2.2. SDG&E's "Enhanced" Northern Route

In response to concerns and suggestions raised by agencies and landowners, SDG&E proposed, after the Phase 1 hearings, an "Enhanced" Northern Route, a 148.6 mile long transmission line that follows the same general corridor as the Proposed Project, with certain modifications.[23] The major changes include:

- Modification of the Anza-Borrego Link's footprint by limiting the 500 kV line to the existing right-of-way for the existing wood pole line in Anza-Borrego, in an attempt to avoid the need to obtain new right-of-way within the Park or de-designate state wilderness;
- A few minor segment alternatives and/or modified reroutes through portions of the Proposed Project's Imperial Valley and Inland Valley Links.

3.2.3. The Final Environmentally Superior Northern Route

The EIR/EIS evaluated and compared various routing alternatives that reduce the environmental impacts of the Proposed Project's route, including the "Enhanced" Northern Route, to identify the least environmentally damaging Northern Route. The Final Environmentally Superior Northern Route, 140.8 miles long, is a combination of segment alternatives and reroutes that "replace" corresponding sections of the Proposed Project. The Final Environmentally Superior Northern Route is almost identical to the Draft Environmentally Superior Northern Route, but was modified to include reroutes suggested by SDG&E that would reduce further the route's environmental

[23] For a more detailed description, see Recirculated Draft EIR/Supplemental Draft EIS, Sec. 5.3.1.

impacts, as analyzed in the Recirculated Draft EIR/Supplemental Draft EIS. The major differences between the Final Environmentally Superior Northern Route and the Proposed Project include:

- Relocation of the 230/500 kV substation east of Anza-Borrego;
- Installation of a double-circuit bundled 230 kV line through Anza-Borrego (the All Underground Option);[24] and
- Construction of the Santa Ysabel All Underground Alternative in the Santa Ysabel Valley.

The EIR/EIS describes the Final Environmentally Superior Northern Route in more detail.[25]

4. Standard of Review and Governing Law

4.1. Burden of Proof

As the Applicant, SDG&E must demonstrate a need for the Commission to issue the CPCN.[26] The utility "has the burden of affirmatively establishing the reasonableness of all aspects of its application. Intervenors do not have the burden of proving the unreasonableness of [the utility's] showing."[27]

Evidence Code §115 defines burden of proof as follows:

> "Burden of proof" means the obligation of a party to establish by evidence a requisite degree of belief concerning a fact in the mind of the trier of fact… The burden of proof may require a party to

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[24] The 230 kV transmission line between the San Felipe Substation and the connection to the Proposed Project would be installed underground in State Route 78 and County Highway S2.

[25] Draft EIR/EIS, Sec. H.

[26] *Investigation into Methodology for Economic Assessment of Transmission Projects*, D.06-11-018, 22 ["The Commission has long held that the applicant carries the burden of proof in a certification proceeding, and we reiterate those determinations today."].

[27] *Southern California Edison Test Year 2006 General Rate Application*, D.06-05-016, 7.

> raise a reasonable doubt concerning the existence or nonexistence of a fact or that he establish the existence or nonexistence of a fact by a preponderance of the evidence, by clear and convincing evidence, or by proof beyond a reasonable doubt.
>
> Except as otherwise provided by law, the burden of proof requires proof by a preponderance of the evidence.

SDG&E argues that the preponderance of the evidence standard should be applied here. Citing D.07-04-049, SDG&E states that the Commission has applied the higher, clear and convincing standard only in general rate cases and reasonableness reviews, and has expressly rejected its use for other purposes.[28] DRA, UCAN, and others point to several rate case decisions and reasonableness review decisions to support their contention that clear and convincing evidence is the correct standard of review for Sunrise.[29] No party refers to a decision on a prior transmission line CPCN.

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[28] *Southern California Edison's Application for Approval of Summer 2007 New Generation RFOs and Cost Recovery,* D.07-04-049. The decision, which modified D.07-01-041 and denied rehearing, among other things determines that the preponderance of the evidence standard applies to review of the contract at issue, whereby Long Beach Generation will repower 260 megawatts of peaking capacity at Long Beach and make this capacity available to Edison for ten years.

[29] The parties' citations include: *Pacific Gas & Electric Co. Energy Cost Adjustment Clause Application*, D.82486, 701 (1980) 4 CPUC2d 693; D.00-02-046, *Southern California Edison General Rate Case*, D.83-05-036, (1983) 11 CPUC2d 474, 475. Our own research indicates that the Commission first appeared to require clear and convincing evidence in D.44923, where in the course of its review of a motion to dismiss a telephone utility's application for a rate increase, the Commission stated:

> We must keep in mind that this is not an adversary proceeding in the sense that, as in an ordinary civil case, only a *prima facie* case must be shown. This is a legislative proceed in which the burden of proof rests most heavily upon applicant to prove by clear and convincing evidence that the present rates of which it complains work a confiscation of its property. [Citations omitted.] (*Pacific Telephone & Telegraph Co Rate Application*, D.44923, (1950) 50 CPUC 247, 248.)

Witkin's explanation of these two standards is instructive. Preponderance of the evidence usually is defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[30] Clear and convincing evidence "has been defined as 'clear, explicit and unequivocal,' and 'so clear as to leave no substantial doubt,' and 'sufficiently strong to command the unhesitating assent of every reasonable mind.'"[31]

The preponderance of the evidence is generally the default standard in civil and administrative law cases and we apply that standard in this decision.[32]

4.2. Section 1001 et seq.

Section 1001 et seq. establishes the framework for our review of Sunrise and we focus, here, on the two basic components of that framework, §§ 1001 and 1002(a). Before we can authorize a CPCN for the Proposed Project or an alternative, § 1001 mandates that we find that the "present or future public convenience and necessity require or will require its construction." In reaching that ultimate determination, § 1002(a) mandates that we consider four factors: community values; recreational and park areas; historical and aesthetic values; and influence on the environment. The Commission has concluded that § 1002 imposes a "responsibility *independent of CEQA* to include environmental influences and community values in our consideration of a request for a

However, it is unclear from the discussion in D.44923 whether the Commission used the words "clear and convincing" in a lay sense only, or whether it was adopting a specific legal standard.

[30] Witkin, Calif. Evidence, 4th Edition, Vol. 1, 184.

[31] Witkin, Calif. Evidence, 4th Edition, Vol. 1, 187.

[32] California Administrative Hearing Practice, 2d Edition (2005), 365.

CPCN."[33] The Commission has determined that the fourth factor – consideration of a project's "influence on the environment" – is appropriately addressed through the CEQA process.[34] Given the terrain through which the Proposed Project and transmission line alternatives would pass, the Sunrise EIR/EIS necessarily addresses not only environmental impacts, but also impacts on recreational and park values, and on historic and aesthetic values. We review this comprehensive record, and the record on these issues developed in Phase 2 hearings, in Sections 14, 15, 16 of this decision. The extensive record on community values implications has been developed by the parties and through public input and we review this part of the record in Sections 14-16, and in Section 17.

4.3. Section 399.25

Section 399.25(a) provides, in part, that "an application of an electrical corporation for a certificate authorizing the construction of new transmission facilities shall be deemed to be necessary to the provision of electric service…if the commission finds that the new facility is necessary to facilitate achievement of the renewable power goals established under Article 16."

SDG&E argues that Sunrise should be deemed necessary under § 399.25 since it facilitates achievement of the state's renewable power goals.[35] In support of this argument SDG&E states that:

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[33] *Application of Southern California Edison for CPCN for Kramer-Victor Transmission Line,* (1990) 37 CPUC2d 413, 453.

[34] *Application of Lodi Gas Storage for CPCN for Gas Storage Facilities,* D.00-05-048, 28 ["[T]he appropriate place for the parties to address [the issue of a project's influence on the environment] was in the EIR, so that the parties would not duplicate their efforts in both portions of the proceeding."].

[35] SDG&E Phase 2 Opening Brief, 8.

- There is insufficient renewable potential in the San Diego basin to allow SDG&E to meet the state's RPS goals.
- The Imperial Valley and adjacent regions are unique in the state in that they hold enormous renewable resource potential for wind, solar and geothermal generation – potential that will not be developed absent new high voltage transmission.
- Since the Sunrise application was filed, more than 6,600 MW of diverse renewable generation, including wind and solar, in the Imperial Valley, eastern San Diego county, and adjacent northern Mexico that could be facilitated by Sunrise has applied to the CAISO interconnection queue. In contrast, the Tehachapi transmission upgrades were justified and approved based on 4,300 MW of generator interconnection requests, all of which are limited to wind energy.
- SDG&E has received substantial bids for renewable resources that would be facilitated by the development of Sunrise, yet it has received no bids from the Tehachapi region in its last two renewables RFOs.
- An 1,150 MW dispatch limit currently exists on the SWPL between the Miguel Substation and the Imperial Valley Substation, potentially preventing thousands of MWs of proposed new renewable generation from ever being developed. Thus, without Sunrise, the CAISO has determined that only 500 MW of the more than 7,000 MW of renewable generation that is currently in the CAISO queue could be developed and simultaneously dispatched.
- Given the existing system's constraints and that SDG&E depends on Imperial Valley renewables to meet its RPS goals, without Sunrise SDG&E cannot deliver sufficient renewable energy to meet its RPS goals for 2010.
- Sunrise will increase SDG&E's import capability by 1,000 MW.

Nevada Hydro argues that SDG&E errs in its reading of § 399.25 by putting too much weight on the word "facilitate" and by doing so "essentially assumes away the legislature's use of the word 'necessary'."[36] Nevada Hydro explains that even though Sunrise may "'facilitate' accomplishment of RPS goals, the record clearly shows that it is not necessary to facilitate achieving that objective."[37]

UCAN argues that § 399.25 should not apply and that SDG&E is required to show more than facilitation of RPS goals. UCAN argues that the application now before us is distinguishable from D.07-03-012, in which the Commission granted a PTC for a transmission facility in the Tehachapi region based on § 399.25, because in the case of the Tehachapi project (1) "[the project] was built to a unique area in which the wind resources were proven," (2) "no other entity [had] proposed a line to the region," (3) "industry commitment to develop the…area for RPS purposes was significant," and (4) "utilities [had] received winning bids from, and SCE signed, contracts with developers of wind projects, the output of which cannot be fully delivered without increased transmission capacity."[38]

4.3.1. Discussion

In D.07-03-012 the Commission found that in order to rely on § 399.25 a project proponent must demonstrate: (1) that a project would bring to the grid renewable generation that would otherwise remain unavailable; (2) that the area within the line's reach would play a critical role in meeting the RPS goals; (3) that the cost of the line is appropriately balanced against the certainty of the line's contribution to economically rational RPS compliance.

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[36] Nevada Hydro Phase 2 Reply Brief, 7.

[37] *Id*.

[38] UCAN Phase 1 Reply Brief, 7-8.

In developing the above three part standard the Commission had to reconcile various potential interpretations of the phrase "necessary to facilitate" in § 399.25. First the Commission rejected the argument that "necessary to facilitate" meant "necessary," "inevitable," or "logically unavoidable" since it was "hard to imagine that any project could pass such a test."[39] The Commission also rejected reading "necessary to facilitate" to simply mean "make easier" or "help bring about," as SDG&E argues it should be read, since that would establish such a low threshold that all proposed projects would likely meet it.[40] Instead the Commission found that the standard needed to be interpreted within the broader statutory context of ambitious renewable goals, reasonable rates, and environmental protection.

In D.06-06-034, in the context of backstop cost recovery for network upgrades available under § 399.25, the Commission found that "a winning renewable bid created a prima facie finding that the network upgrade will facilitate achievement of the renewable power goals set forth in Article 16 of SB 1078." The Commission noted that "transmission capacity expansions necessary to access renewable energy resources are often described by a step function, in which the most economic transmission expansion to accommodate build-out of the resource exceeds the capacity required for a given project."[41] The Commission concluded that "building surplus capacity from the outset may offer economies of scale to the extent that it is reasonable to assume that

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[39] D.07-03-045, 14-15.

[40] *Id*.

[41] D.06-06-034, 10.

additional renewable projects will come online at a later date, filling the capacity."[42]

When we applied the three prong test adopted in the D.07-03-045, we found that the Antelope-Vincent Transmission Project was necessary because: (1) it had an undeveloped potential of generating 1,400 GWh per year, with about 4,500 MW of installed capacity; (2) there was significant industry commitment to develop the Tehachapi area for RPS purposes as demonstrated by the 4,000 MW of wind capacity in the ISO queue; (3) that without system improvements the grid could not support to growing amounts of wind from the region; (4) that SCE had signed contracts with wind developers in the region; (5) that the total cost of approximately $173 million was justified "based upon the high degree of certainty we have that the project is critically needed to ensure development of RPS resources in the Tehachapi area."[43]

In D.07-03-012 the Commission granted a CPCN for the $92.5 million Antelope-Pardee Transmission Project based on the same underlying potential renewable capacity in the Tehachapi region.

In June of 2007 SCE filed A.07-06-031 for the remainder segments 4-11 of the Tehachapi Transmission Project which would connect to the Antelope-Vincent and Antelope-Pardee segments. The total price for the Tehachapi Transmission Project is estimated to be $1.8 billion. SCE argues that development and delivery of the full 4,000 MW or more of potential wind capacity in the Tehachapi region is dependent on construction of all 11 segments of transmission described in the Antelope-Vincent decision, the Antelope-Pardee decision, and the pending Tehachapi Transmission Project Application.

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[42] *Id.*

[43] D.07-03-045, 16-18.

We find that the Sunrise project is necessary under § 399.25 as applied in D.07-03-045.

1) Sunrise will bring to the grid renewable generation that would otherwise remain unavailable. Since the Sunrise project was announced there have been over 5,000 MW of new generator interconnect requests in the CAISO queue for renewable resources.[44] Sunrise would facilitate the development of 900 MW of solar thermal and 1,000 MW of geothermal resources, which would result in an additional 9,900 GWh of renewable generation from the Imperial Valley.[45] Perhaps most importantly, it has been demonstrated that Imperial Valley will bring to market a diversity of different renewable technologies including an estimated 2,300 MW or more of baseload geothermal.[46] This value was not considered in the CAISO's cost analysis.

As discussed below, the CAISO has demonstrated that without system improvements there is a substantial likelihood that only a fraction of the renewable MWs now in the CAISO queue will be able to be delivered to market due to system constraints.[47] CAISO concludes that absent Sunrise, 1,900 MW of renewable generation would not come online.

(2) The area within Sunrise's reach would play a critical role in meeting the RPS goals. We find it persuasive that 60% of the energy currently under contract needed by SDG&E to comply with the RPS mandate, or approximately 2000 GWh, is in the Imperial Valley and contingent on Sunrise.[48] The

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[44] *Id.*, 98.

[45] CAISO Exhibit I-2, Table 4.7, 65.

[46] SDG&E Phase 1 Opening Brief, 99.

[47] *Id.*, 100, citing "Sparks, Ex. 1-6 at 34:1-6."

[48] SDG&E Phase 1 Opening Brief, 91.

Commission has already approved four renewable contracts in the Imperial Valley, including ones submitted by utilities other than SDG&E that would be facilitated by Sunrise. This further supports the conclusion that bringing Imperial Valley renewables online will play a critical role in meet the RPS goals.

The Imperial Valley region's potential 9,900 GWh per year even exceeds the significant potential of the Tehachapi region.[49]

(3) The cost of Sunrise is appropriately balanced against the certainty of the line's contribution to economically rational RPS compliance.

As required by RPS statutes and Commission policy, each IOU conducts annual requests for offers for new renewable projects. The IOU's apply a "least cost best fit" evaluation method to determine which project should be granted a power purchase agreement, which is then submitted to the Commission for approval. "Economically rational RPS compliance" therefore necessarily depends upon the "least cost best fit" evaluation process and ongoing Commission oversight.[50] The projects that are awarded contracts, which are those that we expect to rely on for RPS compliance purposes, are not the same as the resources identified as the lowest cost resources in the CAISO's analysis in Figure 1 in Section 10.3 below. Cost is only one factor in "least cost best fit." Project viability, capacity factors, and ancillary services must also be considered.

As stated above, there have been over 5,000 MW of new generator interconnect requests in the CAISO queue for renewable resources. The

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[49] We further note that the draft RETI report ranks the Northern Imperial Valley competitive renewable energy zone, which is dependent on the Sunrise Powerlink, as one of the best potential renewable development areas in the state on the basis of a combination of economic and environmental scores. Renewable Energy Transmission Initiative, Phase 1B, Draft Report, October 2008, ES-7.

[50] See, e.g., § 399.14.

Commission has approved four contracts with projects in the Imperial Valley to date. These facts are sufficient to demonstrate that there is a significant commitment on the part of industry to develop Imperial Valley renewable resources. Based on the record in this proceeding, it is reasonable to conclude that the Imperial Valley has an unparalleled potential for renewable resource mix. The significant potential renewable capacity of the area combined with the diversity of potential renewable technologies accessed by the project, and the demonstrated commercial interest as evidenced by interconnection requests in the CAISO queue and Commission approved contracts with renewable resources persuades the Commission that the cost of the line would be offset by the line's significant and certain contribution to SDG&E's RPS compliance obligations in 2010 and beyond.

Having concluded that the Sunrise transmission project meets the requirements of § 399.25 we need not reach the question of what other economic benefit the line may provide and could grant the CPCN on this basis alone. Since it has been demonstrated that the line offers significant economic and reliability benefits, however, we will proceed to that analysis below.

4.4. Rebuttable Presumption of Economic Need

The Commission's *Economic Methodology Decision*[51] adopted principles and minimum requirements to be followed in modeling the economic benefits generated by a proposed transmission line. The *Economic Methodology Decision* creates a rebuttable presumption in favor of an economic evaluation approved by CAISO's Board of Directors, provided the economic evaluation meets the decision's principles and minimum requirements and CAISO complies with

[51] *Economic Methodology Decision,* D.06-11-018.

specific procedural safeguards. Those safeguards are intended to ensure, among other things, that CAISO provided an opportunity for public comment on its economic evaluation and substantively considered any public comment in the evaluation presented to its Board. The *Economic Methodology Decision* expressly restricts application of the rebuttable presumption to future proceedings unless the economic analysis at issue "complies with the safeguards and requirements of this decision and the assigned commissioner of a pending transmission proceeding issues a ruling that explicitly elects to apply it to that application."[52]

CAISO and SDG&E argue that this rebuttable presumption should apply to CAISO's economic evaluation of the Proposed Project. We disagree. At the time the *Economic Methodology Decision* issued, SDG&E's 2005 Application had been pending for almost one year. Likewise, CAISO's Board already had approved CAISO's economic evaluation of the Proposed Project, which had been presented to the Board as part of CAISO's South Regional Transmission Plan. Furthermore, the assigned Commissioner for Sunrise never issued a ruling that elected to apply the rebuttable presumption to either the 2005 Application or the subsequent 2006 Application. CAISO acknowledges that no party ever moved for a ruling and no such ruling ever issued. However, CAISO characterizes the absence of a ruling as a "lack of technical compliance with the precepts" of the *Economic Methodology Decision*.[53] We do not agree.

The *Economic Methodology Decision* was issued to ensure that parties know early in a pending proceeding what evidentiary burden will bear in challenging a CAISO economic analysis. The Assigned Commissioner's ruling required by the

[52] D.06-11-018, 26.

[53] CAISO Phase 1 Opening Brief, 19.

decision serves an important substantive purpose and is not a procedural technicality.

In addition, in the CPCN review at the Commission CAISO has not relied upon the economic evaluation presented to its Board. Instead, CAISO presented an entirely new economic analysis, which it developed during Phase 1 and 2 hearings, largely in response to comments from the parties. Thus, the CAISO Board-approved economic evaluation has become irrelevant.[54]

To the extent SDG&E and CAISO argue that a rebuttable presumption should be granted CAISO' subsequent economic evaluation (the one developed during our CPCN review), we decline to do so for at least three reasons. First, the *Economic Methodology Decision* adopted the rebuttable presumption to "streamline" the CPCN portion of a proceeding by having an economic evaluation that reflects a significant amount of public review and input presented at the beginning of a proceeding.[55] The economic evaluation CAISO developed during the course of our Sunrise CPCN review, while helpful to the record and informed by public input, does not fulfill this streamlining purpose. Second, though CAISO's economic evaluation is extensive, it does not comply with CAISO's own Transmission Economic Assessment Methodology (TEAM)[56]

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[54] Moreover, the CAISO Board-approved economic evaluation does not comply with the principles and minimum requirements of the *Economic Methodology Decision*, nor does it comply with the express procedural safeguards that decision requires before a rebuttable presumption can apply.

[55] See, e.g., *Economic Methodology Decision*, 3 [a rebuttable presumption is granted provided "the CAISO Board-approved evaluation is submitted to the Commission within sufficient time to be included within the scope of the proceeding."].

[56] TEAM is CAISO's proposed methodology for quantifying the economic benefits of transmission projects. CAISO considers five aspects of this methodology, which it terms key principles, to be necessary to any economic evaluation of a proposed transmission project." One of these five key principles is an uncertainty analysis. The

for economic evaluations, nor does it comply with the principles and minimum requirements set forth in the *Economic Methodology Decision.* Third, granting a rebuttable presumption at this stage would be fundamentally unfair to the other parties, who have already developed their showing with the understanding that the rebuttable presumption does not apply to Sunrise.

5. SDG&E's Electric System

It is important to understand the structure of SDG&E's electric system to understand the potential role Sunrise[57] may play in that system.

SDG&E's service area covers all of San Diego County and some of Southern Orange County. SDG&E serves its customer demand through a combination of in area generation resources and imported capacity delivered from the east and south through the Imperial Valley and San Miguel (Miguel) Substations and delivered from the north through the San Onofre Nuclear Generating Station (SONGS) switchyard. We first discuss SDG&E's transmission and generation resources, including future generation resources that may be added to SDG&E's system. We then discuss the reliability criteria that establish SDG&E's Local Capacity Requirements, and how these criteria determine the generation and transmission resources SDG&E needs to operate its system. We

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Economic Methodology Decision describes CAISO's TEAM methodology in more detail. See *Economic Methodology Decision,* 10-11.

[57] Though as a general rule throughout this decision we use "Sunrise" as defined in the EIR/EIS to refer to the Proposed Project and all of its alternatives, including both transmission and generation alternatives, for purposes of the discussion in Sections 5 through 14, however, we follow the convention followed by parties in the CPCN portion of this proceeding and use "Sunrise" to mean the Proposed Project and all of the Northern and Southern Route Alternatives considered in the EIR/EIS. In other words, in Sections 5-14, we use "Sunrise" to mean all transmission alternatives except the LEAPS Transmission-Only Alternative (which is included in the LEAPS Transmission Plus Generation Alternative).

then describe the future transmission plans of SDG&E's eastern neighbor, the Imperial Irrigation District, including the proposed Green Path project.

5.1. SDG&E's Transmission Resources

SDG&E's service area has three high voltage transmission connections with other service areas: Path 44 to the San Luis Rey and Talega Substations, the Imperial Valley Substation linking to the Southwest Powerlink and other lines, and the Miguel Substation, linking to the Tijuana Substation in Baja, Mexico.

Path 44, running north and south between the SDG&E and Edison service areas, consists of five 230 kV lines, two from SONGS to SDG&E's Talega Substation, and three from SONGS to SDG&E's San Luis Rey Substation. The rating for Path 44, which has not been updated since 2001, is 2,500 MW.[58]

The Imperial Valley Substation connects SDG&E's system to the Imperial Irrigation District, Baja California in Mexico, and points east. SDG&E's Southwest Powerlink transmission line, which is SDG&E's only 500 kV transmission line, connects SDG&E's system to Arizona. It runs from SDG&E's Miguel Substation in the west of its service area to the Imperial Valley Substation at the eastern edge of SDG&E's service area, and then to the Palo-Verde transmission hub in Arizona. Transmission lines also run from the Imperial Valley Substation to:

- The Imperial Irrigation District system via a 230 kV transmission line that runs north from the Imperial Valley Substation to El Centro.
- The La Rosita Substation in Baja, Mexico via a 230 kV line that runs south from the Imperial Valley Substation; and
- Three gas fired generators totaling 1,070 MW of capacity in Baja, Mexico. The 600 MW *Termoelectrica de Mexicali* plant is

[58] UCAN Phase 1 Opening Brief, 78.

owned by an affiliate of SDG&E; the 160 MW *Ciclo Combinado Mexicali* plant and the 310 MW *Central La Rosita* plant are owned by affiliates of Intergen.

SDG&E also connects to the *Comision Federal de Electricidad* (Mexican Electricity Commission) system via a 230 kV transmission line from the Miguel Substation to the Tijuana Substation in Baja, Mexico.

5.2. SDG&E's Generation Resources

Existing generation resources in San Diego's service area include:

- The Palomar Energy Facility – 541.5 MW[59] connected at 230 kV;
- The Encina Power Plant – 960 MW connected at 138 and 230 kV;
- The South Bay Power Plant – 702 MW connected at 69 and 138 kV;
- A number of combustion turbines, qualifying facilities and small renewable generators totaling 728 MW and connected at lower voltages;
- A 50 MW (nameplate) wind generation facility connected at 69 kV; and
- A 4.5 MW contract with the San Diego County Water Authority for power from the Rancho Peñasquitos Hydro Facility.

[59] Unless otherwise stated, capacities are Net Qualifying Capacity as set forth in CAISO's Compliance Exhibit. CAISO determines Net Qualifying Capacity to establish how much a generator will count towards meeting peak demand in the Local Reliability Area where it is located. CAISO defines Net Qualifying Capacity as the capacity of a generator under summer peak load conditions. CAISO measures Net Qualifying Capacity at the generator's terminal.

5.3. Future Generation Additions

The existing South Bay Power Plant and part of the Encina Power Plant are likely to retire at some point in the next decade. As a result, several future generation additions are planned for SDG&E's service area.

SDG&E has signed Power Purchase Agreements for the following future resource additions to serve its bundled customer load:

- The 561 MW Otay Mesa Generating Project in the southern portion of SDG&E's service area projected to be online in 2009;
- Contracts with the 94 MW Pala Peaker under development by J Power at SDG&E's Pala Substation and the 44 MW Margarita Peaker under development by Wellhead Power at SDG&E's Margarita Substation, both projected to be online before 2010;
- The 40 MW Lake Hodges Pumped Storage Project projected to be online by 2010;
- The 20 MW Bull Moose Biomass Facility projected to be online by 2010; and
- A 20 MW increase in capacity at the existing Palomar Energy Facility due to the installation of air inlet coolers by 2010.

SDG&E also has contracts with several demand response suppliers, including:

- An 8 MW contract with Envirepel at Ramona; and
- A 20 MW contract with EnerNOC.[60]

SDG&E has also announced Power Purchase Agreements with projects in the Imperial Valley including:

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[60] SDG&E also has a signed contract for an additional 30 MW with EnerNOC that was submitted to the Commission for approval via an Advice Letter. The Commission rejected the Advice Letter because the authority sought requires CPCN review. SDG&E has not yet submitted the CPCN application.

- A three phase contract for 900 MW of solar thermal generation with Stirling Energy Systems;
- Two 20 MW contracts with Esmeralda for geothermal generation; and
- Two 49.5 MW contracts with Bethel solar thermal generation.

There are also three combined cycle generation facilities proposed for construction in SDG&E's service area. They are in varying stages of development, and are described in more detail in Section 6.7 below:

- The South Bay Replacement Project - 620 MW (nameplate capacity);
- The San Diego Community Power Project (also known as the ENPEX project) – 750 MW (nameplate capacity)
- The Encina Power Plant Repowering (also known as the Carlsbad Energy Center) - 540 MW (nameplate capacity)

Additionally, SDG&E issued 2006 and 2007 Requests for Offers for peaking and baseload resources to come online in 2008 and 2010-2012 respectively (2006 and 2007 Peaker RFOs). These solicitations resulted in SDG&E's signed contracts for the Pala and Margarita Peakers, totaling 138 MW (as mentioned above). There is evidence that SDG&E continues to negotiate with some of the bidders in those solicitations and that additional generation resources may be available in SDG&E's service area after 2010. These projects include:

- A 49 MW contract with the Miramar II Peaker, which was submitted to this Commission for approval on June 16, 2008;[61]
- A 15 MW diesel fired peaking plant in Borrego Springs; and
- The repowering of the MMC Generation Facility located in Chula Vista and currently in permitting at the Energy

[61] A.08-06-017. We do not prejudge the outcome of other pending applications in this decision.

> Commission. The repowering would replace an existing 44.5 MW gas fired peaking plant with a nominal 100 MW gas fired peaking plant.

Finally, the Commission has approved the installation of a significant amount of new solar photovoltaic (PV) capacity in SDG&E's service area pursuant to the California Solar Initiative. SDG&E and others have provided a range of the firm capacity associated with this new resource, from 70 MW[62] to 150 MW[63] or more.[64] In addition, SDG&E has an application pending before this Commission to build, own, and operate an additional 35 MW (alternating current) of solar PV in its service area.[65]

5.4. Local Capacity Requirement

SDG&E's Local Capacity Requirement – both now and in the future – is a critical factor in determining whether Sunrise or other generation or transmission resources are needed to meet reliability criteria. Pursuant to reliability criteria established by the North American Electric Reliability Corporation (NERC), SDG&E must have enough local generation resources to reliably serve all load in its Local Reliability Area[66] after the loss of the largest generating unit in its service area followed by the loss of its most critical transmission line (the "G-1/N-1" criteria). The G-1/N-1 criteria determine SDG&E's "Local Capacity Requirement" since the Local Capacity Requirement is the amount of local

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[62] See note 108, below.

[63] SDG&E Exhibit SD-26, Exhibit A, 15.

[64] UCAN Phase 1 Opening Brief, 173.

[65] A.08-07-017.

[66] SDG&E's Local Reliability Area is currently the same geographic region as SDG&E's service area.

generation that SDG&E must have to continue operating reliably after a G-1/N-1 event.

Today, the worst G-1/N-1 event for the San Diego area would be the overlapping outage of the SDG&E-owned Palomar power plant (G-1) plus loss of the Imperial Valley – Miguel 500 kV segment of Southwest Powerlink (N-1).[67] This G-1/N-1 event will change when a generator with a greater capacity than Palomar is installed in the SDG&E Local Reliability Area (for example, Otay Mesa) or if a new transmission line interconnects into the SDG&E Local Reliability Area and the loss of that line results in a greater reduction in import capacity than the loss of the Imperial Valley – Miguel segment of the Southwest Powerlink. Additionally, CAISO constantly reevaluates the Local Capacity Requirement and may modify it due to many factors, including changes in the regional transmission grid, or changes in the amount of generation available in SDG&E's Local Reliability Area.

5.5. Upgrades Planned for Neighboring Transmission Systems

5.5.1. Imperial Irrigation District Transmission Upgrades

Imperial Irrigation District claims to have several transmission projects underway that will either complement a Southern Route Alternative[68] to Sunrise or will provide the ability to deliver renewable (and non-renewable) energy from the Imperial Valley to CAISO customers. In addition to the Green Path project described below, Imperial Irrigation District is developing the following projects:

- The Coachella Valley-Devers 2 project, which will carry up to 1,600 MW via either a double-circuit 230 kV or single-circuit

[67] SDG&E Phase 1 Opening Brief, 83.

[68] We describe the Southern Route Alternatives in Section 16.7.

500 kV line from the Imperial Irrigation District's Coachella Valley Substation to the proposed Devers 2 Substation, thus connecting to the Los Angeles Department of Water and Power and CAISO control areas:[69]

- The new 230 kV Midway-Bannister line which will allow 1,200 MW of renewable energy to flow from Imperial Irrigation District to Edison or SDG&E;[70]
- The new 230 kV Dixieland-Imperial Valley line, which will increase export capability from the Imperial Irrigation District to SDG&E by 400 MW;[71] and
- A re-rating of and upgrades to Path 42, which interconnects the Imperial Irrigation District and Edison systems. Imperial Irrigation District is increasing the rating of Path 42 from 600 MW to 800 MW in order to increase the amount of resources that will flow to the CAISO grid through Edison's system. This change in rating will not require any transmission upgrades.[72] In addition to the re-rating, CAISO assumes that additional upgrades will occur on Path 42 to increase its transfer capability to 1,200 MW.[73]

Imperial Irrigation District also has plans to expand its system to the east to connect to the Arizona Public Service grid and the Southwest Powerlink via a project known as the Highline-Knob-North Gila transmission line.[74]

5.5.2. Green Path

Green Path is a very large transmission project sponsored by the Los Angeles Department of Water and Power, the Imperial Irrigation District, and

[69] Imperial Irrigation District Exhibit ID-3, 8.

[70] Imperial Irrigation District Exhibit ID-3, 4-5.

[71] Imperial Irrigation District Exhibit ID-3, 4-6.

[72] Imperial Irrigation District Phase 2 Opening Brief, 21.

[73] The Compliance Exhibit makes this assumption.

[74] UCAN Phase 2 Opening Brief, 39.

possibly Citizens Energy.[75] Green Path will interconnect the Imperial Irrigation District grid with the CAISO and Los Angeles Department of Water and Power grids, thereby allowing, among other things, transmission of Imperial Valley renewables to load centers in Southern California.[76]

Green Path consists of two major transmission components. The southern component, which we refer to as Green Path South, consists of a transmission path connecting Imperial Irrigation District's existing Coachella Valley Substation to Edison's existing Devers Substation, passing through Imperial Irrigation District's proposed Indian Hills Substation and Edison's proposed Devers 2 Substation.[77] Green Path South would not directly interconnect with the SDG&E system. The northern component of Green Path would continue north and then west from the new Devers 2 Substation, up to Los Angeles Department of Water and Power's service area.[78]

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[75] RT 5571.

[76] RT 2661-2662.

[77] The southern component of Green Path consists of: (1) a new 500 kV Devers 2 Substation; (2) one or two new one-mile 500 kV lines connecting the new Devers 2 Substation to the existing Devers Substation (which would be the point of interconnection between Green Path and the CAISO grid); (3) a new 30-mile 500 or 230 kV transmission line from a new Imperial Irrigation District Indian Hills Substation to the new Devers 2 Substation; and (4) a new 230 kV line from the new Imperial Irrigation District Indian Hills Substation to its existing Coachella Valley Substation.

[78] The northern component of Green Path consists of: (1) a new 500 kV Hesperia Substation; (2) a new, 85-mile, 500 kV transmission line from the Devers 2 Substation to the Hesperia Substation; and (3) a new 5-mile 287 kV tap line from the Hesperia Substation to the existing Victorville – Century line, which would create a Century – Hesperia 287 kV line. The Hesperia – Victorville portion, approximately 17 miles long, would be upgraded to 500 kV.

CAISO assumes that Green Path, in conjunction with the proposed Talega/Escondido – Valley/Serrano transmission line (TE/VS),[79] would allow delivery within the CAISO system of up to 2,000 MW of renewable resources from the Imperial Valley and points east or south.[80]

6. Modeling Assumptions for the Analytical Baseline

As we discuss in Section 4.2, before granting a CPCN for Sunrise, we must find it is needed within the context of § 1001. SDG&E claims that Sunrise is needed to provide the following benefits to its ratepayers:

- Access to low cost out-of-state power;
- Enhanced reliability; and
- Access to low cost renewable resources.

These three benefits mirror the three Basic Project Objectives identified for use in our environmental analysis of Sunrise. The CPCN portion of this proceeding has, to a great extent, been devoted to quantifying these three benefits to determine whether the Proposed Project can meet these goals more economically than other alternatives.

We model SDG&E's three benefits as follows:

- Access to low cost out-of-state power = energy benefits generated by energy cost savings;
- Enhanced reliability = reliability benefits generated by reducing Local Capacity Requirements; and

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[79] TE/VS is described in more detail in note 256, below, and in the text accompanying that note.

[80] CAISO Phase 1 Opening Brief, 30.

- Access to low cost renewable resources = RPS compliance savings generated by developing the most cost-effective renewable resource areas first.[81]

The assumptions underlying the modeling have significant impacts on the projected benefits generated by the models. For example, a typographical error by SDG&E regarding future gas prices produced estimated energy benefits of $468 million per year – nearly five times its previous estimates, and more than twice the next highest estimate SDG&E used in this proceeding.[82]

Consequently, the debates over modeling have focused on the parties' assumptions underlying their modeling – the Analytical Baseline from which their modeling starts. Section 6 explores those Analytical Baseline disputes and adopts the Analytical Baseline assumptions we rely upon to determine the energy benefits, reliability benefits, and RPS compliance savings generated by the various Sunrise alternatives.

Section 7 explains what the Analytical Baseline assumptions tell us about the reliability need or "shortfalls" predicted for SDG&E's service area, when they will be, and how large they will be.[83]

Following the discussion of reliability need in Section 7, we address the parties' efforts to model energy benefits (Section 8), reliability benefits (Section 9), RPS compliance savings generated by the Sunrise alternatives

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[81] There are a number of qualitative benefits that cannot be quantified at all, and we address those benefits in Section 9.3.4, below.

[82] See discussion in Section 8.3, below.

[83] It is important to note that the baseline assumptions are based on reasonably foreseeable future events occurring. However, we remain cognizant that actual resources will be developed pursuant to the applicable statutes and policies, and therefore the model is not dictating a particular outcome. Actual resource development will significantly impact future reliability "shortfalls."

(Section 10), and the net benefits they project for the Sunrise alternatives (Section 11). Net benefits are calculated by adding together energy benefits, reliability benefits, and RPS cost savings and then subtracting the projected cost of the project. In each of these sections, we identify our conclusions on the major areas in dispute.

After considering the net benefits, we examine in Section 11.3 the net benefit results from CAISO's Compliance Exhibit - modeling performed by CAISO at the end of the proceeding using many of our Analytical Baseline assumptions. In Section 11.4 we "update" the Compliance Exhibit (Update) to estimate net benefits for the Proposed Project and its alternatives based on our adopted Analytical Baseline assumptions. Based on this Update, and the net benefits it projects, we summarize our conclusions about the benefits of the transmission and generation alternatives, and consequently the need for Sunrise.

6.1. Summary of Adopted Analytical Baseline Assumptions

We adopt CAISO's modeling approach to quantifying energy and reliability benefits, and RPS compliance savings, but we deviate from CAISO's final Phase 2 modeling assumptions in the following ways:[84]

- We rely on the Energy Commission staff's November 2007 Forecast of 1-in-10 peak demand (Section 6.2), including its embedded assumptions for the California Solar Initiative (Section 6.3), energy efficiency (Section 6.4), and other distributed generation (Section 6.5);
- We adjust the November 2007 Forecast by including the demand response savings we have approved in SDG&E's most recent Long Term Procurement Plan (Section 6.6);

[84] Table B-1 in Appendix B sets forth all of the assumptions modeled in the CAISO Compliance Exhibit.

- We assume that the existing South Bay Power Plant will retire by December 31, 2012 or the end of the year in which Sunrise comes online, whichever is earlier (Section 6.7.1);
- We assume 540 MW from the Carlsbad Energy Center will come online in the summer of 2013, resulting in a net increase of 222 MW (Section 6.7.3);
- We assume only 25% of the new coal fired generation identified in the SSG-WI database[85] will come online and that gas fired combined cycle resources will be used to replace the canceled coal plants (Section 6.8);
- We assume that at least 50% of the out-of-state renewables identified by CAISO for its RPS Cost Savings modeling will be available to California (Section 6.11);
- We adopt CAISO's initial renewable cost estimates (Section 6.13);
- We assume the implementation of UCAN's Miguel Import Limit Upgrade (Section 6.14.2);
- We assume Imperial Irrigation District's Path 42 increased rating and upgrades (reflecting a transfer capability of 1,200 MW) and its Dixieland-Imperial Valley line (Section 6.14.5);
- We assume Rancho Peñasquitos' proposed Coastal Link Alternative (Section 6.14.7); and
- We assume SDG&E's estimated capital costs for all of the Sunrise alternatives, and SDG&E's 58-year amortization period for the Sunrise transmission alternatives (Section 6.17).

These assumptions, in conjunction with CAISO's other modeling assumptions, form our Analytical Baseline for determining the energy benefits, reliability benefits, and RPS compliance saving estimates generated by all of the Sunrise alternatives.

[85] See note 160 below.

6.2. Assumptions Regarding the Proper Peak Demand Forecast

6.2.1. Parties' Positions

Parties have proposed a variety of different approaches to determining the peak demand forecast for use in the Analytical Baseline. Most parties, including SDG&E, UCAN, and DRA, started with some iteration of the Energy Commission's 1-in-10 peak demand forecast from the 2006 Integrated Energy Policy Report (2006 Forecast). During the course of the proceeding, the Energy Commission staff updated its 1-in-10 peak demand forecast several times. Some parties adjusted their peak demand forecasts to more or less track the Energy Commission changes. The 2006 Forecast, and those afterward, include the impact of expected savings from energy efficiency and distributed generation (including the California Solar Initiative), but do not include savings projected from demand response, including savings expected from the installation of advanced metering infrastructure (AMI).

SDG&E originally relied upon the 2006 Forecast.[86] SDG&E amended its Analytical Baseline in Phase 1 to address, in part, the Energy Commission staff's May 2007 update.[87]

CAISO began with the Energy Commission staff's May 2007 forecast,[88] but it did not use the Energy Commission staff projections of peak demand in future years. Instead, it took the 1-in-10 peak demand forecasted by the Energy Commission for 2008 and then escalated it by 1.7% per year to generate the peak demand forecast for future years. CAISO used this escalation rate because it was

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[86] SDG&E Exhibit SD-26.

[87] SDG&E Phase 1 Opening Brief, 64.

[88] CAISO Phase 1 Opening Brief, 21, referring to Energy Commission, "Staff Forecast of 2008 Peak Demand," report Energy Commission-200-2007-006, May 2007.

equal to the historic growth in peak demand from 2006-2008. However, 1.7% is not the long term rate used to generate future peak demand in either the May or November 2007 forecasts.[89] CAISO relied on its own future forecasts, and made no revisions to its escalation rates, for the duration of the proceeding. CAISO claims it evaluated the impact of correcting its escalation rates to be consistent with the November 2007 Forecast, and determined that the impact was not significant.[90] Though CAISO refers to this evaluation in its Phase 2 Opening Brief, CAISO never offered the evaluation in evidence and the evaluation is not part of the record of this proceeding.[91]

UCAN began with the 2006 Forecast, but made a number of adjustments in projected demand-side reductions to reflect what it characterized as more recent updates.[92] At the end of Phase 1, UCAN recommended using the Energy Commission staff's October 2007 forecast, with adjustments to supply discussed below.[93]

In Phase 2, all of the parties except CAISO used the November 2007 Forecast as the basis of their peak demand forecasts in their Analytical Baselines. As stated above, CAISO continued to rely upon its initial demand forecast throughout the proceeding.

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89 See, e.g., California Energy Demand 2008-2018, Staff Revised Forecast, California Energy Commission-200-2007-015-SF2, November 2007, 144 (November 2007 Forecast).

90 RT 5540-5541.

91 CAISO Phase 2 Opening Brief, 10; RT 5418.

92 UCAN Phase 1 Opening Brief, 9.

93 UCAN Motion Requesting the Commission Take Official Notice of Regulatory Filings, November 9, 2007.

6.2.2. Discussion

The Scoping Memo ordered parties to use, to the degree possible, "the most recent Commission-adopted assumptions, goals, policies and levels of effort in its base case forecasts of loads and resources."[94] The *Economic Methodology Decision* sets forth this requirement also.[95] The Commission's December 2007 decision in the Long Term Procurement Plan proceeding (*LTPP Decision*) uses the Energy Commission's November 2007 Forecast.[96] While the *LTPP Decision* relies on a 1-in-2 peak demand forecast for determining procurement authorization, the November 2007 Forecast also includes a 1-in-10 peak demand forecast. For consistency with the *LTPP Decision*, we adopt the November 2007 Forecast of 1-in-10 peak demand.

6.3. California Solar Initiative Adjustments to the Peak Demand Forecast

6.3.1. Parties' Positions

In Phase 1, SDG&E's projected load reduction associated with the California Solar Initiative increased from 2 MW in 2008 to 150 MW in 2015. This assumption is consistent with SDG&E's 2006 Long Term Procurement Plan application.[97] SDG&E characterized its assumptions regarding the penetration rate of solar PV as well as the coincidence factor (i.e., that the solar PV systems will generate at 50% of their installed capacity during peak hours) as "extremely

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[94] *Scoping Memo*, 13.

[95] *Economic Methodology Decision*, Attachment A, 5-6.

[96] *LTPP Decision,* D.07-12-052, 39.

[97] SDG&E Compliance Filing in R.06-02-013, "2007-2016 Long Term Procurement Plan," (December 11, 2006).

aggressive."[98] In Phase 2, SDG&E lowered its projections, consistent with the November 2007 Forecast, to 13 MW in 2010 and 30 MW by 2015.[99]

CAISO assumes California Solar Initiative impacts consistent with SDG&E's Phase 1 and Phase 2 estimates. UCAN claims that SDG&E stopped increasing the impacts of the program after 2015 and that SDG&E could achieve an additional 60 MW of solar PV capacity by 2017.[100]

In Phase 2, Powers Engineering presented an alternative to Sunrise based entirely on solar PV, other forms of distributed generation, and energy efficiency. This alternative is described in the Powers Engineering report, "San Diego Smart Energy 2020 – The 21st Century Alternative" (Smart Energy Report).[101] The Smart Energy Report proposes the "San Diego Solar Initiative" to install 2,040 MW (nameplate, alternating current) of rooftop solar PV, with an emphasis on large commercial installations, coupled with battery storage to allow full use of this capacity during peak demand periods.[102] This proposal anticipates financing through $1.5 billion of ratepayer funded incentive programs.[103] Under the proposal, solar PV and other renewable distributed generation would provide half of the San Diego County energy demand that Powers Engineering projects for 2020.[104]

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98 SDG&E Phase 1 Opening Brief, 47.

99 SDG&E Phase 2 Reply Brief, 240-41.

100 UCAN Phase 1 Opening Brief, 14.

101 RT 3403.

102 Powers Engineering Exhibit Powers-1, Attachment B, 3.

103 Powers Engineering Exhibit Powers-2, 3. Powers Engineering also proposes a scaled-down Solar Initiative of 920 MW of solar PV at a projected cost of $700 million.

104 Powers Engineering Exhibit Powers-2, 3.

SDG&E opposes the Powers Engineering proposal because none of its thousands of megawatts are identified as under construction, sited, or even proposed by developers.[105] SDG&E further questions the accuracy of the Powers Engineering cost-effectiveness claims, cost assumptions, program penetration assumptions, and the technical feasibility of the battery backup systems proposed to meet the utility's peak demands.[106]

6.3.2. Discussion

The November 2007 Forecast includes an adjustment to peak demand to reflect Energy Commission staff estimates of the effects of the California Solar Initiative programs.[107] However, these estimates differ significantly from those initially assumed by SDG&E and other parties in this proceeding. For example, parties generally assumed in Phase 1 that the California Solar Initiative would reduce peak demand by approximately 150 MW by 2015, while the November 2007 Forecast assumes that it will reduce peak demand in 2015 by only 30 MW.[108] For consistency with the *LTPP* Decision, we adopt these determinations of the November 2007 Forecast for purposes of the Analytical Baseline. However, we

[105] SDG&E Phase 2 Opening Brief, 237.

[106] SDG&E Phase 2 Opening Brief, 237-8.

[107] SDG&E Phase 2 Opening Brief, 136.

[108] SDG&E implies that its Phase 2 California Solar Initiative levels are too low and should be at least 70 MW, rather than the 33 MW that the November 2007 Forecast assumes for 2016 and that it uses in this proceeding. SDG&E claims that the Commission has allocated California Solar Initiative funds such that SDG&E will receive enough funding to acquire 180.3 MW (nameplate). See D.06-12-033, Appendix B, Table 11. SDG&E claims that the firm peak delivery from those solar PV units will be 39% of nameplate. See SDG&E Exhibit SD-27, 6, e.g. 180.3 MW * 39% = 70 MW. This is significantly greater than 33 MW. See SDG&E Phase 1 Opening Brief, 47-48.

revisit the import of the California Solar Initiative, and its impacts on the need for Sunrise, in Section 11.3, below.

6.4. Energy Efficiency Adjustments to the Peak Demand Forecast

6.4.1. Parties' Positions

The 2006 and 2007 Energy Commission forecasts include energy efficiency assessments. However, UCAN asserts that the forecasts do not reflect all feasible energy efficiency improvements. Thus, UCAN makes a number of adjustments to the 2006 and 2007 Forecasts, pointing to more recent Energy Commission forecasts projecting higher levels of energy efficiency impacts in SDG&E's territory.[109] UCAN recommends adjusting the November 2007 Forecast to reflect post-2008 energy efficiency impacts of 0 MW in 2009, 26 MW in 2010, and 115 MW in 2016.[110] UCAN also points to approximately 102 MW of additional energy efficiency attributable to new building standards that will materialize over a 10-year period, at about 10 MW a year.[111]

Powers Engineering recommends reducing SDG&E's forecasted energy usage by 20% relative to a 2003 baseline through energy efficiency measures.[112] SDG&E challenges this proposal, claiming that Powers Engineering fails to identify any energy efficiency measures incremental to that already assumed by SDG&E and the Energy Commission.[113] SDG&E claims that the cost-effectiveness of the one specific measure Powers Engineering identified, the installation of

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109 UCAN Phase 1 Opening Brief, 43; see also UCAN Phase 2 Opening Brief, 60-61.

110 UCAN Phase 2 Opening Brief, 60.

111 UCAN Exhibit 10, 23-24.

112 Powers Engineering Exhibit Powers-1, 5.

113 SDG&E Phase 2 Opening Brief, 238.

high-efficiency air conditioners, is highly questionable due to the conflation of incremental and replacement costs.[114]

6.4.2. Discussion

We decline to adopt the energy efficiency assumption changes proposed by UCAN and Powers Engineering. For consistency, we adopt the approach followed in the *LTPP Decision,* which assumes the level of energy efficiency already embedded in the November 2007 Forecast.[115]

6.5. Distributed Generation Adjustments to the Peak Demand Forecast

6.5.1. Parties' Positions

The 2006 and 2007 Energy Commission forecasts take projected distributed generation into account. Nevertheless, UCAN points to SDG&E's "Utility of the Future" proposal and claims that SDG&E asserts that this program might induce 48-159 MW of additional distributed generation.[116] Powers Engineering suggests an additional 700 MW of "clean" distributed generation from combined heat and power sources.[117]

6.5.2. Discussion

The November 2007 Forecast includes adjustments for the effects of the distributed generation and we accept those adjustments here to be consistent with the *LTPP Decision*, which also defers to the November 2007 Forecast.[118]

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114 SDG&E Phase 2 Opening Brief, 238.

115 LTPP Decision, 53.

116 UCAN Phase 1 Opening Brief, 45.

117 Powers Engineering Exhibit Powers-2, 5. This combined heat and power generation is proposed to replace the in-area combined cycle plant in the All-Source Generation Alternative discussed in Section 16.4.

118 *LTPP Decision*, 29.

6.6. Demand Response Adjustments to the Peak Demand Forecast

6.6.1. Parties' Positions

The 2006 and 2007 Energy Commission forecasts do not take into account projected impacts of demand response, including those expected from the installation of AMI.[119] Thus, parties attempted to quantify those impacts in this proceeding. Parties' positions on both of these issues changed multiple times during the proceeding, and the amount of demand response to include in the final Analytical Baseline was under debate through the last days of record development.

SDG&E and CAISO's original Analytical Baselines contained no demand response.[120] However, over time both CAISO and SDG&E agreed to include some demand response to meet Local Capacity Requirements, and to thus make demand response adjustments to the peak demand forecast. SDG&E eventually adjusted its peak demand forecast in its Analytical Baseline to account for 29 MW of demand response; CAISO adjusted its Analytical Baseline to account for 59 MW of demand response, which consisted of 3 contracts: Celerity (20 MW), Converge (9 MW), and EnerNOC (20 MW). DRA and UCAN recommended that the Analytical Baseline include CAISO's projected demand response, plus an additional 30 MW contract with EnerNOC that SDG&E has signed.[121] SDG&E

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119 Demand response is a resource that allows end-use electric customers to reduce their electricity usage in a given time period, or shift that usage to another time period, in response to a price signal, a financial incentive, an environmental condition, or a reliability signal. The Commission has concluded that one of the benefits of AMI will be increased use of demand response.

120 See SDG&E Exhibit SD-5, Vol. 2, Part 1, Chap. 2, page II-29; CAISO Exhibit I-1, Exhibit A, 3.

121 UCAN Phase 2 Opening Brief, 5; see also DRA Phase 1 Opening Brief, 9.

and CAISO point out that this Commission did not approve the contract when SDG&E submitted it as an Advice Letter. UCAN and DRA respond that the Commission did not rule on the merits of the contract, but rather rejected the Advice Letter as an improper vehicle for review of the contract. The Commission invited SDG&E to file an application for CPCN review, but SDG&E has not yet done so.[122]

UCAN continues to assert that SDG&E's Analytical Baseline does not properly account for committed demand response savings. With respect to demand response not related to AMI, in addition to the 30 MW EnerNOC contract starting in 2008, UCAN asserts SDG&E's Analytical Baseline is still missing 4 MW starting in 2010.[123]

It has been difficult to determine how much AMI should be included in the Analytical Baseline. SDG&E initially assumed the same estimates contained in its AMI application approved by this Commission.[124] DRA assumed the same amounts. CAISO claims to have accounted for the impacts of SDG&E's AMI program, although CAISO's reported values were 72 MW less in 2010 than those reported by SDG&E, and approximately 26 MW less in 2011 through 2020.

UCAN adds an incremental 77 and 96 MW in 2010 and 2020, respectively, to SDG&E's AMI estimates, contending that SDG&E included these amounts in its Test Year 2008 General Rate Case.[125] SDG&E argues that UCAN's proposal is

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122 RT 4852-4853.

123 UCAN Phase 1 Opening Brief, 44.

124 SDG&E Phase 1 Opening Brief, 51.

125 UCAN Phase 1 Opening Brief, 44-45.

unreasonable since our final decision in that proceeding adopts a lower number.[126]

Later in Phase 1, SDG&E reduced its AMI estimates to 82 MW in 2010 and 232 MW in 2020, claiming that the Commission settlement in its General Rate Case will result in lower AMI savings than SDG&E projected.[127]

Powers Engineering recommends reducing electric demand by 1,136 MW relative to the 2007 peak demand, in part through demand response programs, including AMI.[128] With respect to demand response, Powers Engineering suggests that 231 MW of peak demand can be met by demand response.[129] It is not clear if this value is incremental to, or duplicative of, SDG&E's 279 MW (in 2020) AMI reductions.

6.6.2. Discussion

The parties differ significantly regarding their projections of future demand response, including impacts associated with AMI. The levels of demand response assumed by SDG&E in this proceeding do not reflect the current state of its demand response programs. For consistency with determinations made pursuant to the Long Term Procurement Plan proceeding, we adopt the demand response savings projected in SDG&E's most recent Long Term Procurement

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126 SDG&E Phase 1 Reply Brief, 12. UCAN Exhibit U-66 is SDG&E's testimony in its 2008 Phase 2 General Rate Case (A.07-01-047). The AMI projections eventually adopted in D.08-02-034 (the Commission's decision on Phase 2 of SDG&E's General Rate Case) were lower than those shown in UCAN Exhibit U-66, which imply lower levels of AMI impacts. See *Motion for Adoption of All Party and All Issue Settlement*, A.07-01-047, November 1, 2007, Attachment 1, 7.

127 SDG&E Phase 1 Opening Brief, 50-51, referring to D.07-04-043.

128 Powers Engineering Exhibit Powers-1, Attachment B, 3.

129 Powers Engineering Exhibit Powers-1, Attachment B, 73.

Plan, which also accounts for AMI and other price-sensitive demand response.[130] Table B-2 in Appendix B presents SDG&E's approved demand response impacts relative to the November 2007 Forecast.

6.7. Assumptions Regarding In-Area Fossil Resources

While parties initially disagreed over which in-area fossil resources to include in the Analytical Baseline, their proposals merged substantially over time. Table 1 sets forth the parties' final positions on which in-area fossil resources should be included in the Analytical Baseline:

130 Approved in Resolution E-4189 (September 4, 2008).

Table 1: Parties' Positions Regarding In-Area Fossil Resources

	Retirement Date	**Projected On Line Date – if applicable**					
Party	**Existing South Bay Power Plant**	**Otay Mesa – 561 MW**	**Pala and Margarita Peakers – 138 MW[131]**	**Other Peakers**	**Carlsbad Energy Center – 540 MW[132]**	**Palomar Air Inlet Coolers**	**Other Resources**
SDG&E[133]	End of 2009	2009	2010	N/A	N/A	N/A	N/A
CAISO[134]	2010	2009	Before 2010	N/A	N/A	2010	N/A
UCAN[135]	N/A	2009	Before 2010	46 MW for 2012 and beyond	By end of 2012	Before 2010	49 MW from MMC – in permitting
DRA[136]	No position	2009	Before 2010	N/A	N/A	N/A	N/A
South Bay[137]	After Feb 2010	N/A	N/A	N/A	N/A	N/A	N/A
Adopted Baseline[138]	No later than end of 2012	Before 2011	Before 2011	N/A	Before Summer 2013	Before 2011	N/A

Parties generally agree on the amount of capacity provided by the existing generating units within SDG&E's service area. CAISO's capacity values differ slightly from those presented by others because it uses its established Net Qualifying Capacity values in its analysis, while others use dependable summer capacity. We adopt CAISO's Net Qualifying Capacity values for existing

131 See note 147, below.

132 This project consists of nameplate capacity of 540 MW, but given the repowering nature of the project, it results in a net increase of 222 MW to SDG&E's service territory.

133 SDG&E Exhibit SD-16, 21; SDG&E noted that the South Bay retirement would likely be contingent on Sunrise coming. SDG&E Exhibit SD-7C, page II 13, note 18.

134 CAISO Exhibit I-6, 31, Table 5.

135 UCAN Phase 1 Reply Brief, 16; UCAN Phase 1 Opening Brief, Table 1; UCAN Phase 1 Opening Brief, Table 1.

136 DRA Phase 2 Opening Brief, 27; DRA Exhibit D-66, Vol. 1, 3, Table ES-1.

137 South Bay Phase 2 Opening Brief, 5.

138 Compliance Exhibit, SDG&E LnR Table (Updated aug26cdr v3 E3.xls).

generation because CAISO is the organization responsible for assessing Local Capacity Requirements. We assume the same level of in-area fossil generation assumed by CAISO, as set forth in our description of SDG&E's system in Section 5.

Remaining disagreements focus on parties' projections of which plants will retire when, and what will replace them. We focus in the next three Sections on the most significant resources in question, and make findings and conclusions to arrive at our Analytical Baseline assumptions. We do not prejudge any pending application that may be addressing any specific resource discussed here.

6.7.1. The Existing South Bay Power Plant

The existing South Bay Power Plant is a 702 MW combined cycle facility located in the City of Chula Vista.[139] Parties disagree over what date to assume this plant will retire. Some units of the existing plant operate under Reliability Must Run (Must Run) contracts with CASIO and those units cannot retire until the CAISO releases them from their Must Run obligations.

The South Bay Replacement Project would replace the existing plant with a 620 MW facility located on a much smaller portion of the same site. Chula Vista officials oppose replacing the existing plant in its current location given interest in developing the existing plant's bay property. LS Power, the replacement project's developer, withdrew its Energy Commission Application for Certification for the repower in the face of this opposition and because it failed to obtain a Power Purchase Agreement from SDG&E for the replacement project. It is unclear if, or when development efforts will resume.

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[139] The South Bay Power Plant consists of five units: four dual-fuel steam units (Units 1-4) and one combustion turbine (Unit 5). The five units of the existing South Bay Power Plant were installed between 1960 and 1971.

6.7.1.1. Parties' Positions

SDG&E and CAISO assume in Phase 1 that the existing South Bay Power Plant will retire before 2010. DRA disagrees, but does not offer an alternative date for its retirement.

South Bay points out that the existing South Bay Power Plant will not retire until three months after the last of three events occur: (1) the last day of the primary term of the lease (November 1, 2009); (2) certain bonds are paid off and retired; and (3) CAISO terminates and does not subsequently reinstate the Must Run status of the plant.[140] The key factor, according to South Bay, is CAISO's termination of the plant's Must Run status. South Bay argues that given the plant's size and strategic location within the San Diego load pocket, additional resources beyond those assumed in SDG&E's Analytical Baseline would be needed before CAISO would terminate the Must Run status of the plant. Thus, South Bay claims that one cannot assume that CAISO will allow the existing South Bay Power Plant to retire before the replacement resources are operational, and thus CAISO and SDG&E assumptions of a retirement before 2010 are unrealistic.

CAISO's position regarding the conditions under which it will release the existing South Bay Power Plant from its Must Run status have varied throughout the proceeding. However, CAISO has always been clear that the existing South Bay Power Plant cannot retire until CAISO releases it from these obligations.[141]

Initially, CAISO appeared to take the position that the existing South Bay Power Plant could retire upon operation of Sunrise. However, a letter from

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[140] South Bay Phase 1 Opening Brief, 19.

[141] RT 1834.

CAISO to Chula Vista[142] describes that at least two of three sets of facilities are required to be online prior to a retirement of the existing South Bay Power Plant: the Otay Mesa Generating Facility, the Pala and Margarita Peakers, or Sunrise.

CAISO addressed additional conditions to the existing South Bay Power Plant's retirement in a CAISO study regarding the need for ocean-cooled power plants (like the existing South Bay Power Plant) to maintain reliability and integrate renewable resources.[143] In that study, CAISO implied that the existing South Bay Power Plant would not be able to retire until 900 MW came online from the Stirling Solar Project, or some similar project in the Imperial Valley.

CAISO also states that it will be "critically important" to maintain existing generating capacity to accommodate renewable resources that will come under the state's RPS program.[144]

6.7.1.2. Discussion

There is no question that the South Bay Power Plant is an old power plant and that it is critical to SDG&E's current reliability needs. We are not convinced, given the ages of the various units and the costs to replace them, that the existing South Bay Power Plant is viable as a long term resource. No party presented any engineering evidence that the existing South Bay Power Plant could continue to operate for an extended period. However, SDG&E and CAISO will rely on the existing South Bay Power Plant in the short term if Sunrise is not online by 2010 and there is insufficient alternative in-area generation to meet reliability needs.[145] SDG&E admits that keeping the existing South Bay Power Plant in operation is

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[142] DRA Exhibit D-102, Attachment I.

[143] CAISO Exhibit I-11.

[144] CAISO Exhibit I-10, 14.

[145] RT 1832-1835.

probably the most reasonable option if Sunrise is delayed.[146] Thus, we conclude that it is highly likely that at least some units of the existing South Bay Power Plant will be kept online until Sunrise is in service or sufficient new in-area generation is built. Consequently, for our Analytical Baseline, we assume that the existing South Bay Power Plant will retire December 31, 2012 or the end of the year in which Sunrise comes online, whichever is earlier. While we believe this is a safe assumption for modeling purposes, we are cognizant that continuing to operate South Bay, with its continued reliance on its once through cooling system, runs counter to several state environmental policy objectives.

6.7.2. Peakers

6.7.2.1. Parties' Positions

CAISO, UCAN, and DRA all believe that the Pala and Margarita Peakers resulting from SDG&E's 2006 solicitation will come online before 2010.[147] UCAN

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[146] RT 1764; see also SDG&E Exhibit SD-26, 56.

[147] On September 20, 2008, CAISO issued an updated Local Capacity Requirements analysis stating that the Lake Hodges, Otay Mesa, and Pala and Margarita Peakers projects are being removed from the 2009 Local Capacity Requirements study "because of information provided by developers indicating that the 'in-service date' for these projects has been delayed beyond summer of 2009, making it [sic] ineligible for inclusion in the 2009 LCR Study." 2009 Local Capacity Technical Analysis – Report and Study Results Update for San Diego Area 1 (September 30, 2008). There is no indication that any of these projects will not be online before the end of 2010 in this report or in the record of this proceeding. This report is not part of the record in this proceeding.

proposes that we include an additional 46 MW of peaking capacity in the Analytical Baseline after 2010. In support, it identifies three potential plants to come online before 2012, including the 49 MW expansion of the MMC Power Plant in Chula Vista, which is in permitting before the Energy Commission,[148] and two other peakers SDG&E is negotiating with as a result of its 2006 and 2007 RFOs – the Miramar II project and a new peaker in Borrego Springs. UCAN also claims that there are numerous other peaker projects being developed in SDG&E's service area. For example, UCAN identifies 330 MW of new combustion turbine capacity seeking to interconnect at SDG&E's Otay Mesa Substation.[149]

6.7.2.2. Discussion

We agree it is reasonable to include the Pala and Margarita Peakers as available before 2011 in the Analytical Baseline, and we understand that the CAISO has made this adjustment to its own Analytical Baseline. Even if these projects are delayed, there is still enough time to construct these plants or their replacements.

We find it more reasonable to consider other potential future peaker capacity as an alternative to Sunrise, rather than as part of the Analytical Baseline, since SDG&E theoretically could avoid the need for additional peakers if Sunrise were constructed. Thus, we do not include UCAN's other additional peaker capacity in the Analytical Baseline.

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[148] The new MMC project is replacing an existing 45 MW peaking plant at the same site. The new facility has a nominal capacity of 100 MW. See link at: http://www.energy.ca.gov/sitingcases/chulavista/index.html.

[149] See UCAN Phase 2 Opening Brief, 58.

6.7.3. Other Fossil Resources

6.7.3.1. Parties' Positions

All parties agree that the 561 MW Otay Mesa Generating Project in the southern portion of SDG&E's service area should be included in the Analytical Baseline. It has a signed Power Purchase Agreement with SDG&E, is under construction, and is expected to be operational before 2011.

UCAN believes that we can expect the development of over 800 MW of new fossil fired plants in SDG&E's service area by 2016, and it identifies the following potential resources, in addition to the peakers discussed above:

- 222 MW of new net capacity in 2011 or 2012 from the Carlsbad Energy Center, currently in permitting at the Energy Commission;
- 565 MW from a new combined cycle plant interconnected in the Escondido area; and
- The planned addition of air inlet coolers at Palomar (20-24 MW).[150]

Cabrillo, the operator of the existing Encina Power Plant and the developer of the Carlsbad Energy Center that would replace part of Encina, notes that the Carlsbad Energy Center has filed an Application for Certification with the Energy Commission[151] and expects it to be acted on by the end of 2008. The existing plant has a nominal rated capacity of 965 MW. The new Carlsbad Energy Center would replace the existing steam boilers at Encina Units 1-3 (318 MW) with a more efficient 540 MW combined-cycle power plant.[152] The repowering would result in a 222 MW net increase in capacity at the Encina site.

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[150] UCAN Phase 2 Opening Brief, 58.

[151] Docket 07-AFC-06.

[152] Cabrillo Phase 1 Opening Brief, 3.

DRA asserts that it is unrealistic to assume that other existing in-area generation, in particular the Encina Power Plant, will remain in operation until 2020.[153] DRA notes that additional generation could be developed pursuant to offers currently pending before SDG&E in its 2007 request for offers (RFO), but it offers no assumptions to include in our Analytical Baseline.[154]

6.7.3.2. Discussion

CAISO includes the 561 MW Otay Mesa Generating Project and 20 MW from the Palomar air-inlet coolers in its updated Analytical Baseline, and we conclude that is appropriate to assume they will both be online before 2011 for our own Analytical Baseline.

Based upon the number of proposals for conventional fossil generation facilities in SDG&E's service area, and the advanced status of at least one of those proposals, we find it reasonable to expect that at least one other combined cycle unit, in addition to the Otay Mesa Generating Project, will come online in the next several years. We agree with UCAN that the Carlsbad Energy Center, in permitting at the Energy Commission, has a high likelihood of coming online by 2012 or 2013. For that reason, we assume a net increase of 222 MW before Summer 2013 as a result of including the Carlsbad Energy Center in the Analytical Baseline.

6.8. Assumptions Regarding Out-of-State Generation – Including Coal Plant Construction

An important assumption in the Analytical Baseline is the availability of out-of-state resources. If neighboring states in the Western Electricity

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153 DRA Phase 1 Opening Brief, 17-19.

154 DRA Phase 1 Opening Brief, 16.

Coordinating Council (WECC)[155] have more low cost resources than they can use, then Sunrise may increase the amount of imported generation from these resources to the CAISO control area, thus potentially lowering energy prices in California. This is one component of the potential "energy" benefits generated by Sunrise.

A significant amount of the new import capability assumed for the future in WECC is coal fired generation. Thus, the Commission's decision on how much we assume actually will be constructed is important, both because of the impact of that assumption on the magnitude of the energy benefits for Sunrise and because of our decision's impacts on how we implement California's GHG policies pursuant to AB 32,[156] SB 1368,[157] and our own loading order.[158]

6.8.1. Parties' Positions

Parties disagree significantly over the availability and type of low cost power to assume in WECC. Specifically, many parties believe that SDG&E and CAISO overestimate the amount of new generation that will be constructed in WECC.[159]

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155 WECC is the interconnected transmission region in which California's investor-owned utilities operate. It is comprised of the western states, Baja California, and parts of Canada. A transmission line added to WECC grid will impact the dispatch of generation resources throughout WECC. Thus, we consider Sunrise's impact on that dispatch here.

156 AB 32 (Stats. 2006, c 598), codified at Health & Saf. Code § 38500 et seq.

157 SB 1368 (Stats. 2006, c 488), codified at §§ 8340-8341.

158 Energy Action Plan 1, May 8, 2003, 4; Energy Action Plan II, September 21, 2005, 2.

159 These parties argue that this overstatement results in an overstatement of the energy benefits the Sunrise transmission alternatives will generate by displacing in state generation with low cost imports.

Both SDG&E and CAISO modeled energy dispatch behavior throughout WECC using SSG-WI data regarding the transmission, loads, and generation forecasted for WECC.[160] SDG&E modified the SSG-WI data in a number of ways. Most significantly, SDG&E replaced 1,300 MW of peakers assumed by SSG-WI to come online in the area of the Palo Verde Substation with combined cycle facilities that would generate more low priced power than the peakers they replaced.[161]

CAISO relied on SDG&E's modifications to the SSG-WI database in preparing its CAISO South Regional Transmission Plan[162] report for CAISO Board approval of Sunrise. However, after performing a "top-to-bottom" review of its CAISO South Regional Transmission Plan input assumptions early in this proceeding, CAISO elected not to retain most of SDG&E's changes to the SSG-WI data, including the replacement of the Palo Verde peakers with combined cycle facilities.[163]

SDG&E's use of the modified SSG-WI database (including the peaker to combined cycle adjustment discussed above) assumes that 6,988 MW of thermal capacity (a mix of coal, oil, gas, and nuclear) will be added in Arizona and New Mexico by 2015, of which 3,697 MW (over 57%) will be coal. Over the same time frame, CAISO projects 6,532 MW of thermal capacity additions in Arizona and

160 SSG-WI was a volunteer effort staffed by WECC participants which, among other things, facilitated transmission planning across the western interconnect. SSG-WI members assembled a database identifying existing and future loads and generation and transmission resources throughout WECC. Ultimately, the SSG-WI database was turned over to WECC and it is now managed and updated by WECC's Transmission Expansion Planning and Policy Committee (TEPPC).

161 CAISO Exhibit I-1, Exhibit A, 7.

162 2006 Application, Volume 2 Part 2, Appendix I-1, 63, Table 6.16.

163 RT 2591.

New Mexico, of which 3,308 MW will be coal. In total, the SDG&E and CAISO Analytical Baselines both project over 12,000 MW of new coal plant construction in WECC by 2015, with approximately 7,500 MW constructed in the Rockies (including Alberta), 700 MW in Nevada, and 500 MW in the Pacific Northwest.[164] This new coal fired generation would exert downward pressure on regional spot prices, which could benefit SDG&E and other California load serving entities.

UCAN asserts that SDG&E assumes a "huge amount" of future overbuilding of coal and natural gas plants in Arizona and elsewhere, which Sunrise would supposedly import to California.[165] UCAN claims that only 400 MW of the 3,697 MW of coal plants included by SDG&E in Arizona and New Mexico (less than 11%) have been justified.[166] UCAN argues that using Sunrise to facilitate the delivery of coal fired resources to California conflicts with Commission policy discouraging reliance upon such fuels.[167]

SDG&E responds that state law only proscribes California load serving entities from entering into new long term contracts to purchase the output of high-GHG emitting sources, such as coal fired generation. SDG&E states that the law does not prevent load serving entities from "lowering their commodity costs by taking advantage of the lower spot market energy prices."[168]

UCAN also asserts that by assuming the construction of the combined cycle plants near Palo Verde Substation, plants which have not even been

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[164] CAISO Exhibit I-7.

[165] UCAN Exhibit U-1, 6.

[166] UCAN Phase 1 Opening Brief, 197-198.

[167] CAISO Exhibit I-4, 120.

[168] SDG&E Exhibit SD-15, 29.

proposed, SDG&E unreasonably increases the projection of the amount of low cost generation in Arizona flowing to California over Sunrise.[169]

DRA believes that SDG&E assumes an "unsupportable WECC capacity expansion plan" for its modeling, including projections of 12,000 MW of new coal plant capacity. DRA questions the accuracy of the SSG-WI database relied upon by SDG&E, and believes SDG&E should have verified the database resource expansion assumptions through: (1) review of existing studies that have used the SSG-WI database; (2) discussion with the analysts who put that database together; and (3) review of the "reasonableness" of the results.[170] SDG&E states that it conducted such reviews and discussions, and checked the reasonableness of its results.[171]

DRA also argues that the SSG-WI database assumes unrealistic future planning margins, claiming that the developers of the SSG-WI database believe that the "[a]ggregate planning margin of 29% suggests we added too much generation… [The] [m]arket would not support/finance excessive generation capacity." [172]

SDG&E responds that it has conducted a detailed review of the resources in the current WECC database (which is based on the SSG-WI data) and has found that, in aggregate, WECC planning reserve margin in year 2015 is closer to 23% than the 29% claimed.[173] SDG&E says that even this calculation of the planning reserve margin is inflated due to the potential transmission constraints,

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169 UCAN Phase 1 Opening Brief, 195.

170 DRA Exhibit D-56, 5.

171 SDG&E Exhibit SD-15, 66.

172 DRA Exhibit D-56, 6; see also CAISO Exhibit I-7, 35.

173 SDG&E Exhibit SD-15, 59.

rainfall variation, and weather conditions that may affect solar and wind resource output. On balance, SDG&E believes that more reasonable calculations produce a 20% planning reserve margin for 2015.[174]

South Bay, like UCAN and DRA, is highly critical of SDG&E and CAISO's assumed resource additions in WECC. South Bay assumes that only 400 MW of the 5,945 MW of new thermal generation expected to be built in Arizona and New Mexico by 2015 will be coal.[175] South Bay observes that assuming generation in excess of what reasonably would be in place serves to depress the prices of imported power, which increases the benefits of Sunrise. South Bay argues that the 2005 SSG-WI database forecasts about 17,000 MW more new generation than should reasonably be assumed to come online between 2006 and 2015.[176] In support, South Bay points to the anomalous results that occur when the SSG-WI database is run, including new plants that do not operate and market heat rates below 6,000 British thermal units (Btu) per kilowatt hour (kWh). South Bay also points to renunciations by the database's authors.[177] Both DRA and UCAN agree with South Bay's assessment that the anomalous results generated by modeling with the SSG-WI database demonstrate that its future generation assumptions are flawed.[178]

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174 SDG&E Exhibit SD-15, 60.

175 SDG&E Exhibit SD-31, 7.

176 South Bay Phase 1 Opening Brief, 20.

177 South Bay Phase 1 Opening Brief, 21-22. South Bay's witness routinely tracks and forecasts planned resource additions throughout the West. His testimony in this case was based on these routine assessments rather than a special study for this proceeding. RT 1262-1263.

178 DRA Exhibit D-56, 6-8; see also, UCAN Exhibit U-1, 6; UCAN Exhibit U-4, 120.

South Bay also argues that SDG&E and CAISO assumptions concerning new coal fired generation in the Southwest are flawed in four respects. First, South Bay states that concerns about global warming make it less likely that new conventional coal generation will be constructed. Second, South Bay asserts that new coal fired generation in the Southwest is unlikely to serve California load. Third, according to South Bay, the large planning reserve margin in the SSG-WI assumptions likely would not support coal investment. Fourth, South Bay suggests that the high coal generation assumptions depend on the completion of upgrades to transmission lines between northern Arizona and northwestern New Mexico that would facilitate the flow of power from the Four Corners region to California.[179]

South Bay believes its assumption that only 400 MW of new coal generation will be constructed in the Southwest over the next eight years is more reasonable. South Bay points out that WECC's 2006 load and resources summary also projects only 400 MW of new coal added to WECC system by 2015.[180]

South Bay also disputes the SDG&E assumption that numerous new combined cycle power plants will be built near the Palo Verde Substation, resulting in excess power that will be sold to California.[181] South Bay first argues that this assumption conflicts with economic reality and recent trends. Specifically, South Bay notes that load is growing rapidly in parts of the Southwest and that the load serving entities there are already securing available

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[179] South Bay Phase 1 Opening Brief, 25-26.

[180] South Bay Phase 1 Opening Brief, 27.

[181] Early in the proceeding CAISO agreed that SDG&E had added too many combined cycles at Palo Verde. We agree with CAISO's final Analytical Baseline assumptions regarding the amount of gas fired power to assume in the Palo Verde area by 2015.

capacity. Second, South Bay states that new power plants are only being built in response to requests for offers from the load serving entities in the Southwest, not as merchant power plants. Third, according to South Bay, the Arizona Corporation Commission's recent rejection of the Devers-Palo Verde 2 project reveals a disinclination, at least among regulators, to approve facilities in the Southwest for the benefit of customers in California. Finally, South Bay claims that investors currently are not showing an interest in developing merchant power plants in the Southwest in the hope of serving the California market.[182]

Nevada Hydro concurs with South Bay and assumes 400 MW of new coal generation in its modeling.[183]

SDG&E responds to the intervenors' claims on several points. First, SDG&E explains that CAISO assumed significant combined cycle additions in the Palo Verde area in its assessment of the Devers-Palo Verde 2 project. Second, SDG&E points to WECC's July 2006 10-year loads and resources plan projecting 5,070 MW of new generation in the Southwest, of which 4,171 MW is combined cycles and 19 MW is combustion turbines. Third, SDG&E identifies several proposed generation projects in Nevada projected to be online by 2010, including 5,756 MW of new coal fired generation.[184]

CAISO does not address the accuracy of these assumptions. Instead, CAISO claims that assuming too much generation in WECC does not affect the magnitude of Sunrise's energy benefits, as excess generation impacts both the "with" and "without" Sunrise cases equally.[185] In summary, CAISO argues that

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182 South Bay Phase 1 Opening Brief, 23-24.

183 SDG&E Exhibit SD-31, 7.

184 SDG&E Exhibit SD-15, 4-5.

185 CAISO Exhibit I-6, 12-13.

if the types of power assumed are the same both in and out-of-state, excess power out-of-state will not impact the price of power in state. It states that "[t]he same SSG-WI resources are used in both the base case and its alternatives. The presence of alleged excess generation would not necessarily bias [CAISO's] analysis towards Sunrise."[186] CAISO argues that "[a]s long as the marginal generation units within and outside California are similar natural-gas-fired units and the locational natural gas price difference is small, the excess generation levels in the SSG-WI database should not have a material effect on CAISO's energy benefit estimate."[187] CAISO asserts that all these criteria have been met, and thus the impact on its incremental analysis of excess capacity in the Southwest is small.

DRA, TURN, and South Bay all dispute CAISO's claim that assuming excess power in WECC will not impact the energy benefit projections for Sunrise. South Bay responds that cheaper out-of-region generation will create phantom congestion coming into the state and Sunrise will be assumed to relieve that congestion, thus generating energy benefits.[188]

UCAN points out that SDG&E's own modeling demonstrates that reducing resources in the southwest results in significant reductions in estimated energy benefits. For example, UCAN claims that reducing capacity in the southwest by 2000 MW results in a 56% reduction in SDG&E's estimated energy benefits related to Sunrise.[189]

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186 CAISO Exhibit I-6, 12-13.

187 CAISO Exhibit I-6, 13.

188 South Bay Phase 1 Opening Brief, 23.

189 UCAN Phase 1 Opening Brief, 198.

6.8.2. Discussion

We agree that SDG&E and CAISO have overstated the amount of fossil fired generation that will be built in WECC in their Analytical Baselines. We also agree that this overstatement results in a lowering of out-of-state power prices, which competes with in state generation, making Sunrise appear more cost-effective than is reasonable to assume. CAISO's modeling confirms this.[190]

We are not convinced by CAISO that this overstatement has only trivial impacts on the cost-effectiveness results. CAISO's argument assumes that new out-of-state generation will be similar to California's generation resources. However, CAISO projects an excess of coal fired generation from out-of-state, and assumes that the in state generation is gas fired. Thus, the modeling should reflect that lower cost, out-of-state, coal fired power will compete with more expensive, in state, gas fired generation, and attribute economic benefits to Sunrise because of its out-of-state import capability. As pointed out by UCAN, SDG&E's modeling confirms that a reduction in out-of-state capacity reduces energy benefits by over 50%, which is far from trivial.

We agree that the SDG&E and CAISO assumption of approximately 12,000 MW of new coal generation construction in WECC makes no sense in today's world. First, we believe the long term carbon-procurement restrictions in SB 1368, among other factors, will discourage the construction of new coal plants in proximity to California. It is not reasonable to assume generation developers will build large, base load coal plants merely to sell into the spot market. Second, the looming potential for carbon regulation and an interest in federal climate legislation make forecasts of extensive new conventional coal generation very unlikely. Third, we are no more interested in promoting new conventional coal

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[190] Compliance Exhibit, 7.

plants through transmission than we are through procurement. Justifying new transmission by its potential to promote new coal plant development is contrary to state policy.

Given the wide range in coal plant projections, the anomalous impacts high projections have on modeling, and our assessment based on current polices that conventional coal plant development will not approach the extreme levels projected by CAISO and SDG&E, we include only 25% of the coal fired generation identified in the SSG-WI database in the Analytical Baseline.

6.8.3. Mexican Imports

Parties generally agree that the existing combined cycle plants located in Baja, Mexico that sell power into the United States, described in Section 5.2 above, will continue to operate in the future. Therefore, we agree with the CAISO Analytical Baseline that includes all of these resources.

6.9. Assumptions Regarding In-Area Renewables

6.9.1. Parties' Positions

Parties disagree about the renewable development potential in SDG&E's service area. SDG&E's Analytical Baseline assumes that 40 MW from the Lake Hodges pumped storage project will come online in 2008 and that 20 MW from the Bullmoose biomass project will come online in 2009. SDG&E assumes that all other in-area renewable generation will remain at current levels.[191] CAISO includes those resources, as well as a 4.5 MW contract with the San Diego County Water Authority, in its Analytical Baseline.[192]

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[191] SDG&E Exhibit SD-26, Appendix I, page I-2.

[192] CAISO Phase 1 Opening Brief, Table V-1, 21.

SDG&E acknowledges the tremendous renewable potential in its service area, but argues that most of it is not economically viable. SDG&E states that up to 10% of its retail load could be met by biomass projects in the San Diego area, but to date only 150 MW has been proposed and only 2.2 MW is viable.[193] SDG&E fails to explain how it defined viability in the context of this biomass analysis.

In Phase 1 of this proceeding, SDG&E pointed to a lack of developer interest in responding to its RPS solicitations to support its claims that in-area renewables are not viable.[194] SDG&E claimed that, while it has received over 190 offers totaling 8,300 MW of capacity from all regions, only 51 of these offers (for 988 MW) were from developers proposing to interconnect anywhere in SDG&E's service area other than to the Southwest Powerlink.[195] Of these bids, SDG&E signed 11 contracts totaling 107 MW.

SDG&E estimates that wind generation in the eastern parts of its service area could reach 500 to 600 MW and offers the greatest potential for new, in basin renewables. However, SDG&E claims that $300 million in new transmission infrastructure is required to deliver this power to SDG&E customers. As a result, SDG&E has deemed in-area wind projects previously bid into SDG&E solicitations to be uneconomic.[196]

6.9.2. Discussion

We do not accept SDG&E's arguments that future in-area renewables are not economically viable. A supply curve developed by CAISO in this

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193 SDG&E Phase 1 Opening Brief, 93.

194 SDG&E Phase 1 Opening Brief, 92-94.

195 SDG&E Phase 1 Opening Brief, 92.

196 SDG&E Phase 1 Opening Brief, 93.

proceeding, and reproduced in Section 10.3, shows that approximately 750 MW of incremental in-area wind generation could be developed with a delivered cost of $77 per megawatt hour (MWh) (levelized 2007$), making it CAISO's lowest cost incremental source of new renewable generation. CAISO's supply curve shows that these wind resources would be significantly less costly than renewable resources delivered from the Imperial Valley.

However, instead of adjusting the Analytical Baseline to reflect a more accurate amount of future renewable development in SDG&E's service area, we consider future in-area renewable generation in both the All-Source Generation and In-Area Renewable Alternatives to Sunrise. We describe those alternatives in Sections 16.4 and 16.5, below.

We adopt the same in-area renewables for our Analytical Baseline that CAISO assumes: the Lake Hodges Pumped Storage Project (40 MW online in 2008), the Bullmoose Biomass Project (20 MW online 2009) and the 4.5 MW contract with the San Diego County Water Authority.

6.10. Assumptions Regarding Imperial Valley Renewables

6.10.1. Parties' Positions

While all of the parties seem to agree that construction of Sunrise (or any other transmission line from the Imperial Valley to the CAISO grid) will result in the development of some incremental amount of Imperial Valley renewables, they disagree about the amount of development such a line will generate, and the time frame for that development. Additionally, notwithstanding these positions on development, only CAISO and DRA assumed increased development as a result of Sunrise. All of the other parties assumed the same level of renewable development with or without Sunrise in their Analytical Baselines.

Table 2 sets forth the Imperial Valley renewable development assumptions made by the parties for 2010 and 2015:

Table 2: Parties' Positions Regarding Incremental Imperial Valley Renewable Resource Additions (MW)

	With Sunrise			Without Sunrise		
Party	**Existing**	**Additions through 2010**	**Additions 2011 - 2015**	**Existing**	**Additions through 2010**	**Additions 2011 - 2015**
SDG&E[197]	783	785 (geo.) 300 (solar) 21 (wind) 1106 (total)	1000 (geo.) 600 (solar) 1600 (total)	783	785 (geo.) 300 (solar) 21 (wind) 1106 (total)	1000 (geo.) 600 (solar) 1600 (total)
CAISO[198]		785 (geo.) 300 (solar) 21 (wind) 1106 (total)	1600 (geo.) 900 (solar) 2500 new (total)		785 (geo.)	
UCAN[199]		At most 178	At most: 1075 (geo.) 810 (solar) 1885 (total)		At most 178	At most: 1075 (geo.) 810 (solar) 1885 (total)
Nevada Hydro[200]			600 new			600 new
DRA[201]						>600 new
South Bay Replacement Project[202]			0-725 new			0-725 new

[197] SDG&E Exhibit SD-26, Joint Exhibit A, 8; SDG&E Exhibit SD-6, Appendix IV, page IV-8, Table IV-14.

[198] CAISO Exhibit I-1,at 28, 30 and Exh. A, 8; CAISO Exhibit I-2, 16.

[199] UCAN Exhibit U-4, 100, 102-103.

[200] Nevada Hydro Exhibit N-11, 6.

[201] South Bay Exhibit S-5, 3.

[202] SDG&E Phase 1 Opening Brief, 98.

SDG&E assumes a significant amount of renewable development in Imperial Valley, in both its "with" and "without" Sunrise cases. To support its projections of over 1,100 MW of new renewable development in Imperial Valley by 2010 and a total of over 2,700 MW by 2015, SDG&E points to over 5,000 MW of new generator interconnection requests[203] that Sunrise would "facilitate," including 3,000 MW of wind that would connect at the Imperial Valley Substation.[204] However, SDG&E fails to quantify the amount of Imperial Valley development it projects as a result of Sunrise (as opposed to development that would happen without Sunrise). SDG&E justifies this omission by explaining that it would be too difficult to separate the renewable benefits of Sunrise from its total projected benefits.[205] Thus, SDG&E assumes the same level of aggressive renewable development in the Imperial Valley both with and without Sunrise. SDG&E's Analytical Baseline assumes no incremental renewable resource additions in the Imperial Valley after 2015.[206]

CAISO assumes that approximately 600 MW of geothermal resources would be developed in the Imperial Valley and delivered over the existing Path 42 between the Imperial Irrigation District and Edison.[207] In addition, CAISO assumes that if Sunrise is developed 900 MW of solar thermal and 1,000 MW of geothermal resources will come by 2015, which would result in an

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[203] SDG&E Phase 1 Opening Brief, 98.

[204] SDG&E Exhibit SD-15, 50.

[205] SDG&E Phase 1 Opening Brief, 160.

[206] SDG&E SD-26, Exhibit A, 8.

[207] CAISO Exhibit I-2, Table 4.3, 49.

additional 9,900 GWh of renewable generation from the Imperial Valley.[208] CAISO assumes that absent Sunrise, this incremental 1,900 MW of renewable generation does not come online in the Imperial Valley.[209]

Observing the slow pace of development in the Imperial Valley, UCAN assumes only 178 MW of new Imperial Valley renewables will come online by 2010 with or without Sunrise.[210] It assumes for analytical purposes a total of 1,885 MW of renewable resources online in the Imperial Valley in 2015, with or without Sunrise.[211]

DRA does not propose assumptions for the renewable portion of the Analytical Baseline. However, it does state that SDG&E does not need Sunrise to meet its RPS obligations, but that Sunrise will facilitate (and likely reduce) the costs of RPS compliance by reducing barriers to delivery of Imperial Valley renewable resources to the CAISO grid, and possibly accelerating incremental investment in Imperial Valley renewable resources.[212]

6.10.2. Discussion

It is reasonable to assume that, without a secure transmission path, no significant amount of new renewable generation will be constructed in the Imperial Valley. Developers will not risk their capital investment without

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208 CAISO Exhibit I-2, Table 4.7, 65. CAISO assumes no wind development in the Imperial Valley. CAISO Exhibit I-2, Table 4.3, 49.

209 See Compliance Exhibit Work Papers. CAISO assumes that SDG&E receives Resource Adequacy credit for the new renewables in the Imperial Valley only if Sunrise comes online. Thus, these resources would create a reliability benefit.

210 UCAN Exhibit U-4, 100-103.

211 UCAN also appears to contemplate the possibility of only 700 MW of renewable development in the Imperial Valley. See, e.g., UCAN Phase 1 Opening Brief, 60-63.

212 DRA Phase 1 Opening Brief, 26.

certainty that their projects' generation will be deliverable to loads. However, the converse is also true: adequate transmission does not guarantee that new renewable generation will be developed and delivered to the CAISO grid. In the Imperial Valley there are at least three potential markets for new renewable generation: the CAISO grid via the existing Southwest Powerlink, Sunrise, or Green Path South; the Imperial Irrigation District or Los Angeles Department of Water and Power via Green Path; and utilities to the east of California via the Southwest Powerlink or other lines currently in operation or in permitting. Depending on the demand for renewable generation, ownership of the generation projects in the Imperial Valley, the ease of contracting, and other factors, new transmission to the CAISO grid from the Imperial Valley does not guarantee that new generation will be built to serve CAISO load.

On balance, we agree with CAISO and SDG&E that the construction of Sunrise would encourage the development of renewable resources in the Imperial Valley. Even with the problems associated with the CAISO interconnection queue,[213] there has been a significant increase in development activity in the Imperial Valley since SDG&E announced the Proposed Project.

CAISO assumes 200 MW of incremental geothermal capacity and 180 MW of solar thermal capacity per year from 2011 through 2015.[214] While the precise level of annual resource additions is uncertain, this is a reasonable assumption to make about the level of incremental renewables from the Imperial Valley by 2015. We adopt the level of Imperial Valley renewable resource development CAISO assumes in its modeling runs for our Analytical Baseline.

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[213] CAISO Exhibit I-10, 7-10.

[214] Compliance Exhibit Work Papers, "Template_case11_use_sunrise_v3.xls," tab "RPS Capacity."

6.11. Assumptions Regarding the Availability of Out-of-State Renewables to California

6.11.1. Parties' Positions

In its modeling of RPS compliance savings, CAISO adjusted its assumptions regarding the availability of out-of-state renewable resources to California several times, ultimately concluding that between 25% and 50% of the renewable resources it identified in WECC (outside of California) would be developed and delivered to California.[215]

Nevada Hydro takes issue with CAISO's assumption, pointing out that CAISO did not make any assumptions regarding the failure of renewable resources planned for development in California.[216]

UCAN also challenges CAISO's assertion that such a small portion of renewable resources from California's neighbors will be available, arguing that many new out-of-state renewable projects will not require new transmission designed exclusively for export to California. UCAN believes that many new out-of-state renewables only will require connections to the existing grid for deliveries to California.[217]

6.11.2. Discussion

We agree with CAISO that some portion of out-of-state resources will not be available to California. However, we find CAISO's suggestion that 75% of these projects will not be available too extreme. We agree with UCAN that many out-of-state renewables will be deliverable to California without new transmission facilities, as demonstrated by SDG&E's Advice Letter filing

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215 CAISO Exhibit I-6, 44-45.

216 Nevada Hydro Phase 1 Opening Brief, 34-35.

217 UCAN Phase 1 Opening Brief, 181-182.

requesting approval of two Montana wind contracts for a total capacity of 210 MW.[218] We adopt CAISO's initial assumption that 50% of CAISO-identified out-of-state renewables will be available to California.

6.12. Assumptions Regarding Development of Renewables in Mexico

6.12.1. Parties' Positions

Parties generally agree on the level of future renewable generation in Mexico that should be included in the Analytical Baseline. While SDG&E contends that several thousand megawatts of new wind generation are being developed to use Sunrise, it does not assume any new generation from Mexico in its modeling.[219]

Similarly, CAISO's modeling does not assume any new renewable generation in Mexico, though it does acknowledge that a transmission line from Mexico to the United States has been proposed, and that Sunrise or some other transmission upgrade will be required to deliver this wind power to California.[220]

UCAN is skeptical of SDG&E claims about the level of wind generation potential in Mexico.[221] It cites the inconsistencies in SDG&E's showing and also points out that having projects in the CAISO interconnection queue does not guarantee that they will be built.[222]

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[218] SDG&E Advice Letter 1997-E, June 4, 2008.

[219] SDG&E Exhibit SD-6, Appendix IV, Table IV-11, page IV-5.

[220] RT 5412.

[221] UCAN Phase 1 Opening Brief, 69-70.

[222] UCAN Phase 1 Opening Brief, 74.

6.12.2. Discussion

We agree with the assumptions used by both CAISO and SDG&E and assume no future renewables from Mexico in the Analytical Baseline. Among other things, the proposed 500 kV line for delivery of power from Mexico is not approved, and the CAISO interconnection queue is not a reasonable indicator of the amount of generation that will be developed in a particular area.

6.13. Assumptions Regarding Renewable Costs

6.13.1. Parties' Positions

CAISO initially relied upon two sets of cost estimates in its RPS compliance savings modeling. For in-state resources, CAISO used cost estimates contained in a study prepared in 2005 by the Center for Resource Solutions for the Commission.[223] For out-of-state resources, CAISO relied principally on the Northwest Transmission Assessment Committee report on Canada-Northwest-California transmission costs from May of 2006 (together, CAISO's CRS Renewable Costs).[224] CAISO later proposed using alternative renewable cost assumptions, assuming lower generation costs for solar thermal ($100/MWh in place of $120/MWh) and higher costs for wind projects ($85/MWh in place of $66/MWh) (CAISO's Alternative Renewable Costs).[225] CAISO justified its increase in wind cost estimates on an Energy Commission staff report,[226] and

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[223] CAISO Phase 1 Opening Brief, 31, citing to "Achieving a 33% Renewable Energy Target," The Center for Resource Solutions, November 1, 2005."

[224] See CAISO Exhibit I-2, 48, which cites to "Canada-Northwest-California Transmission Options Study," Northwest Power Pool, Northwest Transmission Assessment Committee, Canada-NW-California Study Group, May 16, 2006. Neither this study, nor the Center for Resource Solutions study, are part of the record in this proceeding.

[225] CAISO Exhibit I-5, 43-45.

[226] CAISO Exhibit I-6, 44.

based its proposed solar thermal cost estimates on anecdotal information from developers.[227]

UCAN and DRA take issue with CAISO's Alternative Renewable Costs. UCAN suggests that CAISO selectively chose costs from an Energy Commission staff report for wind but ignored the Energy Commission's solar thermal cost estimates. UCAN claims that if CAISO had used both the solar thermal and wind costs from the Energy Commission staff report, it would have found that its alternative renewable cost scenario would have generated Sunrise RPS compliance costs of $828 million per year, rather than generating RPS compliance savings of $160 million per year.[228]

DRA suggests that CAISO has engaged in "cherry-picking" and that it fails to consider other, equally plausible, renewable cost scenarios.[229]

In Phase 2, DRA used CAISO's model to develop its own estimates of RPS compliance savings. DRA made a number of changes to the model's inputs, including changes to various renewable costs. Having made those changes, DRA examines a number of different renewable development scenarios. DRA's estimates of gross annual benefits over the life of Sunrise vary from as little as $1 million to over $100 million per year, depending on the scenario examined and the assumed online date for Sunrise.[230]

CAISO takes issue with DRA's use of CAISO's model, and its revisions to CAISO's cost estimates. CAISO claims that DRA's assumptions regarding higher geothermal generation costs and lower wind generation costs are implausible

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[227] RT 5557-5561.

[228] UCAN Phase 1 Opening Brief, 304.

[229] DRA Phase 1 Opening Brief, 68-69.

[230] DRA Phase 2 Opening Brief, 30-32.

and that even DRA's own witness agreed that DRA's assumptions were unlikely.[231]

6.13.2. Discussion

In its initial analysis, CAISO relied on renewable energy cost assumptions from two primary sources, ensuring that CASIO's analysis was based on consistent assumptions across technologies. It claimed this consistency across its cost assumptions as a strength of its analysis. However, it later recommended other cost assumptions, revising only its solar thermal and wind cost projections. Thus, the internal consistency of relying on cost estimates from only two sources was lost. Unlike its review of combustion turbine costs, CAISO admitted that its re-assessment in support of these new renewable costs was not extensive.[232]

We find CAISO's initial approach of using cost estimates primarily from two consistent sources superior to using costs based on information from a wide variety of potentially inconsistent sources, which can lead to conflicting assumptions. Consequently, we adopt CAISO's CRS Renewable Costs for our Analytical Baseline.

6.14. Assumptions Regarding Transmission Resources

Transmission upgrades, modifications, or additions to SDG&E's and neighboring systems can significantly affect the need for Sunrise. Consequently, parties debated the transfer capability of existing resources that should be assumed in the Analytical Baseline, and the impact and viability of potential upgrades, modifications, and large transmission additions to both the SDG&E and Imperial Irrigation District grids.

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[231] CAISO Phase 2 Reply Brief, 39-40.

[232] RT 5557-5561.

6.14.1. The Dispatch Limit at Imperial Valley Substation

6.14.1.1. Parties' Positions

UCAN contends that SDG&E understates the import capability of the Southwest Powerlink and, as a result, overstates the need for resources within its service area. In short, UCAN asserts that increasing the assumed transfer capability of the Southwest Powerlink would allow more energy to flow into SDG&E's service area, reducing the need for either in-area generation, Sunrise, or both.[233] Consequently, UCAN has made several proposals to increase the transfer capability of various parts of the SDG&E system, as summarized below, and the parties spent significant time and effort debating the merits of those proposals in Phase 1.

In its Phase 2 opening testimony, CAISO announced limitations on the amount of generation that could be dispatched from the Imperial Valley Substation. CAISO states that in late 2007 (after the conclusion of the Phase 1 hearings), it established a 1,150 MW dispatch limit for all generation connected to the Imperial Valley Substation or the Imperial Valley-Miguel portion of the Southwest Powerlink.[234] CAISO states that it imposed this dispatch limit after an interconnection study revealed a "dramatic increase" in risk to the Mexican electrical system when generation above 1,150 MW is added to the Imperial Valley Substation.[235] CAISO stated that "[The Mexican Electricity Commission] is currently unwilling to accept this increased risk to its system and, as a result, a joint decision was made by CAISO, SDG&E, and [The Mexican Electricity

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[233] UCAN Exhibit U-4, 48-50.

[234] CAISO Exhibit I-8, 22.

[235] CAISO Phase 2 Opening Brief, 6.

Commission] to establish the dispatch limit."[236] CAISO claims that reliability criteria prescribe the 1,150 MW dispatch limit because an outage of any single transmission element cannot exceed the maximum amount of generation that can be tripped simultaneously. In SDG&E's case, this simultaneous outage would be equivalent to one unit of SONGS (e.g., 1,150 MW).[237]

Pursuant to this dispatch limit, CAISO will not allow more than 1,150 MW of generation connected directly to the Imperial Valley substation to be dispatched at the same time. Although more generation can be connected at the Imperial Valley substation, not all can operate simultaneously. Therefore, CAISO contends that the Analytical Baseline cannot assume the dispatch of more than 1,150 MW of generation directly interconnected to the Imperial Valley Substation.

UCAN challenges the dispatch limit, arguing that it is "perfectly feasible to have more than 1,150 MW both connected to [Imperial Valley] substation and/or [Southwest Powerlink], and have more than 1,150 MW generating, and have a loss of either a Miguel transformer or the [Southwest Powerlink] line itself, and still not need to trip more than 1,150 MW of generation" and "[i]f SDG&E means to imply that there is an 1,150 MW limit on Southwest Powerlink flows then this is a false statement.[fn] If SDG&E means to imply there's an 1,150 MW limit on deliveries to the Miguel substation or to the Imperial Valley substation, that's also false."[238]

CAISO states that UCAN is wrong because the "Miguel transformer tripping scheme protects the Miguel transformers but does not protect the

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236 CAISO Phase 2 Opening Brief, 6.

237 RT 5319.

238 UCAN Phase 2 Opening Brief, 52, 72.

parallel [Mexican] system" and that UCAN "overlooks the adverse impacts on the [Mexican] system that would be caused by the interconnection of more than 1,150 MW of generation at the [Imperial Valley] substation."[239]

6.14.1.2. Discussion

We are troubled by the timing of the CAISO's disclosure of the dispatch limit. There is evidence that it was in place before Phase 2 and was overlooked by CAISO earlier in the proceeding -- SDG&E testified in Phase 1 that such a dispatch limit was in place.[240] Aside from the unfortunate timing of the disclosure, CAISO has presented credible evidence on this issue. Consequently, we adopt the 1,150 MW dispatch limit CAISO has assumed for purposes of the Analytical Baseline.

6.14.2. Upgrades at Miguel Substation

6.14.2.1. Parties' Positions

UCAN proposes two sets of modifications to SDG&E's Miguel Substation: (1) increase the all-hours import limit into the Miguel Substation from 1,450-1,700 MW to 1,900 MW (Miguel Import Limit Upgrade) and (2) increase the all-hours export limit from the Miguel Substation from 1,900 MW to 2,100 MW (Miguel Output Limit Upgrade).[241] UCAN contends both upgrades would allow greater flows of energy over the Southwest Powerlink.

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[239] CAISO Phase 2 Reply Brief, 28.

[240] RT 520.

[241] UCAN Exhibit U-4, 11-13.

UCAN explains that to implement the Miguel Import Limit Upgrade CAISO only would need to approve a Remedial Action Scheme[242] permitting the tripping of a second transformer at Miguel Substation when two conditions exist: (1) the first transformer at Miguel Substation trips and (2) flows over the Southwest Powerlink exceed 1,450 MW. UCAN claims that instituting this Remedial Action Scheme would increase CAISO's ability to import renewable and low cost energy over the Southwest Powerlink by 200 to 450 MW when all equipment at Miguel Substation is operating (which is most hours of the year). This change would allow the Miguel Substation to accommodate additional imports and move them to other parts of SDG&E's system. UCAN contends that implementation of the Remedial Action Scheme is costless. UCAN filed a motion in Phase 1 asking the Commission to order SDG&E to implement the Miguel Import Limit Upgrade.[243]

Neither SDG&E nor CAISO claims that the Miguel Import Limit Upgrade proposal is infeasible. They concede it has promise and that they planned to study it to ensure that other systems are not affected.[244]

UCAN predicts that implementing the Miguel Output Limit Upgrade would require a number of upgrades and potential implementation of another Remedial Action Scheme and estimates that the incremental cost of this upgrade

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[242] Remedial Action Schemes allow the dropping of load resulting in an outage in certain circumstances to prevent damage to the system and to avoid otherwise costly upgrades.

[243] *Motion by Utility Consumers' Action Network to Compel SDG&E to Upgrade its Import Capability at Miguel Substation*, June 5, 2007.

[244] See, e.g., SDG&E Phase 1 Reply Brief, 59; CAISO Phase 1 Reply Brief, 28.

would be between $4 million and $35 million.[245] SDG&E has not rebutted this evidence.[246]

6.14.2.2. Discussion

We find UCAN's Miguel Import Limit Upgrade proposal to be reasonable. Effectively endorsed by SDG&E, CAISO is currently reviewing it. The proposal requires no physical upgrades, only implementation of a Remedial Action Scheme, and thus could be implemented quickly. We adopt it for the Analytical Baseline, and as a condition of the CPCN granted herein, we direct SDG&E to report within 60 days of the effective date of this decision on the status of its implementation and to serve the report on each Commissioner, the Director of the Commission's Energy Division, and the service list for A.06-08-010.

UCAN admits that the Miguel Export Limit Upgrade has very small benefits, since unconstrained flows out of Miguel Substation rarely are expected to exceed 1,900 MW.[247] This upgrade also adds complexity to the operation of SDG&E's system. We decline to assume this upgrade in our Analytical Baseline.

6.14.3. Path 44 Upgrades

6.14.3.1. Parties' Positions

Path 44 links the Edison and SDG&E high voltage transmission systems. UCAN points out that Path 44's rating has not been updated since 2001 and proposes that SDG&E "take the actions necessary" to upgrade the N-1/G-1 rating of Path 44 from 2,500 MW to 2,850 MW.[248] If feasible, this upgrade would

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245 UCAN Phase 1 Opening Brief, 113-114.

246 UCAN Phase 1 Opening Brief, 113-114.

247 UCAN Exhibit U-4, 10.

248 UCAN Phase 1 Opening Brief, 78, 81. UCAN claims that the proposed upgrade would also result in an increase in the N-0 All Lines in Service rating from 2,850 MW to

permit greater energy flows from Edison to SDG&E, reducing the need for new in-area resources. It also would allow increased flows to SDG&E in unconstrained conditions, thereby reducing SDG&E's locational marginal costs and generating ratepayer benefits. UCAN assumes that this upgrade would:

- Require adding a third 230/69 kV transformer at SDG&E's San Luis Rey Substation;[249]
- "[Q]uite possibly" require upgrading the Barre-Ellis transmission line [located in southern Orange County in Edison's service territory)];
- "[M]ay or may not require" upgrades to the SONGS-San Luis Rey corridor;
- Require modifications to the Mira Loma-Chino #3 line; and
- "[P]robably" require reactive devices such as capacitors to be added to the SDG&E system.[250]

SDG&E disagrees with UCAN about the viability of this proposal. First, SDG&E points out that increasing a path rating is a long, complex process. Second, SDG&E claims that a key element to upgrading Path 44 (i.e., upgrading the Barre-Ellis transmission line in Edison's service area) likely is infeasible because that corridor already is very crowded and the proposed upgrade might require setting new towers between existing towers. Third, SDG&E claims that the upgrades required to increase the rating on Path 44 will not be cost-

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3,200 MW, thereby increasing SDG&E's Simultaneous and Non-Simultaneous Import limits by 350 MW. UCAN Phase 1 Opening Brief, 110.

249 UCAN also suggests that addition of a transformer at SDG&E's San Luis Rey Substation (in addition to adoption of the 1,900 MW Miguel Import Limit and apart from the Path 44 Upgrade proposal) would allow the all-lines-in-service rating of the Southwest Powerlink to increase by about 350 MW (from 2,850 MW to approximately 3,200 MW), which also would allow increased imports over the Southwest Powerlink. UCAN Phase 1 Opening Brief, 109-111.

250 UCAN Phase 1 Opening Brief, 81-82.

effective.[251] Finally, SDG&E notes that CAISO's stakeholder process considered and rejected UCAN's Path 44 proposal as an alternative to Sunrise.[252]

UCAN claims that the CAISO stakeholder process cited by SDG&E not only excluded UCAN from participation, but its results have been discredited in hearings and disavowed by CAISO itself.[253]

CAISO opposes UCAN's Path 44 proposal for several reasons. CAISO states that increasing the path rating would result in transient frequency dips in Mexico which would cause NERC criteria violations, specifically, and thermal overloads, generally. CAISO also claims that UCAN's Path 44 proposal might be uneconomic because a decrease in SDG&E's Local Capacity Requirements would be offset by an increase in Local Capacity Requirements in the Los Angeles area.[254]

UCAN disagrees with CAISO's assessment, contending that UCAN's plan of service under the Path 44 proposal includes reinforcements to correct the criteria violations and thermal overloads.[255]

6.14.3.2. Discussion

We are not convinced at this time that UCAN's Path 44 proposal presents a viable means to increase import capability into the SDG&E load area and do not adopt it for the Analytical Baseline. However, we agree that a review of Path 44's rating is warranted, particularly since the last one occurred in 2001, and

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[251] SDG&E Phase 1 Opening Brief, 107-113.

[252] SDG&E Phase 2 Opening Brief, 220.

[253] UCAN Phase 2 Reply Brief, 29-30.

[254] CAISO Phase 1 Opening Brief, 33-36.

[255] UCAN Phase 1 Reply Brief, 48.

UCAN presents credible evidence that an increase in Path 44's rating may be possible.

As a condition of the CPCN granted herein, we direct SDG&E to take the necessary steps to institute a review of Path 44's rating, and to report within 60 days of the effective date of this decision on the status of the review and to serve the report on each Commissioner, the Director of the Commission's Energy Division, and the service list for A.06-08-010.

6.14.4. The Talega-Escondido/Valley-Serrano Transmission Line

The Talega-Escondido/Valley-Serrano 500 kV transmission line (TE/VS) would connect the SDG&E and Edison transmission systems, thus creating a second extra-high voltage interconnection between SDG&E's system and the rest of the CAISO grid. Nevada Hydro proposes TE/VS as a component of the Lake Elsinore Advanced Pumped Storage (LEAPS) project. Nevada Hydro has applied to this Commission for a CPCN for TE/VS and contends it can be online by 2011.[256]

TE/VS would not connect to the Imperial Valley or any other transmission constrained renewable area, and so it would not directly facilitate advancement of California's RPS goals. However, TE/VS could facilitate the movement of

[256] Nevada Hydro Phase 2 Opening Brief, 46. Nevada Hydro filed A.07-10-005, which seeks a CPCN for TE/VS from this Commission. The Sunrise EIR/EIS identifies TE/VS, under the name LEAPS Transmission-Only Alternative, as a transmission-based alternative to the Proposed Project. LEAPS refers to the pumped storage generation component of the larger project which Nevada Hydro proposes to build, which has both generation and transmission aspects, but is not actually part of the LEAPS Transmission-Only Alternative. The Sunrise EIR/EIS identifies this larger project as another alternative, known as the LEAPS Transmission Plus Generation Alternative. We discuss the environmental impacts of both of these alternatives in Section 15.

energy, including renewables, through the CAISO grid[257] by, for example, increasing the transfer capability between the SDG&E and Edison systems, allowing SDG&E to purchase and deliver additional renewable energy from north of the SDG&E system.[258]

6.14.4.1. Parties' Positions

Parties disagree about the transfer capability of TE/VS, the costs to build TE/VS and integrate it into the SDG&E and Edison systems, and the timing of construction.

With regard to the transfer capability of TE/VS, Nevada Hydro claims that TE/VS can deliver 1,000 MW between the Edison and SDG&E service territories, while SDG&E contends that the transfer capability is only 795 MW.[259]

Nevada Hydro has not provided any evidence regarding costs to construct TE/VS, but claims that TE/VS will cost less than $400 million.[260]

SDG&E contends that the costs to integrate TE/VS into its system (to accommodate approximately 795 MW of transfer capability) would be approximately $1 billion, with a total installed cost of $1.8 billion.[261] Nevada Hydro disputes this estimate, asserting that CAISO analysis shows that TE/VS (in conjunction with Green Path) can provide virtually the same levelized net

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[257] See, e.g., Imperial Irrigation District Phase 2 Opening Brief, 5-6. Imperial Irrigation District explains how, relying on both TE/VS and proposed Imperial Irrigation District transmission upgrades, Imperial Valley renewables could be delivered to the SDG&E service area, if necessary.

[258] Nevada Hydro Phase 2 Opening Brief, 39-40.

[259] SDG&E Phase 1 Opening Brief, 134.

[260] Nevada Hydro Phase 2 Opening Brief, 66.

[261] SDG&E Phase 1 Opening Brief, 135.

benefit for ratepayers as Sunrise,[262] and that the Southwest Transmission Expansion Plan process found that a line similar to TE/VS could provide 750 MW of transfer capability with only "minor upgrades."[263]

Finally, parties disagree about the timing of the construction of TE/VS. Nevada Hydro contends that TE/VS can be online by 2011. SDG&E contends that TE/VS will be online in 2012.[264] Ultimately, CAISO changed its Phase 1 assumption of a 2011 date and now agrees with SDG&E.[265]

Nevada Hydro argues that LEAPS, in conjunction with TE/VS, should not be considered as an alternative to Sunrise. It argues that we consider only TE/VS (without the LEAPS component), in our Analytical Baseline, and if not that, then as an alternative to Sunrise.[266]

6.14.4.2. Discussion

We agree that TE/VS alone is more relevant to evaluation of both our economic and environmental alternatives. Because we wish to avoid prejudging the pending TE/VS CPCN application, we will not assume that TE/VS exists for purposes of the Analytical Baseline. We study it as an alternative in both the EIR/EIS and in the economic modeling for this proceeding.

6.14.5. Imperial Irrigation District Upgrades

6.14.5.1. Parties' Positions

Section 5.5 above summarizes Imperial Irrigation District's plans to upgrade its high voltage transmission system to deliver Imperial Valley

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262 Nevada Hydro Phase 2 Opening Brief, 6.

263 Nevada Hydro Phase 1 Reply Brief, 22.

264 SDG&E Phase 2 Reply Brief, 132-133.

265 CAISO Phase 2 Opening Brief, 9.

266 Nevada Hydro Phase 1 Opening Brief, 8-9.

renewables to the CAISO and Los Angeles Department of Water and Power control areas. The plans include, among other things, re-rating and upgrading Path 42 and constructing three transmission lines: the Coachella Valley-Devers 2 line, the Midway-Bannister line, and the Dixieland-Imperial Valley line.

Parties disagree about which of these upgrades to assume in the Analytical Baseline. SDG&E states that Imperial Irrigation District's transmission upgrades and new facilities are only one part of an overall solution to accessing renewable resources from the Imperial Valley and that, without Sunrise, Imperial Valley renewables will, to a great degree, remain stranded even if all of Imperial Irrigation District's upgrades are assumed to occur.[267]

UCAN notes that Imperial Irrigation District's proposals to upgrade Path 42 and construct the Coachella Valley-Devers 2 transmission line will double the existing transfer capability between it and Edison. UCAN suggests that Imperial Irrigation District's proposed 230 kV Dixieland-Imperial Valley line will also increase Imperial Valley exports to the CAISO grid. UCAN also notes the potential for other new transmission interconnections from the Imperial Irrigation District system to the east (the proposed Highline-Knob-North Gila transmission line) to connect to Arizona Public Service and the Southwest Powerlink.[268]

CAISO states that the planned Path 42 upgrades will increase the transfer capability between Edison and the Imperial Irrigation District Systems to 1,200, and that it included this assumption in its modeling.[269]

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[267] SDG&E Exhibit SD-37, pages 3.1-3.3.

[268] UCAN Phase 2 Opening Brief, 39.

[269] CAISO Exhibit I-2, 12-13.

6.14.5.2. Discussion

We adopt the assumption for our Analytical Baseline that Path 42 will be upgraded this year to 1,200 MW and that the Dixieland-Imperial Valley line, approved by the Imperial Irrigation District Board, will be in service by the middle of 2010.[270]

6.14.6. The Green Path Transmission Line

As described in Section 5.5.2 above, Green Path is a 500 kV transmission project proposed to deliver energy from the Imperial Irrigation District system to the CAISO and Los Angeles Department of Water and Power control areas. CAISO assumes that Green Path will allow delivery to the CAISO grid of up to 2,000 MW from the Imperial Valley and points east or south.[271]

Since Green Path does not interconnect with the SDG&E system, it cannot deliver renewable resources from Imperial Valley directly to SDG&E's service area. However, renewable resources delivered to the CAISO system can be counted for RPS compliance purposes. Thus, Green Path might facilitate RPS goals by providing renewable resources access to the CAISO grid.

6.14.6.1. Parties' Positions

In Phase 1, CAISO assumed that Green Path would come online in 2010. However, in Phase 2, CAISO revised the in-service date to 2011.[272] SDG&E suggests that Green Path cannot be assumed to deliver renewables to the CAISO grid, and is therefore not an alternative to Sunrise, because the Los Angeles

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[270] Imperial Irrigation District Phase 2 Opening Brief, 20.

[271] CAISO Phase 1 Opening Brief, 30.

[272] CAISO Phase 2 Opening Brief, 9.

Department of Water and Power intends to rely on Green Path to meet its own 20% renewable requirement.[273]

UCAN argues that we should include Green Path in our Analytical Baseline because: (1) the Imperial Irrigation District testified to its commitment to Green Path in Phase 1; (2) Green Path has already reached the third (and final) step in WECC review and approval process; and (3) CAISO now assumes Green Path will be built as part of its Local Capacity Requirement and deliverable studies.[274]

6.14.6.2. Discussion

We did not identify Green Path as an alternative to Sunrise in our environmental analysis. Because it is still so speculative, we conclude that Green Path should not be included in the Analytical Baseline. However, because of its potentially significant impact on Sunrise-related benefits, CAISO considers Green Path, in combination with LEAPS and TE/VS, in its modeling as an alternative to Sunrise. Therefore, we review the results of CAISO's modeling in Section 11 to understand the risk that construction of Green Path would diminish the benefits of Sunrise.

6.14.7. Modified Coastal Link

6.14.7.1. Parties' Positions

In Phase 1, Rancho Peñasquitos identified a series of transformer and reconductoring projects intended to eliminate the need for the Proposed Project's 230 kV Coastal Link transmission line segment, which is described in Section 3.2.1, above. Rancho Peñasquitos suggested that its Coastal Link

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273 SDG&E Phase 1 Opening Brief, 97.

274 UCAN Exhibit U-100, 7.

Alternative would minimize local impacts (by eliminating the line through the community entirely) and reduce costs.[275]

SDG&E's Phase 2 changes to the transmission topology used to analyze powerflows required Rancho Peñasquitos to revamp its alternative. As revised, the Rancho Peñasquitos Coastal Link Alternative includes: (1) installation of an additional 230/69 kV, 224 MVA transformer at SDG&E's Sycamore Canyon Substation with associated substation upgrades; (2) reconductoring both 69 kV circuits of the Sycamore Canyon to Pomerado Substation transmission line; (3) reconductoring the 69 kV circuit of the Sycamore Canyon to Scripps transmission line;[276] and (4) the installation of a 230/138 kV, 392 MVA transformer at SDG&E's Encina Substation, unless CAISO approves a Remedial Action Scheme designed to move Encina Power Plant generation to solve overloads on the Sycamore Canyon to Chicarita 138 kV transmission line.[277]

In Phase 1, SDG&E argued that the Rancho Peñasquitos reliability analysis was inadequate to support the conclusion that this alternative could replace the Coastal Link. SDG&E noted that the Coastal Link is more expensive than the Rancho Peñasquitos alternative because of the extensive undergrounding needed to minimize the community impact of the Proposed Project.[278]

In Phase 2 SDG&E estimates that Rancho Peñasquitos' Coastal Link Alternative will cost $83.66 million assuming a 2012 date.[279] SDG&E has

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[275] Rancho Peñasquitos Phase 1 Opening Brief, 7-10.

[276] Between Phases 1 and 2 of this proceeding, SDG&E cancelled a transmission project which would have obviated the need for this reconductoring.

[277] Rancho Peñasquitos Phase 2 Opening Brief, 16-17.

[278] SDG&E Phase 1 Reply Brief, 52.

[279] Rancho Peñasquitos Phase 2 Opening Brief, 17-18.

continued to object to the Rancho Peñasquitos alternative, has argued for the alleged technical superiority of the Coastal Link,[280] and has claimed that Rancho Peñasquitos' alternative requires the installation of a transformer at Encina.[281]

CAISO studied several scenarios proposed by Rancho Peñasquitos in Phase 1 and found that its Coastal Link Alternative could adequately meet reliability needs.[282] CAISO also studied Rancho Peñasquitos' proposed alternatives in Phase 2 and did not take issue with their reliability.

6.14.7.2. Discussion

We adopt Rancho Peñasquitos' Coastal Link Alternative, defined in Rancho Peñasquitos' Phase 2 Reply Brief, as part of the Analytical Baseline. CAISO does not oppose Rancho Peñasquitos' alternative and finds it an acceptable alternative to SDG&E's proposed Coastal Link. SDG&E's arguments are not convincing, particularly since, as Rancho Peñasquitos points out, SDG&E ignores the significantly lower costs and lesser environmental impacts of the Rancho Peñasquitos Coastal Link Alternative compared to SDG&E's proposed Coastal Link.[283]

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[280] SDG&E Phase 2 Reply Brief, 156-157.

[281] SDG&E Phase 2 Reply Brief, 155-156. SDG&E does not clarify if the transformer would be at the Encina Power Plant or the Encina Substation.

[282] CAISO Phase 1 Opening Brief, 42.

[283] The EIR/EIS analyzed Rancho Peñasquitos' Coastal Link Alternative and determined it to be environmentally superior to SDG&E's proposed Coastal Link. Consequently, the Rancho Peñasquitos Alternative replaces the SDG&E's proposed Coastal Link in both the Final Environmentally Superior Northern and Southern Routes.

6.15. Assumptions Regarding Gas Price Forecasts

6.15.1. Parties' Positions

Gas price forecasts are a key input to the SDG&E and CAISO production cost models. SDG&E's modeled price of gas at the California border begins at approximately $7 per million Btu (MMBtu) in 2007 and escalates to over $9/MMBtu in 2020 (nominal dollars).[284] SDG&E does not add intrastate gas transportation charges to derive a burnertip gas price for generators in California.

In its modeling, CAISO assumes gas at the southern California border to be held constant at $6.89/MMBtu in 2015.[285] CAISO adds intrastate gas transportation charges of $0.3935/MMBtu and $0.1651/MMBtu for gas delivered to generators in the Southern California Gas and Pacific Gas and Electric Company service areas, respectively. After UCAN pointed out that CAISO had failed to include gas taxes in Arizona,[286] CAISO added 5.6% to the border gas price for generators in Arizona.[287] Given this change, UCAN generally supports CAISO's gas price forecast, especially when compared to that used by SDG&E.[288]

DRA asserts that SDG&E's forecast is too high for a base case analysis and that it inflates the benefits of Sunrise.[289]

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284 SDG&E Exhibit SD-27, 56.

285 CAISO Exhibit I-2, 17.

286 UCAN Phase 1 Opening Brief, 198-199.

287 CAISO Exhibit I-2, Appendix A, 1.

288 UCAN Phase 1 Opening Brief, 249.

289 DRA Phase 1 Opening Brief, 51-52.

6.15.2. Discussion

Assumptions regarding gas prices have a major impact on the economic benefits of Sunrise. CAISO's gas price forecast addresses the difference in gas prices paid by Arizona and California generators, which impacts the value of Sunrise. SDG&E's gas price forecasts do not. In addition, CAISO's gas price forecasts are conservative, as recommended by DRA. For these reasons, we adopt CAISO's gas price forecasts for our Analytical Baseline.

6.16. Assumptions Regarding Combustion Turbine Costs

6.16.1. Parties' Positions

Reliability benefits include the cost of any new generation that is deferred by a generation or transmission resource proposed to fill a reliability need. These benefits are quantified in this proceeding as the value of deferred combustion turbines. In calculating reliability benefits in Phase 1, CAISO valued deferred combustion turbines at $78/kW-year (2007$, escalated at 2% per year), plus an interconnection cost adder of 35.2% of the cost of the combustion turbine.[290] In Phase 2 CAISO raises this figure substantially, to $162.10/kW-yr (2007$, escalated at 2% per year), based on a December 2007 Energy Commission staff study (December 2007 Study).[291] It retains the 35.2% cost adder for interconnection costs.

UCAN takes issue with CAISO's change in combustion turbine costs between Phase 1 and Phase 2. UCAN argues that CAISO cannot essentially double the cost of new combustion turbines in Phase 2 without increasing the cost of either Local or System Resource Adequacy, which are dependent on

[290] CAISO Phase 1 Opening Brief, 62.

[291] CAISO Exhibit I-12, 6-7.

combustion turbines.[292] CAISO disagrees in part and states that System Resource Adequacy is based on generation costs, not the costs of new combustion turbines.[293]

UCAN also claims that the interconnection costs assumed for new combustion turbines are inconsistent with CAISO's assumptions regarding the costs for Sunrise. UCAN claims that since CAISO assumes new combustion turbine interconnection costs are a fixed percentage of the cost of combustion turbines, these costs effectively double in Phase 2 when CAISO raises the costs of new combustion turbines. According to UCAN, however, CAISO's estimate of the cost of Sunrise does not escalate at nearly the same rate from Phase 1 to Phase 2.[294] CAISO counters that the cost differences are not unreasonable and attributes them to the greater detail underlying the cost estimates for Sunrise. CAISO also argues that even if the new combustion turbine interconnection costs escalate at the same rate as Sunrise costs, Sunrise still will be economically superior to all of the alternatives, assuming 33% RPS and the higher combustion turbine costs CAISO uses.[295]

DRA[296] and SDG&E[297] support CAISO's higher combustion turbine costs.

6.16.2. Discussion

The wide variation between CAISO's Phase 1 and Phase 2 combustion turbine cost estimates is troubling. CAISO and SDG&E claim that we should use

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292 UCAN Comments on Compliance Exhibit, 22-23.

293 CAISO Reply Comments on Compliance Exhibit, 10-11.

294 UCAN Comments on Compliance Exhibit, 21-22.

295 CAISO Reply Comments on Compliance Exhibit, 10.

296 DRA Reply Comments on Compliance Exhibit, 2, note 2.

297 SDG&E Comments on Compliance Exhibit, 3-5.

combustion turbine cost estimates included in an Energy Commission staff study from December 2007 (December 2007 Study). However, from January 2007 through the close of hearings in Phase 1, SDG&E and CAISO used cost estimates for combustion turbines that were less than half those in the December 2007 Study - $78/kW-year verses $162.10/kW-year (both 2007$, escalated at 2% per year).

Moreover, some of the cost estimates from the December 2007 Study are not reasonable. In Phase 2, CAISO uses the December 2007 Study for estimates of the cost of combustion turbines but disavows other cost estimates in the study, such as estimates of the cost of new combined cycle and solar thermal generation.[298] Nevertheless, CAISO testified that it had access to market data and that this information showed that the December 2007 Study's estimates of combustion turbine prices were reasonable.[299] Additionally, DRA and SDG&E support CAISO's Phase 2 combustion turbine prices, and UCAN's arguments do not suggest that the estimates are wrong, only that CAISO has failed to make other adjustments UCAN considers necessary as a result of the higher combustion turbine costs. We find CAISO's Phase 2 combustion turbine costs reasonable, and we adopt them for our Analytical Baseline.

6.17. Assumptions Regarding Project Costs

6.17.1. Parties' Positions

In order to calculate net benefits, we must estimate project costs for each alternative and then subtract those costs from the sum of gross benefits. Project costs include capital costs and operating and maintenance costs, annualized over a specific recovery period. We discuss each of these cost components below.

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[298] See RT 2393-2395; see also RT 5542-5545.

[299] RT 5545.

6.17.1.1. Capital Costs

In Phase 1, SDG&E estimated the capital cost to construct the Proposed Project at $1.265 billion.[300] This estimate includes: the costs of all work on the project, including necessary substation upgrades, transmission line upgrades, and upgrades elsewhere on the SDG&E system; engineering, environmental, construction management, and other support services; and accounting overheads including Allowance for Funds Used During Construction, escalation, and an 18.35% contingency to address unanticipated changes. SDG&E states this cost estimate is based on preliminary design work and claims it has not prepared a detailed cost estimate.

In Phase 2 SDG&E revised its capital cost estimates to reflect a later online date of 2011 and to include environmental mitigation costs. SDG&E estimates capital costs of its Proposed Project to be $1.792 billion, including the costs of mitigation, and after accounting for the RPCC alternative segment.[301] SDG&E claims that no other party has credibly challenged the methodology used to develop these cost estimates.[302]

CAISO also presented capital costs estimates for the Proposed Project and some of its alternatives, based on information from SDG&E and others.

SDG&E and CAISO translate the capital costs for the Proposed Project and various alternatives into levelized annual revenue requirements, as set forth below:

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[300] SDG&E Phase 1 Opening Brief, 74.

[301] SDG&E Exhibit SD-142, Table 11-5.

[302] SDG&E Phase 2 Opening Brief, 45.

Table 3: SDG&E and CAISO Capital Cost Estimates (Annual Levelized $ Million)[303]

Alternative	SDG&E [304]	CAISO [305]
Proposed Project	160	183
TE/VS + LEAPS	-	111
Green Path	-	29
South Bay Repower	-	8
SDG&E Alt. 1: All-Source Generation Alternative	507	-
SDG&E Alt. 2: In-Area Renewable Alternative	544	-
SDG&E Alt. 3: LEAPS Transmission-Only	263	-
SDG&E Alt. 4: Draft EIR/EIS Environmentally Superior Southern Route	150	164
SDG&E Alt. 5: Draft EIR/EIS Environmentally Superior Northern Route	280	306
SDG&E "Enhanced" Northern Route	161	184
SDG&E "Modified" Southern Route	161	-

DRA questions whether SDG&E's estimate fully includes all capital costs and points out that construction costs may change once environmental review is done and the final routing details have been established.[306] DRA also argues that SDG&E should have included the cost of the San Felipe Substation in Imperial Valley in its capital costs, because that substation appears to be necessary to achieve any reduction in Local Capacity Requirements.[307]

UCAN argues that the San Felipe Substation should be included in estimated capital costs, as well as other facilities needed to mitigate the overloads

303 Unless otherwise stated, tables containing annual levelized benefits are for benefits from 2010-2049 for Phase 1 and from 2012-2058 for Phase 2.

304 SDG&E Exhibit SD-142, Table 11-6.

305 CAISO Exhibit I-13, 22. We calculate the capital cost of Green Path by subtracting the capital cost of Sunrise from the Sunrise + Green Path total.

306 DRA Phase 1 Opening Brief, 21.

307 DRA Phase 1 Opening Brief, 71-72.

that UCAN claims Sunrise would cause.[308] UCAN also contends SDG&E "may have failed to include" costs associated with future transmission additions that UCAN asserts will be necessary if Sunrise is constructed.[309] UCAN lists several of these additional projects it asserts may be needed as a result of Sunrise.[310]

6.17.2. Operating and Maintenance Costs

In Phase 1 SDG&E estimated the operating and maintenance costs for Sunrise to be $10 million per year (in 2010 dollars), including associated administrative and general costs.[311] This translated to a $624 million revenue requirement over 40 years. In Phase 2 SDG&E lowered its operating and maintenance revenue requirement to $327 million. According to SDG&E, the revised operating and maintenance forecast is based on a more detailed estimation than its Phase 1 estimates, the annual cost varies from year to year, and the total number of years is extended to 58.[312] UCAN asserts that SDG&E has underestimated its Phase 1 Sunrise operating and maintenance costs by a factor of at least four.[313] UCAN observes that for 2006, SDG&E's transmission operating and maintenance costs totaled over $30 million, or approximately 3.3% of its nearly $1 billion transmission plant valuation. In contrast, SDG&E proposed only 0.7% in operating and maintenance costs for Sunrise, a project which will double its transmission rate base. UCAN proposed that Sunrise's operating and maintenance costs should be estimated at $26.3 million per year,

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[308] UCAN Phase 1 Opening Brief, 292-293.

[309] UCAN Phase 1 Opening Brief, 290.

[310] UCAN Phase 1 Opening Brief, 291-292.

[311] SDG&E Phase 1 Opening Brief, 75.

[312] SDG&E Phase 2 Reply Brief, 245-246.

[313] UCAN Phase 1 Opening Brief, 282.

administrative and general costs should be at least $8.4 million per year, and other fees and charges should be at least $0.6 million per year, for a total of $35.3 million per year.[314]

SDG&E responds that UCAN errs when it divides operating and maintenance in current dollars by the gross book cost of plant, which was recorded many years ago in prior year (deflated) dollars.[315]

CAISO states that it included a level of operating and maintenance costs of approximately $3.9 million per year in the Compliance Exhibit. CAISO criticizes UCAN's higher cost estimates as being flawed. First, CAISO echoes SDG&E's criticism of UCAN's method for deriving an operating and maintenance per dollar of net book estimate for Sunrise. Second, CAISO suggests that the ratio of operating and maintenance costs to capital costs are likely to decline given the increases in costs of transmission construction materials.[316]

Mussey Grade argues that the cost of potential wildfires accidentally started as a result of Sunrise's operation should be estimated and applied to the costs of the project. Mussey Grade estimates these costs to be on the order of $2 million per year.[317] SDG&E responds that Mussey Grade's analysis overstates the risk of fire from Sunrise and that the potential cost of wildfires is already included in SDG&E operating costs through its liability insurance.[318]

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[314] UCAN Phase 1 Opening Brief, 280-286.

[315] SDG&E Phase 1 Reply Brief, 117.

[316] CAISO Reply Comments on Compliance Exhibit, 8-9.

[317] Mussey Grade Phase 1 Opening Brief, 5.

[318] SDG&E Exhibit SD-15, 15.

6.17.3. Cost Recovery Period

In Phase 1, SDG&E and other parties used a 40-year life to amortize Sunrise's capital costs. In Phase 2, SDG&E represents it has reached an agreement with the Federal Energy Regulatory Commission (FERC) regarding amortization of transmission investments and accordingly, that Sunrise should be amortized over 58 years.[319]

UCAN objects to the use of the 58-year amortization period. UCAN contends that because this amortization period was the product of a settlement approved on May 18, 2007 (prior to the date for distributing prepared rebuttal testimony in Phase 1 of this proceeding), SDG&E should have included it in its Phase 1 showing.

6.18. Discussion

We find that SDG&E has offered the best developed capital cost estimates for the Proposed Project and the other transmission alternatives. We adopt these capital cost estimates as Analytical Baseline assumptions.[320] While we are not convinced that SDG&E has the best information available to estimate the capital costs associated with the generation alternatives, no other party has provided cost estimates for them.[321] Therefore, except where we expressly deviate from SDG&E's estimates of the costs of the generation alternatives (as discussed in Section 11), we adopt these SDG&E cost estimates in the Analytical Baseline.

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319 SDG&E Exhibit SD-36, page 11.29.

320 Concerns raised by UCAN and DRA about capital costs associated with the San Felipe Substation are moot because that substation is contingent upon a Northern Route, and we do not approve a Northern Route.

321 Nevada Hydro disputes SDG&E's TE/VS cost estimates. However, Nevada Hydro circulated and then withdrew its own prepared testimony on the cost estimates for the TE/V, so we have no alternative estimate in the record.

We also find that SDG&E's Phase 2 estimates of the project's operating and maintenance costs are reasonable. SDG&E's projections are based on detailed estimates that SDG&E is in the best position to prepare. We agree with SDG&E and CAISO that UCAN make unreasonable assumptions to arrive at their higher operating and maintenance forecast. For the purposes of our Analytical Baseline assumptions we will rely on CAISO's Compliance Exhibit assumption, which is consistent with SDG&E's Phase 2 estimates.

With regard to wildfire costs, we agree that SDG&E's insurance covers potential costs.

We agree with SDG&E regarding the cost recovery period. Even though this parameter changed during the course of this proceeding, the 58-year amortization period is SDG&E's most-current information and is recognized by FERC. Accordingly, we adopt it for our Analytical Baseline assumptions.

7. Estimates of SDG&E's Reliability Need Based on Analytical Baseline Assumptions

7.1.1. Parties' Positions

Using their own, varying Analytical Baseline assumptions (described in the preceding Section), SDG&E, CAISO, and UCAN project when SDG&E will experience a reliability need or "shortfall" in its service area, and how big the shortfall will be. Table 4 sets forth these parties' final estimates of SDG&E's reliability need:

Table 4: Parties' Final Projections of Reliability Need[322]
(MW Surplus / (Deficiency))

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SDG&E[323]	39	78	(104)	(133)	(175)	(229)	(300)	(371)	(440)	-	-
CAISO[324]	12	45	(146)	(187)	(244)	(313)	(403)	(495)	(588)	(683)	(779)
UCAN[325]	2	61	36	14	(8)	(47)	(101)	(157)	(212)	-	-

DRA, Nevada Hydro, and Powers Engineering dispute CAISO and SDG&E estimates of reliability need. DRA concludes SDG&E will not require additional resources until at least 2013, but more likely 2015 or 2016, whether or not Sunrise is built.[326]

Nevada Hydro states that, with the addition of the TE/VS line, SDG&E will require additional resources no sooner than 2020.[327]

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322 Both CAISO and SDG&E originally predicted shortfalls starting in 2010. While neither party revised its Phase 1 load and resource showing, both later acknowledged that Sunrise would not be online in 2010. CAISO assumes that Sunrise will not be online until 2011. CAISO Exhibit I-12, 2. We adjust CAISO's showing in Table 4 to assume that 145 MW will be under a Must Run contract in 2010 and 2011, consistent with the discussion regarding the existing South Bay Power Plan in Section 6.7.1. SDG&E suggested that a reliability need caused by a delay in Sunrise coming online would be addressed by adding new peakers in the San Diego area. See SDG&E Exhibit SD-35. Thus, we assume the addition of these peakers in Table 4, consistent with the discussion in Section 6.7.2.

323 SDG&E Exhibit SD-142, LD2D-#217099-v1-RMR_AlL_Revised_Alternatives_Workpapers. SDG&E's final numbers were adjusted to keep the N-1 import limit at 2,500 MW.

324 CAISO Phase 1 Opening Brief, 21.

325 UCAN Exhibit U-101, "Phase IIrebuttalworkpapers.xls."

326 DRA Phase 1 Opening Brief, 1.

327 Nevada Hydro Phase 1 Opening Brief, 12.

Powers Engineering's proposed combination of increased solar PV, other distributed generation, demand response, and energy efficiency is designed to avoid any need for new resources until 2020.

7.1.2. Discussion

Section 6.1 summarizes our adopted Analytical Baseline assumptions. We adopt the findings in Table 5, which presents the projected "reliability need" for SDG&E's service area applying our adopted Analytical Baseline assumptions.

Table 5: Commission's Adopted Projections of Reliability Need (MW Surplus/(Deficiency)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
MW Surplus / (Deficiency)	773	698	624	55	(22)	(95)	(164)	(237)	(310)	(383)	(456)

Table 5 shows that under our adopted Analytical Baseline assumptions SDG&E's service area has no reliability need for new resources before 2014 and has a surplus of capacity of 773 MW in 2010, 698 MW in 2011, 624 MW in 2012, and 55 MW in 2013. It also shows a reliability need for new resources starting at 22 MW in 2014 and 95 MW in 2015, with a total of 456 MW by 2020.

However, we note that the projection of reliability need shown in Table 5 above, is premised on a number of assumptions. As the parties have demonstrated throughout this proceeding, there are a number of assumptions that could drastically affect the resource mix and availability in San Diego's service territory. For example, the South Bay facility, with a nameplate rating of 702 MW, significantly impacts the reliability need assumptions.[328] In addition,

[328] The baseline assumes that South Bay will operate until the earlier of December 31, 2012 or the end of the year in which Sunrise comes online.

several projects, in various stages of development are assumed to be operational in the baseline assumptions – Carlsbad Energy Center (net 222 MW), Pala & Wellhead (net 138 MW).

Taken as a whole, these facilities represent over 1,000 MW of local generation that is assumed to be operational. South Bay is at the end of its useful life, and only continues to operate because it is designated as a Must Run resource by the CAISO. At this point in time, South Bay is critical to maintaining a reliable electrical system in the San Diego region. According to the CAISO, SDG&E will experience capacity deficiencies if South Bay is taken out of service[329] and there is no viable replacement option available. Simply assuming that South Bay will remain in service until it is no longer needed does not give this Commission much comfort. Relying on a unit that, for all intents and purposes, has far outlived its useful, operable life, to maintain system reliability for the greater San Diego region is a very risky proposition. It would be a far better solution, in terms of reliability, if we actively seek out methods to replace the reliability benefits currently provided by the South Bay unit.[330]

In addition, recent experience suggests that the time required to develop and carry out competitive RFOs, then finance, permit and construct new generation resources – including a cushion to account for unanticipated delays – requires that procurement decisions be made up to seven years in advance of when resources are needed. Otherwise we are forced to perform "just-in-time"

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[329] CAISO Opening Brief on Compliance Exhibit-1, 13.

[330] In addition, supporting or encouraging the retirement or repowering of California's aging power plant fleet supports a number of California's policy objectives (e.g., reduction of once-thru cooling units, Brownfield development per the goals set out in AB 1576, air quality goals, and reduction of GHGs).

procurement that threatens reliability, drives up the cost of delivering power, and typically does not result in additional preferred/renewable resources.[331]

Based on all of the preceding information, we make these baseline assumptions for purposes of project comparison but we are certainly aware of the fact that one incorrect assumption could significantly impact the reliability need in SDG&E's service area.[332]

8. Energy Benefits

8.1. What They Are and How They Are Estimated

SDG&E claims that Sunrise will lower consumer costs by increasing the availability of lower cost, out-of-state power. This cost savings is referred to as an "energy benefit." Other types of energy benefits include:

- Transmission grid efficiencies that reduce the total cost to deliver energy throughout the year, including line loss reductions and congestion cost savings; and
- Increased profits from utility-retained nuclear and hydro generation resulting from reduced market prices, which are passed through to California investor-owned utility ratepayers.[333]

A transmission project like Sunrise will change how the grid operates and how generation resources are dispatched throughout WECC. These changes in grid operations and generation dispatch result in the energy benefits (or costs) described above.

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[331] *LTPP Decision*, 85-86.

[332] A one year delay in commercial operation of the Carlsbad facility could turn a 55 MW reliability "surplus" into a 167 MW deficit.

[333] If profits decline as a result of a proposed project, then this is a project cost, rather than a benefit.

To determine how a proposed high voltage transmission line will impact the grid, planners use sophisticated production cost simulation models to capture the changes in generation dispatch resulting from the proposed line. These models simulate the operation of the utility system by modeling not only the hourly changes in loads across the regions, but also the operation of the fleet of power plants to meet these changing loads in a least-cost fashion given operational constraints, reliability requirements, and power flows on the interconnected grid. Given the resulting dispatch of these fleets of power plants, the models forecast the hourly marginal price of power at various points throughout WECC.[334] The total cost of generated power, assuming that the proposed transmission project is in operation, is then subtracted from the total cost in a reference case that does not assume the line's existence, to arrive at production cost savings resulting from the proposed project.

The assumptions underlying production cost models have a significant impact on modeling results. In this proceeding, both SDG&E and CAISO began their production cost modeling using the databases of generation and transmission resources compiled by SSG-WI. They then modified this data, based on their own assumptions as described in Section 6.8.1 above. Their modeling generated significantly different estimates of energy benefits based on their different assumptions.

8.2. Overview of Conclusions

Four parties submitted production cost modeling cases estimating the energy benefits generated by the Proposed Project and some of its alternatives, while UCAN and DRA derived energy benefits from others' modeling results.

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334 These production cost models can also estimate overall emissions from these power plants, such as GHG emissions, as discussed in Section 13 below.

For the Proposed Project, SDG&E concludes by estimating energy benefits of $105 million per year, which are reduced to $52 million per year when compared to a combustion turbine reference case.[335] CAISO's final estimate of energy benefits is $34 million per year;[336] DRA estimates a range of energy benefits between $20 million and $80 million per year;[337] and UCAN does not separately state energy benefits, but claims that its estimate would be less than SDG&E's.[338]

SDG&E revised its estimated energy benefits many times during the proceeding to address both modeling errors and to test new assumptions. SDG&E's final estimated energy benefits far exceed the projections of the other parties, including CAISO's. Given SDG&E's anomalous showings, and other factors discussed below, we conclude that we cannot rely on SDG&E's estimated energy benefits. We adopt the energy benefits for Sunrise estimated in the Compliance Exhibit of $5 million per year under 20% RPS and $18 million per year under 33% RPS.

8.3. Parties' Modeling Efforts

Parties' estimates of Sunrise's energy benefits have evolved throughout the proceeding in response to SDG&E's changes in assumptions and modeling methodologies and corrections of errors in its analyses.

Table 6 below summarizes the change in SDG&E's projected energy benefits over the course of the proceeding. SDG&E estimated energy benefits of $96 million per year in the 2005 Application, $468 million per year in the 2006 Application, and eventually finished in July 2007 with an estimate of $105 million

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335 SDG&E Exhibit SD-142, 36.

336 CAISO Exhibit I-2, 3-5.

337 DRA Phase 2 Opening Brief, 15.

338 UCAN Phase 2 Opening Brief, 174-176.

per year in energy benefits. When compared to a combustion turbine reference case modeled using its own Analytical Baseline assumptions in Phase 2, SDG&E projects energy benefits of $52 million per year from Sunrise.

Table 6: SDG&E Assessment of Energy Benefits (Annual Levelized $ Millions)

Source	Projected Energy Benefits
2005 Application, page V-13	96
2006 Application, Chap. IV, page IV-8	468
January 2007 Correction to 2006 Application[339]	101
7/25/07 Errata[340]	105
Sunrise compared to combustion turbine reference case[341]	52

CAISO estimated energy benefits of $125 million ($2006) for the year 2015 in its report to its Governing Board. After a top to bottom review of its case at the beginning of Phase 1, CAISO changed its estimate of energy benefits for the

339 Correction to Amended Application of San Diego Gas & Electric Company, filed January 19, 2007, page IV-8.

340 SDG&E Exhibit SD-26, Exhibit J, 6-7.

341 SDG&E Exhibit SD-142, 35. In Phase 2 SDG&E initially submitted calculations of net benefits absent the standard combustion turbine reference case. Instead, SDG&E treated the Proposed Project as the reference case and compared each of the alternatives' net benefits against the net benefits generated by Sunrise. Thus, comparisons with Phase 1 results were difficult. To remedy this shortcoming, the ALJ directed SDG&E to submit testimony with a combustion turbine reference case similar to its Phase 1 assessment, and two additional reference cases. SDG&E presented these results in May 2008, showing substantially lower net benefits than in Phase 1. After the hearings concluded, CAISO claimed in its Phase 2 reply brief that SDG&E's analysis of benefits in response to the ALJ's ruling was fatally flawed. CAISO did not provide an affidavit to substantiate its claims nor propose any remedy. SDG&E did not rely on SDG&E Exhibits SD-142, SD-143, or SD-144 (the results of this analysis) in either its Phase 2 opening or reply briefs.

year 2015 to $140 million ($2015), which is equal to $112 million ($2006).[342] After a workshop among the parties, in March 2007 CAISO revised downward its showing of levelized benefits for Sunrise and projected reduced energy benefits of $34 million per year (2006$).[343]

Instead of pursuing varied assumptions to test these energy benefit revisions, CAISO elected to keep them constant – at $34 million per year – through the rest of the proceeding.[344]

8.4. Discussion

Throughout this proceeding, parties identified numerous errors in SDG&E's energy benefit modeling. While we acknowledge that SDG&E attempted to remedy these defects, we are unable to conclude that SDG&E has identified or corrected all of its modeling errors or the assumptions that drive those models. We also find key SDG&E assumptions unreasonable. For example, SDG&E assumes the same level of renewable resources in the Imperial Valley whether or not Sunrise or other transmission options, such as Green Path, are built. This assumption contradicts SDG&E's testimony regarding the likely level of renewable development in the Imperial Valley without Sunrise.[345] It also is inconsistent with SDG&E's assertion that, without a new transmission line, the

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342 For consistency, CAISO Exhibit I-1 2015 benefits have been brought to 2006 dollars from 2015 dollars by deflating at 2.5%.

343 CAISO Exhibit I-2, 3-5.

344 CAISO did not perform any production cost modeling in Phase 2. Instead, CAISO focused its later modeling efforts on the projected reliability and RPS Compliance benefits of the project. Those efforts are described in the following Sections of this decision.

345 See, for example, SDG&E Exhibit SD-15.

1,150 MW dispatch limit precludes interconnection of new resources at Imperial Valley Substation.[346]

Similarly, CAISO's modeling produced varied results and is based on several significant assumptions we do not adopt. Among other things, CAISO's modeling does not use the November 2007 Forecast of peak demand, and adjustments to that forecast, that we adopt. It also assumes more than 12,000 MW of new coal generation in WECC; we assume only 25% of that coal generation, as discussed in Section 6.11, above. Finally, at the end of Phase 1, CAISO adopted $34 million per year as the estimated energy benefits of Sunrise, and did not run any further production cost models to address potential deficiencies in this showing.

We do not adopt CAISO's energy benefit projections discussed here. Instead, we rely on the energy benefits generated by the CAISO Compliance Exhibit, which scales from CAISO's Phase 1 production cost modeling to apply most of our Analytical Baseline assumptions adopted here. The CAISO Compliance Exhibit, discussed in Section 11.3, estimates energy benefits for both SDG&E's "Enhanced" Northern Route and the Draft EIR/EIS Environmentally Superior Southern Route to be $5 million per year under 20% RPS and $18 million per year under 33% RPS. CAISO estimates no energy benefits for the All-Source Generation Alternative.

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[346] SDG&E's assumption is also inconsistent with CAISO powerflow modeling that found reliability criteria violations with this level of Imperial Valley renewable development absent Sunrise. See, e.g., CAISO Exhibit I-3, which describes criteria violations associated with a UCAN-specified scenario having the same level of renewables in Imperial Valley as assumed by SDG&E.

9. Reliability Benefits

9.1. What They Are and How They Are Estimated

Reliability benefits are savings generated when a generation or transmission resource results in:

- Deferred or avoided new generation (generally quantified as combustion turbine costs); and
- Must Run contract savings – also referred to as "reduced local reliability costs" or "market power mitigation costs."

By improving the transfer capability between the San Diego load area and generation resources outside of the load area, Sunrise will lower the Local Capacity Requirements in the San Diego area, deferring the need for both Must Run contracts and new generation. However, to the extent that Sunrise or other transmission alternatives cause generating capacity in a neighboring Local Reliability Area to become committed to SDG&E, this will simultaneously reduce SDG&E's Local Capacity Requirement and increase the Local Capacity Requirement in neighboring systems. Thus, CAISO assumes in its modeling that Sunrise will increase the Local Capacity Requirement in the Los Angeles Basin,[347] and so it also calculates the "reliability cost" to ratepayers of this System Resource Adequacy generation that Sunrise draws from the Los Angeles basin. CAISO also calculates avoided System Resource Adequacy based on new renewable generation resulting from Sunrise.

The value of avoided Must Run contracts is quantified based on costs. The value of deferred new generation is measured as the discounted difference in the cost of new generation resources (usually combustion turbines) with and without

[347] CAISO assumes Sunrise will draw resources from the Imperial Irrigation District that would have otherwise met Los Angeles basin Local Resource Adequacy needs.

the deferral. For example, the value of a five-year delay in the need for a new combustion turbine is measured as the cost of the combustion turbine built in lieu of Sunrise minus the discounted cost of the combustion turbine built five years later.

A proposed project or its alternatives may have other reliability benefits that are not easily quantified. For example, transmission line alternatives are more susceptible to wildfire-induced outages than generation alternatives. Also, generation alternatives may provide reliability services to CAISO, such as reactive power support and grid regulation, that a transmission alternative cannot provide.

Finally, SDG&E presents a quantitative assessment of the potential customer costs associated with outages on different transmission alternatives.

9.2. Overview of Conclusions

As set forth in Section 7 above, parties predict, based on their own Analytical Baseline assumptions, different reliability needs in SDG&E's service area beginning in different years. SDG&E, CAISO, UCAN, and DRA each modeled reliability benefits. Table 7 presents parties' final estimates of the reliability benefits generated by the Proposed Project:

Table 7: Parties' Final Projected Reliability Benefits
(Annual Levelized $ Millions)

Party	Must Run Contract Savings	Avoided New Generation Costs	System RA Costs	Total Reliability Benefit
SDG&E [348]	$104	$44		$148
CAISO[349]	$35	$231	-$29	$237
DRA[350]				$8 - $117
UCAN[351]				<SDG&E

This table shows CAISO's total projected reliability benefits to be substantially higher than other parties' projections.

We adopt CAISO's modeling methodology for reliability benefits and the results of that modeling, which show reliability benefits of $237 million per year, because CAISO's assumptions are consistent with our adopted Analytical Baseline assumptions.

9.3. Parties' Modeling Efforts

Parties' modeling efforts produce varying results because they predict that SDG&E will have a reliability need at different times, and of different amounts. They also disagree about Sunrise's impacts on SDG&E's Local Capacity Requirement, and how to calculate the value of avoided new generation costs and Must Run contract savings.

In estimating Sunrise's impact on SDG&E's Local Capacity Requirement, CAISO assumes that Sunrise will cause SDG&E's "All Lines in Service"

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348 SDG&E Exhibit SD-142, 28, 32.

349 CAISO Exhibit I-13, Work Papers.

350 DRA Phase 2 Opening Brief, 14.

351 UCAN Phase 1 Opening Brief, 261-63. UCAN does not separately estimate reliability benefits, however its reliability benefits would be less than SDG&E's.

Simultaneous Import Limit to increase from 2,850 MW to 4,200 MW and its Non-Simultaneous (G-1/N-1) Import Limit to increase by 1,000 MW, from 2,500 MW to 3,500 MW.[352] These increased import limits result in a potential reduction in SDG&E's Local Capacity Requirement, and thus a reduction in the amount of new in-area generating capacity and Must Run contracts needed by SDG&E to meet those requirements.

Table 8 shows the progression of CAISO's projected reliability benefits for Sunrise:

Table 8: CAISO Assessment of Annual Levelized Reliability Benefits

Source	Must Run Contract Savings	Avoided New Generation Costs	System Resource Adequacy Cost	Total Reliability Benefits ($ millions)
CAISO Exhibit I-2, Table 3.5 (4/20/07 Second Errata to Testimony, Part II, Phase 1)	42	107	Not calculated	149
CAISO Exhibit I-6, Table 6 (7/12/07 Errata to Rebuttal Testimony, Phase 1)	42	115	-29	129
CAISO Exhibit I-12, Work Papers (Direct Testimony, Phase 2)	36	211	-27	220
CAISO Exhibit I-13 Work Papers (Rebuttal Testimony Work Papers, Phase 2)	35	231	-29	237

CAISO changed its projected reliability benefits for Sunrise several times during Phase 1 of the proceeding in response to parties' comments. For example, CAISO assumed a higher price floor for Resource Adequacy resources and the addition of 660 MW of non-local Resource Adequacy capacity purchases. CAISO also reduced the 2015 Local Capacity Requirements for SDG&E's service area by 242 MW by assuming: (1) increased load growth; (2) increased demand response

[352] CAISO Phase 1 Opening Brief, 21.

(30 MW from the EnerNOC contract); (3) increased AMI savings (which CAISO states will reduce the Local Capacity Requirement by 223 MW); and (4) the addition of 182.5 MW of incremental in-area generation.[353] Finally, CAISO assumed that transmission alternatives would affect Local Capacity Requirements in several ways. First, Sunrise would reduce SDG&E's Local Capacity Requirement by 1,000 MW and, at the same time increase the Local Capacity Requirement in the Los Angeles basin by 1,000 MW. Second, CAISO assumed that new resources developed in the Imperial Valley will reduce the Los Angeles basin Local Capacity Requirement. However, until Imperial Valley renewables develop as a result of Sunrise, Sunrise generates a negative benefit since there are no new resources in the Imperial Valley to counteract the Sunrise-generated increase in the Los Angeles basin Local Capacity Requirement. CAISO calculates the resulting increase of the Los Angeles basin Local Capacity Requirement as a System Resource Adequacy cost to SDG&E of $27/kW-yr ($2006).

Some of these changes tended to increase estimated reliability benefits, and some tended to decrease estimated reliability benefits. In total, CAISO's projected reliability benefits fell by $20 million per year in Phase 1, from $149 million per year to $129 million per year.

In Phase 2, as described in Section 6.16 above, CAISO changed its estimated combustion turbine costs from $78/kW-year to $162.10/kW-yr. This change raised its projected reliability benefits from $129 million per year in Phase 1 to $248 million per year in Phase 2.

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[353] CAISO Exhibit I-6, 16-20, 30-33. CAISO assumed the 182.5 MW of incremental generation would be comprised of: 4.5 MW from the San Diego County Water Authority Project; 20 MW from the Bull Moose Project; 138 MW from the Pala and Margarita Peakers; and 20 MW from the addition of the air inlet coolers at Palomar.

Parties disagree with CAISO's assumptions about Sunrise's impact on SDG&E's Local Capacity Requirements and they disagree with CAISO's calculations of avoided new generation costs and Must Run contract savings. We address each of these issues in turn.

9.3.1. Sunrise's Impact on Local Capacity Requirements

Parties dispute CAISO's conclusions regarding Sunrise's impact on Local Capacity Requirements in San Diego and the Los Angeles basin. Nevada Hydro disputes CAISO's conclusion that TE/VS-generated Local Capacity Requirement reductions in SDG&E's service area will be offset by an identical increase in Local Capacity Requirements in the Los Angeles basin.[354] Nevada Hydro also believes both SDG&E and CAISO have applied more stringent criteria than the applicable standard under CAISO Grid Planning Criteria.[355] SDG&E and CAISO contend that Nevada Hydro misinterprets or does not understand CAISO Grid Standards, in particular how they relate to Path 44.[356]

DRA argues that SDG&E incorrectly assumes that Sunrise will provide 1,000 MW of reduced Local Capacity Requirements and thus over-estimates the reliability benefits of Sunrise, or at least fails to account for the risk that Sunrise will not yield such benefits.[357] DRA also asserts that none of the transmission alternatives will offer significant local reliability benefits to SDG&E customers and that the Commission must continue to monitor SDG&E's local reliability

[354] Nevada Hydro Phase 1 Opening Brief, 32.

[355] Nevada Hydro Phase 2 Opening Brief, 35.

[356] SDG&E Phase 2 Reply Brief, 140-141; CAISO Phase 2 Reply Brief, 14-17.

[357] DRA Phase 2 Reply Brief, 22, 55.

regardless of the action we take on any Sunrise transmission alternative.[358] DRA states that a CAISO report[359] suggests that Sunrise could result in increased Local Capacity Requirements in San Diego. DRA focuses on the report assessment that while Sunrise will reduce the need for new generation in the San Diego local area by 1,000 MW, CAISO's new "South Bay Sub-area" will require contracts with the South Bay Power Plant, a new plant, or upgrades on SDG&E's transmission system, and CAISO's new "Greater Imperial Valley-San Diego" area could require as much as 3,190 MW of local generation.[360]

Both CAISO and SDG&E claim that DRA's analysis is flawed. They contend that resources in the Greater Imperial Valley-San Diego area that do not currently count toward meeting Local Capacity Requirements would be counted once Sunrise comes online and that because little or no incremental costs are associated with these resources, SDG&E will avoid up to 1,000 MW of new capacity. However, CAISO agrees that delays in development of Imperial Valley renewables will result in reduced reliability benefits. According to CAISO, levelized benefits are reduced by $11 million per year if Imperial Valley renewable development occurs slower than expected.[361] SDG&E does not address the impact of delayed renewable development on its reliability benefit projections.

UCAN argues that Sunrise's impact on Local Capacity Requirements is not clear. UCAN states that there are overloads under certain contingencies when Sunrise is analyzed (1) with all lines in service and 4,200 MW of imports or

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358 DRA Exhibit D-101, Volume 1, 38.

359 DRA Exhibit D-45.

360 DRA Exhibit D-101, 8-11, 17-18.

361 CAISO Exhibit I-13, 19.

(2) under G-1/N-1 conditions and 3,500 MW of imports. Because of these overloads, UCAN contends that it is uncertain that Sunrise will increase SDG&E's import capacity under contingency conditions by 1,000 MW (thus lowering Local Capacity Requirements).[362] SDG&E claims that upgrades have been completed to address this issue.[363]

UCAN also argues that Sunrise is extremely oversized relative to the magnitude of need in the SDG&E service area. UCAN states, for example, that Sunrise exceeds, by 994 MW, UCAN's estimated reliability shortfall of 6 MW in 2017.[364]

South Bay agrees with CAISO and SDG&E that Sunrise will increase import capability into San Diego by about 1,000 MW but contends that in-area generation can provide greater reliability benefits at a lower cost.[365] South Bay states that the assumption that additional System Resource Adequacy capacity[366] will be available for import over Sunrise is questionable, given the rapid load

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[362] UCAN Phase 1 Opening Brief, 55, note 214.

[363] SDG&E Phase 1 Reply Brief, 124.

[364] UCAN Phase 1 Opening Brief, 55. UCAN ultimately projects a reliability shortfall of 157 MW in 2017. See Table 4 in Section 7 above.

[365] South Bay Phase 1 Opening Brief, 11.

[366] Under the Commission's System Resource Adequacy requirements, each load serving entity is required to procure the capacity resources, including reserves, needed to serve its aggregate system load. However, the load serving entity is not required to account for local transmission constraints that could prevent the procured capacity from being available to serve load. Thus, load serving entities could be resource-adequate on an aggregate or system basis but transmission-constrained local load pockets could still be resource-deficient. It is this problem that Local Resource Adequacy requirements are intended to resolve. If the transfer capability into a local load pocket area is less than the load demand within the area, then, depending on reliability criteria, additional generation capacity within the load pocket is needed to satisfy the Local Resource Adequacy requirement. See D.06-06-064.

growth in the Southwest that will use that power and the Arizona Corporation Commission's decision to deny the Devers – Palo Verde transmission line. South Bay states that the Arizona Corporation Commission's regulatory decision demonstrates the difficulty in siting out-of-state energy facilities for the benefit of California customers.[367]

South Bay concludes that even with enough System Resource Adequacy capacity, SDG&E will need to procure capacity from local generation resources to meet its Local Capacity Requirements, whether or not Sunrise is built. South Bay points out that local generation, such as the existing South Bay Power Plant or its replacement project, meet both System and Local Resource Adequacy (or Local Capacity) Requirements.[368] Under the Commission's rules on counting capacity for these purposes, imported generation does not meet Local Capacity Requirements.[369]

9.3.2. Estimating Benefits of Deferred New Generation

SDG&E states that the value of combustion turbines deferred by Sunrise represents the value of the avoided revenue requirement associated with its fixed costs. In Phase 1, SDG&E estimated the deferred generation savings attributable to Sunrise at approximately $96 million per year,[370] but SDG&E's Phase 2 showing anticipates reduced savings of only $44 million per year.[371]

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[367] South Bay Opening Phase 1 Brief, 13.

[368] South Bay Opening Phase 1 Brief, 13.

[369] South Bay Exhibit S-8, 2.

[370] SDG&E Exhibit SD-26, Exhibit H, Table H-17.

[371] SDG&E Exhibit SD-142, 32.

In its final Phase 1 showing, CAISO estimated that without Sunrise 313 MW of new combustion turbine resources would be needed in 2015 and valued those combustion turbine additions at $78/kW-year (2007$, escalated at 2% per year), resulting in avoided new generation costs of $115 million per year. As discussed in Section 6.16, CAISO's Phase 2 combustion turbine cost estimates increase to $162.10/kW-yr (2007$, escalated at 2% per year). The updated combustion turbine costs double CAISO's projected generation savings to $231 million per year.[372]

UCAN argued in Phase 1 that SDG&E overstated combustion turbine costs by including 138 MW associated with the Pala and Margarita Peakers.[373] UCAN estimated that including these plants in the reliability benefits calculations overstates the benefits by $15 million per year.[374]

9.3.3. Estimating Must Run Contract Savings

SDG&E estimated the Must Run contract savings of Sunrise to be $96.7 million[375] per year in Phase 1; its Phase 2 estimate is $104 million per year.[376]

CAISO estimated the Must Run contract savings of Sunrise to be $42 million per year in Phase 1; its Phase 2 estimate is $35 million per year. To calculate these benefit estimates, CAISO used a spreadsheet model to determine Must Run contract savings under several different scenarios and compared them to a reference case.

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[372] CAISO Exhibit I-12, 8. The assumed increase of $119 million from updated combustion turbine costs was added to the $87 million non-Must Run reliability benefits from Exhibit I-6, Table 6.

[373] UCAN Phase 1 Opening Brief, 261.

[374] *Ibid*., 263.

[375] SDG&E Phase 1 Opening Brief, 159.

[376] SDG&E Exhibit SD-142, 32.

CAISO's modeling approach rests on several important assumptions. First, CAISO assumes that existing Must Run generators will remain viable and ready to accept a Must Run contract, even if they do not receive a Must Run contract for several years. Second, CAISO assumes that all non-Sunrise scenarios provide the same amount of RPS-related System Resource Adequacy, regardless of the level of in-area renewable generation. Third, CAISO's modeling assumes that Sunrise permanently avoids the construction of new combustion turbines, rather than merely postponing them.

DRA argued in Phase 1 that SDG&E and CAISO Must Run cost estimates were unrealistic because they included older units that DRA contended likely would retire and could not operate economically under CAISO assumptions.[377] DRA estimated the Must Run contract savings associated with reduced Local Capacity Requirements by assuming: (1) higher combustion turbine costs from SDG&E's 2008 Peaker RFO; (2) that all future Must Run contracts would be provided "full cost recovery"; (3) that local units would retire if they did not receive full cost recovery contracts and would be replaced by combustion turbines; and (4) that San Diego customers would continue to pay System Resource Adequacy costs to compensate for reduced Local Capacity Requirements.[378] Based on those assumptions, DRA estimated the total reliability benefits associated with Sunrise at $56 million per year in Phase 1, with Must Run contract savings constituting a portion of that.[379]

In Phase 2 DRA asserts that CAISO improperly assumes that Must Run contract prices will drop as a result of competition. DRA argues that Must Run

[377] DRA Phase 1 Opening Brief, 60-61.

[378] DRA Phase 1 Opening Brief, 65-66.

[379] DRA Phase 1 Opening Brief, 65-67.

contract prices will not fall appreciably below their FERC-established cost of service. Further, given the relative inefficiencies of many Must Run units, DRA challenges CAISO assumptions that Must Run units will recover any of their operating costs from the market. Rather, DRA assumes that existing Must Run units will require contracts that provide them full cost of service recovery.[380] CAISO disagrees, pointing out that Sunrise will reduce the need for Must Run contracts and, as a result, CAISO will be able to contract with lower-cost in-area generators, thereby reducing Must Run contract prices below those available today.[381]

UCAN itemizes numerous changes in SDG&E's and CAISO's assumptions underlying the Must Run benefits calculations, and suggests that eventually both CAISO and SDG&E come close to agreeing with UCAN's opening position.[382] UCAN claims that SDG&E's modeling assumes that the existing Encina units can be mothballed and then returned to service in lieu of building more expensive combustion turbines. UCAN argues that because the Encina units have worse heat rates than new combustion turbines, they are unlikely to ever earn substantial operating profits from energy sales. Consequently, UCAN contends that SDG&E cannot expect the Encina units will be available without capacity payments. UCAN claims that shutdowns would lead to an even smaller number of merchant generators competing to provide resources to meet the Local Capacity Requirement and the net effect would be the same MW of local capacity sold by fewer merchant generators at a higher price.[383]

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380 DRA Exhibit D-101, Vol. 1, 21.

381 CAISO Phase 2 Reply Brief, 40.

382 UCAN Phase 1 Opening Brief, 260.

383 UCAN Exhibit U-4, 162.

9.3.4. Unquantifiable Reliability Benefits

Parties identify a number of difficult to quantify or unquantifiable reliability benefits, ranging from the reduced fire risks inherent in some alternatives,[384] to the general value of long-term improvements to SDG&E's aging transmission infrastructure. SDG&E identifies the following unquantified benefits of Sunrise:

- A reduced vulnerability to fires, as Sunrise would not share a corridor with the Southwest Powerlink;
- Improved maintenance, as Sunrise would allow for "maintenance to be performed more readily on all interconnections with less risk";
- A more robust southern California transmission system;
- Support of future system expansion and interconnection;
- Long-term improvement to the aging infrastructure, including facilitating the replacement of aging power plants in the San Diego area and the consequent reduction in airborne emissions;
- Insurance against unexpected high load growth in SDG&E's service area;
- Reduced uncertainty created by potential qualifying facility contract terminations; and
- Reduced electricity costs by increased competition and fuel diversity in wholesale electricity markets selling into California.[385]

Parties dispute these benefits as either inaccurate or unsubstantiated. For example, Conservation Groups argue that siting Sunrise in "fire prone, remote

[384] Mussey Grade, as well as the EIR/EIS, attempt to quantify some of the fire risks associated with Sunrise and its alternatives. Mussey Grades' efforts are discussed in Section 6.17.2.

[385] SDG&E Phase 1 Opening Brief, 87-91.

areas" increases the risk of fires and the system's vulnerably to them.[386] UCAN argues that SDG&E's claim of improved maintenance is unsubstantiated and that additional costs would result, instead.[387] Nevada Hydro argues that TE/VS not only provides all of the benefits SDG&E lists, but is superior to Sunrise because it provides a link to the north, rather than another link to Arizona.[388]

CAISO agrees Sunrise provides future expandability options,[389] but assigns no more than a 50% probability that an expansion would occur in the next ten years.[390]

Other parties identify unquantifiable benefits associated with generation alternatives. South Bay states that in-area generation offers reliability benefits that a transmission line cannot provide, including: (1) reactive power support that maintains the voltage of the transmission system within required limits,[391] which will be increasingly important as more intermittent renewable generation enters the resource mix; (2) dispatchability by CAISO to mitigate intrazonal congestion,[392] one of the problems requiring the Must Run designation for so much of the San Diego's area's existing generation; and (3) regulation of reserves, essential for maintaining the frequency of the CAISO grid within the specified

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386 Conservation Groups Phase 1 Opening Brief, 37.

387 UCAN Phase 1 Reply Brief, 17-18.

388 Nevada Hydro Phase 1 Reply Brief, 15.

389 CAISO Phase 2 Opening Brief, 14.

390 RT 5432.

391 South Bay Exhibit S-8, 2-3.

392 South Bay Exhibit S-8, 3.

reliability standards and for integration of intermittent renewable resources to effectively serve CAISO load.[393]

9.4. SDG&E's "Decision Quality" Framework Modeling

In Phase 2, SDG&E presented an analytical framework for making strategic decisions "involving multiple stakeholders and values, long time horizons, and significantly different alternatives that will play out in a highly uncertain future."[394] SDG&E proposed this analysis, referred to as the "Decision Quality" framework, to ensure the decision made in this proceeding is the "best course of action for SDG&E's customers and stakeholders[.]"[395]

Using this modeling framework, SDG&E evaluates six decision alternatives[396] applying six criteria: outage risk, in-service date, GHG impact, RPS compliance, reliability need, and future expandability. All but two of the criteria (GHG impact and RPS compliance) attempt to quantify reliability benefits. SDG&E quantifies the output of the analysis based on the six criteria as an expected value for each alternative, bracketed by a range of values representing a 10% to 90% likelihood of outcome. In all cases, SDG&E finds that its "Enhanced" Northern Route is equal or superior to the other alternatives. In particular, SDG&E estimates significant costs associated with the outage risks projected for any other transmission alternative.

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393 South Bay Phase 1 Opening Brief, 15.

394 SDG&E Exhibit SD-34C, 13.1.

395 *Ibid*.

396 The alternatives considered in the modeling were the All-Source Generation Alternative, the In-Area Renewable Alternative, the LEAPS Transmission-Only Alternative, Environmentally Superior Southern Route Alternative, the Environmentally Superior Northern Route Alternative, and SDG&E's "Enhanced" Northern Route. SDG&E Exhibit SD-34c, pages 13.5-13.6.

Parties' generally do not dispute the value of the Decision Quality modeling methodology. Rather, they contest SDG&E's underlying assumptions. SDG&E's modeling witness states that he relied solely upon SDG&E for all of the data input into the model, and that he did not verify the data provided by SDG&E, nor consider other parties' perspectives regarding that data.[397]

9.5. Planning for and Maintaining Reliability

Pursuant to § 451, SDG&E as an electric utility is required to provide "adequate, efficient, just and reasonable service…and facilities,…as necessary to promote the safety, health and convenience of…the public," including obtaining adequate supplies of electricity for use by its customers. In practice, as applied to an electric utility as the Load Serving Entity (LSE), the Commission interprets this language as having the obligation to plan for and to serve the existing and foreseeable electric requirements of its customers' demand within the utility's service area. Separate from its supply service obligation, SDG&E as the owner of transmission and distribution facilities is also obligated both by state and federal law to provide transmission and distribution services to SDG&E's bundled customers as well as customers of other LSEs serving retail customers within SDG&E's service area.

SDG&E's evidence shows SDG&E faces a reliability deficiency in 2010 under a wide variety of scenarios.[398] SDG&E's analysis reflects a reliability deficiency in 2010 of at least 90 MW[399] and as much as 247 MW using the assumptions in SDG&E's January 26, 2007 supplemental testimony.[400]

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[397] RT 5248, 5292.

[398] *See, e.g.,* SDG&E Exhibit SD-26 at 47.

[399] SDG&E Exhibit SD-15, 9, Table 1.

[400] SDG&E Exhibit SD-26, 47.

While intervenors question the need for Sunrise in 2010,[401] no intervenor appears to deny that the San Diego area faces a grid reliability deficiency, and in fact some admit the criticality of the matter.[402] The loss of one of the two primary SDG&E import paths, specifically the Imperial Valley-Miguel 500 kV line, causes significant reliability issues for SDG&E and the interconnected transmission system. To cure this deficiency, DRA believes that substantial new investment in San Diego area resources – including generation and transmission – will be necessary from 2010 to 2020.[403] DRA states, and SDG&E agrees, that Sunrise would likely provide a more reliable means of meeting loads in San Diego than the major generation alternatives[404] and that expanded transmission capacity into San Diego should give SDG&E and other LSEs more procurement options than the purchase of output from a generator in San Diego.[405] UCAN also admits that SDG&E does have legitimate reliability needs over the next decade.[406]

9.5.1. Discussion

We find reasonable CAISO's assumptions regarding Sunrise's impacts on Local Capacity Requirements in both San Diego and Los Angeles. Nevada Hydro's showing is unpersuasive; we do not accept Nevada Hydro's claims that CAISO and SDG&E have used improper metrics in evaluating TE/VS impacts on Local Reliability Requirement, nor that CAISO failed to perform its studies properly.

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[401] South Bay Exhibit S-8, 5; DRA Exhibit D-66, 60:6-7; UCAN Exhibit U-101, 3.

[402] DRA Exhibit D-66, ES-1.

[403] DRA Exhibit D-66, 25:23-25.

[404] DRA Exhibit D-66, 39:13-14.

[405] DRA Exhibit D-66, 40:6-8.

[406] UCAN Exhibit U-04, 2.

We do not accept DRA's arguments about Sunrise's potential impacts on Local Capacity Requirements. CAISO adequately explained errors in DRA's assessment.

UCAN's suggestion that Sunrise may create technical reliability problems concerns us. Neither SDG&E nor CAISO establish that criteria violations in the power flow and other technical modeling of Sunrise are insignificant.

We find reasonable CAISO's modeling of avoided new generation costs. Among other things, we assume the same combustion turbine costs as those used by CAISO in Phase 2.

We agree with UCAN that SDG&E improperly included the 138 MW associated with the Pala and Margarita Peakers in its reliability savings projections. Both the CAISO and our Analytical Baselines include those peakers. As a result, they are not counted as reliability savings generated by Sunrise.

We do not agree with many of the assumptions underlying CAISO's modeling of Must Run contract savings. For example, we do not agree that potential Must Run generators will continue to be available to operate after several years with no Must Run contract. Nor do we agree that Sunrise will permanently avoid the construction of all new combustion turbines, rather we believe that the construction of Sunrise will obviate the need for some combustion turbines and postpone the construction of others. However, we find the CAISO's reliability benefits modeling effort superior to other efforts, which have generated inconsistent results. Thus, we adopt CAISO's reliability benefits modeling methodology, which show reliability benefits of $237 million per year, and the results of that modeling because CAISO's assumptions are consistent with our adopted Analytical Baseline assumptions.

The Commission has acknowledged that there is uncertainty surrounding resource planning and development. Predicting when aging power plants will retire presents a significant challenge to capacity planning. Predicting with absolute accuracy when infrastructure additions– generation and/or transmission – will occur further complicates planning and development efforts. As we have seen in the recent past, it is extremely challenging to permit, site, and construct generation within the state of California.[407] Given the difficult permitting environment, project delay is becoming more of the norm as opposed to the exception. The record before us is clear that SDG&E will face a capacity shortfall. The difficult question to answer is exactly when this shortfall will occur.

Throughout this proceeding parties relied heavily upon modeling efforts to determine need, costs, benefits, etc. of the proposed project and its alternatives. However, it is important to note that the model is not intended to provide an accurate picture of the future. The model is not intended to predict, or dictate future resource procurement activities. Actual resource development will be subject to the various procurement processes established by statute and Commission decisions.

We do not believe that, given California's challenging permitting environment, relying on increasingly adding in-basin generation to SDG&E's service territory is a viable long-term solution to meeting SDG&E's impending capacity shortfall. Adding conventional peaking resources may be an acceptable solution for short-term, unforeseen reliability needs, but is an untenable solution for maintaining system reliability in the long-term. As we have seen in other service territories, short-term, 'just-in-time' procurement is inefficient, costly,

[407] *See*, *LTPP Decision*, 85-86, D.07-12-052, D.08-02-019, and D.08-11-004.

may run afoul of the State loading order, and is far too risky to rely upon to meet reliability needs of SDG&E's (or any other LSE's) ratepayers.[408]

The reliability benefits – both quantifiable and non-quantifiable – of the transmission alternatives presented throughout this proceeding lead us to rule in favor of a transmission solution to meet SDG&E's reliability needs. A transmission solution affords SDG&E the best opportunity to plan for the current *and future* reliability needs throughout its service territory. In addition, a transmission solution – Sunrise – will not only meet SDG&E's reliability needs, but it will facilitate the development of renewable resources, thus advancing state policy to reduce GHG emissions. We agree with SDG&E that Sunrise will also provide a number of desirable, but unquantifiable, reliability benefits. Among other things, Sunrise will create a more robust southern California transmission system, and provide insurance against unexpected high load growth in SDG&E's service area. The generation alternatives will not provide these benefits.

As discussed elsewhere in this decision, the environmental review will guide us in determining the final environmentally superior route for the Sunrise Project.

We give no weight to the results of SDG&E's Decision Quality modeling. While the modeling methodology may have merit, SDG&E's assumptions for the modeling were not verified and may conflict with our adopted Analytical Baseline assumptions.

[408] *LTPP Decision,* 85–86.

10. RPS Compliance Savings

10.1. What They Are

The RPS law requires utilities to engage in renewable energy procurement[409] and SDG&E claims that Sunrise is needed to support the cost-effective development of Imperial Valley renewables. SDG&E should be able to support this claim by showing that Imperial Valley resources will provide ratepayers "RPS compliance savings" in lieu of the costs to develop more expensive renewable resource areas. However, since RPS is a fairly recent development, there is no standardized approach to quantifying RPS compliance savings attributable to developing one renewable resource area ahead of another.

The Renewable Energy Transmission Initiative, also known as "RETI" and begun in mid-2007, plans to issue a report before the end of 2008 that identifies all developable renewable resource areas in California and prioritizes them by economic and environmental criteria to promote development of the most cost-effective and least environmentally damaging renewable resource areas first.[410] However, RETI did not exist when SDG&E filed its 2006 Application. CAISO recognized the need to quantify the value of developing Imperial Valley renewables in comparison to other renewable resource areas and thus developed a new modeling approach for this proceeding. CAISO's model estimates the annual levelized ratepayer benefits of developing one renewable resource area before another.

While lacking the environmental, engineering, and updated RPS cost components included in the RETI analysis, CAISO's modeling of RPS compliance

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[409] See, e.g., § 399.12.

[410] Additional information about RETI is available at http://www.energy.ca.gov/reti/index.html.

savings associated with various renewable resource areas provides useful information regarding Sunrise's cost impacts on renewable development in the Imperial Valley.

10.2. Overview of Conclusions

We commend CAISO for undertaking this RPS compliance savings modeling effort and we adopt its methodology here. Using CAISO's Analytical Baseline assumptions, and assuming 20% RPS, CAISO finds that Sunrise generates no RPS compliance savings. In fact, under most circumstances, Sunrise generates no RPS compliance savings assuming a 26.5% RPS, and only generates RPS compliance savings when CAISO assumes 33% RPS.

CAISO's final showing makes several key assumptions with which we do not agree. We do not adopt CAISO's Alternative Renewable Costs, or its assumption that only 25% of out-of-state renewable resources will be available to California. Instead, our adopted Analytical Baseline assumes CAISO's CRS Renewable Costs, and that 50% of out-of-state renewable resources will be available to California. We also adopt a different approach when the model calculates negative RPS compliance savings. In the Sunrise cases CAISO assumed that the RPS compliance savings could only be positive or zero. However, in the All-Source Generation Alternative, CAISO assumed that the RPS compliance savings could be negative. In other words the alternative could increase the costs of RPS compliance. As discussed further below, we believe the approach CAISO took in the Sunrise cases is more reasonable, and we have modified the All-Source Generation Alternative accordingly.

The model finds that building Sunrise will not generate RPS compliance savings assuming a 20% RPS. However, significant RPS compliance savings are generated assuming a 33% RPS.

10.3. How CAISO Estimates RPS Compliance Savings

CAISO's modeling of RPS compliance savings starts with assumptions about California's RPS. CAISO assumes that SDG&E and the other load-serving entities in CAISO's control area will meet 20% RPS by 2010, and that these entities will increase renewable procurement to meet 26.5% of their load with renewables by 2015 and 33% of their load with renewables by 2020.[411] CAISO also assumes that 75% of the non-Commission regulated utilities will voluntarily comply with 20% RPS by 2010 and 33% RPS by 2020.[412]

Using these assumptions, CAISO developed "least cost" supply curves showing how utilities likely will meet these RPS targets over time, based on the availability and cost of renewable resources in various geographic locations. CAISO started by identifying all RPS-eligible generation resources in the WECC available to be developed and delivered to California in 2010, 2015 and 2020. It then estimated the costs of those resources using its CRS Renewable Costs, developed as described in Section 6.13 above.[413]

Next, CAISO aggregated the renewable resources it identified into 17 geographic "resource areas" and averaged the cost of each resource area.[414] CAISO added transmission-related costs to each resource area to arrive at a levelized cost of delivered renewable resources from each resource area.[415] Once

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[411] CAISO Phase 1 Opening Brief, 29.

[412] CAISO Phase 1 Opening Brief, 30; see also CAISO Exhibit I-2, 31.

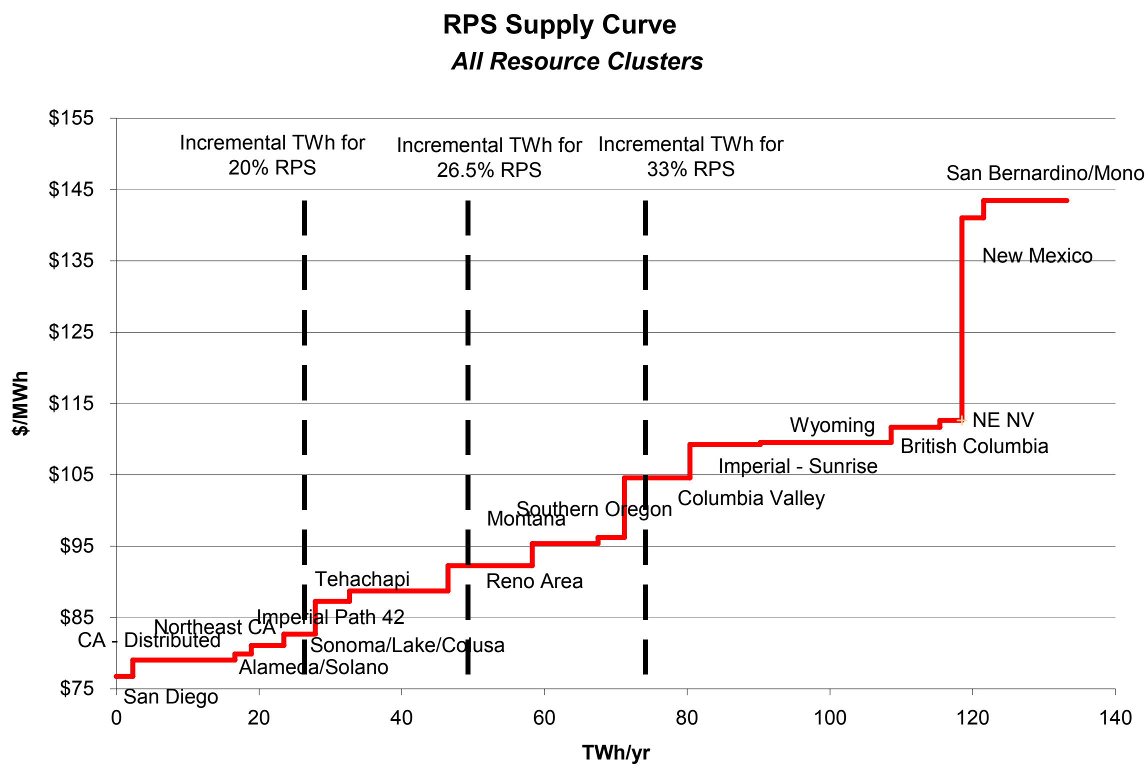
[413] Table 4.3 at CAISO Exhibit I-2, 52 presents CAISO's assumed generation-related costs by type and location. Costs presented in this table do not include delivery costs to the CAISO grid.

[414] Table 4.4 at CAISO Exhibit I-2, 52 presents the resource costs by resource area.

[415] CAISO Exhibit I-2, Table 4.5, 54 presents CAISO's assumed transmission costs by resource area.

CAISO established the quantity and levelized delivered cost of power from each resource area, it ranked each resource area from lowest to highest-cost to create a renewable supply curve. Figure 1 presents CAISO's initial supply curve, prior to the adjustments described below:

Figure 1: CAISO's Initial Supply Curve of Potential Renewable Resources To Meet Varying RPS Levels in California[416]



This figure shows that if all of the renewable resources in the supply curve ultimately were developed, resources in the Imperial Valley delivered over Sunrise (labeled "Imperial – Sunrise" on the figure and referred to here as Imperial Valley Sunrise Renewables) would only be cost-effective at an RPS target above 33%. Using CAISO assumptions, San Diego in-area wind and

416 CAISO Exhibit I-2, Figure 4.1, 66.

distributed generation biomass projects rank as the most cost-effective resources in this supply curve.[417]

In Phase 1, CAISO modeled three cases: (1) Sunrise is online by 2010; (2) Green Path and the TE/VS project are online by 2010; and (3) the 620 MW South Bay Replacement Project is online by 2010.[418] CAISO also developed a combustion turbine reference case assuming 565 MW of capacity online by 2015 (Reference Case).

CAISO constructed three different resource portfolios specific to the three cases it modeled. CAISO's projected levels of Imperial Valley renewable development both with and without Sunrise are set forth in Table 2 in Section 6.10 above. Based on those projections, all of the cases assume that about 700 MW of Imperial Valley geothermal resources are not transmission-dependent and therefore will be online by 2010 (labeled "Imperial – Path 42" on the figure above).[419] However, based on the assumption that transmission to the Imperial Valley will increase renewable development in that area, CAISO assumes greater levels of renewable development in the Imperial Valley for the transmission cases starting in 2011.[420] To model this, CAISO "forces" the Imperial Valley Sunrise Renewables to the front of the supply curve despite the higher costs projected for those resources. Because Sunrise is projected to have a higher

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[417] See CAISO Exhibit I-2, Table 4-3, 52 for a more specific listing of the generation resources.

[418] In Phase 2, CAISO assumes Sunrise is online in 2011, South Bay Replacement Project is online in 2010, and Green Path + TE/VS + LEAPS is online in 2012. CAISO Exhibit I-12, 11.

[419] The cases assume there is adequate capacity on Path 42 between the Imperial Valley and Edison.

[420] See CAISO Exhibit I-12, 9.

transfer capability than Green Path, CAISO assumes a higher amount of Imperial Valley Sunrise Renewables in the Sunrise resource portfolio by 2015 (1,800 MW of geothermal and 900 MW of solar thermal) than in the Green Path + LEAPS resource portfolio (1,341 MW of geothermal and 667 MW of solar thermal).[421]

CAISO then adjusts its initial renewable supply curve assumptions by reducing the amount of out-of-state renewables projected to be developed and delivered to California to 50%. Under that assumption, the levelized costs of Imperial Valley Sunrise Renewables ($109/MWh) are higher than the costs of renewables from other areas until 2020, when they appear less expensive than a small amount of renewable resources from British Columbia, resulting in a savings of $5 million per year starting in 2020.[422] However, before 2020, CAISO's estimated costs for Imperial Valley Sunrise Renewables are significantly higher than renewable resources delivered from other areas.[423] In Sunrise cases where delivering Imperial Valley Sunrise Renewables would result in RPS compliance savings less than zero, CAISO assumes that the savings would be zero.

CAISO later added a second renewable cost scenario assuming lower generation costs for solar thermal and higher costs for wind projects, as discussed in Section 6.13 above.[424] CAISO also adjusted its modeling to assume

[421] CAISO Exhibit I-2, 52, 68-69.

[422] CAISO Exhibit I-2, 69.

[423] CAISO Exhibit I-2, 67. We see this result in CAISO's Compliance Exhibit, discussed below.

[424] CAISO projects no wind in the Imperial Valley and abundant solar thermal resources. See Table 2, in Section 6.10 above. Thus, CAISO's revised renewable cost assumptions tend to improve the economics of Imperial Valley renewables over other renewable resource areas with wind resources.

only 25% (instead of 50%) of out-of-state renewables available to meet RPS.[425] Based on these changes, CAISO estimates Sunrise generates $228 million in RPS compliance savings starting in 2015.

10.4. Discussion

CAISO has presented a comprehensive analysis projecting future renewable costs and levels of renewable development throughout the WECC. No other party, including SDG&E, has provided a similar analysis, and we commend CAISO for taking this step, as it has added significantly to the record.

However, we note that the CAISO's RPS compliance savings modeling does not reflect the way in which the RPS program currently operates in California. As required by the RPS statutes and Commission decision, the investor-owned utilities conduct periodic solicitations for renewable resources. The utilities select resources by applying a "least cost" and "best fit" evaluation method.[426] The criteria applied by the utilities includes quantitative factors such as curtailability, dispatchability, local reliability, and repowering; and qualitative factors such as benefits to low income or minority communities, environmental stewardship, local reliability, and resource diversity.[427] The utilities bring selected renewable contracts to the Commission for approval, and the Commission approves or denies resources based on a number of factors, of which cost is only one. Since 2002 the Commission has approved at least 95 contracts with renewable resources for 5,900 MW including 61 contracts with

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[425] CAISO Phase 1 Opening Brief, 32.

[426] See, e.g., § 399.14.

[427] See, D.04-07-029.

new renewable projects, totaling 4,480 MW, all under the existing RPS framework.[428]

The contracts that have actually been approved by the Commission have not been the same as the lowest cost resources identified in CAISO's analysis. For example, the model's assumptions would suggest that distributed renewable sources such as urban municipal waste and landfill gas would represent a large portion of the resources that will be delivered to meet 20% RPS. A review of the resources actually approved by the Commission demonstrates that distributed resources like these represent a relatively small proportion of the approved resources. In reality the Commission has approved a diverse variety of resources types (including wind, geothermal, and solar) of varying sizes and located throughout California and beyond. Many of the approved resources appear in the CAISO's analysis as relatively higher cost resources.

Nonetheless, we adopt CAISO's RPS compliance savings modeling methodology for this proceeding as a useful tool to identify potential RPS cost savings from the construction of Sunrise and other alternatives. If Sunrise or other alternatives provide access to relatively lower cost renewable resources, then the CAISO serves as a reasonable model for estimating the potential cost savings.

As we discuss above in Section 6.13, we do not adopt CAISO's Alternative Renewable Costs, or its assumption that only 25% of out-of-state renewables will be available to California. Instead, we adopt CAISO's CRS Renewable Costs used in CAISO's initial modeling effort and we assume that 50% of out-of-state renewables will be available to California. Thus, we do not adopt the final results of CAISO's RPS compliance cost modeling.

[428] Renewables Portfolio Standard Quarterly Report, July 2008, 4.

DRA pointed out that CAISO's model for the Compliance Filing did not allow RPS compliance benefits to be less than zero (e.g., to calculate a compliance cost) for the 20% RPS Sunrise cases.[429] However, we believe the approach CAISO took in the Sunrise cases is reasonable.

An underlying assumption of CAISO's model is that the lowest cost renewables should be delivered first. Given that assumption, it would be inconsistent to assume that higher cost renewable energy in the Imperial Valley would be delivered just because Sunrise is built. Therefore, for the purposes of estimating the potential RPS compliance savings, it is most appropriate to assume that the savings cannot go below zero.

In the All-Source Generation Alternative, CAISO assumed that the RPS compliance savings could be negative. To ensure that a consistent approach is taken in all cases, we have assumed that the RPS compliance savings cannot be below zero in the All-Source Generation Alternative.

Applying our adopted Analytical Baseline assumptions, the model finds that Sunrise will generate no RPS compliance savings assuming 20% RPS. However, Sunrise generates significant RPS compliance savings assuming 33% RPS.

This finding can be interpreted as implying that Imperial Valley renewable energy will not be delivered if Sunrise is built and the RPS remains at 20%. As discussed in Section 4.3, the evidence in this case suggests that significant renewable development in and around the Imperial Valley will be facilitated by Sunrise, even if the RPS remains at 20%. The Commission, in fact, has already

[429] DRA Opening Comments on Compliance Exhibit, 6.

approved several utility contracts with Imperial Valley renewable projects.[430] Rather, the RPS compliance savings model is best regarded as an estimate of potential savings given a number of idealized assumptions. The model is not intended to provide an accurate picture of the future. As discussed above, the actual development of RPS projects will be subject to the RPS processes established by statute and Commission decisions.

Similarly, the model's finding that Sunrise will generate no RPS savings assuming a 20% RPS should not be taken out of context. While the CAISO's modeling approach is valid for the purposes of calculating potential RPS savings, in reality there could be RPS cost savings as a result of the construction of Sunrise due to differences between the modeling assumptions and the way in which the RPS program operates. The fact that several contracts with Imperial Valley resources have already been approved suggests that there are relatively attractive renewable resources in the Imperial Valley.

11. Calculating Net Benefits

As described in the three preceding Sections, parties' estimates of the energy and reliability benefits generated by the Proposed Project and some of its alternatives vary greatly. Only CAISO attempted to estimate RPS compliance savings.[431] We calculate net benefits by adding together the three kinds of benefits already discussed – energy benefits, reliability benefits, and RPS compliance savings - and then subtracting project costs.[432] For a sense of the

[430] See, D.07-04-039; Resolutions E-3965, E-4073, E-4126, E-4171.

[431] Essentially, SDG&E assumed that the project would not provide any benefits of reducing RPS Compliance costs, since it assumed the same level of renewables in all scenarios.

[432] We estimate each of the three benefits relative to a reference case. Transmission costs of the reference case are accounted for in the cost of new combustion turbines. Thus,

scope and scale of the resulting net benefit estimates, we calculate net benefits of the Proposed Project and its alternatives relative to a reference case that assumes combustion turbines will be added to meet future reliability needs.

11.1. Overview of Conclusions

Given parties' changing assumptions about combustion turbine costs, renewable costs, capital costs, and other assumptions, their net benefit calculations also changed throughout the proceeding.

Recognizing these disparities, and in an attempt to bring clarity to this proceeding, the Revised Scoping Memo directed CAISO to prepare a Compliance Exhibit using Analytical Baseline assumptions similar to those we adopt in today's decision.[433] The Compliance Exhibit defines a large set of consistent and reasonable assumptions across scenarios. It then varies assumptions regarding RPS compliance requirements, and renewable and combustion turbine prices, to estimate the net benefits generated by three different alternatives -- the "Enhanced" Northern Route, the Draft EIR/EIS Environmentally Superior Southern Route, and the All-Source Generation Alternative[434] -- relative to a combustion turbine reference case (Reference Case). In summary, the Compliance Exhibit finds no net benefits under any alternative assuming the

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we do not subtract Sunrise costs from reference case transmission costs to determine net benefits.

[433] Since the Analytical Baseline assumptions we adopt here were not known when CAISO prepared the Compliance Exhibit, the assumptions in the Compliance Exhibit are not identical to our Analytical Baseline assumptions. We correct for that in an Update, discussed below.

[434] The "Enhanced" Northern Route and Draft EIR/EIS Environmentally Superior Southern Route Alternatives are proxies for all Sunrise transmission routes. They are assumed to generate the same level of gross benefits, and to only vary by capital costs. Consequently, we use the term "Sunrise" here to refer to these cases modeled in the Compliance Exhibit and the Update.

current 20% RPS. It finds the Draft EIR/EIS Environmentally Superior Southern Route has slightly higher net benefits than SDG&E's "Enhanced" Northern Route Alternative under 33% RPS, and positive net benefits for the non-wires All-Source Generation Alternative only under specific combustion turbine and renewable cost assumptions.

In response to discovered errors and comments by parties, and to analyze the Compliance Exhibit's three alternatives using the Analytical Baseline assumptions we adopt here, we have updated the Compliance Exhibit as described in Section 11.4 below.

Based on the results of the Update we find that, assuming a 20% RPS, Sunrise would result in significant economic benefits for ratepayers. The All-Source Generation Alternative would result in even higher net benefits. Assuming 33% RPS, Sunrise is estimated to generate over $125 million per year in net benefits, which is over $30 million per year more than the All-Source Generation Alternative. Adding the unquantifiable benefits of a transmission alternative to our consideration, we find that Sunrise is the superior alternative for meeting SDG&E's longer-term reliability need economically.

11.2. Parties' Modeling Efforts

SDG&E's net benefit estimates generally have diminished throughout the course of the proceeding. Initially, energy benefits were the primary component of SDG&E's benefit showing, varying from $468 million per year in its 2006 Application to $105 million per year by the end of the Phase 1 hearings, to $52 million per year when compared to a combustion turbine reference case modeled using its own Analytical Baseline assumptions.[435] These variations in

[435] See note 338, above.

energy benefits flow through to SDG&E's showing of net benefits for Sunrise, which vary in similar proportions throughout the proceeding, from $57 million per year in its 2005 Application, to $447 million per year in its 2006 Application, to $142 million per year by the end of Phase 1, and to $41 million when compared to a combustion turbine reference case applying SDG&E's own Analytical Baseline. Table 9 presents SDG&E's changing net benefit estimates for the Proposed Project.[436]

Table 9: SDG&E Estimates of Net Benefits (Annual Levelized $ Millions)

Source	Gross Benefits	Costs	Total Net Benefits	Benefit/Cost Ratio
2005 Application, page V-13	210	153	57	1.37:1
2006 Application, Chapter IV, pages IV-8 to V-9	621	174	447	3.57:1
January 2007 Correction to 2006 Application[437]	259	174	85	1.49:1
July 25, 2007 Errata[438]	298	156	142	1.91:1
Sunrise compared to combustion turbine reference case[439]	201	160	41	1.26:1

Likewise, CAISO's net benefit showing has varied – from $52 to $145 million per year (assuming lower renewable costs) to $226 to $318 million per year (using its Alternative Renewable Costs).[440] In Phase 1 CAISO estimated

[436] The gross benefits in Table 9 apply to Sunrise, regardless of its routing. However, the costs of the various Sunrise routes differ. Therefore, net benefits, which take costs into account, differ by route.

[437] Correction to Amended Application of San Diego Gas & Electric Company, January 19, 2007, pages IV-8 to IV-9; see also SDG&E Exhibit SD-6, pages IV-8 to IV-9.

[438] SDG&E Exhibit SD-26, Exh. J, 6.

[439] SDG&E Exhibit SD-142, 14.

[440] These renewable costs are addressed in Section 6.13 above.

the net benefits of Sunrise under 33% RPS to range from $52 to $226 million per year.[441] The lower estimates assumed CAISO's CRS Renewable Costs; the higher estimates assumed CAISO's Alternative Renewable Costs (higher wind and lower solar thermal costs) and only 25% of out-of-state renewables available to California.

In Phase 2, CAISO concludes that Sunrise under 33% RPS will provide net benefits between $145 million and $318 million per year.[442] CAISO attributes the bulk of this increase from its Phase 1 projected benefits to its changed assumption in Phase 2 of increased combustion turbine costs, which has two opposing effects on net benefits: (1) it increases reliability benefits, thereby increasing net benefits for all alternatives; and (2) it increases the cost of alternatives heavily dependent on combustion turbines, thereby decreasing their net benefits. Table 10 presents CAISO's changing net benefit estimates for the Proposed Project, using CAISO's CRS Renewable Costs and assuming 33% RPS.

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441 CAISO Phase 1 Opening Brief, 15.

442 CAISO Phase 2 Opening Brief, 13.

Table 10: CAISO Estimates of Net Benefits Under 33% RPS Assuming CRS Renewable Costs (Annual Levelized $ Millions)

Source	Gross Benefits	Costs	Total Net Benefits	Benefit/Cost Ratio[443]
Exhibit SD-5, Appendix I-1 (CAISO South Regional Transmission Plan)[444]	3,241	2,059	1,182	1.57:1
Exhibit I-1, 41 (1/26/07 Testimony, Part I, Phase 1)[445]	250	163	87	1.54:1
CAISO Exhibit I-2, 6 (4/20/07 Second Errata to Testimony, Part II, Phase 1)	241	157	84	1.54:1
CAISO Exhibit I-6, 45 (7/12/07 Errata to Rebuttal Testimony, Phase 1)	209	157	52	1.33:1
Exhibit I-12, 3 (3/12/08 Testimony, Phase 2)	305	182	123	1.68:1
Exhibit I-13, 22 (3/28/08 Rebuttal Testimony Phase 2)	327	183	145	1.79:1

Table 11 below presents CAISO's changing net benefit estimates for the Proposed Project, using CAISO's Alternative Renewable Costs and assuming 33% RPS.

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443 Benefit/Cost Ratios = Gross Benefits/Costs.

444 Benefits and costs are NPV 2010$.

445 Benefits are 2015 nominal dollars and costs are levelized costs of transmission.

Table 11: CAISO Estimates of Net Benefits Under 33% RPS Assuming CAISO's Alternative Renewable Costs (Annual Levelized $ Millions)

Source	Gross Benefits	Costs	Total Net Benefits	Benefit/Cost Ratio[446]
CAISO Exhibit I-6, 46 (7/12/07 Errata to Rebuttal Testimony, Phase 1)	383	157	226	2.44:1
Exhibit I-12, 3 (3/12/08 Testimony, Phase 2)	473	182	291	2.60:1
Exhibit I-13, 22 (3/28/08 Rebuttal Testimony Phase 2)	500	183	318	2.73:1

Except for SDG&E and CAISO, parties generally argue that Sunrise will generate little or no net benefits, and may even result in net costs to ratepayers. UCAN claims that SDG&E overstates the benefits of Sunrise, understates its costs, and overstates the costs of the baseline combustion turbine case. In Phase 1, UCAN projected Sunrise would cost ratepayers $81 million per year more than its combustion turbine reference case.[447] In Phase 2, UCAN projects Sunrise will cost ratepayers $74 million per year more than its combustion turbine reference case and "up to" $120 million per year more that other alternatives.[448] In contrast, UCAN estimates positive net benefits for its own all-source generation alternative. UCAN provides no net benefit estimates for other alternatives.

Similarly, in Phase 1, DRA estimated that Sunrise would cost $37.8 million per year more than the combustion turbine reference case, resulting in a benefit-

[446] Benefit/Cost Ratios = Gross Benefits/Costs.

[447] UCAN Phase 1 Opening Brief, 302.

[448] UCAN Phase 2 Opening Brief, 4.

cost ratio of 0.76:1.[449] In Phase 2 DRA claims that "despite [SDG&E's] ongoing adoption of many corrections suggested by intervenors," SDG&E's economic case is still "deeply flawed," and that correcting additional deficiencies will reduce the benefit cost ratio to below one.[450]

Not all parties have estimated net benefit or benefit-cost ratios for the Proposed Project and its alternatives and parties that developed estimates did not calculate the net benefits of all alternatives. To demonstrate the disparities among the parties' calculations, Table B-3 in Appendix B presents the parties' final net benefit and/or benefit-cost ratios for the Proposed Project and its alternatives. Among other things, Table B-3 shows:

- The change in net benefits between the TE/VS + Green Path and the Sunrise + TE/VS + Green Path cases estimates a decrease in benefits if Sunrise is added after TE/VS and Green Path are built, such that Sunrise provides no incremental benefits;
- Southern Route Alternatives generally provide larger net benefits than Northern Route Alternatives;
- There is an enormous disparity in parties' estimated net benefits for TE/VS and LEAPS; and
- Only DRA provided a range of net benefits, even though SDG&E was required to provide sensitivity analysis.

11.3. CAISO's Compliance Exhibit

11.3.1. Overview

The Revised Scoping Memo directed CAISO to prepare a Compliance Exhibit consisting of additional model runs that employ a set of assumptions specified in the Revised Scoping Memo. CAISO proposed modifications to these

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[449] DRA Phase 1 Opening Brief, 74.

[450] DRA Phase 2 Opening Brief, 8.

assumptions, and the final assumptions that CAISO modeled are set forth in Table B-1 in Appendix B.

Many of the assumptions used in the Compliance Exhibit are consistent with the Analytical Baseline assumptions adopted here. The Revised Scoping Memo directed that where it did not specify assumptions, CAISO should use its preferred modeling assumptions from Phase 2 of this proceeding.[451] The Revised Scoping Memo ordered CAISO to evaluate the operational grid impacts of each alternative and to estimate for each alternative its energy benefits, reliability benefits, and RPS compliance savings. Where CAISO determined that specific alternatives were equivalent, it did not perform separate analyses.

In August 2008, CAISO prepared a draft Compliance Exhibit, including preliminary estimates of net benefits. The draft was the subject of a workshop on August 22, 2008, where parties also discussed CAISO's methodology. Based on comments received from parties, CAISO revised its draft and served the Compliance Exhibit on August 26, 2008.[452]

The Compliance Exhibit estimates net benefits for 13 cases,[453] based on three alternatives:

- A combustion turbine reference case;
- SDG&E's "Enhanced" Northern Route;
- The Draft EIR/EIS Environmentally Superior Southern Route; and
- The All-Source Generation Alternative.

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451 Revised Scoping Memo, 2.

452 Consistent with the Revised Scoping Memo, the Compliance Exhibit, including its Work Papers, has been received in evidence as Exhibit Compliance-1. It is the only compliance exhibit in the record.

453 Net benefits for each case are estimated relative to the three combustion turbine Reference Cases, Cases 1, 5, and 10.

Cases 2-4 in the Compliance Exhibit present net benefits for each alternative under 20% RPS. Cases 6-8 present net benefits under 33% RPS. All of these cases assume the CAISO's lower Phase 1 combustion turbine costs. Case 9 presents net benefits assuming Sunrise comes online in 2011, rather than 2012, as assumed for all the other cases.[454] CAISO added cases 11-13, which estimate net benefits under 33% RPS using the higher combustion turbine costs it assumes in Phase 2. CAISO used SDG&E's estimated capital costs for the alternatives, consistent with our adopted Analytical Baseline assumptions. However, to provide a range of renewable resource costs for the All-Source Generation Alternative,[455] CAISO also ran Cases 4b, 8b, and 13b using its CRS Renewable Costs, consistent with our adopted Analytical Baseline assumptions.

To calculate gross benefits for each alternative under the new assumptions, CAISO needed to calculate energy benefits, reliability benefits, and RPS compliance savings for each case relative to a reference case. However, CAISO declined to perform new GridView runs using the assumptions in the Revised Scoping Memo – which are necessary to estimate energy benefits – given time constraints and data development difficulties. Evidence in the record at that point suggested that, on balance, energy benefit calculations using the Revised Scoping Memo assumptions would result in energy benefit estimates of less than $34 million per year, a small number compared to the value of other benefits at issue. Thus, instead of running production cost models to calculate energy

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[454] For the reasons discussed in Section 15.5, the Compliance Exhibit and our Update assume that SDG&E's Enhanced Northern Route will come online in 2012, rather than in 2011, as assumed by SDG&E and CAISO. SDG&E Phase 2 Opening Brief, 281; CAISO Phase 2 Reply Brief, 33.

[455] The cost of the transmission alternatives are not impacted by renewable costs.

benefits, CAISO estimated energy benefits using results from prior production cost modeling.[456]

CAISO calculated reliability benefits and RPS compliance savings — the first and second most significant benefits on a dollar basis — using its own spreadsheet models, which were made available to parties.

CAISO presented load and resource tables to support the Compliance Exhibit. These tables show that there is no need for additional in-area generating capacity until 2014 at the earliest,[457] primarily due to the assumptions that the existing South Bay Power Plant will stay online through 2012 and that the Carlsbad Energy Center (which replaces Units 1-3 at the Encina Power Plant) will come online before Summer 2013.

Table 5 in Section 7, above summarizes by year the Compliance Exhibit findings we adopt regarding the reliability need in SDG&E's service area.

The 13 cases (plus the 3 cases using CAISO's CRS Renewable Costs) modeled by CAISO and their estimated net benefits are set forth in Table 12 below. The Compliance Exhibit shows:

- Under 20% RPS, all of the generation and transmission alternatives are more expensive than the combustion turbine reference case, assuming the lower Phase 1 combustion turbine costs (Cases 2 through 4b);
- Under 33% RPS assuming the lower Phase 1 combustion turbine costs, the "Enhanced" Northern Route and the Draft EIR/EIS Environmentally Superior Southern Route Alternatives have positive net benefits of $22 and $25 million per year, respectively (Cases 6 and 7). The Southern Route

[456] CAISO provided parties with work papers describing its approach and parties were given the opportunity to comment on the approach.

[457] Compliance Exhibit, 6-8.

has higher net benefits because of its lower projected capital costs;

- Under 33% RPS assuming the substantially higher Phase 2 combustion turbine costs, the projected net benefits of the "Enhanced" Northern Route and the Draft EIR/EIS Environmentally Superior Southern Route Alternatives are 5 to 6 times greater (at $129 and $132 million per year, respectively) than estimates under the lower Phase 1 combustion turbine costs (Cases 11 and 12 compared to Cases 6 and 7);
- Under all RPS scenarios and combustion turbine cost assumptions, the All-Source Generation Alternative is not economic using SDG&E's proposed renewable costs (Cases 4, 8, and 13);
- Assuming CAISO's CRS Renewable Costs, the lower Phase 1 combustion turbine costs, and 33% RPS, CAISO estimates that the All-Source Generation Alternative produces net costs of $3 million per year (Case 8b);
- Assuming CAISO's CRS Renewable Costs, the higher Phase 2 combustion turbine costs, and 33% RPS, CAISO estimates that the All-Source Generation Alternative produces net benefits of $49 million per year (Case 13b); and
- Delaying the online date of the "Enhanced" Northern Route from 2011 to 2012 increases the net benefits of that alternative by $2 million per year (compare $22 million per year in Case 6 assuming a 2012 online date to $20 million per year in Case 9 assuming at 2011 online date).[458]

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[458] This is consistent with CAISO's results from Phase 1, which showed that 2010 was not the optimal online date for Sunrise.

Table 12: Summary of CAISO Compliance Exhibit (Annual Levelized $ Millions)

Case #	Name	RPS	CT Costs	Other Variation	Net Benefits Relative to Reference Case ($ million)
1	Combustion Turbine Reference Case	20%	Phase 1[459]		N/A
2	SDG&E's Enhanced Northern Route	20%	Phase 1		-57
3	Draft EIR/EIS Environmentally Superior Southern Route	20%	Phase 1		-54
4	All Source Generation Alternative	20%	Phase 1	SDG&E RPS Costs	-125
4b	All Source Generation Alternative	20%	Phase 1	CRS RPS Costs	-33
5	Combustion Turbine Reference Case	33%	Phase 1		N/A
6	SDG&E's Enhanced Northern Route	33%	Phase 1		22
7	Draft EIR/EIS Environmentally Superior Southern Route	33%	Phase 1		25
8	All Source Generation Alternative	33%	Phase 1	SDG&E RPS Costs	-94
8b	All Source Generation Alternative	33%	Phase 1	CRS RPS Costs	-3
9	SDG&E's Enhanced Northern Route	33%	Phase 1	On Line 2011; 2012 for all other cases	20
10	Combustion Turbine Reference Case	33%	Phase 2		N/A
11	SDG&E's Enhanced Northern Route	33%	Phase 2		129

[459] In Phase 1 the CAISO estimated combustion turbine costs at $78/kW-year. In Phase 2 the CAISO revised this estimate to $162.10/kW-year (both 2007$, escalated at 2% per year).

12	Draft EIR/EIS Environmentally Superior Southern Route	33%	Phase 2		132
13	All Source Generation Alternative	33%	Phase 2	SDG&E RPS Costs	-42
13b	All Source Generation Alternative	33%	Phase 2	CRS RPS Costs	49

Production cost modeling for the Compliance Exhibit would have given us a better understanding of the impact of our decision to assume only 25% of the coal fired generation projected to be built in the WECC. In the absence of such modeling, we must accept CAISO's estimates of energy benefits based on prior production cost modeling results. This approach results in estimated Sunrise energy benefits of $5 million per year for 20% RPS cases and $18 million per year for 33% RPS cases. CAISO assumed the All-Source Generation Alternative would provide no energy benefits.

Several parties filed comments on the Compliance Exhibit. UCAN observes that if the California Solar Initiative program is forecasted to be a success, solar PV costs under the program should not be included as incremental costs in the cost of the All-Source Generation alternatives because such costs have already been included in the costs of the California Solar Initiative program.[460] In addition, CAISO recognized that it did not revise Sunrise costs to include the UCAN operations and maintenance estimates. However, we are relying on the operating and maintenance assumptions from the CAISO's Compliance Exhibit for our Analytical Baseline assumptions.

[460] UCAN Comments on Compliance Exhibit, 9.

11.3.2. Discussion

Notwithstanding its errors, the Compliance Exhibit, which applies many of the Analytical Baseline assumptions we adopt here, provides insight into how changes in RPS compliance requirements, and renewable and combustion turbine prices, influence the net benefits of Sunrise and the All-Source Generation Alternative, compared to the Reference Case. The Compliance Exhibit demonstrates that none of the alternatives are economic compared to the Reference Case under 20% RPS. Assuming 33% RPS and low combustion turbine costs, the Compliance Exhibit also shows that the net benefits of the transmission alternatives are positive but not very large, whereas the net benefits of the generation alternatives are negative (e.g., that there are costs, not savings). Assuming 33% RPS and CAISO's Phase 2 combustion turbine costs (which we adopt for our Analytical Baseline), we find that the transmission alternatives provide significantly greater net benefits than the All-Source Generation Alternative, regardless of renewable cost assumptions.

Assuming 33% RPS, CAISO Phase 2 combustion turbine costs, and CAISO CRS Renewable Costs, we estimate Sunrise will produce net benefits exceeding those of the All-Source Generation Alternative by approximately $80 million per year.[461]

11.4. The Commission's Update to the Compliance Exhibit

11.4.1. Overview

We have applied all of our Analytical Baseline assumptions adopted in this decision to prepare an Update to the Compliance Exhibit (Update). Most

[461] Using SDG&E's renewable costs for the All-Source Generation Alternative increases the relative benefit of Sunrise to nearly $110 million per year.

significantly, we apply CAISO's Phase 2 combustion turbine costs to the 20% RPS cases. Our Update makes four other changes to the Compliance Exhibit. First, CAISO used the wrong mix of generation resources for the All-Source Generation cases (Cases 5, 5b, 8, 8b, 13, and 13b), overstating the amount of renewables in that case. CAISO inadvertently assumed 300 MW of solar thermal, 400 MW of wind, 100 MW of biomass/biogas, and 210 MW of solar PV by 2016, which is the total amount of renewables specified in the EIR/EIS for the In-Area Renewable Alternative.[462] We correct this error in the Update, assuming 200 MW of wind, 50 MW of biomass/biogas, and 210 MW of solar PV by 2016, as specified for the All-Source Generation Alternative.[463]

Second, we agree in part with UCAN's observation that the solar PV costs associated with the 105 MW (firm capacity) due to the California Solar Initiative are not incremental to the Reference Case and, as a result, should not be included in the cost estimates of the All-Source Generation Alternative. However, instead of deducting all of the solar PV costs, we assume that by 2016 approximately 37 MW (firm capacity) of the solar PV capacity added as part of the All-Source Generation Alternative will be provided under the California Solar Initiative and therefore those costs are not attributable to the All-Source Generation Alternative.[464] Both of these changes result in lower cost estimates for the All-Source Generation Alternative.

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[462] No party noted this error in the Draft Compliance Exhibit workshop or in their Compliance Exhibit comments.

[463] All capacity values are nameplate.

[464] In 2016, our adopted Analytical Baseline assumes 33 MW (firm) of solar PV. However, as discussed in note 108 above, SDG&E assumes that SDG&E's firm capacity under the California Solar Initiative will be between 70 MW and 150 MW. We conservatively assume that SDG&E's installed capacity will be 70 MW under the California Solar Initiative, meaning that the costs of 37 MW (70 MW – 33 MW) beyond

In summary, our Update makes the following changes to the Compliance Exhibit:

- We assume CAISO's Phase 2 combustion turbine costs for all cases;
- We adjust the amount of in-area renewables in the All-Source Generation Alternative, thereby changing the distribution of renewables throughout the WECC, consistent with CAISO's assumed supply curves;
- We subtract $367 million per year from the assumed capital cost of the All-Source Generation Alternative in each scenario to address the 37 MW of solar PV already paid for in the California Solar Initiative program;[465] and
- We adjust the modeling for the All-Source Generation Alternative so that RPS compliance savings cannot be negative.

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our Analytical Baseline should not be attributable to the All-Source Generation Alternative.

[465] We assume CAISO's CRS Renewable Costs for solar PV. Assuming SDG&E's estimated solar PV costs, we would subtract $776 million from the cost of the All-Source Generation Alternative.

The Update generates the following results:

Table 13: Commission Update to Compliance Exhibit (Annual Levelized $ Million)

Case #	Name	RPS	Variations in Assumptions	CT Costs – Compliance Exhibit	CAISO Compliance Exhibit Net Benefits	CT Costs – CPUC Update	CPUC Update Net Benefits
1	Combustion Turbine Reference Case	20%		Phase 1		Phase 2	
2	SDG&E's Enhanced Northern Route	20%		Phase 1	-57	Phase 2	51
3	Draft EIR/EIS Environmentally Superior Southern Route	20%		Phase 1	-54	Phase 2	47
4	All Source Generation Alternative	20%	SDG&E RPS Costs	Phase 1	-125	Phase 2	92
4b	All Source Generation Alternative	20%	CRS RPS Costs	Phase 1	-33	Phase 2	92
5	Combustion Turbine Reference Case	33%		Phase 1		Phase 2	
6	SDG&E's Enhanced Northern Route	33%		Phase 1	22	Phase 2	129
7	Draft EIR/EIS Environmentally Superior Southern Route	33%		Phase 1	25	Phase 2	126
8	All Source Generation Alternative	33%	SDG&E RPS Costs	Phase 1	-94	Phase 2	93
8b	All Source Generation Alternative	33%	CRS RPS Costs	Phase 1	-3	Phase 2	93
10	Combustion Turbine Reference Case	33%		Phase 2		Phase 2	
11	SDG&E's Enhanced Northern Route	33%		Phase 2	129	Phase 2	129
12	Draft EIR/EIS Environmentally Superior Southern Route	33%		Phase 2	132	Phase 2	126

13	All Source Generation Alternative	33%	SDG&E RPS Costs	Phase 2	-42	Phase 2	93
13b	All Source Generation Alternative	33%	CRS RPS Costs	Phase 2	49	Phase 2	93

11.4.2. Discussion

The Update differs from the preliminary findings in the Compliance Exhibit. Unlike the Compliance Exhibit, the Update estimates that assuming a 20% RPS, Sunrise will result in significant cost savings for ratepayers—approximately $50 million per year. The increased benefits are largely generated by assuming the CAISO Phase 2 combustion turbine costs. The benefits generated by the All-Source Generation Alternative also increase substantially to $92 million per year. The increased benefits in the All-Source Generation Alternative are due to the assumption that RPS compliance savings cannot go below zero. According to the modeling, the All-Source Generation Alternative has higher net benefits than Sunrise assuming a 20% RPS.

Assuming 33% RPS and CAISO Phase 2 combustion turbine costs, the Update estimates Sunrise will generate over $125 million per year in net benefits, which significantly exceeds the $93 million per year of net benefits estimated for the All-Source Generation Alternatives.

Because of its higher estimated capital costs, the Draft EIR/EIS Environmentally Superior Southern Route is estimated to generate $3 million per year less in net benefits than SDG&E's "Enhanced" Northern Route.

Taking into account the unquantifiable reliability costs and benefits discussed in Section 9 above, and the environmental issues discussed in Sections 15 and 17 below, we find that the Final Environmentally Superior Southern Route (which is a variation on the Draft EIR/EIS Environmentally

Superior Southern Route modeled in the Compliance Exhibit and Update) is the superior alternative.

12. Uncertainty Analysis

As the net benefits discussion in Section 11 reflects, there is a tremendous amount of uncertainty regarding conclusions reached by the models used in this case. Given the inherent uncertainty in all modeling efforts, we specifically addressed this issue in our *Economic Methodology Decision*, and we expressly required in that decision that economic analyses presented for the Commission's consideration include uncertainty analyses. Attachment A to that decision sets specific minimum requirements for those uncertainty analyses.[466]

Because of the significant role uncertainty might play in the modeling of economic benefits related to Sunrise, the Scoping Memo reiterated SDG&E's obligation to perform such an analysis, consistent with the requirements of the *Economic Methodology Decision*.[467] However, though SDG&E included an uncertainty analysis with the 2005 Application, it did not perform an uncertainty analysis for the 2006 Application, or any of the updates that followed, contending instead that the uncertainty analysis in the 2005 Application suffices.[468] SDG&E also contends that CAISO's RPS compliance savings analysis meets the requirement.[469] Finally, SDG&E argues that it has addressed risks through the many analyses it conducted responding to requests from intervenors.[470]

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[466] *Economic Methodology Decision,* Attachment A, 5.

[467] Scoping Memo, 15-16.

[468] SDG&E Phase 1 Opening Brief, 167-168.

[469] SDG&E Phase 1 Opening Brief, 169-173.

[470] SDG&E Phase 1 Opening Brief, 174.

DRA asserts that any conclusions that can be drawn from the scenarios modeled in the 2005 Application are highly suspect given the major changes SDG&E has made to its case since 2005, including the "top-to-bottom" review that caused an interruption of Phase 1 hearings in July, 2007.[471] UCAN concurs, characterizing the data underlying the 2005 Application as "hopelessly flawed."[472]

SDG&E counters that the changes in its analysis since 2005 are not so substantial as to necessitate updating the risk analysis and that "[w]hat should be clear from this exhaustive record and the level of study undertaken by SDG&E and CAISO under numerous scenarios and for many data requests, is that risk and uncertainty are fully bracketed by these studies."[473]

CAISO has not performed an uncertainty analysis either, even though its TEAM Methodology requires one, and even though it performed one for its CAISO South Regional Transmission Plan report presented to its Governing Board for approval of Sunrise.[474] In sum, both SDG&E and CAISO claim that their various economic analyses take uncertainty into account, either through conservative assumptions, or through the shear volume of modeling and the number of alternatives considered.[475]

DRA has provided several sets of uncertainty analyses. It provided ranges for reliability, energy, and RPS compliance benefits as well as estimated net

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[471] DRA Phase 1 Opening Brief, 78.

[472] UCAN Phase 1 Opening Brief, 302.

[473] SDG&E Phase 1 Reply Brief, 126.

[474] SDG&E Exhibit SD-5, Appendix 1, 55.

[475] CAISO also noted that it did not have enough time to perform such an assessment. RT 2260-2265.

benefits for Sunrise.[476] Even though DRA did not present its own model, we commend its efforts to at least identify the range of uncertainty in Sunrise benefits.

13. Green House Gas Impacts

AB32 requires that California reduce its GHG emissions to 1990 levels by 2020.[477] This Commission, with the Energy Commission, has adopted recommended policies and rules to be implemented by the California Air Resources Board to meet California's GHG reduction objectives in the energy sector. Among them is a recommendation that the required share of renewable energy in California's resource mix be increased from 20% in 2010 to 33% by 2020 and that this requirement be extended to all California retail providers, including publicly owned utilities.[478] This recommendation is incorporated in CARB's *Climate Change Proposed Scoping Plan* for achieving the emissions reductions mandated under AB 32.[479] In addition, California's Attorney General is enforcing strict compliance with GHG emission goals and full disclosure of potential climate change impacts in EIRs.[480] Consequently, as the lead CEQA agency, we included a GHG emission analysis in the EIR/EIS which quantifies CO_2 emissions related to the Sunrise transmission alternatives and considers and compares the GHG impacts of the generation alternatives to Sunrise.

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476 See, e.g., DRA Exhibit D-66, 27-38.

477 See note 156, above.

478 See *Greenhouse Gas Regulatory Strategies,* and two prior decisions in our GHG rulemaking, D.08-03-018 and D.07-09-017.

479 California Air Resources Board, *Climate Change Proposed Scoping Plan*, October 2008, 44-46. A vote to adopt this document is currently scheduled for CARB's December 11, 2008 board meeting.

480 Conservation Groups Phase 2 Opening Brief, 69-70.

13.1. GHG Emissions Projected in the EIR/EIS

The Draft and Final EIR/EIS begin by estimating CO_2 emissions due to the two-year construction of Sunrise. They find that 109,000 tons of emissions will result from construction activities, primarily from the operation of on and off-road equipment used during construction, as well as material deliveries, water and fuel transport, and worker commutes.[481] These construction-phase emissions are then compared to emissions associated with the operation of Sunrise and its alternatives.

As discussed elsewhere one of the primary benefits of the Sunrise Powerlink is to facilitate RPS compliance by significantly increasing access to Imperial Valley's rich renewable energy resources. However, the Draft and Final EIR/EIS do not consider avoided emissions resulting from implementation of either the current 20% RPS or increasing the mandate to 33% by 2020. The CAISO production cost modeling that they rely upon assumes a mandate of 33% renewables by 2020 for investor-owned utilities and voluntary compliance with this standard by 75% of publicly owned utility loads.[482] The comparisons presented in the Draft and Final EIR/EIS focus exclusively on *incremental* changes in WECC-wide CO_2 emissions resulting from dispatching the entire system under alternative scenarios for transmission and generation build-out through 2015. In all of the cases CAISO analyzed, it assumed that all retailers are halfway between the 2010 and 2020 targets, delivering 26.5% renewable energy in 2015 (the only year modeled).

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481 Draft EIR/EIS, Sec. D.11-52.

482 We note that this is a significant omission. CARB's Scoping Plan projects that raising the share of renewable energy to 33% statewide by 2020 from the current 20% RPS will reduce California's GHG emissions by 21.3 million metric tons of CO_2 equivalent per year. CARB *Scoping Plan*, 46.

CAISO's data and analyses on CO_2 emissions under these alternative scenarios were provided in response to a data request by our environmental consultant. On our own motion to ensure the completeness of the record we identify "Information Request #2 to California Independent System Operator" as CAISO Exhibit I-16 and receive it in evidence on the effective date of this decision. Note that this document is included as a reference in the Air Quality section of the EIR/EIS (see References, Section D.11.21, page D.11-80). A copy of this document was posted to the CEQA website[483] on October 11 and November 14 of 2007 and an updated version sent to parties via email by CAISO on August 4, 2008. This updated version, included among the workpapers CAISO provided supporting its response to the *Revised Scoping Memo*, reflects a correction to the fuel oil emissions rate used in the original analysis.

Based upon that CAISO modeling, the Draft EIR/EIS projected Sunrise would reduce WECC-wide CO_2 emissions by 1,650 tons in the year 2015 under a scenario in which a substantial amount of the renewable potential in the Imperial Valley is developed and delivered via Sunrise. After release of the Draft EIR/EIS, DRA identified emission rate errors in CAISO's production cost modeling.[484] The Final EIR/EIS adopts CAISO's correction of these errors, and estimates that Sunrise will reduce CO_2 emissions by 8,950 tons in the year 2015. Because CAISO only modeled emission information for the year 2015, the Final EIR/EIS estimates long-term avoided CO_2 emissions over a 40-year period by multiplying the 2015 rate by 40 years, estimating that Sunrise would provide 358,000 tons of net CO_2 savings over 40 years. This approach implicitly holds the WECC's current resource mix constant for the next four decades, and does not

[483] (http://www.cpuc.ca.gov/Environment/info/aspen/sunrise/data_reqs.htm)

[484] DRA Exhibit D-100, 10-1.

take into account further additions to California's renewable resources resulting from meeting a 33% target in 2020. This estimate does not account for Sunrise's construction-related CO_2 emissions, since our environmental consultant computed them separately. More important, however, it fails to acknowledge that there may be CO_2 emissions associated with the construction of other transmission facilities that might be required to access the resources CAISO assumed in the 2015 timeframe. In fact, CAISO testimony shows that if Sunrise is not built then other transmission will be needed to deliver 26.5% renewables in 2015.[485]

The same CAISO analysis also indicates that, if Sunrise were constructed, but the renewables necessary to achieve the 26.5% level were developed outside of the Imperial Valley, Sunrise would actually reduce incremental emissions by 23,325 tons in the year 2015, or over 2.5 times the level of reductions that would be realized if Sunrise were used to transport renewable energy from the Imperial Valley. Over 40 years this would yield a potential reduction of 933,000 tons of CO_2.

The Final EIR/EIS points out that these estimates are uncertain because they are based on CAISO's assumption that the utilities will comply with 26.5% RPS whether or not Sunrise is built.[486] The Final EIR/EIS thus suggests its projections of reduced GHG emissions are dependent on actual development of renewable resources, and potentially a change in the RPS law. However, the Final

[485] The CAISO's response to Request ISO-4 (Exhibit CAISO I-16, p. 1) identifies several California wind and geothermal projects in northeast California that would need to be developed in order to reach 26.5% renewables in 2015 without Sunrise. CAISO Exhibit I-2, Table 2.1, identifies transmission additions associated with these and other incremental renewable resources. These include a 1,000 MW transmission line to northeast California.

[486] Final EIR/EIS, Sec. D.11-50.

EIR does not conclude that this renewable development needs to occur in the Imperial Valley, only that it needs to occur. The Final EIR/EIS concludes that absent this projected level of renewable resources, Sunrise may not offset the estimated 109,000 tons of construction-related CO_2 emissions.[487]

13.1.1. Parties' Positions

SDG&E initially argued that Sunrise would reduce GHG emissions by over one half million tons of CO_2 emissions per year and that the Imperial Valley renewable development supported by Sunrise would dwarf Sunrise construction-related emissions.

SDG&E's revised position agrees with the Final EIR/EIS in claiming that Sunrise would reduce CO_2 by 8,955 tons in 2015 for a total of 358,000 tons over a 40-year period.[488] This figure does not account for Sunrise's construction-related CO_2 emissions. DRA confirms this estimate, but argues that neither SDG&E's nor CAISO's GridView modeling should be relied upon to estimate GHG impacts because of their embedded assumptions. UCAN objects to relying on the CAISO's GridView modeling to estimate GHG impacts, and argues that Sunrise will likely increase coal fired generation, thereby increasing GHG emissions, rather than reducing them.[489]

SDG&E contends that the EIR/EIS estimates of net construction-related CO_2 emissions are overly conservative because there is no quantification of construction-related CO_2 emissions associated with building transmission for

487 Final EIR/EIS, D.11-55.

488 SDG&E Phase 2 Opening Brief, 87.

489 UCAN Phase 1 Reply Brief, 30.

other facilities that would need to be built to meet RPS targets if Sunrise is not built.[490]

While Conservation Groups emphasize that construction-related GHG impacts must be mitigated,[491] they focus on whether renewable resources will actually flow on Sunrise in amounts sufficient to offset the GHG impacts generated by Sunrise's construction and WECC-dispatch impacts. Conservation Groups argue that without a guarantee that renewables will flow over Sunrise, there are no guarantees that CO_2 emission reductions associated with WECC-dispatch impacts (operational CO_2 emissions) will compensate for construction-related CO_2 emissions.[492] They propose that we ensure reductions in operational CO_2 emissions by requiring SDG&E to contract with viable renewables whose output would fill Sunrise. Conservation Groups cite to a Minnesota example, where regulators conditioned their approval of the line in this way.[493]

SDG&E urges the Commission to ignore Conservation Groups' "Minnesota approach." SDG&E points out that it already "has a Commission-approved power purchase contract with Stirling that contemplates three stages of development up to a total of 900 MW. In addition, SDG&E has a Commission-approved power purchase contracts [sic] with Esmeralda Energy for 20 MW and has entered into power purchase contracts with Bethel Energy for 98.8 MW… all of which will be located in the Imperial Valley and will be deliverable across

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490 SDG&E Phase 2 Opening Brief, 89.

491 Conservation Groups Phase 2 Opening Brief, 66.

492 Conservation Groups Phase 2 Opening Brief, 66-67.

493 Conservation Groups Phase 2 Opening Brief, 29-30, referring to *Order Granting Certificates of Need Subject to Conditions,* Minnesota Public Utilities Commission, Docket No. E-002/CN-01-1958 (March 11, 2003).

Sunrise."[494] SDG&E also claims that there are numerous Imperial Valley renewable generators "lining up at the door waiting for Sunrise to be built." [495] Thus, SDG&E argues that the Commission can disregard the possibility that Stirling might not be viable in assessing GHG impacts.

13.1.2. Discussion

While we agree with DRA and UCAN that GridView modeling has a number of faults, we do find it provides useful high level information. In the Compliance Exhibit, CAISO did not update its 2015 GridView modeling, but it did correct the emission rate errors from Phase 1. Its final quantification of GHG emissions matches that of the Final EIR/EIS and is within 5 tons of SDG&E's own correction.[496]

We conclude that it is likely that Sunrise in combination with renewable penetration of 26.5% or higher will generate GHG reductions by displacing some fossil fired generation. However, we have insufficient information to conclude that the amount of operational CO_2 emission reductions resulting from Sunrise combined with 20% renewable penetration would be sufficient to offset Sunrise's construction-related CO_2 emissions as the CAISO did not model a 20% renewables case.

We assume the construction-related CO_2 emission estimates in the EIR/EIS. We agree with Conservation Groups that construction-related GHG emissions should be mitigated to the maximum extent possible and we have addressed that in the EIR/EIS mitigation measures. We also agree with SDG&E

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[494] SDG&E Phase 2 Reply Brief, 75.

[495] SDG&E Phase 2 Reply Brief, 76.

[496] CAISO's Compliance Exhibit finds Sunrise would reduce CO_2 emissions in 2015 by 8,949 tons.

that the construction-related CO_2 emission estimates in the Draft EIR/EIS are conservative given the lack of a reference case in which additional transmission is built to meet the RPS targets.. However, as noted by SDG&E, there is no information in the record to support a modification of these estimates.

Based on the assumption that Sunrise's two-year construction will generate over 100,000 tons of CO_2, we share Conservation Groups' concern regarding whether Sunrise will generate sufficient operational CO_2 emission reductions to offset these construction-related impacts absent an aggressive GHG reduction policy implemented by SDG&E. SDG&E has stated that it does not have a written policy or plan to reduce GHG emissions,[497] stating that it will "…comply with the goal—with the state laws. That is our policy."[498]

CAISO modeling has shown that Sunrise could potentially carry significant fossil fueled power because of its projected availability and cost, and a portion of this power may be coal fired. However, as noted above, CAISO modeling also indicates that whether or not Sunrise carries renewable energy from the Imperial Valley, Sunrise in combination with renewable penetration of 26.5% results in reductions in operational CO_2 emissions relative to the base case. The range of GHG savings relative to the base case runs from 8,950 tons CO_2 per year if Imperial Valley Renewables are developed to 23,325 tons of CO_2 emissions per year if Imperial Valley renewables are replaced instead with renewables developed elsewhere.[499,500]

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497 RT 3256; SDG&E Phase 2 Reply Brief, 88.

498 SDG&E Phase 2 Reply Brief, 88.

499 CAISO Exhibit 1-16.

500 We note that while the projected operational CO_2 emissions reductions for Sunrise are fairly large relative to the line's estimated construction-phase emissions, these amounts are miniscule when considered in the context of overall WECC-wide

Importantly, CAISO's analysis did not include a scenario in which the level of renewable penetration is assumed to be dependent on the availability of Sunrise. This limits, for example, our ability to assess the relative GHG impacts of Sunrise relative to a base case in which less renewable energy is available than if Sunrise had been built. However, it seems reasonable to assume that this would cause a relative increase in base case GHG emissions, thereby increasing the GHG savings that could be attributed to Sunrise if it were built.

Given CAISO's analyses and the implications thereof we think it is reasonable to conclude that Sunrise will yield significant GHG emission reductions relative to what would occur absent its construction if one accepts the assumption that in all cases the same level of renewable development will occur. Conservation Groups express a concern and solution to that concern that appears to be premised in part on a relaxation of this assumption by suggesting that unless Sunrise is explicitly dedicated to transporting renewable energy from the Imperial Valley, the GHG benefits of the line will be compromised. Implicitly, this assumes that unless the line leads to development of Imperial Valley renewables, fewer renewables overall will be developed than otherwise would be statewide. As the CAISO analysis demonstrates, and the EIR essentially accepts, this is not necessarily the case. It may be that in the absence of Imperial

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emissions. In its responses to our environmental consultant's data requests, CAISO only projected differences in WECC-wide CO_2 emissions between its Base case and alternatives (including Sunrise). However, projections recently presented by E3 at a Western Climate Initiative workshop help place these figures in perspective: E3 projected that in 2020 WECC-wide CO_2 emissions will be 432 MMT CO_2 per year. The estimated impacts presented in the EIR/EIS are derived by projecting WECC-wide emissions under different scenarios and calculating the difference between the transmission alternatives and the Base Case. The differences are on the order of a few one thousandths of a percentage point of WECC-wide emissions. For E3 projections see: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F20156.PDF.

Valley renewable development, other renewable resources will be developed in their stead. Indeed this would certainly be the case if a statewide mandate of 33% renewables by 2020 is adopted and fully implemented, as we have recommended and CARB appears poised to require.

We, therefore, do not think it reasonable to impose the "Minnesota approach" offered by Conservation Groups as a solution, at least not on the basis of the CAISO analysis, given the speculative nature of the problem this solution purports to solve.

Our choice to not impose the "Minnesota approach" should not be interpreted as a lack of commitment to achieving the environmental goals we have established. We cannot stress enough that we remain fully committed to meeting and exceeding California's already ambitious renewable energy and climate change related policies and goals. The record before us clearly demonstrates that one of the main goals of Sunrise is to access renewable resources – much of which are baseload geothermal resources – that otherwise would not be available. We want to be certain that construction of Sunrise will facilitate the development of renewable resources in the Imperial Valley. However, we do not believe that we need to subject SDG&E to additional compliance requirements.

We reach this conclusion based on several factors. First, we already have in place several very aggressive environmental goals - AB32, SB1368,[501] and the RPS statutes, each of which on its own requires that SDG&E continue to

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[501] SB 1368 (Stats. 2006, c. 598) prohibits IOUs from entering into long-term contracts (greater than five years in duration) with any resource that has an emission rate greater than 1,100 lbs/MWh.

aggressively procure renewable resources. In addition, pursuant to AB 57[502] SDG&E is required to file biannual long-term procurement plans. Subject to that procurement plan, SDG&E must file for Commission approval, any long-term contract. Pursuant to SB 107[503] SDG&E is required to file annual RPS procurement plans. SDG&E must file any RPS eligible contract with the Commission for approval.

In order to effectively implement and monitor our procurement policies, we require several periodic reports be filed with the Commission. These reports include:

- semi-annual RPS compliance report
- semi-annual RPS project status report
- quarterly procurement transaction compliance report

In addition to these reporting requirements we require that SDG&E consult with a procurement review group and utilize an independent evaluator when conducting competitive procurement. Put simply, SDG&E must comply with all applicable state and federal environmental laws as well as the various procurement policies established by this Commission. Each of these State laws and Commission procurement policies carry penalties associated with noncompliance. We currently have multiple avenues in which we can monitor, evaluate, influence and enforce investor-owned utility compliance with our policies. We see no need to add an additional compliance requirement in order to guarantee that renewable generation is delivered via Sunrise.

Further, we agree with SDG&E that it should expeditiously seek to replace any Sunrise dependent RPS contract that, for one reason or another, is

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[502] AB 57 (Stats. 2002, c. 850, Sec. 3) is codified at § 454.5.

[503] Stats. 2006, c. 464.

determined to no longer be viable.[504] We believe that aggressively procuring renewable resources, especially those in the Imperial Valley will provide significant benefits to SDG&E's ratepayers.

Should SDG&E deviate from the stated purposes of Sunrise – especially with respect to the development of renewable resources – we shall not hesitate to bring forth appropriate sanctions.

13.2. GHG Impacts of the Proposed Alternatives

The Draft EIR/EIS estimates the operational and construction CO_2 emissions associated with the various Sunrise routing alternatives. The Draft EIR/EIS does not provide a reference case for those estimates, other than the environmental baseline required by CEQA, nor does it quantify the GHG impacts of any of the generation alternatives set forth in the Draft EIR/EIS. The Draft EIR/EIS acknowledges that, with regard to the generation alternatives, the total amount of construction, the duration of construction, and the intensity of construction activity would have a substantial effect upon the amount of construction-related CO_2 emissions. It assumes that certain alternatives could be built without exceeding the 109,000 tons of CO_2 emissions estimated for Sunrise, but that other larger-scale projects would trigger comparable or greater emissions.

The Final EIR/EIS includes clarifications to allow a comparison of the alternatives to Sunrise. It shows that while building transmission lines causes significant GHG emissions, building and operating a new fossil fueled power plant would cause substantially more GHG emissions.[505] Lacking a specific reference case for quantification, the Final EIR/EIS concludes that the All-Source

[504] RT 8 – 10.

[505] Final EIR/EIS, 2-44.

Generation Alternative described in that document would greatly increase GHG impacts compared to Sunrise.

13.2.1. Parties' Positions

SDG&E claims that the All-Source Generation and LEAPS Transmission Plus Generation Alternatives in the Draft EIR/EIS are similar to certain CAISO GridView cases.[506] SDG&E then concludes that the All-Source Generation Alternative in the Draft EIR/EIS emits approximately 200 times more CO_2 than Sunrise, while the LEAPS Generation Plus Transmission Alternative emits approximately 110 times more CO_2 than Sunrise.[507]

UCAN takes issue with these SDG&E estimates. Among other things, UCAN argues that it is unreasonable to assume an increase in GHG emissions in 2015 associated with the South Bay Repower Project (a potential component of the All-Source Generation Alternative) since SDG&E's analysis fails to quantify GHG emissions associated with generation elsewhere in WECC.[508]

13.2.2. Discussion

We agree with the EIR/EIS that it is likely some of the alternatives will have less and some will have more GHG construction-related impacts than Sunrise, and that these emission impacts are difficult to quantify accurately given the number of unknown variables. We also agree with the Final EIR/EIS that the All-Source Generation Alternative will greatly increase GHG impacts relative to Sunrise.

We reject SDG&E's attempts to quantify the GHG emission impacts of the Sunrise alternatives. SDG&E gives no basis for its contentions that the cases

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[506] SDG&E Exhibit SD-35, 4.21.

[507] SDG&E Phase 2 Opening Brief, 90.

[508] UCAN Phase 2 Reply Brief, 19.

analyzed by CAISO are in any way comparable to those defined in the Draft EIR/EIS. CAISO's Part 2 testimony (which SDG&E cites as the source of its estimated emissions levels) does not address GHG emissions, nor does it provide updated GridView modeling. In addition, SDG&E provides no record of conducting the updated production cost modeling that would be necessary to derive WECC-wide estimates of GHG emissions related to Sunrise alternatives.

14. The Northern Routes' Anza-Borrego Link

Because the routing of the Proposed Project, the "Enhanced" Northern Route, and the Final Environmentally Superior Northern Route through Anza-Borrego touches on a host of issues addressed by many of the participants in this proceeding, for increased clarity we address those issues here, apart from the rest of the environmental discussion in Section 16 of this decision.

14.1. Overview of the Proposed Project's Route through Anza-Borrego

One of the most notable and troubling aspects of Sunrise is that SDG&E proposes to site 22.6 miles of the Proposed Project through Anza-Borrego, which many consider the "crown jewel" of the California State Park system.[509] SDG&E's proposal would route the new transmission line through Anza-Borrego in place of a 69-92 kV line constructed in the 1920s, prior to Anza-Borrego's designation as a State Park. That existing line is suspended from wood poles with an average height of 60 feet. The Proposed Project would replace the wood poles with 144 500 kV steel towers, each of which averages 130 feet in height and spans 85-105 feet at the base.[510] The existing 92 kV line (east of Narrows Substation) and 69 kV line (west of Narrows Substation) would be installed

[509] See public statements quoted in Section 1.

[510] Draft EIR/EIS, ES-3.1, B.3.1 (Figure B-15 and Figure B-19), D.5-31 (Impact WR-2).

underground or would be added to the 500 kV towers as an "underbuild." The existing wood poles would be removed.[511]

The Proposed Project is significantly larger and more invasive, both physically and visually, than the existing 69-92 kV wood pole line. Siting, construction, and maintenance of the 500 kV line would require de-designation of approximately 50 acres of state wilderness.[512] Construction and maintenance of the 500 kV line would result in helicopters near or in wilderness areas and would require 8 new miles of access roads.[513] The taller, wider structures would be much more visible from wilderness areas and extremely noticeable in certain campgrounds located in Anza-Borrego.[514]

The path of the Proposed Project follows the right-of-way within Anza-Borrego currently occupied by the wood poles. However, as discussed in Sections 14.3.3, the legal rights to the right-of-way are hotly contested, and it is unclear how much additional right-of-way SDG&E needs to acquire, from whom SDG&E must acquire it, or what additional permits are necessary before the steel towers could be built through the corridor occupied by the old, wood pole line.

14.2. Anza-Borrego's Place in the State Park System

[511] In order to stay within a narrower right-of-way, SDG&E's "Enhanced" Northern Route requires more towers than the Proposed Project or the Final Environmentally Superior Northern Route, and the height of those towers is greater. Both factors result in greater environmental impacts than either the Proposed Project or the Final Environmentally Superior Northern Route.

[512] Draft EIR/EIS, ES-5.3.

[513] RT 5176; Draft EIR/EIS, ES-3.1.

[514] Draft EIR/EIS, ES-5.3, ES-7.1.2; RT 3727-3728, 3765-3766.

Anza-Borrego was established in 1957, when the former Anza Desert State Park and the Borrego State Park were combined.[515] This Park of 600,000 plus acres[516] is among the largest state parks in the United States.[517] It includes about 460,000 acres of state wilderness,[518] which not only represents the largest area of state wilderness in California,[519] but also 80% of all state wilderness within this state. In 1974, the Secretary of the Interior approved Anza-Borrego's designation as a National Natural Landmark[520] and in 1981 and 1982, the State Parks and Recreation Commission classified approximately two-thirds of the acreage then comprising the Park as state wilderness[521] to be held "unimpaired for all generations."[522] In 1985, the United Nations named Anza-Borrego a member of the International Biosphere Reserve Program.[523]

The Park consists of washes, alluvial fans, badlands, and vast open spaces. Wildflowers, palm groves, and cacti, along with golden eagles, peninsular bighorn sheep, kit foxes and desert iguanas, as well as numerous other forms of plant and animal life, call Anza-Borrego home.[524] Two national trails run

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[515] Draft EIR/EIS, Sec. D.2.1.2.1.

[516] State Parks Foundation Exhibit P-1, 5.

[517] State Parks Phase 2 Opening Brief, 1-2.

[518] State Parks Foundation Exhibit P-1, 6.

[519] State Parks Foundation Exhibit P-2. This exhibit is the internet address for the Anza-Borrego General Plan: http://www.parks.ca.gov/?page_id=21314. The quoted portion refers to Chapter 1 of the Anza-Borrego General Plan, page 1-3.

[520] Draft EIR/EIS, Sec. D.2.1.2.1.

[521] Draft EIR/EIS, Sec. D.2.1.2.1.

[522] State Parks Phase 2 Opening Brief, 1-2.

[523] Draft EIR/EIS, Sec. D.2.1.2.1.

[524] Draft EIR/EIS, Sec. D.2.1.2.1.

through Anza-Borrego: the Pacific Crest Trail and the Juan Bautista de Anza National Historic Trail.[525]

Anza-Borrego is also a place of rich cultural heritage. Its valleys were transportation corridors throughout the prehistoric and historic period, and areas with water sources were preferred habitation locales.[526] The Park contains over a hundred archaeological sites, the majority of them prehistoric in nature. Anza-Borrego's cultural history is still alive -- local Native Americans continue to visit the area because of the extreme importance of the Park's sites to their culture and history.[527]

State Parks manages Anza-Borrego.[528] Consistent with Anza-Borrego's General Plan, ongoing management must "preserve the unique and diverse natural, cultural, and scenic resources of this Western Colorado Desert Region and provide high quality recreation that supports a healthy natural environment."[529] One of the General Plan's stated goals is to continue to expand the amount of state wilderness by adding and designating more land to the Park.[530]

As we have heard in both the formal hearings and the Public Participation Hearings, many people consider Anza-Borrego to be a unique and irreplaceable desert environment. The record is replete with testimony that confirms the

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[525] Draft EIR/EIS, Sec. D.2.1.2.1.

[526] Draft EIR/EIS, Sec. D.7.3.

[527] Draft EIR/EIS, Sec. D.7.3.

[528] State Parks Phase 2 Opening Brief, 1-2; Pub. Resources Code §§ 5001, 5019.50.

[529] State Parks Foundation Exhibit P-1, Reference #2 (Anza-Borrego Final General Plan & EIR, page XII).

[530] State Parks Foundation Exhibit P-1, Reference #2 (Anza-Borrego Final General Plan & EIR, page XII).

strong language in the Vision Statement of Anza-Borrego's General Plan, a portion of which we quote in Section 1 and which we quote more fully here:

> Anza-Borrego is a place of awe, inspiration, and refuge. The vast desert landscape and scenery are preserved in a pristine condition. The full array of natural and cultural resources are cared for so as to perpetuate them for all time while supporting those seeking enjoyment from these resources ...[531]
>
> Emphasis is placed on having park visitors experience the true, real, tangible desert environment, even if it leads to some level of uncertainty or discomfort, because this leads to personal insight and perspective only gained by first-hand knowledge…. The Park is a place where silence can be found and total darkness achieved. At this Park, the forces of nature remain undeniably stronger than human forces, and people, in general, visit, but do not remain.[532]

14.3. Legal Issues Unique to the Anza-Borrego Link

14.3.1. Anza-Borrego's General Plan

Anza-Borrego's General Plan governs State Parks' management of the Park. The General Plan's "Declaration of Purpose" recognizes the special role of the desert park environment, which "nurtures peaceful solitude, astronomical clarity, amazing forms of life, glimpses of the past, and a tremendous scope for the imagination."[533] The Declaration of Purpose provides that "management of Anza-Borrego Desert State Park will be based upon the goal of preserving,

[531] State Parks Foundation Exhibit P-1, Reference #2 (Anza-Borrego Final General Plan & EIR, page 3-8).

[532] State Parks Foundation Exhibit P-1, Reference #2 (Anza-Borrego Final General Plan & EIR, page 3-8).

[533] State Parks Foundation Exhibit P-1, Reference #2 (Anza-Borrego Final General Plan & EIR, page XII).

instilling an appreciation for, and making available these treasured qualities and experiences for present and future generations."[534]

SDG&E and State Parks disagree whether State Parks would need to amend the General Plan before SDG&E could construct a 500 kV transmission line through the Park. SDG&E claims that State Parks has overstated alleged inconsistencies between the General Plan and the Proposed Project, and argues that plan amendments are unnecessary. State Parks argues that SDG&E's position is fundamentally at odds with the authority accorded a general plan, which serves as a blueprint for management and development, and requires that subordinate actions be consistent with that blueprint.[535]

State Parks represents that it could determine *any* route through Anza-Borrego to be inconsistent with the existing Anza-Borrego General Plan on any one of three grounds:

- Conflict with the State Wilderness designation;
- Conflict with the Backcountry Zone designation; and/or
- Overall conflict with General Plan Goals and Guidelines.

If State Parks made such a determination, the State Parks and Recreation Commission would have to exercise its discretionary authority to adopt revisions to the General Plan to allow the siting and construction of such a major transmission line before State Parks could issue any permits.[536]

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[534] State Parks Foundation Exhibit P-1, Reference #2 (Anza-Borrego Final General Plan & EIR, page XII).

[535] State Parks Phase 2 Opening Brief, 5.

[536] State Parks Phase 2 Opening Brief, 2, 8.

SDG&E challenges State Park's position that routing the transmission line through Anza-Borrego could be inconsistent with the General Plan.[537] SDG&E relies, in part, on the statement in the General Plan that "[r]econciling the inherent conflicts between the future electrical needs of the State and the protection of Park resources, will require the utility companies and State Parks to work closely together in planning for the size and location of these future facilities."[538] It also relies upon one of the General Plan's goals for infrastructure and operations within Anza-Borrego, "Infrastructure Goal 4," which directs State Parks to "work with local agencies, Caltrans, and utility companies to minimize the adverse impacts associated with developments."[539]

State Parks disagrees with SDG&E's interpretation of the General Plan's goals and guidelines, and argues that Infrastructure Goal 4 should be seen "at best, as a modest accommodation for an existing use otherwise at odds with the statutory guidance for management of State Parks."[540] That statutory guidance provides that "[i]mprovements that do not directly enhance the public's enjoyment of the natural, scenic, cultural, or ecological values of the resource … shall not be undertaken."[541] State Parks acknowledges that its General Plan does not exclude all new transmission facilities in the Backcountry Zone, but contends that both the Proposed Project and the "Enhanced" Northern Route could be found inconsistent with the Backcountry Zone due to their size and scope.[542]

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[537] SDG&E Phase 2 Opening Brief, 42.

[538] SDG&E Exhibit SD-35, Attachment 6-3 at 2-96.

[539] SDG&E Exhibit SD-35, Attachment 6-3 at 3-52.

[540] State Parks Phase 2 Opening Brief, 14.

[541] Pub. Resources Code § 5019.53.

[542] State Parks Phase 2 Reply Brief, 3.

The General Plan also requires State Parks to "preserve sensitive species and habitats and encourage their recovery" and "[e]nsure … that the protection of sensitive species and habitats receives the highest priority."[543] This requirement has implications, in particular, for Peninsular bighorn sheep and its critical habitat, which we discuss in greater detail in Section 14.4.1.2. Critical habitat for Peninsular bighorn sheep was certified in order to promote the recovery and survival of a federally endangered species.[544] Based on the evidence and its own position in this proceeding, State Parks reasonably could conclude that the Proposed Project, and the two other Northern Routes, would significantly harm the Peninsular bighorn sheep's critical habitat and therefore inhibit the bighorn sheep's recovery and survival.[545]

A number of parties have identified specific General Plan Goals and Guidelines which may be inconsistent with both the Proposed Project and the "Enhanced" Northern Route. We mention of few of these here:

> **Goal Recreation 1:** Maintain the Park's qualities of solitude and wildness. Management decisions will favor the desert environment, promote the health and well being of desert ecosystems, and promote those activities that are sustainable over time in providing for the health, inspiration, and education of Californians.[546]

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[543] Anza-Borrego General Plan, Guidelines – Biota 1a and 1c, 3-24, 3-25.

[544] Draft EIR/EIS, Sec. D.2.11.

[545] Draft EIR/EIS, Sec. D.2.11, D.16.4.2; Conservation Groups Exhibit C-23, C-24.

[546] State Parks Foundation Exhibit P-2, 3-42.

State Parks contends that the scope and size of the transmission facilities defeat Recreation Goal 1 since the Proposed Project would be visible from a large portion of state-designated wilderness.[547]

> **Landscape Linkages Goal Link-1:** Maintain and enhance the movement and dispersal of native animals and plants through the Park and the regional ecosystems.[548]

Because the Proposed Project would create new physical barriers, especially in areas like Grapevine Canyon, State Parks reasonably could find that these barriers frustrate native species movement and therefore interfere with Landscape Linkages Goal Link-1.

> **Cultural Resources Goal 2**: Identify, protect, and interpret places within [Anza-Borrego] holding special cultural or religious significance to Native Americans and other ethnic communities.[549].
>
> **Cultural Resources Goal 3**: Protect, stabilize, and preserve cultural resources within Anza-Borrego.[550]
>
> **Cultural Resources Guideline 4c**: Future management plans will identify areas of the Park with highly significant cultural remains that warrant higher levels of protection. Recommended protective actions may include Superintendent-ordered closures and designation of certain areas as Cultural Preserves.[551]

SDG&E has acknowledged that the "Enhanced" Northern Route, which would require installation of 500 kV transmission towers through a Traditional Cultural Property, may be inconsistent with many of the Cultural Resources

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[547] State Parks Phase 2 Opening Brief, 15.

[548] State Parks Foundation Exhibit P-2, 3-29.

[549] State Parks Foundation Exhibit P-2, 3-32.

[550] State Parks Foundation Exhibit P-2, 3-32.

[551] State Parks Foundation Exhibit P-2, 3-35.

Goals and Guidelines in the Anza-Borrego General Plan.[552] SDG&E has conceded that the "Enhanced" Northern Route would create a greater adverse impact on the Grapevine Canyon cultural site than would the Proposed Project.[553]

We do not presume upon State Parks' decisionmaking authority, but rather seek to inform our own jurisdictional determination. Both on the facts and on the law, SDG&E's position is unpersuasive. While we cannot ascertain definitively whether or not State Parks would find the Proposed Project and the two other Northern Routes inconsistent with Anza-Borrego's General Plan, we conclude that State Parks reasonably could, and likely would, so find based on its own submissions and the evidence in this proceeding.

14.3.2. The California Wilderness Act and Potential Wilderness De-designation

We are bound to consider the exercise of our authority in the context of other law that governs the use of the land at issue -- in this case, the implications of the California Wilderness Act for the Proposed Project and the two other Northern Routes.[554] The EIR/EIS does so[555] and our Phase 2 hearings also examined pertinent issues.

The California Wilderness Act begins with a declaration of state policy to preserve the "enduring resource of wilderness" against future encroachment:

> [It is] the policy of the State of California to secure for present and future generations the benefits of an enduring resource of

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[552] RT 3960:8-13.

[553] RT 3966:1-12.

[554] The California Wilderness Act is codified at Pub. Resources Code § 5093.30 et seq.

[555] Draft EIR/EIS, Sec. D.5.3.

> wilderness... ***[i]n order to assure that an increasing population…does not occupy and modify all areas on state-owned lands within California, leaving no areas designated for preservation and protection in their natural condition***.[556]

The Act establishes a California wilderness preservation system composed of state-owned areas designated by the Legislature as "wilderness areas" and units of the state park system classified as "state wilderness" by State Parks. Anza-Borrego contains both types of areas; with the exception of All Underground Option for the Final Environmentally Superior Northern Route, all Northern Route Alternatives would pass through wilderness lands classified as such by State Parks.

The California Wilderness Act defines state wilderness as:

> [A]n area where the earth and its community of life are untrammeled by man, where man himself is a visitor who does not remain. A wilderness area… is an area of relatively undeveloped state-owned land which has retained its primeval character and influence or has been substantially restored to a near natural appearance, without permanent improvements or human habitation, other than semi-improved campgrounds and primitive latrines, and which is protected and managed so as to preserve its natural conditions . . . . [557]

The California Wilderness Act specifically prohibits both temporary and permanent encroachments into state wilderness.[558] Except for property rights that preexist a wilderness designation,

> [T]here shall be no commercial enterprise and no permanent road within any wilderness area and, except as necessary in emergencies involving the health and safety of persons within

[556] Pub. Resources Code § 5093.31 (emphasis added).

[557] Pub. Resources Code § 5093.33(c).

[558] Pub. Resources Code § 5093.36(b).

> the wilderness area, there shall be no temporary road, no use of motor vehicles, motorized equipment, or motorboats, no landing or hovering of aircraft, no flying of aircraft lower than 2,000 feet above the ground, no other form of mechanical transport, and no structure or installation within any wilderness area.[559]

Though no other party agrees, SDG&E argues that the land occupied by the 60 foot high wooden poles installed roughly 80 years ago (and prior to the wilderness designation) is already "disturbed" and therefore, that the California Wilderness Act is not at issue.[560] We disagree. The record establishes that the wood pole line passes through land that carries a state wilderness designation and the EIR/EIS exhaustively documents the environmental damage to Anza-Borrego that would occur if any of the Northern Routes are constructed, including permanent damage to its historic and aesthetic resources. Impacts of this sort do not meet specified exemption criteria and the magnitude of such impacts cannot be reconciled with the California Wilderness Act's comprehensive charge to protect and preserve wilderness for future generations.

The EIR/EIS concludes that the Proposed Project's Anza-Borrego Link will encroach upon 50.2 acres of state wilderness. Most of this acreage is attributable to the Proposed Project's need to deviate from the existing wood pole line right-of-way in Anza-Borrego by 50 feet in order to address engineering concerns associated with installing taller towers and heavier lines, and to avoid particular environmental impacts in the Park. This deviation encroaches upon 48.1 acres within the Pinyon Ridge Wilderness Area and 1.3 acres within the Grapevine Mountain Wilderness Area. Encroachments require the formal de-designation of

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[559] Pub. Resources Code § 5093.36(b) (emphasis added). Limited exemptions from this law exist, such as operating aircraft for the purposes of "the aerial stocking of fish or the conduct of aerial surveys of wildlife species. Pub. Resources Code § 5093.36(c)5.

[560] RT 3280.

state wilderness – something that has never been done in California.[561] All of the affected wilderness would have to be de-designated.

In addition, transmission line footings necessitate disturbances, and in some places, encroachments, and construction and maintenance processes will disturb land both inside and outside of the wilderness zone in a manner that has not occurred before in this area. In the Vallecito Mountains Wilderness Area, for example, portions of three temporary pull sites needed to string 500 kV conductors for the Proposed Project will result in impacts to nearly another acre of wilderness, which would have to be de-designated.[562]

We find no support for SDG&E's contention that the Wilderness Act does not apply here. Further, the protections the Act mandates provide no exemption for projects like a major transmission line. As we discuss more fully in Section 14.5, the environmental damage to Anza-Borrego that would result from construction of any of the Northern Routes militates heavily against any order by this Commission that would require de-designation of wilderness.

14.3.3. SDG&E's Right-of-Way through Anza-Borrego

The Proposed Project would require a continuous right-of-way through Anza-Borrego, 150 feet wide. This route requires an expansion in SDG&E's existing right-of-way by at least 50 feet into the designated wilderness area along most of the route. As previously noted, SDG&E developed the "Enhanced" Northern Route primarily to respond to concerns about the Proposed Project's

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[561] State Parks, Phase 2 Reply Brief, 2; Draft EIR/EIS, Sec. D.5.3.

[562] In comments on the Draft EIR/EIS, SDG&E modified its "Enhanced" Northern Route to eliminate all pull sites and access roads with direct impacts on wilderness.

impacts on wilderness lands in Anza-Borrego and purports this new route would keep all transmission facilities within the existing 100-foot right-of-way.

SDG&E, BLM, Imperial Irrigation District and State Parks contest the width and continuity of the existing easement through Anza-Borrego.[563] While we agree with SDG&E that this proceeding is not the forum to determine the validity of SDG&E's property rights, the issue is relevant in determining of the feasibility of the line.[564] We summarize below the evidence on the problems[565] that could arise if we were to grant a CPCN for any Northern Route.

Examination of the land records along the existing wood pole line corridor shows that in some areas there is no recorded right-of-way or reservation of right in SDG&E's favor.[566] In other areas, there is a recorded right-of-way, but the recorded documents do not specify its width. Additionally, where ownership rights are not at issue, but where SDG&E has no easement, the utility may be unable to acquire the necessary right-of-way. For example, in order to pursue a Northern Route, SDG&E must use right-of-way owned by Imperial Irrigation District and currently occupied, in part, by a 92 kV transmission line. However, Imperial Irrigation District has not agreed to the relocation of its own transmission line or to SDG&E's use of that right-of-way in Anza-Borrego.[567]

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[563] State Parks Phase 2 Reply Brief, 14.

[564] SDG&E Phase 2 Opening Brief, 9.

[565] State Parks Exhibit PR-10, 1-4.

[566] Draft EIR/EIS, Sec.B.2.2.

[567] Imperial Irrigation District Phase 2 Reply Brief, 7; Imperial Irrigation District Exhibit ID-4, 3:22-4:6.

SDG&E has not established that it could condemn Imperial Irrigation District's property.[568]

Given these facts, approval of a Northern Route likely would lead, at minimum, to a complex and significant debate among SDG&E, BLM, Imperial Irrigation District and State Parks over the legal status and rights associated with easements through Anza-Borrego and the courts may be called upon to resolve the issue. We cannot rule out the possibility that SDG&E may be unable to obtain the easements needed for a Northern Route. Regardless, this unresolved dispute easily could delay construction of an approved Northern Route and thus influences our view on the feasibility and reasonableness of a Northern Route.

14.4. Overview of the Environmental Impacts on Anza-Borrego

As described in more detail below (and in Section D of the EIR/EIS), all of the Northern Routes traverse Anza-Borrego. Because of the fragile nature of the desert ecosystem, any route through Anza-Borrego will have numerous significant and long-lasting unavoidable environmental impacts on the Park. We review here the specific environmental impacts that would be created by each Northern Route.

14.4.1. Environmental Impacts of the Proposed Project

See Section 3.2.1 for a description of the Proposed Project.

14.4.1.1. Parties' Positions

SDG&E argues the EIR/EIS overstates the environmental impacts of the Propose Project on biological resources, avian species, cultural resources and

[568] SDG&E Phase 2 Opening Brief, 33-39. SDG&E has established only that it holds some easements outside the eastern entrance to Anza-Borrego and limited easements within Anza-Borrego.

agricultural lands. Furthermore, SDG&E contends, that to the extent that the Proposed Project will cause environmental impacts in the Park or elsewhere along the route, the utility has developed a range of comprehensive and effective avoidance and minimization measures to address those impacts.

Other parties disagree. Conservation Groups contend that the Draft EIR/EIS is deficient in many respects and therefore underestimates the environmental impacts of the Proposed Project (and the two other Northern Routes). Conservation Groups assert the deficiencies in the Draft EIR/EIS include failures to conduct a proper survey of plant species, to fully survey bird data as a basis for a proper evaluation of risk to avian species, to consider adequately the impacts of roads and other forms of habitat fragmentation, and to consider adequately the impacts to regional conservation plans. Conservation Groups also assert that the Proposed Project will harm the already endangered Peninsular Bighorn Sheep in and near Anza-Borrego and that the GHG emissions from construction will violate state law and policy. Conservation Groups conclude that the Proposed Project (and other Northern Routes) will have significant environmental impacts on parks, forests, wilderness, recreation areas, public lands, public and private preserves, threatened and endangered species, landscape level impacts on the ecosystem, ecosystem services, and regional conservation plans.

UCAN asserts that the Proposed Project's environmental impacts are among the most significant of any of the alternatives. With respect to the Proposed Project's impacts on Peninsular bighorn sheep, UCAN argues that SDG&E has tried to minimize impacts by inaccurately characterizing the way the transmission line would intersect Peninsular bighorn sheep habitat.

14.4.1.2. Discussion

As we discuss in Section 16.1, below, the Final EIR/EIS concludes that the Proposed Project ranks as the sixth worst alternative among the eight alternatives in terms of its environmental impacts. The Proposed Project has 52 significant, unavoidable environmental impacts (in one or more geographic areas) and will create numerous, direct impacts within Anza-Borrego, including de-designation of state wilderness (discussed in Section 14.3.2), degradation of views and recreational opportunities, impacts on Traditional Cultural Properties, and severe visual effects in the Santa Ysabel Valley. The significant unavoidable impacts affect plants and animals (including endangered species), views, wilderness and recreation, farms, cultural and paleontological sites, noise, air quality, socioeconomics, public services and utilities, and fire and fuels management. We summarize some of the major impacts below.

Aesthetically, the Proposed Project would create a new row of 130-foot tall steel towers and conductors visible from many locations, including across many acres of state wilderness. The Proposed Project would "result in increased structure contrast, industrial character, view blockage, and skylining from eight locations that represent the majority of public views through the State Route 78 and Grapevine Canyon areas of the Park."[569] In addition, once degradation occurs, repair and restoration of the fragile desert environment can take many years. For example, land scarring from use of staging areas and construction yards, construction of new access and spur roads, and activities adjacent to construction sites and along the right-of-way can last years, if not decades, in arid and semi-arid environments where vegetation recruitment and growth are

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[569] Draft EIR/EIS, ES-5.2.

slow.[570] In-line views of linear land scars or newly bladed roads are particularly problematic and introduce adverse visual change and contrast by causing unnatural vegetative lines and soil color contrast from newly exposed soils.[571] While mitigation measures could be imposed to reduce this type of impact, some site-specific conditions may dictate that the only way to reduce the impact to a less than significant level is to construct the project by helicopter.[572]

We disagree with SDG&E's contention that the scope and scale of the "disturbances" to the desert associated with the building of the wood pole line 80 years ago are similar to those that will result from construction of a new, permanent and highly visible, 500 kV steel tower transmission line. The EIR/EIS documents that the Proposed Project and the other two Northern Routes will cause numerous and extensive, significant, unmitigable environmental impacts.

The Proposed Project's environmental impacts affect the following special status species[573]: Peninsular bighorn sheep (a federally and State listed endangered species), flat-tailed horned lizards, golden eagles, quino checkerspot butterflies (a federally listed endangered species), and barefoot banded geckos.[574] Among these impacts, the greatest risk is to endangered bighorn sheep in the Peninsular Ranges. Without obtaining a federal permit from United States Fish and Wildlife Services (US Fish and Wildlife), it is illegal to "take" endangered or threatened species. "Take" is defined as "to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to engage in any such

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570 Draft EIR/EIS, Sec. D.2.5.

571 Draft EIR/EIS, Sec. D.3.6.

572 Draft EIR/EIS, Sec. D.3.6.

573 As defined in the Draft EIR/EIS, Sec. D.2.

574 Draft EIR/EIS, ES.5.2.

conduct."[575] "Harm" includes any act that actually kills or injures fish or wildlife, including significant habitat modification or degradation that significantly impairs essential behavioral patterns of fish and wildlife.

On February 1, 2001, US Fish and Wildlife designated final critical habitat for the Peninsular bighorn sheep on approximately 844,897 acres in Riverside, San Diego, and Imperial Counties.[576] The Proposed Project's Imperial Valley and Anza-Borrego Links pass through an extensive section of bighorn sheep critical habitat.[577] Without obtaining the requisite permit from US Fish and Wildlife, it is illegal to do anything that results in impacts to critically designated habitat.[578]

In 2004 approximately 700 Peninsular bighorn sheep were living range wide in Southern California, including an estimated 400 to 450 in Anza-Borrego.[579] Decline of the Peninsular bighorn sheep is attributed to the following factors: habitat loss, degradation, and fragmentation; disease from domestic cattle; low lamb survival rates; and predation coinciding with low population numbers.[580] In addition, numerous researchers have expressed concern over the impact of human activity on these animals. As a wilderness animal, Peninsular bighorn sheep fail to thrive in contact with urban development.[581] Installation of transmission towers, stringing the lines (possibly by helicopter), the presence of transmission towers and lines, creation and use of access roads, and maintenance

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[575] Draft EIR/EIS, Sec. D.2.3.1.

[576] Draft EIR/EIS, Sec. D.2.1.2.1.

[577] Draft EIR/EIS, Sec. D.2.1.2.2.

[578] Draft EIR/EIS, Sec. D.2.3.1.

[579] Draft EIR/EIS, Sec. D.2.11.

[580] Draft EIR/EIS, Sec. D.2.11.

[581] Draft EIR/EIS, Sec. D.2.11.

activities in Peninsular bighorn sheep habitat could cause bighorn sheep to avoid affected areas and could interfere with the use of resources such as escape terrain, water, mineral licks, rutting, lambing, or feeding areas, the use of traditional movement routes, and/or could cause physiological stress or increased predation. Based on the high sensitivity of this species and evidence that shows that human activities significantly affect it, the EIR/EIS determines that these impacts would adversely affect survival and recovery of the species. Although the EIR/EIS proposes a number of mitigation measures to help reduce the impacts to Peninsular bighorn sheep, it finds that the impact would remain significant and unavoidable.[582]

For the reasons described above, Peninsular bighorn sheep may avoid areas near the Proposed Project and not migrate to land below it. If this occurs, transmission line would sever the entire United States population into two separate populations. Field observations and genetic analysis establish that gene flow historically has occurred throughout the range, and that it continues today.[583] Severing the population may increase the entire population's risk of genetic and demographic extinction, because smaller and isolated populations tend to have a higher risk of extinction than larger and interconnected ones.[584]

Habitat fragmentation also may result in a loss of habitat diversity[585] by restricting Peninsular bighorn sheep from using the full range of resources they need to survive. Desert bighorn sheep live in a harsh environment and their survival depends on their ability to move among various resources over different

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[582] Draft EIR/EIS, D.2.11.

[583] Conservation Groups Exhibit C-23, 6.

[584] Conservation Groups Exhibit C-23, 6.

[585] Conservation Groups Exhibit C-23, 6.

time periods, some very short and some much longer. For example, they may need to shift their distribution in response to changes in food quality or abundance as a result of localized summer rain showers, or they may need to shift to a neighboring canyon because a water source has dried up. Fragmentation would cut them off from these crucial resources. For these reasons, habitat fragmentation is seen as a major threat to bighorn sheep[586] and it is particularly risky to bighorn sheep in the Peninsular Ranges because a narrow, elevational band of suitable habitat exists in these mountains.[587] Increased traffic and construction disturbance will not only increase the risk of habitat fragmentation, but will also increase the risk of invasion by exotic invasive plants, such as Saharan mustard (*Brassica tournefortii*), tamarisk (*Tamarix* spp.), and cheatgrass (*Bromus tectorum*), which, over time, will decrease habitat quality for bighorn sheep.[588] In addition, ongoing transmission line maintenance activities will result in significant and unmitigable disturbance to the bighorn sheep or even, mortality.[589] Conservation Groups testified: "[I]t would be unwise to experiment with a Federally endangered population, and we should therefore err on the side of caution to protect bighorn sheep in the Peninsular Ranges . . ."[590] SDG&E itself presented an unpublished report that states:

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586 Conservation Groups Exhibit C-23, 6.

587 Conservation Groups Exhibit C-23, 7.

588 Conservation Groups Exhibit C-23, 5-7.

589 Draft EIR/EIS, ES-5.3.

590 Conservation Groups Exhibit C-23, 7.

"[E]mphasis should be placed on siting of project facilities to the extent possible *away* from optimal habitat and other features of high value to sheep."[591]

UCAN argues that SDG&E has tried to minimize, inaccurately, the Proposed Project's impacts on Peninsular bighorn sheep by contending that the Proposed Project "primarily follows State Route 78 which, as a paved road, is already a barrier to sheep.[592] We agree with UCAN. Use of the adverb "primarily" makes the sentence technically true, since the Proposed Project parallels State Route 78 for about 15 out of 22 miles inside Anza-Borrego. But the characterization is misleading because it ignores the other seven miles through Grapevine Canyon. These are *the* seven miles of Peninsular bighorn sheep habitat, and they are not bisected by State Route 78.[593] In fact, the Proposed Project affects approximately 147.5 acres of Peninsular bighorn sheep critical habitat (90.3 acres of temporary disturbance and 57.2 acres of permanent impact through habitat removal). The EIR/EIS, in Significance Criterion 1.d., states that the Proposed Project would have a substantial adverse effect on designated critical habitat for a federal listed species through temporary or permanent disturbance.[594]

With respect to Conservation Groups' contention that the Draft EIR/EIS is deficient, we find that the Final EIR/EIS responds adequately and in detail to Conservation Groups argument and expert testimony.[595]

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591 RT 3576 (referring to SDG&E Exhibit SD-59 erroneously; the report is SDG&E Exhibit SD-58 [Impacts of the Palo Verde to Devers 500 kV Transmission Line Final Report]).

592 SDG&E Phase 2 Opening Brief, 100.

593 UCAN Phase 2 Reply Brief, 36.

594 Final EIR/EIS, Sec. D.2-111.

595 See Final EIR/EIS, Response to Comment Set B0041, and, in particular, Response to Comment B0041-13.

14.4.2. Environmental Impacts of the "Enhanced" Northern Route

See Section 3.2.2 for a description of the "Enhanced" Northern Route.

14.4.2.1. Parties' Positions

SDG&E supports the "Enhanced" Northern Route which, unlike the Proposed Project, would be constrained to a 100-foot right-of-way within Anza-Borrego. Because all of the Northern Routes create similar impacts, opposing parties generally raise the same or similar criticisms against each of them and those concerns are set out in Section 14.4.1.1.

The "Enhanced" Northern Route has two unique impacts in Anza-Borrego. It would be constructed through Native American cultural sites and a Park campground. SDG&E has offered to work with State Parks on redesigns to minimize these impacts, but such redesigns necessitate leaving the 100-foot right-of-way, and obviate the purported advantage of the "Enhanced" Northern Route, since wilderness encroachment would result.

State Parks cautions that even if SDG&E keeps the "Enhanced" Northern Route within the existing 100-foot right-of-way, for various reasons that route could be found to be incompatible with Anza-Borrego's General Plan, which would require a Plan amendment.[596]

14.4.2.2. Discussion

As set forth in Section 16.1, below, the Final EIR/EIS concludes that the "Enhanced" Northern Route falls next-to-last in the environmental ranking, placing it below both the Final Environmentally Superior Northern Route and the Proposed Project. The "Enhanced" Northern Route has 44 significant,

[596] State Parks Phase 2 Opening Brief, 20-24.

unavoidable environmental impacts (in one or more geographic areas), including numerous impacts on Anza-Borrego.[597]

The major differences between the environmental impacts attributable to the "Enhanced" Northern Route and the Proposed Project are associated with limiting the path of the 500 kV transmission line through the Park to the 100-foot right-of-way currently occupied by the 69-92 kV wood pole line. It is unclear that a new 500 kV line can be restricted, successfully, to such a narrow corridor.[598] However, were it possible to do so, while that would eliminate direct impacts to state wilderness, the line's greater number of towers, and their increased height, would permanently change the character of Anza-Borrego and decrease its recreational value. Towers would vary in height from 135 to 175 feet, compared to an average height of 130 feet for the structures in this same segment of the Proposed Project. The larger number of towers, the more complex design (known as Delta configuration) of the structures needed to support taller towers, and locating the transmission line closer to State Route 78 (which requires more road spans within Anza-Borrego) all create greater visual impacts.

Constraining the "Enhanced" Northern Route to a 100-foot right-of-way eliminates the ability to avoid significant Native American archaeological sites

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[597] The "Enhanced" Northern Route has fewer significant, unmitigable impacts than the Proposed Project only because the CEQA/NEPA review process established fewer "key view points" for visual resources analysis. A key view point is representative of the most critical locations from which a project can be seen. Most of the view points established for the Proposed Project within Anza-Borrego also apply to this alternative.

[598] State Parks Phase 2 Opening Brief, 18 ["In two areas along the existing transmission corridor bordered by State Wilderness, the right-of-way is less than 100′, necessitating the need for an additional grant by [State Parks] that would result in encroachment into State Wilderness."]

and the new 500 kV line is forced to cross the large cultural resources complex in the western part of Anza-Borrego, the highly sensitive Angelina Springs Cultural District in Grapevine Canyon.[599] The line's path passes through the center of the primary site and requires more towers within the boundaries of the complex.

The "Enhanced" Northern Route's new alignment also undoes many of the small route adjustments made to the Proposed Project to avoid or minimize other impacts to Anza-Borrego. For example, the Proposed Project skirts the Tamarisk Grove Campground, avoiding the need to remove the tamarisk trees growing there. The "Enhanced" Northern Route cannot avoid the campground and, in order to meet the safety requirement of the Commission's General Order 95,[600] some of the tamarisk trees located there would need to be removed.[601]

Though SDG&E has stated it is willing to work with State Parks on a redesign of the "Enhanced" Northern Route to avoid impacts on the cultural complex and the Tamarisk Grove Campground, such an effort undermines the major reason SDG&E proposed the "Enhanced" Northern Route. Avoiding those impacts requires creating a new or wider right-of-way and locating the 500 kV line on wilderness land, which necessitates de-designation of wilderness.

Finally, even if constrained to the 100-foot right-of-way, the "Enhanced" Northern Route would have significant negative impacts on wilderness. We have described the "Enhanced" Northern Route's greater visual impacts on Anza-Borrego. In addition, during construction, heavy equipment and helicopters could encroach on portions of state wilderness, creating the potential for extended periods of abrasive noise and dust, and risking permanent damage

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[599] Draft EIR/EIS, Sec. D.7.19 and Appendix 1-68 and 1-69.

[600] General Order 95 sets out rules for overhead electric line construction.

[601] Draft EIR/EIS, ES-7.1.2.

to the land.[602] Construction of a high voltage transmission line requires significant land for staging, tower assembly, pull sites, and other activities. Individual sites would be cleared to install the transmission line support structures and facilitate access for future maintenance of the transmission line and associated structures. For example, at each structure location, a bulldozer or backhoe would clear an area approximately 100 feet by 100 feet, plus an area adjacent to an access road of approximately 35 feet by 75 feet.[603] If solid rock is encountered at a structure location, additional equipment may be required to blast through the rock.[604]

14.4.3. Environmental Impacts of the Final Environmentally Superior Northern Route

See Section 3.2.3 for a description of the Final Environmentally Superior Northern Route.

14.4.3.1. Parties' Positions

Because the Northern Routes create similar impacts, opposing parties generally raise the same or similar criticisms against each of them and those concerns are set out in Section 14.4.1.1. The Final Environmentally Superior Route differs from the two other Northern Routes primarily in that it would be undergrounded through Anza-Borrego to avoid permanent impacts on wilderness and to mitigate visual impacts.

14.4.3.2. Discussion

As discussed in Section 16.1, below, the Final EIR/EIS concludes that the Final Environmentally Superior Northern Route ranks as the fifth ranked

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602 Draft EIR/EIS, Sec. D.8.6, D.11.6, and D.3.6.

603 Final EIR/EIS, Sec. B.4.1.1.

604 Draft EIR/EIS, Sec. B.4.

alternative among eight alternatives in terms of its environmental impacts, but above both the Proposed Project and the "Enhanced" Northern Route. The Final Environmentally Superior Northern Route has 37 significant, unavoidable impacts (in one or more geographic areas) and will create numerous direct impacts within Anza-Borrego, though it has no direct effect on state wilderness. The environmental impacts affect biological resources, visual resources, wilderness and recreation, agricultural resources, cultural resources, noise, air quality, socioeconomics, public services and utilities, and fire and fuels management.

The major advantage of the Final Environmentally Superior Northern Route over both the Proposed Route and the "Enhanced" Northern Route is the underground, rather than overhead, construction of part or all of the Anza-Borrego Link in the State Route 78 roadway. The portion east of San Felipe and Santa Ysabel Valleys also would be undergrounded if the All Underground Option of the Final Environmentally Superior Northern Route were built. Because the new 500/230 kV substation would be located to the east of Anza-Borrego, rather than to the west, the transmission line through the Park would need to be only 230 kV, rather than 500 kV. Undergrounding through Anza-Borrego avoids direct impacts to a one-mile area of state-designated Grapevine Canyon Wilderness and does not permanently diminish the recreational value of Anza-Borrego, the Pacific Crest Trail and the San Dieguito River Park, unlike the Proposed and "Enhanced" Northern Routes. It also avoids significant and unavoidable impacts to rural residences, visual resources, and agricultural resources within San Felipe Valley.

Even though this partial underground alternative creates fewer visual impacts, the Final Environmentally Superior Northern Route has significant, unmitigable impacts on wildlife and its habitat. Construction of an underground line through Anza-Borrego creates a permanent impact on 63.4 acres of flat-tailed horned lizard habitat outside a Management Area through habitat removal at the San Felipe Substation site and the harm, harassment, or direct disturbance of the lizards. The EIR/EIS finds these impacts significant under Significance Criterion 1.f. (directly or indirectly cause the mortality of a special status wildlife species). They are significant and not mitigable to less than significant levels (Class I) because land adequate to compensate for the impacts may be unavailable.[605]

The underground line passes through designated critical habitat for Peninsular bighorn sheep, though most of the construction is expected to occur within the existing roadway boundaries. However, tower pads, an access road, and two pull sites for the one-mile overhead segment would create impacts to critical bighorn sheep habitat (3.4 acres of temporary disturbance and 3.6 acres of permanent impacts).[606] Construction in this area would extend outside the existing roadway, and it is possible that blasted rock and/or debris also might end up outside the construction zone. Any impact to critical habitat is significant according to Significance Criterion 1.d. (substantial adverse effect on designated critical habitat for a federal listed species through temporary or permanent disturbance). The impacts would be significant and not mitigable to less than significant levels (Class I) because replacement critical habitat for Peninsular bighorn sheep, or other suitable habitat (as determined by US Fish and Wildlife, BLM, California Department of Fish and Game, and State Parks), may be unavailable.[607] Even if enough suitable land is available to mitigate habitat

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[605] Draft EIR/EIS, Sec. D.2.22.1.

[606] Draft EIR/EIS, Sec. D.2.22.1.

[607] Draft EIR/EIS, Sec. D.2.22.1.

impacts to below a level of significance, human and construction activity in Peninsular bighorn sheep habitat could cause the sheep to avoid affected areas, thereby adversely affecting the survival and recovery of the species.[608] Other endangered species, like the least Bells vireo, are present along this route, and this undergrounding alternative would create significant impacts for them.[609]

Though undergrounding through Anza-Borrego minimizes or avoids some environmental impacts, it also creates unique impacts. Specifically, it places a double-circuit 230 kV transmission line underground within State Route 78 and County Highway S2, within the Earthquake Valley Fault, which presents a risk of potential, substantial adverse effects from a surface fault rupture. It also results in increased, short-term impacts to traffic and transportation along State Route 78 and County Highway S2, including temporary road and lane closures that would disrupt traffic flow and visitor access to the Park. Additionally, should SDG&E pursue, at some time in the future, a transmission expansion via the San Felipe Substation (a component of the Final Environmentally Superior Northern Route) as many as four additional 230 kV circuits and one additional 500 kV circuit may be required through Anza-Borrego.

Finally, the Final Environmentally Superior Northern Route, compared to the Final Environmentally Superior Southern Route, has greater impacts on biological resources, visual resources, cultural resources, paleontological resources, public health and safety, air quality, geology, mineral resources and soils, socioeconomics, and public services and utilities.[610]

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[608] Draft EIR/EIS, Sec. D.2.22.1.

[609] Draft EIR/EIS, Sec. D.2.22.1.

[610] Draft EIR/EIS, Sec. H.5.3.

14.5. Conclusions Regarding Any Route Through Anza-Borrego

As §1002(a)[611] requires, we have developed a comprehensive record (in the EIR/EIS and in Phase 2 hearings) on the environmental impacts on Anza-Borrego of any Northern Route. Together with input from speakers at Public Participation Hearings, this comprehensive record likewise documents Northern Route impacts on the three other § 1002(a) factors we must consider – community values, recreational and park areas, historical and aesthetic values.

We find that building any route through Anza-Borrego, including the Final Environmentally Superior Northern Route, is inconsistent with each of these factors. More specifically, we find that any Northern Route: (1) would have massive significant and unmitigable environmental impacts on Anza-Borrego; (2) be contrary to community values – both those of the people who visit Anza-Borrego, as well as the values embodied in our state laws protecting areas like Anza-Borrego; (3) be permanently detrimental to recreational and park areas within Anza-Borrego; and (4) would have permanent and negative impacts on historical and aesthetic resources in Anza-Borrego. The degradation of community, recreational, historical and aesthetic values particular to the Park, together with the well-documented adverse impacts on the Park's environment, requires that we reject any Northern Route. The evidence developed in this proceeding strongly suggests that our determination is wholly consistent with Anza-Borrego's General Plan and the goals and purposes of the California Wilderness Act, both of which are designed to protect such areas.

As discussed above, State Parks reasonably could conclude that construction of any route through Anza-Borrego would require amendments to

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[611] See Sections 2.2 and 4.2, above.

the Park's General Plan, de-designation of wilderness,[612] and the grant of new right-of-way or right of entry permits, or both. We reject SDG&E's contention that the Wilderness Act does not apply to the land through which the Northern Routes would pass. The California Wilderness Act requires the protection and management of wilderness "so as to preserve its natural conditions," prohibits temporary or permanent improvements on wilderness areas such as "structure[s] or installation[s]" and also prohibits the temporary construction activities associated with such "improvements." Approving a route through Anza-Borrego would not support or preserve recreational opportunities in a "natural environment" or nurture feelings of "peaceful solitude." The EIR/EIS exhaustively documents the environmental damage to Anza-Borrego, including permanent damage to its historic and aesthetic resources. Where, as here, no exemptions exist, such impacts cannot be reconciled with the charge of the California Wilderness Act.

As far as we know, state wilderness has never before been re-classified or de-designated. No record of re-classification or de-designation of state wilderness has been identified. A determination to de-designate wilderness, and its precedential impact, are very serious matters and approval of a request to construct any of the Northern Routes could be detrimental to this state's efforts to protect wilderness lands in perpetuity.

We are not alone in reaching the ultimate conclusion that Sunrise should not be built through Anza-Borrego. The Energy Commission, which generally subscribes to using "existing rights-of-way"[613] when locating new transmission

[612] State Parks Phase 2 Reply Brief, 2.

[613] SDG&E Exhibit SD-35, 7.10.

lines, declared this Park to be a "no-touch" zone, due to its environmental sensitivity. [614]

Moreover, where we grant CPCN authority to a public utility, the utility acquires the right, to the extent provided by law, to condemn land in order to build its project. This record does not attempt to establish the extent of SDG&E's eminent domain rights with respect to any of the Northern Routes. However, we cannot ignore that significant questions exist about whether SDG&E could acquire sufficient right-of-way to build in the Park. This practical matter militates against any Northern Route. SDG&E's construction schedule has made no provision for delays, whether attributable to continuing litigation or to a determination by State Parks that it must prepare amendments to Anza-Borrego's General Plan. Either source of delay is likely if we approve a route through Anza-Borrego. The history of this proceeding strongly suggests that any route through Anza-Borrego likely would be delayed indefinitely while various stakeholders undertook all legal means available to stop construction of a 500 kV transmission line through the Park. Conservation Groups, for example, have made clear their willingness to litigate to protect Anza-Borrego. They have continued to argue that the EIR/EIS is inadequate and they have contended, forcefully, that the Commission has insufficient environmental information to approve any transmission alternative through Anza-Borrego.[615] They claim that all of the Northern Routes would violate state law protecting parks and wilderness.[616]

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[614] Conservation Groups Exhibit C-26, 2.

[615] Conservation Groups Phase 2 Opening Brief, 5, 51, 54-55, 85-86.

[616] Conservation Groups Phase 2 Reply Brief, 12.

If changes to the General Plan were to be made, State Parks estimated it would need 395 to 455 days (about 13 to 15 months) to prepare major revisions for consideration by the State Parks and Recreation Commission (this estimate presumes that State Parks' reliance on a Commission-certified EIR/EIS to meet the requirements of CEQA). Even if that timeframe could be compressed further, the delay still would be eight months to a year.[617]

15. Wildfire Risks

15.1. Overview

Wildfires pose a significant and continuing risk in California generally, and to Southern California and San Diego County in particular.[618] There is evidence from Cal Fire investigation of wildfires that power lines have played a meaningful part in San Diego County's wildfire history. Consequently we discuss here, separate from our review of other environmental impacts of Sunrise in Section 16, both the risk that a new transmission line may ignite a fire under severe wind conditions, and the presence of dense, dry fuels, and the potential damage of such a fire. We also review the possibility of a wildfire-induced dual line failure of the Southwest Powerlink – the largest import line into San Diego - and the Proposed Project or a Northern or Southern Route Alternative.[619] (See Section 3.2 for a description of the Proposed Project and other Northern Routes and Section 16.7 for a description of the Southern Route Alternatives.)

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[617] RT: 4222:5-8.

[618] Draft EIR/EIS, Sec. D.15.1. In Section 16 and the related Appendix C, we make no independent assessment of the fire history or determination of the cause of particular fires, but rely on the California Department of Forestry and Fire Protection (Cal Fire).

[619] See Section 17.6, for a discussion of the LEAPS Transmission-Only Alternative, which has lower wildfire risks than the Northern or Southern Route Alternatives but greater environmental impacts, overall, than the generation based alternatives.

We reach two key conclusions based on the fire history discussed below. First, lower voltage distribution and sub-transmission lines, not high-voltage transmission lines, have been responsible for most power line related fires in the San Diego area. Second, we conclude that the increased risk of fire, with potential reliability impacts, is not significantly different between the Final Environmentally Superior Southern and Northern Routes, and that for the Final Environmentally Superior Southern Route in particular, the increased fire risk, including reliability risk, is not significant.

We have reviewed these issues both in the CPCN portion of this proceeding and in the EIR/EIS.

15.2. Risk of Fire Ignition

The presence of dense, dry fuels and periodic Santa Ana winds makes Southern California one of the most fire-prone landscapes in the world.[620] Although fires are a natural process in the chaparral ecosystems in San Diego County, increased human influence across the Southern California landscape has elevated the frequency and intensity of fires,[621] and magnified fire damage to communities, firefighters, and natural resources including air quality, biological resources, and water quality. Assisted by high winds, power line ignitions have caused four of the twenty largest wildfires in California's history from 1932 to 2007, measured by acreage burned, according to the California Department of Forestry and Fire Protection (Cal Fire).[622] Three of these four fires occurred in SDG&E's service area: the 1970 Laguna and Clampitt Fires and the 2007 Witch Fire. The 2007 Rice Fire, also ignited by a power line in SDG&E's service area

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[620] Draft EIR/EIS, Sec. D.15.1.

[621] Draft EIR/EIS, Sec. D.15.2.1.

[622] Draft EIR/EIS, Sec. D.15.1.1 reviews reports of Cal Fire.

according to Cal Fire, is one of the State's twenty largest wildfires by another measurement, number of structures destroyed. Thus, according to Cal Fire, four of the five most destructive California fires caused by power lines occurred in SDG&E's service area. Cal Fire's reports state that three of the four fires were caused by distribution-level lines, that fourth was caused by a 69 kV sub-transmission line, and that the specific causes vary:[623]

- 2007 Witch Fire – Failure of 69 kV equipment due to corrosion and high winds combined with an ignition caused by a hanging cable lashing on a 12 kV distribution-level line;
- 2007 Rice Fire – Failure of a 12 kV distribution-level line ignited by improperly maintained vegetation around the distribution facilities;
- 1970 Clampitt Fire – Ignited when high winds blew down a section of the distribution-level line; and
- 1970 Laguna Fire – Ignited when trees fell across the distribution-level lines.

In addition to the serious threat intense wildfires pose to human life and property in San Diego County, they also pose a transmission reliability risk because of the possibility that a wildfire - or group of wildfires - will require an extended shutdown of transmission lines supplying San Diego with energy. Locating transmission lines in areas with high fire risk creates a reliability risk. Dense smoke or heat from wildfires can "trip" a circuit, causing it to go out of

[623] In addition to Cal Fire's July 10, 2008 reports on the Rice and Witch Fires, the Draft EIR/EIS references the September 2, 2008 report of the Commission's Consumer Protection and Safety Division (CPSD) on the Guejito, Witch and Rice fires. CPSD has asked the Commission to open a formal investigation into, among other things, whether SDG&E (and/or others) bears any responsibility for the fires and whether the rules governing conductor clearances and vegetation management practices should be changed.

service.[624] A forced outage may be necessary to respond to an emergency line de-rating, to prevent thermal damage to the line, to prevent a smoke-caused trip, or to meet the safety needs of firefighters.

Power lines can start fires by creating sparks that then ignite combustible material located on or near a power line. Any of the following factors may induce sparking:

- Transformer or capacitor failures that result in arcing, or leaking equipment;
- Floating or wind-blown debris contacting conductors or insulators, including trees, other vegetation, birds, Mylar balloons, and kites;
- Conductor-to-conductor contact;
- Wood support poles being blown down in high winds;
- Dust or dirt on insulators; and
- Bullet, airplane, and helicopter contact with conductors or support structures.

The San Diego County fire history summarized at the beginning of this Section and SDG&E's fire data for the last four years (2004-2007) both confirm that distribution-level and sub-transmission lines have been responsible for the bulk of power line-related ignitions, and all of the significant property damage caused by fires resulting from such ignitions. Between 2004 and 2007, 85.5% of the power line-related fires (89 ignitions) were distribution system ignitions, 11.5% (12 ignitions) were ignitions of sub-transmission systems of 69-138 kV, and

[624] Smoke can cause an outage as a result of a phase-to-phase or phase-to-ground fault because the ionized air in the smoke can become a conductor of electricity, resulting in arcing between lines on a circuit or between a line and the ground. A "trip" of a transmission line occurs when the system's protective equipment shuts down power flow over a given segment of the line in an effort to mitigate potential damage to the interconnected equipment.

3% (3 ignitions) were 230 kV transmission system ignitions. None of the ignitions was associated with a 500 kV line.[625] Attachment C to today's decision, entitled "Risk of Fire Ignition," provides a more detailed discussion of this topic.

15.3. Risk of Dual Line Failure Due to Wildfire

Given the fire-prone Southern California landscape, wildfire presents an outage risk for any new transmission line, including the Proposed Project and each of the transmission alternatives studied in the EIR/EIS. Both single, isolated fires and conflagrations of multiple fires have the potential to cause an outage. A second issue is reliability-related, that of concurrent failure of the Proposed Project (or other Sunrise transmission alternative) and the existing Southwest Powerlink, due to one fire or simultaneous fires. While the fire history summarized below suggests a concurrent outage involving the Southwest Powerlink and the Environmentally Superior Southern Route is more likely than one involving the Environmentally Superior Northern Route, as we discuss below, a dual line outage could occur whether or not a new transmission line is collocated with the Southwest Powerlink, since special proximity is not the only indicator of a concurrent outage.

Wildfires pose a special risk to SDG&E's largest import line, the 500 kV Southwest Powerlink. Roughly 14 wildfire events have caused an estimated 29 outages in the 23 years of the line's operation.[626] Because of concerns about a concurrent outage between the Proposed Project and the Southwest Powerlink, SDG&E's PEA did not fully consider any transmission alternatives located west of Milepost 36 in the Southwest Powerlink corridor. SDG&E was concerned that WECC would rate any line parallel to the Southwest Powerlink past that

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[625] Draft EIR/EIS, Sec. D.15.1.1.

[626] EIR/EIS, Attachment 1A to Appendix 1, Sec. 5, Table 5.

milepost as a Category C line, and SDG&E wanted the Proposed Project to obtain a Category D rating, which because it represents a higher measure of reliability, might provide further justification for the line. Only three sets of collocated high-voltage transmission lines in California have a Category D rating.[627]

SDG&E filed a Performance Category Upgrade Request (Request) with WECC Reliability Performance Evaluation Work Group (WECC Reliability Work Group) on December 19, 2007, about a year after it filed the 2006 Application. By this time the EIR/EIS process had identified the Northern and Southern Route Alternatives and so the Request evaluated the double-line outage probability for the 500 kV segments of the Northern and Southern Routes that would be collocated with the Southwest Powerlink. SDG&E focused primarily on evaluating the fire-related risks related to the collocated segments but also evaluated the risk of a single fire causing concurrent outages on one of these alternative routes and the Southwest Powerlink, based on the historical fire record. After reviewing SDG&E's Request, WECC Reliability Work Group recommended that the collocated 500 kV segment of the Northern Route (4 miles) be approved as a Category D line and that the collocated segment of the Southern Route (36 miles) be deemed a Category C line.[628]

However, SDG&E's Request to WECC Reliability Work Group failed to evaluate the risk of multiple simultaneous fires affecting both lines and thus, did not permit a fully comparable analysis. Had SDG&E performed a simultaneous wildfire-reliability analysis on the entire length of each route and not just the

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[627] Final EIR/EIS, ES and General Response GR-9.

[628] CAISO argues that the Southern Routes' Category C rating would require a remedial action scheme designed to drop up to 100 MW of load in the San Diego area and trip up to 2000 MW of generation in the Imperial Valley. DRA contends that CAISO's position is flawed.

co-located portion, and had it included fire history data (discussed below) in the Request, it is not clear that the Northern Route would have received a Category D rating. Rather, it seems likely both lines would have been deemed to meet Category C requirements and thus, would have been given the same reliability rating.

The fire history record shows that had both lines been present, it is very likely that the Final Environmentally Superior Northern Route would have experienced a concurrent outage with the Southwest Powerlink twice since 1970 (in 2003 and 2007). There also is a very high likelihood that the Environmentally Superior Southern Route would have experienced a concurrent outage with the Southwest Powerlink five times since 1970 (in 1970, 1975, 1995, 2003, and 2007).

WECC's rating criteria assesses whether any contingency (such as fire, lightning, aircraft crash) that could affect two transmission lines is likely to occur at a frequency between one in three to one in thirty years, and if so, classifies the proposed transmission route as "N-2," which falls within the Category C reliability classification. Therefore, because the Northern Route likely would have experienced an outage concurrent with Southwest Powerlink twice in 30 years, a more accurate assessment of the risk of outage due to concurrent fire appears to fall within Category C standards but does not meet the higher standards of Category D.

These conclusions are based on a spatial analysis of the routes and Cal Fire's Fire and Resource Assessment Program fire perimeter database.[629] However, given frequent experience in Southern California of multiple, large fires during extreme weather conditions, spatial proximity is not the only

[629] See Draft EIR/EIS, Sec. D.15.4.3, which includes the link to http://frap.cdf.ca.gov/infocenter.html.

indicator of concurrent outage due to fire. Even the most spatially removed alternatives from the Southwest Powerlink, the LEAPS Transmission-Only Alternate and the LEAPS Generation and Transmission Alternative (described in Section 16), would have experienced concurrent outages with the Southwest Powerlink three times since 1970 (in 1975, 1989, and 2003).

15.4. Comparison of Fire Risk Across Transmission Alternatives

In an attempt to more clearly present the fire risk presented by each transmission alternative, both in terms of property damage and potential for a concurrent outage, we include here an excerpt from Table ES-3, included in General Response GR-9 and the Executive Summary of the Final EIR/EIS:

Table ES-3. Fire and Fuels Comparison of Alternatives

		A	B	C		D		E	F
Route		Overhead through high-risk fuels (miles)[a]	High/Very High burn probability (miles)	Assets at risk: Normal weather Homes	Acres	Assets at risk: Extreme weather Homes	Acres	Firefighting conflict (miles)	Fire reliability (number outages)[b]
Final Environmentally Superior Northern	230 kV	23	17	400	20,000	770	72,000	11.5	2
	500 kV	0	2	0	0	0	0		
Final Environmentally Superior Southern	230 kV	23	10	150	16,000	560	37,000	8.0	5
	500 kV	62	20	180	36,000	820	161,000		

[a] The number of miles of overhead transmission line through High and Very High Fire Severity Zones as identified by Cal Fire, 2006.
[b] The number of outages that would have occurred concurrently with SWPL from 1970 to 2007, using MGRA Phase 2 Rebuttal testimony methodology excluding "Type 3" outages.

The assets at risk in columns C and D of the Table are raw numbers based on the modeling results presented in the Final EIR/EIS;[630] they have not been weighted based on the probability of ignition. However, because the risk of ignition from a 230 kV line is higher than the risk of ignition from a 500 kV line,

[630] Final EIR/EIS, ES and General Response GR-9.

the 500 kV segments of each of the transmission alternatives (represented by gray shading) are considered to rank lower for ignition risk and potential damage even though, for example, the raw numbers listed for the 500 kV segment of the Final Environmentally Superior Southern Route are larger than the raw numbers for its 230 kV segment. Likewise, while the Tables list a "zero" in Columns A, C and D for the 500 kV segment of the Final Environmentally Superior Northern Route, which crosses a desert area with a very low fuel load, the comparably low risk of a 500 kV ignition reduces the import of that raw data.

The Table also shows that the 230 kV segment of the Final Environmentally Superior Northern Route places a higher number of assets at risk than the 230 kV segment of the Final Environmentally Superior Southern Route, that the Final Environmentally Superior Northern Route creates more significant barriers to firefighting efforts, and that there is a higher risk of a concurrent outage between the Southwest Powerlink and the Final Environmentally Superior Southern Route than the between the Southwest Powerlink and the Final Environmentally Superior Northern Route.

We include the results of this modeling to show comparative risks between the Northern and Southern Routes. Because modeling the impact of future fires is necessarily imprecise, we rely on this modeling only to provide gross comparisons of fire risk between the two routes.[631]

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[631] The number of "Assets at risk" presented in the table was estimated through the Fire Behavior Trend model described in EIR/EIS, D.15.4.3. The Model attempts to predict how ignitions related to project construction, operation, and maintenance would affect the extent of fire damage by simulating wildfire behavior based on known biophysical conditions in the vicinity of the transmission line. The model generates an estimate of the number of acres that would burn if multiple simultaneous ignitions occurred along the length of the transmission corridor. Fuel characteristics were inventoried within and slightly beyond the fire sheds as defined in the EIR/EIS, D.15, and therefore the fire

15.5. Mitigation to Reduce Risk of Fire Ignition

Given the fire risks associated with any transmission line route in San Diego County, approval of the Final Environmentally Superior Southern Route must be conditioned upon the most rigorous, reasonable mitigation available to reduce the risk of fire ignition. Therefore, we impose all feasible mitigation measures identified in the Final EIR/EIS upon construction of the Final Environmentally Superior Southern Route, including:

- Requiring fire-safe construction practices to reduce the risk of wildfire ignitions during construction;
- Prohibiting construction during extreme weather conditions to reduce the risk of potentially catastrophic wildfire ignitions during construction;
- Ensuring adequate coordination for emergency fire suppression to avoid project personnel and equipment interference with firefighting operations;
- Ensuring adequate removal of hazardous vegetation;
- Requiring annual contributions to a Defensible Space Grants Fund that will assist in the maintenance of defensible space requirements and in the implementation of other fire-safe measures at the private residences most at risk of a project-related wildfire;
- Requiring the replacement of existing 69 kV wood poles that are within 100 feet of the project with steel poles to mitigate the potential fire hazard of a wood pole being knocked into the adjacent conductors;

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behavior simulations do not go much beyond the fire shed boundaries. This is a limitation of the model. In addition, because large fires are often sparked by just one or two ignition sources, the outcome of the model is unrealistic, as the transmission line would never be the cause of simultaneous ignitions along the entire length of the corridor. However, the model provides a useful comparison of the relative risk of various routing alternatives.

- Requiring annual contributions to a Firefighting Mitigation Fund that will improve fire prevention measures and help improve fire protection equipment and services;
- Requiring a Memorandum of Understanding between SDG&E, Cal Fire, and Cleveland National Forest to coordinate effective fire plans and emergency procedures;
- Requiring weed abatement and controls for invasive weeds to prevent establishment of non-native plants that have a high ignition potential and carry fires at a high rate of spread; and
- Requiring climbing inspections on 10% of the project structures annually to improve detection of imminent component failures that could result in wildfire ignitions.[632]

15.6. Conclusion

The risk posed by wildfires in Southern California is significant both in terms of their impact on the reliability of SDG&E's system, and in terms of the potential that a transmission line might ignite a fire. We find that 230 kV or 500 kV lines placed on steel towers are highly unlikely to ignite fires, and that mitigation of the type described above should ensure this outcome. We find that the risk of a dual line outage is more likely between the Southwest Powerlink and the Final Environmentally Superior Southern Route, as compared with the Environmentally Superior Northern Route, but that the 230 kV segments of the Environmentally Superior Northern Route put more assets at risk of fire.

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[632] This mitigation shall require something substantially similar in intent to the following:

> **Perform climbing inspections.** The Applicant shall perform climbing inspections on 10 percent of project structures annually, such that every project structure has been climbed and inspected at the end of a 10-year period, for the life of the project. In addition, SDG&E shall keep a detailed inspection log of climbing inspections, and any potential structural weaknesses or imminent component failures shall be acted upon immediately. The inspection log shall be submitted to CPUC for review on an annual basis.

16. Environmental Review

Both § 1002(a) and CEQA require us to consider Sunrise's influence on the environment. Section 14 discusses the significant, unmitigable environmental impacts the Northern Routes present for Anza-Borrego and Section 15 discusses the increased wildfire risk all Northern and Southern Routes pose. As we discuss in this Section, the Proposed Project and alternatives all have many significant unmitigable environmental impacts, and all of the transmission line alternatives have greater, adverse impacts on the environment than the generation-based alternatives. The Final EIR/EIS ranks three alternatives as environmentally superior to the Final Environmentally Superior Southern Route – the All-Source Generation Alternative, the In-Area Renewable Alternative, and the LEAPS Transmission-Only Alternative. However, we conclude that these alternatives are not feasible for purposes of meeting California's broader policy goals, including reduction of GHG emissions. The Environmentally Superior Southern Route Alternative is the environmentally superior alternative to meeting SDG&E's future reliability needs and also accomplishing California's broader policy goals.

The CEQA and NEPA-mandated EIR/EIS process has been the primary forum for environmental review of the Proposed Project. CEQA imposes a general duty on public agencies to avoid or minimize, to the greatest extent possible, the environmental effects of projects they approve.[633] This duty generally is implemented by identifying and then adopting mitigation measures and/or alternatives to the project that will avoid or reduce environmental

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[633] *County of San Diego v. Grossmont-Cuyamaca Community College Dist.* (2006) 141 Cal.App.4th 86, 98; Pub. Res. Code § 21002; 14 Cal. Code Regs. ("CEQA Guidelines") § 15021.

impacts.[634] To this end, CEQA requires that an EIR identify an environmentally superior alternative among the alternatives evaluated.[635] In addition, the lead agency is required to respond to public comments on a Draft EIR that suggest additional mitigation measures or alternatives to the Proposed Project.

The EIR and EIS are informational documents prepared by the state and federal lead agencies. The Final EIR/EIS, which totals over 4,500 pages in addition to the 7,000 page Draft EIR/EIS, has been jointly prepared by Commission staff and BLM, in consultation with numerous other local, state and federal agencies, and with voluminous public input. Below we summarize, in a necessarily abbreviated form, the most significant aspects of the EIR/EIS and the comments made on it during the CPCN proceeding and in the course of the EIR/EIS process. The EIR/EIS provides more extensive descriptions of the Sunrise alternatives considered and the significant environmental impacts of each. The Final EIR/EIS addresses in detail every public comment received during the Draft EIR/EIS and Recirculated Draft EIR/Supplemental Draft EIR review process.[636] Consequently, we provide below specific cross-references to the EIR/EIS, which we certify in Section 18.1 of this decision.

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634 Pub. Resources Code §§ 21100(b)(3), (4), 21003(c) [EIR should emphasize feasible mitigation measures and alternatives]; CEQA Guidelines §§ 15002(f), (h), 15126.4, 15126.6; *Laurel Heights Improvement Assn. v. The Regents of the University of California* (1988) 47 Cal.3d 376, 400-403.

635 CEQA Guidelines §§ 15126.6(a) and (e)(2).

636 The EIR/EIS does not accept every mitigation measure suggested in the public comments and need not do so. See *San Franciscans for Reasonable Growth v. City and County of San Francisco* (1989) 209 Cal.App.3d 1502, 1519; see also *Concerned Citizens of South Central L.A. v. Los Angeles Unified School Dist.* (1994) 24 Cal.App.4th 826, 841 [discussion of mitigation measures is subject to the "rule of reason" and does not require consideration of every "imaginable" mitigation measure]. However, the EIR/EIS indicates reasons why the rejected mitigation measures will not be incorporated (e.g., that the mitigation measures are infeasible; will not be as effective as

16.1. Alternatives Analyzed in the EIR/EIS

The Final EIR/EIS evaluates and compares the environmental impacts of the eight transmission and/or generation alternatives analyzed in that document. The results of this comparison appear below, with the overall environmentally superior alternative listed first and the lowest ranked alternative listed eighth:

1. New In-Area All-Source Generation Alternative (All-Source Generation Alternative), one of the two generation based alternatives;
2. New In-Area Renewable Generation Alternative (In-Area Renewable Alternative), the second generation based alternative;
3. LEAPS Transmission-Only Alternative;
4. Environmentally Superior Southern Route;
5. Environmentally Superior Northern Route;
6. Proposed Project;
7. "Enhanced" Northern Route; and
8. LEAPS Transmission Plus Generation Alternative.

The Final EIR/EIS does not list the No Project Alternative in this environmental ranking, but explains that, because the No Project Alternative contains aspects of the first three alternatives, its environmental impacts are "equivalent to the alternatives ranked first, second, and third…"[637] and it has fewer impacts than any of the transmission alternatives.

The Final EIR/EIS incorporates and expands upon the analyses in the Draft EIR/EIS and the Recirculated the Draft EIR/Supplemental Draft EIS. The

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mitigation measures already recommended in the EIR/EIS; or will not have any substantial mitigating effect in practice).

[637] Draft EIR/EIS, ES.2.

Draft EIR/EIS, the initial document, reports upon the environmental impacts of the Proposed Project and a wide range of alternatives (including alternative routing segments), which were identified because they would attain most of the Basic Project Objectives,[638] be potentially feasible, and avoid or substantially lessen one or more of the significant environmental impacts of the Proposed Project. As documented in detail in the Alternatives Screening Report,[639] we initially considered over one hundred re-routes and other alternatives to the Proposed Project. Eventually, we eliminated seventy of these from detailed consideration because they would not reduce significant impacts of the Proposed Project, did not meet Basic Project Objectives, and/or were not feasible.[640]

The Draft EIR/EIS analyzes twenty-seven separate alternatives, including eighteen alternative route segments for the Proposed Project, four routes following portions of the Southwest Powerlink, two alternatives including components of the LEAPS Project, two generation-based (or non-wires) alternatives, and the No Project/No Action Alternative (referred to as the "No Project Alternative"). The multiple alternative route segments were assembled to create several complete (or "composite") transmission line routes, which were then compared to the other alternatives.

After the Draft EIR/EIS was published, SDG&E proposed an "Enhanced" Northern Route, as discussed in Section 3.2.2. Certain portions of this route have been incorporated in the "Final Environmentally Superior Northern Route." SDG&E also suggested a "Modified Southern Route" to resolve some of the feasibility issues and/or reduce impacts raised by the Draft Environmentally

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638 Section 3.1 contains a complete description of the three Basic Project Objective.

639 Draft EIR/EIS, Appendix 1; see also Draft EIR/EIS, ES.2.

640 For a complete explanation, see Draft EIR/EIS, Appendix 1, 1.4.2.2.

Superior Southern Route. The "Final Environmentally Superior Southern Route" incorporates portions of SDG&E's proposal.

UCAN proposed two revisions to the Environmentally Superior Southern Route in comments on the Draft EIR/EIS and in its Phase 2 brief: "UCAN's Modified Southern Route" and "UCAN's Jacumba to Sycamore Canyon Route." Like SDG&E's "Enhanced" Northern Route, UCAN's alternatives are composed of route segments that were evaluated in the Draft EIR/EIS. UCAN's Modified Southern Route follows a different path through the Cleveland National Forest than the Environmentally Superior Southern Route.[641] However, since the Forest Service has determined that the types of crossings proposed by UCAN are inconsistent with its Land Use Plan, UCAN's Modified Southern Route is impractical. The Final Environmentally Superior Southern Route avoids these conflicts with Forest Service lands.

UCAN's Jacumba to Sycamore Canyon Route follows the same route as UCAN's Modified Southern Route but excludes the easternmost 35 miles of new 500 kV line between the proposed Jacumba Substation and the Imperial Valley Substation. Even in comparison to the Final Environmentally Superior Southern route through the Cleveland Forest, UCAN's Jacumba to Sycamore Canyon Route is not an adequate alternative because it does not meet at least two Basic Project Objectives.[642]

The Recirculated Draft EIR/Supplemental Draft EIS contains significant, new information which became available after release of the Draft EIR/EIS and which required recirculation under CEQA and NEPA. Among other things, the document contains:

[641] Recirculated Draft EIR/Supplemental Draft EIS, Sec. 5.3.3. and Figure, 5-2.

[642] Recirculated Draft EIR/Supplemental Draft EIS, Sec. 5.3.3.

- New and revised analysis of the La Rumorosa Wind Project in Mexico (an indirect effect of the Proposed Project, discussed in Section 16.2, below) and associated transmission/substation upgrade in the United States;
- Description and analysis of the "Enhanced" Northern Route and other route modifications; and
- Revision of components of the Environmentally Superior Northern Route and the Environmentally Superior Southern Route.[643]

16.2. Connected Actions

The EIR/EIS evaluated four projects that are so closely related to the Proposed Project as to be considered part of the project: (1) the Stirling Energy Systems solar facility; (2) the Esmeralda–San Felipe Geothermal Project; (3) the Jacumba 230/500 kV Substation; and (4) a 1,250 MW wind project in northern Mexico's La Rumorosa area. These projects are unlikely to proceed unless either a Northern or Southern Route is constructed first or simultaneously. The first three are part of the "whole of the action" as that term is used in CEQA and are "connected actions" under NEPA.[644] Because the La Rumorosa wind project would be located primarily outside of the United States, it is identified as an "indirect effect" of the Proposed Project.

The EIR/EIS evaluates the environmental impacts of these four projects to educate decision makers and the public about the full impacts of the various Northern and Southern Routes.[645] The Commission must consider this

643 Recirculated Draft EIR/Supplemental Draft EIS, Sec. 1.2.

644 See CEQA Guidelines § 15378; 40 C.F.R. § 1508.25(a)(l).

645 Draft EIR/EIS, Figures B-44 through B-46 show the locations of the various connected actions. Recirculated Draft EIR/Supplemental Draft EIS, Figures 2-1, 2-2, 2-3, 2-4 and 2-5 illustrate the Jacumba 230/500 kV Substation and the La Rumorosa Wind Energy Project as revised in that document.

information as part of its decisionmaking process. However, these actions are not before the Commission for approval at this time, and today's decision does not in any way approve or guarantee approval of any of these projects. Each of them would be subject to separate environmental review by a lead agency with permitting authority.

The major environmental impacts of these four projects include the following:[646]

- The La Rumorosa wind and Stirling solar thermal projects would create thousands of acres of ground disturbance in sensitive desert ecosystems. Stirling components would cover as many as 8,000 acres and result in permanent loss of 2,500 acres of habitat.
- Because all four projects require new transmission lines, generally the same types of impacts identified for the Proposed Project (and its transmission alternatives) would affect the new lines to these to these facilities.

We have considered the environmental impacts of these projects as part of the whole of the Northern and Southern Route Alternatives.

16.3. Future Transmission Expansion

Expansion potential is one of SDG&E's objectives for any Northern or Southern Route, including both the 230 kV and the 500 kV components.[647] Figures B-12a and B-12b in the Project Description of the EIR/EIS illustrate the locations of the potential routes for future expansions interconnecting either with Edison and/or Imperial Irrigation District. SDG&E has indicated that the Proposed Project could lead to development of a 500 kV line from the proposed

[646] The impacts of these projects are described in greater detail in the Draft EIR/EIS, Sec. D.2 through D.15 and in the Recirculated Draft EIR/Supplemental Draft EIS, Sec. 2.

[647] See Section 3.1 for the complete list of SDG&E objectives.

Central East substation or from the alternative Central South Substation (in Santa Ysabel) to Edison's existing Valley-Serrano 500 kV transmission line.[648]

SDG&E also has indicated that a Southern Route could lead to future 230 and 500 kV line development. The Draft EIR/EIS identifies potential routes including 230 kV routes (following existing SDG&E corridors) to reach the substation endpoints identified by SDG&E for the Proposed Project, and a potential 500 kV route from the Modified Route D Substation site south of Interstate 8 or from the Interstate 8 Alternative substation site to connect with the existing Edison Valley-Serrano line.

As a result of the relatively detailed route descriptions provided by SDG&E, the Commission determined that these routes are reasonably foreseeable future expansions of Sunrise and accordingly, analyzed them in the Draft EIR/EIS. The EIR/EIS discloses the reasonably foreseeable impacts of these expansions for each resource area analyzed. The environmental impacts are similar in nature to the impacts of the various transmission routes analyzed in the EIR/EIS, but occur in different locations. However, these expansion projects are not before us for approval at this time, and today's decision does not in any way approve or guarantee approval of any of these projects. If and when they are proposed, these projects will require a separate application and will be subject to separate environmental review. Therefore, we do not discuss their impacts in this decision in detail; however, in making our final determination we have considered the assessment in the EIR/EIS of the likelihood of such future expansion and its environmental impacts.[649]

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[648] SDG&E Exhibit SD-15, Vol. 1 of 2, 42:15-17.

[649] Draft EIR/EIS, ES-5.8.

16.4. All-Source Generation Alternative

16.4.1. Description

The EIR/EIS determines that the All-Source Generation Alternative is environmentally superior to all of the alternatives evaluated in the EIR/EIS, including the Proposed Project. This alternative assumes at least 1,703 MW of power can be developed in the San Diego area in lieu of the Proposed Project through a mix of fossil fuel generation and renewable generation, including some distributed generation.[650] Though the All-Source Generation Alternative identifies specific projects that could be online by 2010, these projects serve as proxies for a wide range of potential development scenarios. Further, because this alternative proposes more generation than needed to meet SDG&E's reliability needs until at least 2016, and because the proposed projects are proxies for the types of projects likely to be developed, no one project in this alternative is essential to the feasibility of the whole of this alternative.[651]

The components of the All-Source Generation Alternative include one gas fired baseload and four gas fired peaking power plants (all proposed by various developers for the San Diego area), as well as a small amount of wind, solar PV, and biomass/biogas. The proxy projects include:[652]

- The South Bay Replacement Project – a 620 MW a gas fired, combined cycle power plant;

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[650] Distributed generation, in contrast to generation built to provide power to the grid, refers to small-scale power generation technologies (typically in the range of 3 kW to 10 MW) designed to meet onsite or local load. Distributed generation can be either renewable, such as solar PV, small wind turbines, and small bio-fueled generators, or fossil-fueled, such as natural gas-powered engines and fuel cells.

[651] Compliance Exhibit, SDG&E LnR Table – All Source cases (adjusted to remove 48 MW of wind, 50 MW of biomass, and 240 MW of solar thermal).

[652] Several of these proxy projects are described in more detail in Section 5.3 above.

- The San Diego Community Power Project – a 750 MW gas fired, combined cycle power plant;
- The Encina Power Plant Repowering – a 450 MW gas fired, combined-cycle power plant;
- A variety of peaking gas turbines totaling 250 MW. Potential projects include the Pala and Margarita Peakers already under contract, Miramar II, and a 15 MW proposal for a fee-for-service development at Borrego;
- A variety of fossil fuel-fired distributed generation facilities totaling 35 MW installed at or near consumer sites such as hospitals and industrial facilities; and
- Renewable distributed generation totaling 203 MW including solar PV installation on residential, commercial and/or industrial building rooftops.

Additional description of this alternative can be found in the EIR/EIS.[653]

16.4.2. Parties' Positions

SDG&E asserts that the All-Source Generation Alternative is infeasible because permits cannot be obtained on a timely basis, the projects are speculative and cost prohibitive, and the projects would not meet reliability and RPS goals.

According to SDG&E, the All-Source Generation Alternative inaccurately assumes timely construction and start up of these future generation facilities. SDG&E claims the need for various regulatory approvals and the construction processes will prevent these projects from coming online before 2012. Further, SDG&E argues the All-Source Generation Alternative's construction assumptions are improper under CAISO Grid Planning Committee Guidelines, as well as past Commission decisions. SDG&E contends CAISO guidelines suggest a five-year planning horizon should count facilities that are under construction and a ten-year planning horizon should count facilities that have an application under

[653] Draft EIR/EIS, Sec. C.4.10.2, E.6; Final EIR/EIS, General Response-1.

review, have obtained regulatory approval, or are under construction. SDG&E claims the Commission's decisions on the Valley Rainbow[654] and Jefferson-Martin[655] transmission line CPCN proceedings support CAISO guidelines.[656] SDG&E states that neither the South Bay Replacement Project, the San Diego Community Power Project, the Encina Power Plant Repowering, nor the Pala Peaker Plant meet the requirements for five-year planning, and that the Encina Power Plant Repowering is the only one that meets the ten-year planning requirement. SDG&E states, moreover, that the Commission's most recent Long Term Procurement Plan decision[657] finds that procurement decisions should be made up to seven years in advance of when the resource is needed.

SDG&E also asserts that in basin renewables do not exist to the extent detailed in the All-Source Generation Alternative and, in particular, that the use of solar PV is unrealistic at the build-out levels contemplated; that the use of renewable energy credits (also known as "RECs") to fulfill its RPS goals is not allowable; and that this alternative is economically infeasible because it will require additional transmission facilities to meet reliability criteria. SDG&E claims that this alternative will cost $420 million and that over twenty years the incremental costs of this alternative, compared to out-of-basin generation with Sunrise in-service, ranges from $444 million to $1.8 billion. Given this alleged infeasibility, SDG&E states it is highly unlikely this alternative will meet SDG&E's post- 2010 reliability needs.

[654] D.02-12-066, 33.

[655] D.04-08-046, 43.

[656] SDG&E Phase 2 Opening Brief, 170-173.

[657] D.07-12-052, 21.

CAISO concludes, similarly, that the generation projects within this alternative will not be built within the timeframe necessary to meet SDG&E's reliability requirements. Consequently, like SDG&E, CAISO finds it imprudent to rely upon these projects to meet SDG&E's needs. Additionally, CAISO notes that the Encina Power Plant Repowering will result in an increase of 220 MW, not the 540 MW that the EIR/EIS assumes, because the project replaces existing capacity rather than adding only new capacity. CAISO states it already has accounted for much of the power from certain peaker plant components of this alternative and regarding the renewable components, contends that certain projects are highly speculative for a variety of reasons, such as land use issues and time constraints. CASIO also argues that some projects, even if constructed, would have limits (e.g., the intermittent nature of some renewables or the 1,150 MW dispatch limit on the Imperial Valley to Miguel Substation portion of the Southwest Powerlink) such that only a portion of the generation could be counted for SDG&E's needs.

DRA points out that the existing South Bay Power Plant may not be retired and, while that makes the South Bay Replacement Project questionable, it also means that the existing facility's 700 MW capacity would remain available to meet SDG&E's reliability needs.

Powers Engineering argues that the All-Source Generation Alternative's peaker plant component should be replaced with solar PV because: (1) solar PV is more reliable due to its distributed nature; and (2) if battery storage is attached, solar PV can be used to provide firm on-peak capacity at or near the nameplate rating. Powers Engineering points out that the Draft EIR/EIS[658] shows that 105 MW of solar PV is possible and that such a program would meet

[658] Draft EIR/EIS, Sec. E.5.1.2.

SDG&E's alleged 2010 capacity need. Further, Powers Engineering contends that the EIR/EIS fails to account properly for energy savings due to energy efficiency and demand response measures and that increased energy efficiency savings could completely eliminate SDG&E's projected shortfalls beyond 2015. Powers Engineering asserts that demand response from air conditioner cycling programs, in conjunction with advanced metering and education about proper air conditioner installment, can reduce peak demand by 350-450 MW. According to Powers Engineering, additional distributed generation subsidies (for combined heat and power) and smaller distributed generation units could substitute for the All-Source Generation Alternative's 620 MW combined cycle plant.

The City of Santee argues that the San Diego Community Power Project component of the All-Source Generation Alternative is infeasible because it is inconsistent with: (1) existing federal, state, and local plans; (2) a wildlife mitigation corridor required under the Fanita Project; and (3) San Diego recreational trail plans. For these reasons, the City of Santee contends the project could not be permitted and constructed by 2010. Furthermore, the City of Santee asserts the EIR/EIS fails to fully analyze the impacts of the San Diego Community Power Project.

UCAN argues that the No Project Alternative is superior to the All-Source Generation Alternative, but contends that the All-Source Generation Alternative is economically superior to the Proposed Project and would meet and exceed SDG&E's reliability needs through 2022. UCAN asserts that 40% of the All-Source Generation Alternative's costs are due to the 10% that comes from solar PV. UCAN claims that since this alternative provides more MW than needed, the solar PV component could be eliminated to make this alternative less costly than the Proposed Project or other Northern Routes. However, if the solar PV component is retained, UCAN characterizes SDG&E's solar PV cost estimates as grossly inflated, claims the utility has disproved its own energy conversion factor, and asserts that ample commercial rooftop exists in San Diego to support large scale solar PV deployment.

Conservation Groups argue that the All-Source Generation Alternative and the In-Area Renewable Alternative are inherently more reliable than any project that requires transmission lines through remote, fire-prone, seismically unstable, and extremely windy areas. Likewise, Conservation Groups state that in basin alternatives do not rely on centralized substations, which are prone to the same risks. Additionally, Conservation Groups assert that the in basin generation alternatives avoid many of the environmental impacts posed by wires and substations. According to Conservation Groups, solar PV is less costly than SDG&E claims. Furthermore, Conservation Groups claim that the renewable portions of both in basin alternatives guarantee renewable power, whereas the Proposed Project and the other transmission alternatives could deliver non-renewable energy, and likely will. Lastly, Conservation Groups state that the transmission alternatives have serious permitting issues with the Park Service, Forest Service, and potentially affected tribal governments.

16.4.3. Discussion

The All-Source Generation Alternative meets the first Basic Project Objective, to maintain reliability, and the third, to promote renewable energy development. While the EIR/EIS indicates that this alternative also meets the second Basic Project Objective, to reduce energy costs, because no party modeled the energy benefits of this alternative in the CPCN portion of the proceeding, that outcome is not clear.

With respect to the first Basic Project Objective, the All-Source Generation Alternative maintains SDG&E's reliability needs as determined in Section 7. With respect to the Second Basic Project Objective, the All-Source Generation Alternative delivers a generation portfolio similar to the Proposed Project without that transmission alternative's environmental impacts. However, while this alternative adds newer, more efficient in area generation to the existing generation mix in SDG&E's service territory, the cost of these additions may not be competitive with the out of area resources that could be accessed via a new, high-voltage transmission line. Thus, the cost impacts are highly dependent upon assumptions about the costs of imported power and the cost of the new transmission line. With respect to the Third Basic Project Objective, even though the All-Source Generation Alternative does not facilitate delivery of power from new renewable sources in the Imperial Valley, it promotes renewable power development in the local San Diego area.

By definition, the All-Source Generation Alternative's environmental impacts generally occur in the more developed San Diego area, rather than in the remote and scenic areas through which the Proposed Project or other transmission alternatives would pass. The All-Source Generation Alternative results in reduced ground disturbance largely because gas fired generation would occur at sites already disturbed and only 11 miles of new transmission line would be built. This alternative minimizes environmental impacts to biological resources, visual resources, and wilderness and recreation. It has no impact on state parks or National Forest lands.

Significant, unmitigable impacts occur to water resources and public services due to use of water for evaporative cooling (unless dry cooling is used) and for particulate matter, ozone, and GHG emissions from natural gas combustion. Public health and safety impacts occur due to air emissions and use and storage of hazardous materials, including aqueous ammonia.

As the GHG discussion in Section 14 reflects, the Final EIR/EIS concludes that the All-Source Generation Alternative would cause substantially more GHG emissions than the Proposed Project and other transmission proposals. The Final EIR/EIS does not quantify these emissions and recognizes that the GHG impacts of generation alternatives will depend upon the type of projects developed (for example, new fossil fuel facilities will exceed the GHG emissions associated with the construction of transmission alternatives).

SDG&E points to evidence that the Imperial Valley has a large potential for renewable energy projects,[659] contends it expects to meet RPS goals by contracting for renewable power there, and asserts that it has 731 GWh reliant upon Sunrise. As described in Section 12, SDG&E's Imperial Valley procurement is heavily dependent upon the success of the Stirling project, which has not yet been permitted. Consequently, SDG&E's argument that the generation facilities identified in the All-Source Generation Alternative are too uncertain applies also to the viability of the Stirling project. Moreover, the 300 MW that Stirling must produce to meet the first part of its contractual obligation is not significantly more than the 203 MW of renewable energy proposed under the All-Source Generation Alternative.

Some parties criticize all or parts of the All-Source Generation Alternative as being infeasible to permit. However, the EIR/EIS recognizes that these generation projects are representative and concludes that these projects or other, similar projects can be permitted in sufficient numbers and on a timely basis. Additionally, the in basin nature of this power removes much of the reliability

[659] SDG&E Phase 2 Opening Brief, 68-71.

concern that comes with long distance transmission lines, such as risks of multiple outages due to wildfires.[660]

Criticisms of the viability of specific projects in the All-Source Generation Alternative are over-stated. While the South Bay Replacement Project has been removed from the Energy Commission review process, the project proponent remains committed to the project and to its advancement.[661] Meanwhile, the existing South Bay Power Plant continues to provide 700 MW to meet SDG&E's reliability needs and it will continue to do so until CAISO releases it from Must Run obligations. The San Diego Community Power Project is in CAISO's interconnection queue; the biggest hurdle to its development is SDG&E's refusal to sign a power purchase contact with that project's proponents, despite their lowest cost bid in SDG&E's solicitation.[662] We find the Carlsbad Energy Center described in Section 6.7 to be viable and assume it will be online before Summer 2013 in our Analytical Baseline. Various peaker plants are at different stages of permitting and review, and while not all of them may be constructed, our findings regarding SDG&E's reliability needs confirm that SDG&E does not need any peakers to be online before 2017, assuming the Carlsbad Energy Center is online by Summer 2013 – if it does not come online then, there will be a need for 222 MW of new peakers by 2013. The potential for timely, incremental generation additions under this alternative minimizes permitting concerns.

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[660] Draft EIR/EIS, E.6; Final EIR/EIS, General Response GR-1.

[661] South Bay Phase 2 Opening Brief, 5.

[662] Final EIR/EIS, General Response GR-1.

16.5. In-Area Renewable Alternative

16.5.1. Description

The EIR/EIS determines that the In-Area Renewable Alternative is the second ranked alternative among the eight alternatives to the Proposed Project in terms of environmental impacts. This alternative is a combination of various San Diego area renewable projects that collectively could provide up to 1,000 MW of nameplate capacity generation by 2016. The renewable projects identified for the In-Area Renewable Alternative are illustrative of the types of projects that might be developed in the San Diego area, and the types of environmental impacts associated with such development. Like the All-Source Generation Alternative, because the In-Area Renewable Alternative analyzes more generation than needed to meet SDG&E's reliability needs until at least 2020, and because the proposed projects are proxies for other, similar projects of the type likely to be developed, no one project in this alternative is essential to the feasibility of the whole of this alternative.[663]

Four renewable sources comprise the alternative and the EIR/EIS identifies potential projects and potential locations for those projects based on a variety of assumptions:

- Solar thermal (290 MW) – potential development in the Borrego Springs vicinity; projected to be a parabolic trough plant design with a heat transferring fluid used to generate steam that is sent to a conventional steam turbine/generator;
- Solar PV (210 MW) – installation on residential, commercial and industrial building rooftops in San Diego County (approximately 60,000 residential systems and 255 commercial systems);

[663] Compliance Exhibit, SDG&E LnR Table – All-Source cases.

- Wind (400 MW) – one component of this source, the Kumeyaay project (46 MW), already is operational; the EIR/EIS estimates that approximately 7,263 acres on reservation and BLM lands in the San Diego area are available for additional wind development; and
- Biomass/biogas resources[664] (100 MW) – this source includes three projects: expansion of existing biogas production at the Miramar Landfill Cogeneration Facility (for an additional 3 MW), construction of a biomass facility near the Miramar Landfill (for an additional 26 MW), and construction of a biomass facility near Fallbrook (67 MW).[665]

16.5.2. Parties' Positions

SDG&E asserts that the In-Area Renewable Alternative is infeasible because it is unduly speculative and cost prohibitive, because timely permits cannot be obtained, and because it will not meet reliability or RPS goals. SDG&E asserts that this alternative, like the All-Source Generation Alternative, is contrary to planning principles articulated by CAISO and past Commission decisions and will require major new transmission system upgrades.

More particularly, SDG&E claims that: the San Diego area only holds 155 MW of dependable renewable energy potential; this alternative's solar thermal component would require a new 230 kV transmission line through Anza-Borrego; solar PV cannot be installed at the rate detailed in the EIR/EIS and is unrealistic; wind resources are speculative and hard to site and develop; and the biomass component is doubtful at best. Given that 80% of the energy from the In-Area Renewable Alternative comes from intermittent technologies, SDG&E claims that it cannot be used to meet reliability needs. SDG&E asserts that providing firm capacity would require either expanding the In-Area

[664] Draft EIR/EIS, Sec. E.5.1.3.

[665] Draft EIR/EIS, Sec. E.5.1.3.

Renewable Alternative or building back up generation plants. Finally, SDG&E claims the In-Area Renewable Alternative costs too much. SDG&E estimates the cost to include over $1 billion in transmission upgrades alone, plus the need to purchase backstop generation and claims the renewable generation portion of the alternative will cost between $661 million to $2.1 billion over the purchase price of out-of-basin renewable projects utilizing the Proposed Project.

CAISO criticisms of the In-Area Renewable Alternative are similar to its criticism of the All-Source Generation Alternative. CAISO contends the alternative is too speculative, will not meet reliability goals, is infeasible due to a 1,150 MW dispatch limit for generation on the Imperial Valley to Miguel Substation portion of the Southwest Powerlink, and fails to meet project objectives.

Powers Engineering supports, in concept, the feasibility of the In-Area Renewable Alternative, but proposes a different mix of resources that promotes additional local solar PV. Whereas SDG&E estimates the San Diego area's dependable renewable energy potential at only 155 MW, Powers Engineering asserts San Diego has 7,400 MW of solar PV alone and argues that the projections in the In-Area Renewable Alternative should be expanded, given the large number of available solar PV business/industrial sites in San Diego. Powers Engineering also proposes a renewable energy park, containing 1 to 10 MW solar PV systems at or near existing or future transmission lines and substations. Powers Engineering claims such energy parks could lead to development of 290 MW of concentrated solar PV; this amount, together with 920 MW of solar PV from commercial and residential installations, provides a viable substitute for the Proposed Project, Powers Engineering argues.

Powers Engineering characterizes SDG&E's solar PV cost estimates as outdated and highly inaccurate, and contends that the true cost of solar PV is one third the utility's estimate. Moreover, Powers Engineering states the existing 69 kV rural grid in San Diego County could accommodate this generation without new lines or upgrades. In addition, Powers Engineering argues this resource is CEQA exempt, would not require construction of transmission facilities, and does not have large land use or recreational impacts. Powers Engineering also claims that 920 MW of solar PV can be online by 2016 and that battery storage for this increment will allow nameplate capacity to be firm on-peak capacity, add only about 10% to the cost, and replace the geographically remote renewable projects in this alternative, thereby avoiding the need for new transmission facilities to reach those distant sites. According to Powers Engineering, energy efficiency, demand response, and other in basin generation projects can address SDG&E's reliability needs. Finally, Powers Engineering argues that the solar thermal plant component of the In-Area Renewable Alternative is infeasible due to its water usage needs which would increase the local, already over-drafted, aquifer withdrawal by around 10%.

UCAN contends that the No Project Alternative is superior to the In-Area Renewable Alternative but notwithstanding this position, UCAN reiterates the concerns it raises about the solar PV portion of the All-Source Generation Alternative -- SDG&E's cost estimates for solar PV are grossly inflated, its energy conversion factor is wrong, and contrary to SDG&E's assertions, San Diego has sufficient commercial rooftop to support large scale solar PV deployment.

Conservation Groups contend that the In-Area Renewable Alternative is inherently more reliable that any project that requires transmission lines through remote areas, avoids many of the environmental impacts of the Proposed Project, guarantees renewables will be developed, and is less costly than the Proposed Project.

16.5.3. Discussion

The In-Area Renewable Alternative, like the All-Source Generation Alternative, largely meets the first and third Basic Project Objectives – reliability and renewables development, respectively. While the EIR/EIS indicates that this alternative also meets the second Basic Project Objective, to reduce energy costs, because no party modeled the energy benefits of this alternative in the CPCN portion of the proceeding, the outcome is not clear. With respect to the third Basic Project Objective, though this alternative promotes renewable power development in the in basin San Diego area, it does not facilitate delivery of power from new Imperial Valley renewables.

The In-Area Renewable Alternative creates fewer environmental impacts than the Proposed Project or other transmission alternatives but significant impacts result from extensive ground disturbance, habitat loss, and the visibility of the large wind and solar thermal components. Ground disturbance and habitat loss result from project construction, as well as construction of 47 miles of associated, new transmission lines. The solar thermal component creates significant visual and recreation impacts on the Borrego Springs, which is highly visible from surrounding Anza-Borrego Wilderness areas. The In-Area Renewable Alternative has no impact on National Forest lands. Because this alternative consists solely of renewables, it would result in substantial GHG emission reductions compared to the transmission alternatives, though the Final EIR/EIS does not quantify those differences.

San Diego's service area contains sufficient renewable resources to pursue this alternative. Aggressive projections show that the San Diego region has approximately 7,400 MW of solar PV potential on commercial and residential structures;[666] more modest projections show a potential for over 4,100 MW of solar rooftop PV.[667] Regardless of the wide range between these estimates, even the low end represents substantial potential. As of January 2006, SDG&E had 18 MW of solar PV installed in its service area;[668] SDG&E's recently filed solar PV application seeks authority for 77 MW,[669] and SDG&E has acknowledged that its service area could support a program similar to one that Edison has proposed (250 MW, with the potential to expand to 500 MW).[670]

In response to parties' claims that in-area renewable development is not feasible within the time frame required to meet SDG&E's reliability needs, our reliability findings conclude that SDG&E does not need the generation in this alternative to be online until 2014, at the earliest. The In-Area Renewable Alternative's potential for timely, incremental generation additions as early as 2010 minimizes permitting concerns.

16.6. LEAPS Transmission-Only Alternative

16.6.1. Description

The EIR/EIS evaluates two LEAPS projects as alternatives to the Proposed Project: the LEAPS Transmission-Only Alternative[671] and the LEAPS Generation Plus Transmission Alternative, which is the subject of Section 16.9, below. The LEAPS Transmission-Only Alternative is identical to the TE/VS project proposed

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[666] Powers Engineering Phase 2 Opening Brief, 7.

[667] UCAN Exhibit U-93, 1.

[668] UCAN Exhibit U-93, 1.

[669] A.08-07-017.

[670] SDG&E Exhibit SD-115; SDG&E Exhibit SD-116.

[671] Evaluated in Section E.7.1 of the Draft EIR/EIS.

by the Elsinore Valley Municipal Water District and Nevada Hydro, which is pending at the Commission as A.07-10-005. We describe the TE/VS project, and its companion generation proposal, the Lake Elsinore Pumped Storage Project, in greater detail in Section 6.14.4.

The EIR/EIS concludes that the LEAPS Transmission-Only Alternative is the third most environmentally superior alternative to the Proposed Project. It is the shortest transmission alternative, consisting of 32 miles of new 500 kV line connecting SDG&E and Edison service areas, as well as upgrades to 48 miles of 230 kV line; the interconnection with Edison would create a second extra-high voltage link between SDG&E's system and the CAISO grid.

16.6.2. Parties' Positions

SDG&E contends that a number of factors make the LEAPS Transmission-Only Alternative infeasible or even illusory; CAISO and Jacqueline Ayers echo these criticisms. Some parties also argue that the EIR/EIS understates the environmental impacts of the LEAPS Transmission-Only Alternative or that the EIR/EIS fails to fully analyze those impacts. Though the premises are different, both arguments lead to the same claim - that the comparative impact analysis among the various project alternatives is skewed by the analysis of this alternative. Nevada Hydro asserts that the LEAPS Transmission-Only Alternative will provide a viable conduit for delivery of geothermal energy produced in the Imperial Valley once other, pending transmission line projects have been completed and that therefore, this alternative adequately addresses all Basic Project Objectives.

On the issue of feasibility, SDG&E points to several factors: uncertainty over Nevada Hydro's intentions regarding the larger proposed LEAPS Project (i.e., the LEAPS Generation and Transmission Alternative); potential delays and uncertainties in the state and federal permitting processes, which now will not allow start-up before 2011 or 2012 at the earliest; and the costs of the LEAPS Transmission-Only Alternative, which SDG&E estimates to approach $968 million.[672] SDG&E and CAISO also contend that additional costs will be incurred to accommodate this alternative because technical factors and existing system parameters within SDG&E's service area severely limit the alternative's actual import capacity. SDG&E claims that these system limitations can be overcome only by upgrades costing in the range of $1.5 billion (for 500 MW capacity) to $1.8 billion (for 1,000 MW capacity). Jacqueline Ayers advances variations of some of these arguments.

Nevada Hydro disputes the foregoing contentions and estimates the actual cost of the LEAPS Transmission-Only Alternative at approximately $350 million in 2006 dollars. Nevada Hydro further argues that the evidence does not support the contentions of the other parties concerning costs and technical issues, or is refuted by other evidence, including evidence offered by Nevada Hydro. SDG&E and other parties point out that Nevada Hydro's own contentions lack detailed factual or analytical support.

Jacqueline Ayers, in particular, contends that the EIR/EIS understates the wildfire impacts of the LEAPS Transmission-Only Alternative and fails to consider impacts beyond fire shed boundaries. SDG&E contends that the EIR/EIS overstates the actual impacts (particularly after application of proposed mitigation measures) of both the Proposed Project and the "Enhanced" Northern Route, which causes the LEAPS Transmission-Only Alternative to be ranked too highly.

[672] See SDG&E Phase 2 Opening Brief, 205-210.

Finally, on the issue of deliverability of renewables, Nevada Hydro contends that once Imperial Irrigation District completes the proposed Coachella Valley-Devers 2 project, which will increase the transfer capability with the Edison system, the LEAPS Transmission-Only Alternative could deliver geothermal energy from the Imperial Valley. Imperial Irrigation District generally supports this argument. Nevada Hydro also contends that the new LEAPS interconnection would facilitate the delivery to SDG&E of energy from Edison's proposed Tehachapi Renewable Transmission Project, but SDG&E and other parties disagree. They stress that even assuming these connections to renewable resources are made, the LEAPS Transmission-Only Alternative at best would be an unsatisfactory substitute for direct, immediate connection to Imperial Valley and other renewable energy sources – a connection which the Northern and Southern Routes provide.

16.6.3. Discussion

As well as being ranked third in terms of environmental superiority overall, the LEAPS Transmission-Only Alternative is the environmentally superior transmission alternative. With its new 500 kV transmission component limited to 31.8 miles, the LEAPS Transmission-Only Alternative is substantially shorter than the other transmission alternatives. Overall, the LEAPS Transmission-Only Alternative requires almost 100 fewer miles of new transmission line construction than the Final Environmentally Superior Northern Route and approximately 60 miles less than the Final Environmentally Superior Southern Route. Compared to these and the other transmission alternatives, the LEAPS Transmission-Only Alternative minimizes biological, visual, agricultural,

cultural/historical, paleontological, transportation/traffic, air quality, water resources, geology/soils, socioeconomic and wildfire impacts.[673]

Like all of the transmission alternatives, the LEAPS Transmission-Only Alternative will have significant and unavoidable adverse impacts in some of these areas. In addition to more obvious construction-related impacts, for example, socioeconomic impacts occur when private properties along the right-of-way are acquired and impacts to cultural resources occur when Native American burial sites, currently unknown, are discovered during construction. While the majority of these unavoidable, significant impacts are temporary impacts associated with construction, some major impacts, particularly biological and visual resource impacts, would be permanent. For example, the LEAPS Transmission-Only Alternative would be highly visible in Cleveland National Forest. In some other areas (land use, wilderness and recreation, noise, and public health and safety), this alternative ranks only second or third among all transmission alternatives. Nevertheless, on the whole, the balance of environmental considerations favors the LEAPS Transmission-Only Alternative over other transmission alternatives.

However, the LEAPS Transmission-Only Alternative still has a greater impact on the environment than the two generation-only or non wires alternatives. Specifically, this alternative has substantially greater wildfire risk. We disagree, however, with parties' contentions that the EIR/EIS understates the wildfire impacts of the LEAPS Transmission-Only Alternative. Even assuming greater weight were given to wildfire impacts and allowance were made for allegedly overstating the impacts of the Northern Route Alternatives, the LEAPS

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[673] Draft EIR/EIS, Sec. H.5.3 and Table H-25.

Transmission-Only Alternative remains the environmentally superior transmission line alternative among all those analyzed in the EIR/EIS.

The EIR/EIS concludes, based on the information available at the time of its preparation, that the LEAPS Transmission-Only Alternative meets the first and second Basic Project Objectives, (to increase reliability and to reduce energy costs). It also concludes that the LEAPS Transmission-Only Alternative partially meets the third Basic Project Objective (promote renewable energy development). Based on our review of the record in the CPCN portion of this proceeding, we find that the LEAPS Transmission-Only Alternative only minimally meets the first and second Basic Project Objectives and does not meet the third.

Regarding the first Basic Project Objective (to increase reliability), while the alternative would contribute to maintaining reliability in the San Diego area, it would be at the expense of the Los Angeles area. Further, it does not provide the same degree of reliability contemplated by the Proposed Project. The transfer capability will be something significantly less than 1,000 MW without substantial additional network upgrades.[674]

Regarding the second Basic Project Objective (to reduce energy costs), while all transmission lines theoretically reduce the cost of energy, there is no credible evidence in the record to suggest that the LEAPS Transmission-Only Alternative will generate sufficient energy cost savings that result in net savings to customers in the region.

With regard to the third Basic Project Objective, the EIR/EIS concludes that the LEAPS Transmission-Only Alternative will only partially meet the objective to accommodate the delivery of Imperial Valley or San Diego County

[674] See, e.g. discussion at Section 9 above.

renewable resources absent several other, unrelated transmission upgrades. However, based on the CPCN record, we find that the LEAPS Transmission-Only Alternative does not meet the third Basic Project Objective. While this alternative may facilitate the flow of power among service areas, any transmission line that connects two service areas accomplishes this. Because the LEAPS Transmission-Only Alternative does not terminate in a transmission-constrained area with undeveloped renewable resource potential, it does not facilitate the development of renewable energy. The LEAPS Transmission-Only Alternative is not an appropriate substitute for a direct connection from the Imperial Valley to a load center.

Therefore, upon consideration of the record as a whole, we do not find substantial evidence that this alternative adequately can meet at least two of the Basic Project Objectives. The LEAPS Transmission-Only Alternative is best considered as a potential, future, additional regional project, and we reach no conclusion today about its technical, economic and environmental merits. Thus, our decision does not prejudge any portion of project, which is the subject of A.07-10-005.

16.7. Final Environmentally Superior Southern Route

The EIR/EIS evaluates a number of alternatives that parallel a portion of the Southwest Powerlink in order to bring Imperial Valley renewables to San Diego from the south. These alternatives completely avoid Anza-Borrego, while providing a transmission-based approach to meeting all Basic Project Objectives. We refer to these routes collectively as the "Southern Route Alternatives" or "Southern Routes" to identify the transmission "spine" that, if built, would bring power from the Imperial Valley to San Diego via a southern path that avoids

Anza-Borrego. The Final EIR/EIS determines the Final Environmentally Superior Southern Route to be the preferred Southern Route.[675]

Commission staff and BLM identified a series of potentially feasible Southern Routes and alternatives to certain segments of these routes for analysis in the EIR/EIS. The process involved consultation with SDG&E, numerous federal, state and local agencies, Native American tribes, and members of the public. The Final Environmentally Superior Southern Route, like all of the Southern Routes analyzed in the EIR/EIS, begins at the Imperial Valley Substation and ends at Proposed Project milepost 131, where it then follows the Proposed Project west to the Sycamore Canyon Substation. West of that substation, the Final EIR/EIS replaces the Proposed Project with the environmentally superior Coastal Link Upgrades Alternative Revision.[676] There are many hybrid routing combinations that could constitute a Southern Route.

16.7.1. Parties' Positions

SDG&E raises numerous concerns about any Southern Route that requires the crossing of tribal lands or incompatible Forest Service land use zones.[677] Conservation Groups contends that a finding of infeasibility for a route across the Campo Reservation must be supported by evidence of a good faith effort to pursue all reasonable negotiation options between SDG&E and the Tribe.[678] SDG&E also expresses concern about the potential for any Southern Route to

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[675] For a detailed description of the Final Environmentally Superior Southern Route, see Final EIR/EIS, ES.7.2.

[676] Recirculated Draft EIR/Supplemental Draft EIS, Sec. 3.2.3, Sec 5.2.

[677] SDG&E Phase 2 Opening Brief, 141-143.

[678] Conservation Groups Phase 2 Reply Brief, 15.

have an environmental impact on cultural resources along the segment referred to as the Interstate 8 Alternative.

16.7.2. Discussion

The Final EIR/EIS ranks the Final Environmentally Superior Southern Route fourth among all the alternatives studied, below the LEAPS Transmission-Only Alternative but above the Final Environmentally Superior Northern Route and other Northern Routes. Running a total of 123 miles, this alternative is substantially shorter than the Proposed Project or other Northern Routes and avoids Anza-Borrego. It crosses 19.2 miles of National Forest land but does so within acceptable land use zones and makes use of a Draft Department of Energy Section 368 West-wide Energy corridor.[679] In addition, the alternative is collocated with the Southwest Powerlink for only 36 miles, in an area of comparatively low fire risk.

The Final EIR/EIS modifies the route proposed in the Draft EIR/EIS to avoid both the Campo and La Posta Reservations.[680] Having reviewed the requirements for finding a route through the Campo Reservation infeasible and the case cited by Conservation Groups to support their argument,[681] we have determined that routing a transmission line across the Campo Reservation is

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[679] The Energy Policy Act of 2005, Section 368, required designation of energy corridors on federal lands.

[680] The Final Environmentally Superior Southern Route could still cross Viejas land if any additional concerns about the eastern end of Alpine Boulevard are identified through additional tribal consultation between the Viejas Tribe and BLM prior to construction based on preliminary cultural resources investigations. (See additional explanation in Draft EIR/EIS, Sec. H.4.5.)

[681] The opinion cited by the Conservation Groups, *Center for Biological Diversity v. Rey* (9th Cir. 2008) 2008 WL 2051072, has been amended and superseded by *Sierra Forest Legacy v. Rey* (9th Cir. 2008) 526 F.3d 1228. We have considered both of these opinions.

legally infeasible given the Campo Tribe's refusal to grant the necessary easement and the fact that neither SDG&E nor the Commission has the authority to impose or implement a route through this land.[682]

The Final Environmentally Superior Southern Route also contains modifications to avoid Forest Service land use zones that do not allow transmission lines or new access roads. Commission staff and BLM consulted extensively with the Forest Service and SDG&E to identify route modifications within Cleveland National Forest to minimize impacts to Forest Service resources and avoid incompatible land use zones.

Though the Final EIR/EIS acknowledges SDG&E's concern about the potential for cultural resource impacts along the Interstate 8 Alternative segment, further research into the site descriptions and boundaries of the cultural site previously identified as being within Alpine Boulevard show that the site does not extend south of Interstate 8, and would not be affected.[683] As a result, the Star Valley Option, which would have significant visual impacts, would not be included as part of the Final Environmentally Superior Southern Route. However, the Star Valley Option (as modified by SDG&E reroutes described in the Star Valley Option Revision) still could be used if additional concerns about the eastern end of the Alpine Boulevard are identified through any additional tribal consultation prior to construction based on the preliminary cultural resources investigations. Therefore, the Final Environmentally Superior Southern Route retains the entire Interstate 8 Alternative segment underground in Alpine Boulevard.

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682 See Pub. Resources Code § 21004.

683 Final EIR/EIS, Sec. 4, responses to Comment Set F008 (Viejas Tribe).

16.8. Northern Routes

We describe the Proposed Project, "Enhanced" Northern Route, and the Final Environmentally Superior Northern Route in Section 3.2, and discuss the environmental impacts of each of these Northern Routes in Section 14. We find that the unmitigable significant, environmental impacts of the three Northern Routes on Anza-Borrego cannot justify their construction.

16.9. LEAPS Transmission Plus Generation Alternative

As described more fully in Section 6.14.4 and noted in Section 16.6, the LEAPS Generation and Transmission Alternative[684] includes the LEAPS Transmission-Only Alternative, also known as the TE/VS project and the Lake Elsinore Pumped Storage Project.

Based on its environmental impacts, the LEAPS Generation and Transmission Alternative is the lowest ranked of all the alternatives -- the EIR/EIS ranks it below the Proposed Project. This alternative has the same environmental impacts as the LEAPS Transmission-Only Alternative, with the added impacts created by the construction and operation of the proposed 500 MW pumped storage facility. Consequently, given the record as a whole, and our decisions here regarding the LEAPS Transmission-Only Alternative, we do not address this alternative further.

16.10. No Project Alternative

16.10.1. Description

The No Project Alternative envisions a range of options likely to occur in the event Sunrise is not built and identifies the environmental impacts of the No Project Alternative based on that range of options. The EIR/EIS concludes that

[684] Evaluated in Section E.7.2 of the Draft EIR/EIS.

without Sunrise, the following actions are likely to occur in the foreseeable future:

- Existing transmission and generation facilities will continue to operate until other major generation or transmission projects can be developed.
- Electricity consumption and peak demand within the SDG&E service territory will continue to grow. To serve this growth, additional electricity will need to be generated within San Diego County or imported by existing or modified facilities.
- Certain demand-side or supply-side actions likely will occur beyond the levels currently planned by SDG&E. Demand-side actions include increased levels of energy conservation (energy efficiency) or load management (demand response). Supply-side actions include development of new generation, whether conventional, renewable, or distributed generation, as well as construction of other major transmission projects.

Thus, the EIR/EIS assumes that, in the absence of Sunrise, the San Diego area will see the pursuit of a combination of generation and transmission actions, which likely will include components of the All-Source Generation, In-Area Renewable, and LEAPS Transmission-Only Alternatives.

16.10.2. Parties' Positions

SDG&E recognizes that the No Project Alternative contains aspects of the In-Area Renewable, All-Source Generation, and LEAPS Transmission-Only Alternatives and consequently states the same concerns about the No Project Alternative, characterizing it as infeasible, overly costly, unable to meet reliability needs, and likely to create more environmental damage than the Propose Project with regard to GHG emission impacts.

Like SDG&E, CAISO states that the No Project Alternative contains many of the drawbacks of the All-Source Generation, In-Area Renewable, and LEAPS

Transmission-Only Alternatives, including an inability to deliver renewable energy to SDG&E or to meet reliability needs.

UCAN states that the EIR/EIS fails to identify and consider factors that would reduce the environmental impacts of the No Project Alternative. According to UCAN, upgrades to Path 44, modifications at the Miguel Substation, and increases in energy efficiency and distributed generation beyond that envisioned in the Draft EIR/EIS are realistic assumptions, and would minimize the No Project Alternative's environmental consequences. More particularly, UCAN argues that a Path 44 upgrade is likely to occur due to other already proposed system upgrades and will increase SDG&E import capacity by 350 MW and that increasing the Miguel Substation capability to 1,900 MW would increase SDG&E's ability to import renewables from the Imperial Valley.

16.10.3. Discussion

Our conclusions with respect to the All-Source Generation and In-Area Renewables apply here. The fossil fired and renewable in-area generation identified in these EIR/EIS alternatives is neither unrealistic nor unduly speculative and sufficient levels of both can be brought online in time to meet SDG&E's reliability needs, which we find to be less urgent than SDG&E asserts. Since only about 1,000 MW of in basin generation or transmission import capacity is necessary to replace the Proposed Project, and since a combination of the two top ranked alternatives can provide that amount, the No Project Alternative has adequate resources. Therefore, it meets the first and third Basic Project Objectives. Given the CPCN record, however, the No Project Alternative may not reduce the cost of energy in the region, which is the second Basic Project Objective. Unlike the parties, we do not factor development of the LEAPS Transmission-only Alternative into our assessment of likely development under the No Project alternative because as discussed in Section 17.6, we find that the CPCN record renders the LEAPS Transmission-only Alternative less attractive economically than the EIR/EIS suggests.

16.11. Conclusions Drawn from Environmental Review

The EIR/EIS evaluated a range of alternatives to identify potentially feasible ways to achieve the Basic Project Objectives at a lower environmental cost. We have carefully scrutinized the information in the EIR/EIS, and we rely on its conclusions with respect to the environmental impacts of the various alternatives and its ranking of the environmental superiority of these alternatives. We have also examined the extent to which each of these alternatives can feasibly meet the Basic Project Objectives, informed by the record in the CPCN portion of the proceeding.

The Proposed Project and all of the alternatives would create many significant, unmitigable impacts on the environment. The Final EIR/EIS concludes that three alternatives – the All-Source Generation Alternative, the In-Area Renewable Alternative, and the LEAPS Transmission-Only Alternative – have fewer significant unmitigable impacts than the Final Environmentally Superior Southern Route. However, we find that the three alternatives that the Final EIR/EIS determines to be environmentally superior to the Final Environmentally Superior Southern Route are not feasible when we consider certain other considerations, including meeting California's broader policy goals.

As discussed in Section 14 above, AB 32 requires that California reduce its GHG emissions to 1990 levels by 2020. The energy sector is expected to contribute a significant amount to those reduction goals. Our recent GHG decision[685] making recommendations to the California Air Resources Board on its Draft Assembly Bill 32 Scoping Plan[686] commits this Commission to achieving 33% RPS, assuming certain safeguards. Thus, this Commission is committed to achieving GHG reductions in the energy sector, in part, through renewable procurement at 33% RPS levels.

The Final Environmentally Superior Southern Route is the highest ranked Alternative that will facilitate our policy to achieve GHG reductions through renewable procurement at 33% RPS levels in the shortest time possible with the greatest economic benefits. The three top ranked alternatives would not facilitate even half the amount of renewable development that the Final Environmentally Superior Southern Route will facilitate. In our Analytical Baseline, we assume, consistent with CAISO, that construction of a Northern or Southern Route Alternative will facilitate the development of over 2,800 MW of Imperial Valley renewables between 2011 and 2015.[687] In contrast, the All-Source Generation Alternative proposes the development of 203 MW of solar PV in San Diego's service area. The In-Area Renewable Alternative proposes the development of a total of 1,000 MW of renewable resources in San Diego's service area, 900 MW of which are intermittent solar and wind resources. Thus, both the All-Source Generation Alternate and the In-Area Renewable Alternative propose to develop substantially less renewable energy than will be facilitated by Sunrise. Further,

[685] *Greenhouse Gas Regulatory Strategies*, D.08-10-037.

[686] Climate Change Draft Scoping Plan, a framework for change, June 2008 Discussion Draft Pursuant to AB 32 the California Global Warming Solutions Act of 2006 Prepared by the California Air Resources Board for the State of California, June 26, 2008, available at http://www.arb.ca.gov/cc/scopingplan/document/draftscopingplan.pdf. The Air Resources Board released its Proposed Scoping Plan on October 15, 2008 and it is available at http://www.arb.ca.gov/cc/scopingplan/document/psp.pdf.

[687] See Table 2 at Section 6.10.

neither alternative will facilitate the development of geothermal resources, which are a high capacity renewable resource that will flow more often than wind or solar resources. CAISO projects that the Environmentally Superior Southern Route would facilitate the development of 1,600 MW of geothermal resources in the Imperial Valley. The LEAPS Transmission-Only Alternative is only projected to facilitate the flow of power between the Edison and SDG&E service areas, but not to actually increase the development of renewables in the Imperial Valley or elsewhere.[688]

The All-Source Generation Alternative is not likely to off-set its construction-related GHG emissions, while the Final Environmentally Superior Southern Route will generate substantial GHG emission reductions if operated as conditioned here. The Final EIR/EIS recognizes that construction and operation of the fossil fueled generation component of the All-Source Generation Alternative will generate substantially more GHG emissions than the construction-related emissions associated with Sunrise. The Final EIR/EIS concludes that the All-Source Generation Alternative (which is considered equivalent to the No Project Alternative) would greatly increase GHG impacts compared to Sunrise.[689]

The Final Environmentally Superior Southern Route will generate more economic benefits to ratepayers than the top ranked alternatives. The record shows that if Sunrise operates under a renewable procurement framework that reaches 33% RPS levels, it is estimated to generate net benefits of over $100 million per year.[690] In contrast, the All-Source Generation Alternative is

[688] See Section 17.6 above.

[689] See discussion at Section 14.3.

[690] See Table 13, Section 11.4.

estimated to generate net benefits of $36 million to $74 million per year, depending upon renewable costs. While the In-Area Renewables Alternative was not modeled in the Compliance Exhibit and the Update, earlier estimates projected significantly lower net benefits given the higher level of renewable resources in that alternative.[691] Thus, we reject the All-Source Generation, In-Area Renewable, and LEAPS Transmission-Only Alternatives and find them infeasible for the reasons discussed above.

We find that the Final Environmentally Superior Southern Route will facilitate our policy goal of renewable procurement at 33% RPS levels within a reasonable period of time with the greatest economic benefits at the lowest environmental cost. While the Northern Routes analyzed in the EIR/EIS could achieve these benefits, they would do so at significantly greater environmental expense.[692] We therefore reject the Proposed Project, SDG&E's "Enhanced" Northern Route, and the Final Environmentally Superior Northern Route as environmentally infeasible.

17. Community Values and Other Requirements Pursuant to Public Utilities Code Section 1002(a)

As discussed above in Section 4.2, in addition to the effect of a project on the environment, and park and recreation values, Public Utilities Code Section 1002(a) requires us to consider community values and historical and aesthetic values. The most extensive record on these issues, apart from the impacts on Anza-Borrego which we discuss in Section 14, concerns the impacts that would result from siting the Inland Valley Link of the Northern Route

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[691] SDG&E estimates that the net benefits for the In-Area Renewable Alternative would be approximately $180 million per year less than the All-Source Generation Alternative. See SDG&E Exhibit SD-142, Table 11-6, 14.

[692] EIR/EIS, Section H.

Alternatives near Mussey Grade Road (in the vicinity of Ramona), and impacts that other routing Links (see Section 3.2.1) would have on agricultural communities. We also address community values articulated at Public Participation Hearings by residents of the San Diego back country.

17.1. Mussey Grade Road and Backcounty Areas

The record on community values has been developed largely through public input – testimony at Public Participation Hearings and written comment (letters and emails), the latter generally sent to the Commission's Public Advisor's Office or provided through the EIR/EIS process. Mussey Grade, an association of people who live in the Mussey Grade Road area near Ramona, in West-Central San Diego County, participated in the Phase 1 and Phase 2 hearings as a party. Overwhelmingly, the public statements, like Mussey Grade's participation, register opposition to the Proposed Project and other transmission alternatives. Many have asked whether SDG&E was not seeking to apply a 20th century solution to a 21st century problem.

Understandably, people are interested in protecting their local environment, the quality of its aesthetic experience and, in some instances, the value of their property. However, while self-interest may motivate some of the opposition to the Proposed Project, much of the opposition has arisen from an altruistic spirit, environmental concerns going beyond immediate locales, and deep reverence for nature. For example, Mussey Grade, which strongly protests construction of the Proposed Project's Inland Valley Link, argues that "[t]he community values of Mussey Grade Road are antithetical to this proposed massive power line project and it is inappropriate to route a transmission line through historic rural communities.[693] Mussey Grade offered testimony of several long-time residents about the community, historical and aesthetic values of the area. One person stated:

> Life here is uncomplicated. The people I know along Mussey Grade Road all have this common sense of possessiveness about the road, about the land and about the way we live. There's much more involvement in nature and in the preservation of the wild areas and the wild animals. There's a love for the land and a respect – I have the sense that there are roots growing into the ground from my feet – a sense of being rooted and loved altogether. And regarding the landscape, as one of our friends said, 'There's an Ansel Adams out every window."[694]

Another person described the people who are attracted to the area:

> The people are individualist, yet interested in maintaining a closer-knit group, especially in regard to the preservation of Mussey Grade and its environment. The residents have common causes such as wildland fire protection and deep environmental concerns.[695]

Another individual described the strong community involvement in issues that affect the area:

> Whenever an issue arose, like the proposed off-road vehicle park that a group wanted to put in, we fought it and won and then the land it was going to be on became part of the Boulder Oaks County Open Space Preserve. When there was a road proposed to go to Barona Indian Reservation, we fought the idea and prevailed. When it was determined that people were speeding on Mussey Grade Road, we got the speed limit reduced. When we felt there was a threat to the historic oak trees along the road that might be cut down, we got the road designated as a historical point of interest by the state. This road used to be a

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693 Mussey Grade Phase 1 Opening Brief, 37-39.

694 Mussey Grade Exhibit MG-3, 3:4-10.

695 Mussey Grade Exhibit MG-4, 2:5-8.

stagecoach road from San Diego to the gold mines in Julian. And now we are fighting the Sunrise Powerlink.[696]

The website maintained by the Mussey Grade Road community at www.musseygraderoad.org, provides a tangible example of "community values" and includes photographs of community landmarks and scenic areas.

SDG&E has stated that it considered various community values in the siting and development of the Proposed Project.[697] SDG&E contends that it has undertaken a comprehensive and extensive public outreach plan, seeking input from both the public and project stakeholders, including residential and commercial customers, community and business leaders, environmental groups, and elected officials.[698] SDG&E states that these efforts sufficiently addressed community values pursuant to § 1002 and notes that from a procedural perspective, the 2006 Application has involved an extensive community outreach process.[699]

Regardless of the extent of SDG&E's outreach program, the Proposed Project is very much at odds with the community values of the residents who live near Mussey Grade Road and other backcountry areas. There always will be trade-offs between the desire to protect such communities and the need to expand infrastructure. For the reasons set forth in Section 17.11 above, we conclude that the Final Environmentally Superior Southern Route is the superior

[696] Mussey Grade Exhibit MG-2, 4:1-10.

[697] SDG&E Phase 1 Reply Brief, 132.

[698] SDG&E Phase 1 Opening Brief, 176-177; SDG&E Exhibits SD-11, Ex. SD-12.

[699] SDG&E Phase 1 Opening Brief, 6, 7, 27-30, 176 and 177. SDG&E's PEA includes information regarding the approximately 350 communications and presentations SDG&E made to federal, state and local agencies, elected officials, community groups and the public prior to date, when the PEA was filed.

alternative. However, we require mitigation to address concerns raised by Mussey-Grade and others.

17.2. Agricultural Community Values

Imperial Irrigation District and Farm Bureau focus on Northern Route segments outside Anza-Borrego and express concern about impacts to agricultural lands in Imperial Valley.[700] They argue it is wrong to harm the Imperial Valley agricultural community by siting a 500 kV transmission line on valuable agriculture land when less harmful alternative routes available. They contend the Proposed Project (and two other Northern Routes) cut through some of the Imperial Valley's most productive farmlands and would impose severe impacts upon farms, dairies, irrigation systems and other agricultural operations. Imperial Irrigation District and Farm Bureau argue that SDG&E has not adequately analyzed the true impact to farming in the Imperial Valley given the unique and complex system of irrigation canals and drains used there. Imperial Irrigation District supports only a Southern Route or alternatively, a route that was eliminated from further study early on, the Western Route in the Desert Link.[701] Imperial Irrigation District contends that the Eastern Route in the Desert Link unnecessarily affects farmlands, dairies and irrigation facilities in the community.[702]

SDG&E does not dispute that agricultural lands, dairies and irrigation systems have value or that we should consider this value along with other resources and values as we assess the merits of competing transmission route

[700] Farm Bureau Phase 2 Opening Brief, 7-8.

[701] Imperial Irrigation District Phase 1 Opening Brief, 15-20.

[702] Imperial Irrigation District Phase 1 Opening Brief, 36.

alternatives.[703] In fact, SDG&E claims that it "attempted to site the project to avoid impacting agricultural lands to the extent feasible."[704] To this end, SDG&E classified agricultural lands as a high to moderate constraint during its study of siting opportunities,[705] and the Proposed Project follows property boundaries and section lines of agricultural lands.[706] Also, in agricultural areas SDG&E switched structure types from lattice towers to steel poles to reduce impacts.[707] As a result, impacts to agricultural land use are limited to structure footprints, access roads, and pull sites, not the entire right-of-way.

Gov. Code § 51238, also known as the Williamson Act, is in effect in Imperial County and provides that, unless otherwise specified by local regulations, plans or standards, the construction, operation and maintenance of electric facilities are compatible with other uses under the Williamson Act, including agricultural uses.[708] The applicable Imperial County plans and ordinances provide that electric facilities are either permitted uses or conditionally allowed uses in agricultural lands.[709] Moreover, SDG&E's prior projects, like the Southwest Powerlink in the Imperial Valley, demonstrate that linear transmission lines can be compatible with agricultural uses. Imperial Irrigation District itself owns transmission lines, maintains transmission lines,

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[703] SDG&E Phase 1 Reply Brief, 138.

[704] SDG&E Phase 1 Reply Brief, 138.

[705] SDG&E Exhibit SD-11, Figures 18, 20 and 21.

[706] SDG&E Exhibit SD-9, 2-23 and Figure 4.1-1A; SDG&E Exhibit SD-11, Figure 16.

[707] SDG&E Exhibit SD-9, 2.3-1.

[708] SDG&E Exhibit SD-10, 5-1.7.

[709] SDG&E Exhibit SD-10, 5-1.7 to 5-1.8.

and has proposed transmission line upgrades through similar agricultural areas in Imperial County.

We find that the EIR/EIS has adequately considered the concerns of the affected agricultural communities in siting the Final Environmentally Superior Southern Route and that the impacts on agricultural lands are significantly mitigated because of our approval of the Final Environmentally Superior Southern Route rather than a Northern Route.

18. Certification of Final EIR, Project Authorization, Statement of Overriding Considerations, and Related Issues

18.1. Certification of Final EIR

Before approving an application for a CPCN, the Commission must certify the Final EIR.[710] We hereby certify that:

- The Final EIR/EIS has been completed in compliance with CEQA.
- The Final EIR/EIS was presented to the Commission, and the Commission has received, reviewed, and considered the information contained in the Final EIR/EIS.
- The Final EIR/EIS reflects the Commission's independent judgment and analysis.

The certification extends to the EIR/EIS's analysis of connected actions, indirect effects, and potential future transmission expansion, which we have received, reviewed, and considered in making our decision on this project. However, as explained above, none of the connected actions, indirect effects, or potential future transmission expansion projects are before us for approval at this time, and our action on SDG&E's CPCN application does not approve or guarantee any future approval of any of these projects.

[710] CEQA Guidelines § 15090.

18.2. Authorization of the Final Environmentally Superior Southern Route

Based on the considerations above, we authorize SDG&E to construct the Final Environmentally Superior Southern Route as set forth in and described in the CEQA Findings of Fact (Exhibit E). In connection with this authorization, we adopt the findings set forth in Exhibit E, pursuant to CEQA Guidelines § 15091.

18.3. Statement of Overriding Considerations

The Commission recognizes that significant and unavoidable environmental impacts will result from construction and operation of the Final Environmentally Superior Southern Route. Having (1) adopted all feasible mitigation measures; (2) adopted certain alternatives that reduce the impacts of the Final Environmentally Superior Southern Route; (3) rejected as infeasible alternatives to the Final Environmentally Superior Southern Route; (4) recognized all significant, unavoidable impacts; and (5) balanced the benefits of the Final Environmentally Superior Southern Route against its significant and unavoidable impacts, the Commission hereby finds that the benefits outweigh and override the significant unavoidable impacts for the reasons stated below.

The Commission adopts and makes this statement of overriding considerations concerning the Final Environmentally Superior Southern Route's unavoidable significant impacts to explain why its benefits outweigh its unavoidable impacts.

Sections 15 and 17 describe each alternative that was considered in the Final EIR/EIS and explain why each one has been included in the Final Environmentally Superior Southern Route, or rejected.

As we conclude in Section 17.11 above, the Final Environmentally Superior Southern Route will provide substantial benefits, in that it will facilitate our policy goal of renewable procurement at 33% RPS levels within a reasonable period of time with the greatest economic benefits at the lowest environmental cost. As described in Section 9, it will also provide unquantifiable benefits, including a more robust southern California transmission system, long-term improvement of California's aging energy infrastructure, and insurance against unexpected high load growth in SDG&E's service area. We set forth the reasons for finding these substantial benefits, with citations to the record, throughout this decision. The Commission finds that the Final Environmentally Superior Southern Route's unavoidable impacts are acceptable in light of these substantial benefits, which constitute an overriding consideration warranting approval of the project, despite each and every unavoidable impact. Each benefit set forth above and throughout this decision constitutes an overriding consideration warranting approval of the project, independent of the other benefits, despite each and every significant unavoidable impact.

18.4. Mitigation Monitoring

The Final EIR/EIS includes a proposed Mitigation Monitoring, Compliance, and Reporting Program (MMCRP or Mitigation Monitoring Program) for the mitigation measures it recommends for the proposed project and all alternatives. MMCRP tables are presented at the end of each issue area section in the Final EIR/EIS (Sections D.2 through D.15). These tables, along with the full text of mitigation measures applicable to the Environmentally Superior Southern Route Alternative, form the Mitigation Monitoring Program. The Mitigation Monitoring Program is designed to ensure compliance with the changes in the project and mitigation measures imposed on the authorized project during implementation and recommends a framework for implementation of the Mitigation Monitoring Program by this Commission as the CEQA lead agency. We adopt the Mitigation Monitoring Program.

18.5. Electro Magnetic Field (EMF) Issues

The Commission has examined EMF impacts in several previous proceedings.[711] We found the scientific evidence presented in those proceedings was uncertain as to the possible health effects of EMFs,[712] and we did not find it appropriate to adopt any related numerical standards. Because there is no agreement among scientists that exposure to EMF creates any potential health risk, and because CEQA does not define or adopt any standards to address the potential health risk impacts of possible exposure to EMFs, the Commission does not consider magnetic fields in the context of CEQA and determination of environmental impacts.

However, recognizing that public concern remains, we do require, pursuant to GO 131-D, Section X.A, that all requests for a CPCN include a description of the measures taken or proposed by the utility to reduce the potential for exposure to EMFs generated by the proposed project. We developed an interim policy that requires utilities, among other things, to identify the no-cost measures undertaken, and the low-cost measures implemented, to reduce the potential EMF impacts. The benchmark established for low-cost measures is 4% of the total budgeted project cost that results in an EMF reduction of at least 15% (as measured at the edge of the utility right-of-way). Section D.10.22.3 of the EIR/EIS sets forth the no- and low-cost mitigation SDG&E proposed to implement to mitigate EMFs for the Proposed Project. Consistent with its obligations under G.O. 131-D, SDG&E included, with its

[711] D.06-01-042 and D.93-11-013.

[712] EIR/EIS Section D.10.21.

application and Proponent's Environmental Assessment, an EMF Field Management Plan.[713] In this plan, SDG&E proposes to incorporate various no-cost mitigation measures to reduce field levels. It also considers, but does not propose to adopt, certain low-cost mitigation measures. The proposed plan does not analyze potential impacts across each of the various alternative route alignments identified in the Draft EIR/EIS and carried forward in the Final EIR/EIS.

As discussed elsewhere in this order, we authorize SDG&E to construct the Final Environmentally Superior Southern Route along an alignment that differs significantly from that originally proposed by the utility in the Proposed Project. Given these modifications, SDG&E shall amend its EMF management plan as needed to apply its no-cost EMF management techniques to the Final Environmentally Superior Southern Route.

Consistent with D.06-01-042 and D.93-11-013, we also require that SDG&E undertake low-cost EMF mitigation. Where such design modifications are consistent with our low-cost policy, SDG&E shall increase tower and conductor heights by 20 feet along any portions of the overhead transmission corridor where there are residences within 50 feet of the side of the right of way closest to the new 500 kV transmission lines. Previous decisions have established that this design modification would reduce magnetic fields by 15% at the edge of the right of way.[714]

We require that SDG&E apply this low-cost EMF mitigation measure where there are existing residential properties and also where development of new residences is underway at the time that SDG&E undertakes final project

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[713] A.06-08-010, PEA Appendix G and EIR/EIS Appendix 7.

[714] D.07-03-012.

design. Consistent with guidance in D.06-01-042, we do not require that SDG&E attempt to determine possible future uses of undeveloped land. If applicable, SDG&E is not required to raise tower heights near any residential properties that will be acquired and converted from residential use in order to allow construction of the Final Environmentally Superior Southern Route.

The cost of the adopted EMF mitigation measure may be less than SDG&E estimated for its Proposed Project. In any event, it is likely that the cost will be much less than the Commission's 4% benchmark for low-cost EMF mitigation. As described in this order, SDG&E may seek an increase in the approved maximum cost of the Final Environmentally Superior Southern Route if the adopted low-cost EMF mitigation measure causes the cost cap to be exceeded.

19. Compliance with Public Utilities Code Section 625

Section 625 provides that a public utility that offers competitive services may not condemn any property for the purpose of competing with another entity unless the Commission finds that such an action would serve the public interest based on a hearing for which the owner of the property to be condemned has been noticed and the public has an opportunity to participate (§ 625(a)(1)(A)). However, an exception is made for condemnation actions that are necessary solely for an electric or gas company to meet a Commission-ordered obligation to serve. In that circumstance, the electric or gas company is required to provide notice on the Commission Calendar if and when it pursues installation of facilities for the purpose of providing competitive services (§ 625(a)(1)(B)).

SDG&E proposed Sunrise to meet its obligation to serve its electric customers, and we authorize it for that purpose. In D.01-10-029, the Commission addressed the applicability of § 625 where the utility is implementing a project to meet its obligation to serve, but aspects of the project may have a competitive purpose later. We described that § 625 provides two different levels of notice and oversight and that, "The lesser standard requires that when condemning properties to carry out a commission-ordered obligation, § 625(a)(1)(B) is applicable, which only requires notice be provided to the Commission Calendar." We conclude that the lesser standard of notice applies for Sunrise.

20. Specification of Maximum Reasonable Cost

While FERC ultimately will decide how much of the costs for this project SDG&E may recoup in transmission rates, we have jurisdiction pursuant to § 1005.5(a) and the responsibility to specify in the CPCN a "maximum cost determined to be reasonable and prudent" for the Sunrise project.

In setting the maximum reasonable cost, the Commission must take several factors into consideration, including the design of the project, the expected duration of construction, an estimate of the effects of economic inflation, the level and complexity of necessary environmental mitigation, and any known engineering difficulties associated with the project.

We adopt a maximum cost for the Final Environmentally Superior Southern Route pursuant to § 1005.5(a) of $1.89 billion ($2012).[715] Based on our assessment, this amount includes the capital costs of the Final Environmentally Superior Southern Route and the mitigation[716] prescribed in the Final EIR/EIS. It

[715] To arrive at this estimate, we started with construction costs and AFUDC of $1.674 billion ($2012) (SDG&E Chapter 8, page 8.1) and added mitigation costs of $190 million ($2012) (SDG&E Exhibit 142), for a total of $1.864 billion, which includes SDG&E's proposed Coastal Link. To adjust for the adopted Coastal Link Alternative, we deduct $156 million ($2012), which is SDG&E's assumed cost of its proposed Coastal Link, and add in the estimated cost of the adopted Coastal Link Alternative of $84 million ($2012) (U-101, page 39). We then added a 10% contingency amount.

[716] Mitigation includes environmental mitigation measures, construction mitigation measures, and compliance monitoring. See SDG&E Exhibit SD-35, 3.18-3.25.

also covers direct labor and construction contracts, materials and equipment, land and land rights, indirect costs and overheads (which include but are not limited to EMF mitigation), allowance for funds used during construction (also known as AFUDC), a contingency amount, and escalation to 2012 dollars.

We believe the maximum cost deemed reasonable of $1.89 billion ($2012) has included a sufficient allowance for contingency costs to accommodate final design changes, increases in mitigation costs throughout the development of the final proposed project, and overall uncertainty in mitigation costs. However, the Commission has previously recognized the need for adjustments to cost caps in other decisions granting CPCNs. For example, several decisions adopting an estimate of the maximum reasonable and prudent cost allowed for adjustments to the estimated cost cap e.g., the Devers-Palo Verde 2 project,[717] Otay-Mesa Transmission Project,[718] Silvergate Substation Project,[719] and the Jefferson-Martin 230 kV transmission project.[720]

Upon completion of the final, detailed engineering design-based construction estimates for the authorized project, SDG&E may apply for a higher maximum cost if it can provide adequate justification, and must apply for a lower maximum if it appears that actual cost will be lower than the adopted estimated by at least 1%.

21. Miscellaneous Procedural Matters

We resolve all pending motions in the ordering paragraphs. Likewise, on our own motion, we formally receive in evidence certain exhibits that were

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[717] D.88-12-030, 30 CPUC2d 4.

[718] D.05-06-061.

[719] D.06-09-022.

[720] D.04-08-046, 2004 Cal. PUC LEXIS 391.

overlooked during the press of hearing as well as additional, specified CAISO workpapers and a data request response, and we receive as reference exhibits, the Draft EIR/EIS, the Recirculated Draft EIR/Supplemental Draft EIS, the Final EIR/EIS, and the Revisions to the Final EIR/EIS, which constitute the complete EIR/EIS prepared for Sunrise.

22. Comments on Alternate Proposed Decision

The alternate proposed decision of President Michael R. Peevey in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _______ by _________.

23. Assignment of Proceeding

Dian M. Grueneich is the assigned Commissioner. Steven Weissman was assigned as the ALJ in this proceeding in August 2006 and Jean Vieth was co-assigned in August 2008.

24. Conclusion

California has established the most aggressive set of comprehensive climate change goals and policies in the country. AB 32 requires that greenhouse gas emissions be reduced to 1990 levels by 2020 and to 80 percent below 1990 levels by 2050. California's RPS law requires SDG&E – and all CPUC Jurisdictional LSEs – to meet 20% of retail sales with renewable resources by 2010.[721] A fundamental feature of the law requires LSEs to maintain that minimum level of 20% renewable retail sales beyond 2010. It is also highly likely that California's RPS will increase in the coming years in order to comply with

[721] See note 11, above.

the goals set forth in AB 32. The Second Energy Action Plan calls for the Commission and the Energy Commission to work together to evaluate the potential for producing 33% of the power delivered in California from renewables.[722] Additionally, our recent GHG decision[723] making recommendations to the California Air Resources Board on its Draft Assembly Bill 32 Scoping Plan[724] commits this Commission to achieving 33% RPS, assuming certain safeguards.

SDG&E proposed this project based upon essentially three primary objectives: to maintain reliability in the delivery of power to the San Diego region; to reduce the cost of energy in the region; and, to accommodate the delivery of renewable energy to meet state and federal renewable energy goals from geothermal and solar resources in the Imperial Valley and wind and other sources in San Diego County.

Modeling performed by the CAISO demonstrates total projected reliability benefits of Sunrise to be $237 million per year. Sunrise will also provide a number of desirable, but unquantifiable, reliability benefits. Among other things, Sunrise will create a more robust southern California transmission system, and provide insurance against unexpected high load growth in SDG&E's service area. The generation alternatives will not provide these benefits.

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[722] Energy Action Plan II, September 21, 2005, page 6, Key Action #5.

[723] *Greenhouse Gas Regulatory Strategies.*

[724] Climate Change Draft Scoping Plan, a framework for change, June 2008 Discussion Draft Pursuant to AB 32 the California Global Warming Solutions Act of 2006 Prepared by the California Air Resources Board for the State of California, June 26, 2008, available at http://www.arb.ca.gov/cc/scopingplan/document/draftscopingplan.pdf. The Air Resources Board released its Proposed Scoping Plan on October 15, 2008 and it is available at http://www.arb.ca.gov/cc/scopingplan/document/psp.pdf.

A transmission solution affords SDG&E the best opportunity to plan for the current *and future* reliability needs throughout its service territory. In addition, Sunrise will not only meet SDG&E's reliability needs, but it will facilitate the development of renewable resources, thus advancing state policy to reduce GHG emissions.

The economic modeling performed in this proceeding, demonstrates that Sunrise is not *required* for SDG&E to meet SDG&E's 2010 RPS requirements. However, as discussed in Section 4.3, we find that Sunrise will play a critical role in meeting SDG&E's RPS goals – both 20% and 33% targets. Sunrise is vital because it will deliver renewable generation that would otherwise remain unavailable. Further, we find that the cost of Sunrise is appropriately balanced against the certainty of the line's contribution to economically rational RPS compliance.

CAISO's modeling shows that Imperial Valley renewable resources do not generate RPS compliance savings assuming a 20% RPS. However, as discussed in Section 10, the CAISO's economic modeling does not accurately reflect how the RPS program operates. In addition, while the CAISO model does not yield RPS compliance savings assuming a 20% RPS, there are substantial savings assuming a 33% RPS.

Further, the record demonstrates that 60% of SDG&E's RPS compliance obligation comes from Imperial Valley renewable resources that are dependent upon Sunrise.[725] SDG&E may be able to replace these resources with renewables that are not dependent upon Sunrise. However, that is not the underlying issue here. The issue is whether, and to what extent, the Sunrise transmission project will enable SDG&E to meet its current and future RPS – and coincidentally its

[725] SDG&E Phase 1 Opening Brief, 91.

GHG reduction – goals. We find clear evidence that Sunrise will indeed, provide a critical pathway to facilitate the delivery of renewable resources that otherwise may not be available to SDG&E or other LSEs throughout California.

However, CAISO models present the possibility that a portion of Sunrise's capacity may be utilized to deliver fossil fuel resources depending on market dynamics. Because of the possibility that nonrenewable resources may flow over the Sunrise project, we take note of the various Regulatory safeguards that we have at our disposal to make certain that construction of Sunrise does facilitate the development of valuable renewable resources in the Imperial Valley. Although we do not add an additional compliance requirement upon SDG&E as a condition to our approval of Sunrise we emphasize here that we remain fully committed to meeting and exceeding California's ambitious renewable energy and GHG reduction goals. We believe that our procurement policies and programs offer sufficient safeguards that Sunrise will facilitate the development of renewable resources in the Imperial Valley.

It is beyond question that the level of scrutiny applied to Sunrise has been unprecedented. After review of the extensive record and for all of the reasons discussed above, we conclude that we should grant SDG&E's request for a CPCN to construct Sunrise using the Final Environmentally Superior Southern Route. We conclude that the Environmentally Superior Southern Route offers the best option for meeting SDG&E's long-term resource and reliability needs. In addition, this option will produce significant net economic benefits, and facilitate the delivery of renewable energy to SDG&E customers, as well as customers of other LSEs.

Findings of Fact

1. Sunrise is necessary under § 399.25, as applied in D.07-03-045, because as discussed herein, it will bring to the grid renewable generation that would otherwise remain unavailable, the area within Sunrise's reach would play a critical role in meeting the RPS goals, and the cost of Sunrise is appropriately balanced against the certainty of the line's contribution to economically rational RPS compliance.

2. Even though we could grant the CPCN on sole basis that Sunrise complies with § 399.25, because it has been demonstrated that the line offers significant other economic benefits, we exercise our discretion to review that analysis.

3. At the time the Commission's *Economic Methodology Decision* issued, SDG&E's 2005 Application had been pending for almost one year and CAISO's Board already had approved CAISO's economic evaluation of the Proposed Project. The assigned Commissioner never issued a ruling that elected to apply the rebuttable presumption in the *Economic Methodology Decision* to the economic analysis approved by CAISO's Board.

4. In the CPCN review at the Commission, CAISO has not relied upon the economic evaluation presented to its Board but has presented an entirely new economic analysis, which it developed during Phase 1 and 2 hearings. The assigned Commissioner never issued a ruling that elected to apply the rebuttable presumption in the *Economic Methodology Decision* to this new economic analysis by CAISO.

5. The CAISO Board-approved economic evaluation has become irrelevant. The subsequent CAISO economic evaluation does not fulfill the streamlining purpose of the *Economic Methodology Decision*, does not comply with CAISO's own TEAM criteria nor with the principles and minimum requirements of the

Economic Methodology Decision, and granting a rebuttable presumption at this stage would be fundamentally unfair to the other parties.

6. For purposes of developing an Analytical Baseline for determining the energy benefits, reliability benefits, and RPS compliance savings estimates generated by all of the Sunrise alternatives, it is reasonable to adopt CAISO's modeling approach to quantifying energy benefits, reliability benefits, and RPS compliance savings and to use CAISO's final Phase 2 modeling assumptions with the following deviations:

(a) use the Energy Commission staff's November 2007 Forecast of 1-in-10 peak demand, including its embedded assumptions for the California Solar Initiative, energy efficiency, and other distributed generation;

(b) adjust the November 2007 Forecast by including the demand response savings we approved in SDG&E's most recent Long Term Procurement Plan;

(c) assume that the existing South Bay Power Plant will retire by December 31, 2012 or the end of the year in which Sunrise comes online, whichever is earlier;

(d) assume 540 MW from the Carlsbad Energy Center will come online in the summer of 2013, resulting in a net increase of 222 MW;

(e) assume only 25% of the new coal fired generation identified in the SSG-WI database will come online and that combined cycle resources will be used to replace the canceled coal plants;

(f) assume that at least 50% of the out-of-state renewables identified by CAISO for its RPS Cost Savings modeling will be available to California;

(g) adopt CAISO's initial renewable cost estimates;

(h) assume the implementation of UCAN's Miguel Import Limit Upgrade;

(i) assume Imperial Irrigation District's Path 42 increased rating and upgrades (reflecting a transfer capability of 1,200 MW) and its Dixieland-Imperial Valley line;

(j) assume Rancho Peñasquitos' proposed Coastal Link Alternative; and

(k) assume SDG&E's estimated capital costs for all of the Sunrise alternatives, and SDG&E's 58-year amortization period for the Sunrise transmission alternatives.

7. Given its relative low cost and apparent feasibility, SDG&E should implement UCAN's Miguel Import Limit Upgrade proposal and accordingly, UCAN's motion should be granted as specified herein.

8. A review of Path 44's rating is warranted given the passage of time since the last review and given UCAN's credible evidence that an increase in Path 44's rating may be possible.

9. Table 5 in Section 7.1.2 of this decision reasonably projects, based on our adopted Analytical Baseline assumptions, the "reliability need" for SDG&E's service area by 2014 and perhaps sooner given the many uncertainties inherent in these assumptions.

10. The Compliance Exhibit energy benefits estimates of $5 million per year under 20% RPS and $18 million per year under 33% RPS are the most reasonable estimates in the record.

11. We find that the combustion turbine costs assumed by CAISO are reasonable; we adopt CAISO's modeling methodology for reliability benefits and the results of that modeling, which show reliability benefits of $237 million per year, because CAISO's assumptions are consistent with our adopted Analytical Baseline assumptions.

12. Applying CAISO's RPS compliance savings model, Sunrise will not generate RPS compliance savings assuming a 20% RPS. Under 33% RPS, Sunrise generates significant RPS savings.

13. CAISO's RPS compliance savings modeling does not reflect the way in which the RPS program currently operates in California. However, CAISO's model is a useful tool to identify potential cost savings from the construction of Sunrise.

14. Since 2002 the Commission has approved at least 95 contracts with renewable resources for 5,900 MW including 61 contracts with new renewable projects, totaling 4,480 MW, all under the existing RPS framework. These contracts have not been the same as the lowest cost resources identified in CAISO's analysis.

15. Our Update to the Compliance Exhibit corrects for discovered errors and makes adjustment in response to comments by parties in order to reasonably analyze the Compliance Exhibit's 4 cases against the Analytical Baseline assumptions. The Update reasonably makes the following adjustments to the Compliance Exhibit:

(a) assumes CAISO's Phase 2 combustion turbine costs for all cases;

(b) adjusts the amount of in-area renewables in the All-Source Generation Alternative, thereby changing the distribution of renewables throughout the WECC, consistent with CAISO's assumed supply curves;

(c) subtracts $367 million per year from the assumed capital cost of the All-Source Generation Alternative in each scenario to address the 37 MW of solar PV already paid for in the California Solar Initiative program; and

(d) adjusts the modeling of the All-Source Generation Alternative so that RPS compliance savings cannot be negative.

16. 60% of the energy currently under contract that SDG&E needs to comply with the 20% RPS mandate, or approximately 2,000 GWh, is located in Imperial Valley and contingent upon Sunrise.

17. Imperial Valley supports an unpararelled diversity of potential renewable generation technologies that would be facilitated by Sunrise, including 2,300 MW of baseload geothermal.

18. Since the Sunrise project was announced, there have been over 5,000 MW of new renewable generator interconnect requests in the CAISO queue that would be facilitated by Sunrise.

19. Without the Sunrise Powerlink there is a substantial likelihood that only a fraction of the potential generating capacity in Imperial Valley will come online.

20. The Commission has already approved 4 RPS PPAs in the Imperial Valley that would be facilitated by Sunrise.

21. In D.07-03-012 the Commission found that in order to rely on § 399.25 a project proponent must demonstrate: (1) that a project would bring to the grid renewable generation that would otherwise remain unavailable; (2) that the area within the line's reach would play a critical role in meeting the RPS goals; (3) that the cost of the line appropriately balanced against the certainty of the line's contribution to economically rational RPS compliance.

22. Assuming a 20% RPS, Sunrise will result in approximately $50 million per year in net benefits.

23. Assuming a 20% RPS, the All-Source Generation Alternative results in higher net benefits than Sunrise, under two different renewable cost scenarios.

24. Assuming 33% RPS and CAISO Phase 2 combustion turbine costs, Sunrise will generate over $125 million per year in net benefits, which significantly

exceeds the $93 million per year of net benefits estimated for the All-Source Generation Alternative.

25. There is a tremendous amount of uncertainty regarding conclusions reached by the models used in this case.

26. Neither SDG&E nor CAISO provided a systematic analysis regarding the sensitivity of the projected economic benefits of Sunrise under uncertainty; their alternative efforts do not meet or substitute for the requirements of our *Economic Methodology Decision*, Decision 06-11-018.

27. Anza-Borrego's General Plan, which governs State Parks' management of the Anza-Borrego, does not provide an exemption from its mandate for construction and maintenance of a major transmission line like the Proposed Project.

28. If State Parks determined that any Northern Route through Anza-Borrego was inconsistent with the existing Anza-Borrego General Plan, the State Parks and Recreation Commission would have to exercise its discretionary authority to adopt revisions to the General Plan to allow the siting and construction of this kind of project before State Parks could issue any permits, which would cause substantial delay.

29. The Proposed Project's Anza-Borrego Link will require de-designation of 50.2 acres of state wilderness; other Northern Routes would have a lesser, direct impact on wilderness but still might require de-designation of some wilderness land.

30. Because SDG&E, BLM, Imperial Irrigation District and State Parks contest the width and continuity of the existing easement through Anza-Borrego, any approval of a Northern Route likely would lead, at minimum, to a complex and

significant debate over the legal status and rights associated with easements through Anza-Borrego, and would cause substantial delay.

31. Any Northern Route would have massive significant and unmitigable environmental impacts on Anza-Borrego; be contrary to community values – both those of the people who visit Anza-Borrego, as well as the values embodied in our state laws protecting areas like Anza-Borrego; be permanently detrimental to recreational and park areas within Anza-Borrego; and have permanent and negative impacts on historical and aesthetic resources in Anza-Borrego.

32. Based on the fire history reviewed herein, 230 kV and 500 kV lines placed on steel towers are highly unlikely to ignite fires. However, given the fire risks associated with any transmission line route in San Diego County, approval of the Final Environmentally Superior Southern Route must be conditioned upon the most rigorous, reasonable mitigation available to reduce the risk of fire ignition; therefore, this Commission should impose all feasible mitigation measures specified in the ordering paragraphs.

33. While the fire history reviewed herein suggests a concurrent outage involving the Southwest Powerlink and the Environmentally Superior Southern Route is more likely than one involving the Environmentally Superior Northern Route, a dual line outage could occur whether or not a new transmission line is collocated with the Southwest Powerlink, since special proximity is not the only indicator of a concurrent outage. Moreover, the 230 kV segments of the Environmentally Superior Northern Route put more assets at risk of fire.

34. The All-Source Generation Alternative, the In-Area Renewable Alternative, and the LEAPS Transmission-Only Alternative – the three alternatives that the Final EIR/EIS determines to be environmentally superior to the Final Environmentally Superior Southern Route, are not feasible when the

Commission factors in certain other considerations, including meeting California's broader policy goals.

35. The Final Environmentally Superior Southern Route is the highest ranked Alternative that will facilitate Commission policy to achieve GHG reductions through renewable procurement at 33% RPS levels in the shortest time possible with the greatest economic benefits; therefore, the Final Environmentally Superior Southern Route is necessary to meet California's GHG goals by facilitating increased levels of renewable development.

36. Approval of Sunrise should be conditioned as specified in the ordering paragraphs to address community values concerns raised by Mussey Grade and others.

37. The EIR/EIS has adequately considered the concerns of the affected agricultural communities in siting the Final Environmentally Superior Southern Route; moreover, approval of the Final Environmentally Superior Southern Route rather than a Northern Route significantly mitigates impacts on agricultural lands.

38. SDG&E should notify the Commission of any changes in the final project development schedule for the Final Environmentally Superior Southern Route.

39. The Final EIR/EIS was presented to the Commission, and the Commission has received, reviewed, and considered the information contained in the Final EIR/EIS.

40. The Final EIR/EIS reflects the Commission's independent judgment and analysis.

41. Significant and unavoidable environmental impacts will result from construction and operation of the Final Environmentally Superior Southern Route; however, the Commission has adopted all feasible mitigation measures;

adopted certain alternatives that reduce the impacts of the Final Environmentally Superior Southern Route; rejected as infeasible alternatives to the Final Environmentally Superior Southern Route; recognized all significant, unavoidable impacts; and balanced the benefits of the Final Environmentally Superior Southern Route against its significant and unavoidable impacts.

42. The benefits of the Final Environmentally Superior Southern Route outweigh and override its significant and unavoidable impacts, for the reasons set forth in the statement of overriding considerations in Section 18.3 of today's decision.

43. The proposed Mitigation Monitoring, Compliance, and Reporting Program (Mitigation Monitoring Program) in the Final EIR/EIS is designed to ensure compliance with the changes in the project and mitigation measures imposed on the authorized project during implementation and recommends a framework for implementation of the Mitigation Monitoring Program by this Commission as the CEQA lead agency.

44. SDG&E should amend its EMF Management Plan as needed to apply its no-cost EMF management techniques to the Final Environmentally Superior Southern Route and also should undertake the low-cost EMF mitigation specified in the ordering paragraphs.

45. As discussed herein, the Commission requires periodic reports in order to implement and monitor established procurement policies and, in addition, has multiple avenues to monitor, evaluate, influence and enforce utility compliance with those policies. Further, the Commission can seek sanctions should SDG&E deviate from the stated purposes of Sunrise – especially with respect to the development of renewable resources. No additional compliance requirements are necessary to guarantee that renewable generation is delivered via Sunrise.

46. As it has proposed, SDG&E should seek expeditiously to replace any Sunrise dependent RPS contract that is determined to no longer be viable.

47. The reasonable maximum cost for the Final Environmentally Superior Southern Route pursuant to § 1005.5(a) is $1.89 billion ($2012), as calculated in Section 20 of today's decision.

48. SDG&E should take the necessary steps to institute a review of Path 44's rating, should report within 60 days of the effective date of this decision on the status of the review and should serve the report on each Commissioner, the Director of the Commission's Energy Division, and the service list for A.06-08-010.

49. The exhibits specified in the ordering paragraphs were identified at hearing but inadvertently, were not received in evidence. The CAISO Workpapers and data request response specified in the ordering paragraphs should be identified and received in evidence, respectively, as CAISO Exhibit I-15 and CAISO Exhibit I-16. To ensure the completeness of the record, the complete EIR/EIS should be made a reference exhibit as indicated in the ordering paragraphs.

Conclusions of Law

1. The Commission has jurisdiction over the proposed transmission project pursuant to § 1001 et seq.

2. The preponderance of the evidence standard, the default standard in civil and administrative law cases, is the applicable standard of review here.

3. Neither the CAISO Board-approved economic evaluation nor the subsequent CAISO economic evaluation should be granted a rebuttable presumption under the Commission's *Economic Methodology Decision*.

4. Sunrise will bring to the grid renewable generation that would otherwise remain unavailable.

5. The area within Sunrise's reach would play a critical role in meeting RPS goals.

6. The cost of Sunrise is appropriately balance against the certainty of the line's contribution to economically rational RPS compliance.

7. Economically rational RPS compliance necessarily depends upon the "least cost best fit" evaluation process and ongoing Commission oversight.

8. Sunrise is "necessary to facilitate achievement of the renewable power goals" pursuant to § 399.25. Therefore, we need not reach the question of what other economic benefit the line may provide and could grant the CPCN on this basis alone.

9. Anza-Borrego is subject to the California Wilderness Act.

10. The Final EIR/EIS has been completed in compliance with CEQA and should be certified.

11. The Mitigation Monitoring Program in the Final EIR/EIS should be adopted.

12. Consistent with our interpretation of § 625 in D.01-10-029, the appropriate standard of notice for Sunrise is that prescribed by § 625(a)(1)(B), which only requires notice to the Commission Calendar.

13. The Commission has jurisdiction and responsibility pursuant to § 1005.5(a) to specify a "maximum cost determined to be reasonable and prudent" for the Sunrise project. If, as specified in the ordering paragraphs, the cost estimates for the Final Environmentally Superior Southern Route should prove to be materially lower than or higher than the adopted cost cap, SDG&E shall request an adjustment to the cost cap.

14. Since no party will be prejudiced thereby, the exhibits specified in the ordering paragraphs should be received in evidence and the complete EIR/EIS should be made a reference exhibit.

15. UCAN's motion regarding its Miguel Import Limit Upgrade proposal should be granted as specified in the ordering paragraphs. Since no party will be prejudiced thereby, these motions should be granted: all pending motions of the CAISO for leave to file late and leave to submit additional testimony; all pending motions to adopt transcript corrections; the motion of Powers Engineering Requesting Permission for Late Filing of Brief and Reply Brief. Today's decision on the merits of Sunrise renders all other pending motions moot.

O R D E R

IT IS ORDERED that:

1. The request of San Diego Gas & Electric Company (SDG&E) for a certificate of public convenience and necessity to construct the proposed Sunrise Powerlink Transmission Project (Sunrise) is granted for the routing alternative identified in the Final Environmental Impact Report/Final Environmental Impact Statement (Final EIR/EIS) as the Final Environmentally Superior Southern Route, subject to the requirements in Ordering Paragraphs 3 through 6.

2. The Final EIR prepared for Sunrise is certified.

3. SDG&E shall notify the Commission of any changes in the final project development schedule for the Final Environmentally Superior Southern Route.

4. The Mitigation Monitoring Program for the Final Environmentally Superior Southern Route in the Final EIR/EIS is adopted and all feasible mitigation measures identified in the Final EIR/EIS are imposed upon construction of the Final Environmentally Superior Southern Route, including:

(a) requiring fire-safe construction practices to reduce the risk of wildfire ignitions during construction;

(b) prohibiting construction during extreme weather conditions to reduce the risk of potentially catastrophic wildfire ignitions during construction;

(c) ensuring adequate coordination for emergency fire suppression to avoid project personnel and equipment interference with firefighting operations;

(d) ensuring adequate removal of hazardous vegetation;

(e) requiring annual contributions to a Defensible Space Grants Fund that will assist in the maintenance of defensible space requirements and in the implementation of other fire-safe measures at the private residences most at risk of a project-related wildfire;

(f) requiring the replacement of existing 69 kV wood poles that are within 100 feet of the project with steel poles to mitigate the potential fire hazard of a wood pole being knocked into the adjacent conductors;

(g) requiring annual contributions to a Firefighting Mitigation Fund that will improve fire prevention measures and help improve fire protection equipment and services;

(h) requiring a Memorandum of Understanding between SDG&E, Cal Fire, and Cleveland National Forest to coordinate effective fire plans and emergency procedures;

(i) requiring weed abatement and controls for invasive weeds to prevent establishment of non-native plants that have a high ignition potential and carry fires at a high rate of spread; and

(j) requiring climbing inspections on 10% of the project structures annually to improve detection of imminent component failures that could result in wildfire ignitions.

5. SDG&E shall amend its Electro Magnetic Field (EMF) Management Plan as needed to apply its no-cost EMF management techniques to the Final Environmentally Superior Southern Route and also shall undertake the following low-cost EMF mitigation:

(a) Where such design modifications are consistent with low-cost policy set forth, for example, in Decision (D.) 07-03-012, SDG&E shall increase tower and conductor heights by 20 feet along any portions of the overhead transmission corridor where there are residences within 50 feet of the side of the right of way closest to the new 500 kV transmission lines.

(b) The mitigation described in subsection (a), above, shall apply where there are existing residential properties and also where development of new residences is underway at the time that SDG&E undertakes final project design, consistent with D.06-01-042.

6. A cost cap of $1.89 billion ($2012) is adopted for the Final Environmentally Superior Southern Route. SDG&E shall apply to the Commission for an adjustment of the cost cap in the following instances:

(a) Once SDG&E has developed a final, detailed engineering design-based construction estimate for the Final Environmentally Superior Southern Route, if this estimate is one percent or more lower than the authorized maximum reasonable and prudent cost identified, SDG&E shall, within 30 days, file an advice letter to show cause why the Commission should not adopt a lower amount as the maximum reasonable and prudent cost to reflect the final estimate.

(b) If SDG&E's final, detailed engineering design-based construction estimate for the authorized project exceeds the authorized maximum cost, SDG&E shall, within 30 days, file an advice letter to seek an increase in the approved maximum cost pursuant to § 1005.5(b).

7. SDG&E shall seek expeditiously to replace any Sunrise dependent RPS contract that is determined to no longer be viable.

8. The documents that constitute the Final EIR/EIS are received as Reference Exhibits on the effective date of this decision, as follows:

(a) Draft EIR/EIS – Reference Exhibit A;

(b) Recirculated Draft EIR/Supplemental Draft EIS – Reference Exhibit B;

(c) Final EIR/EIS – Reference Exhibit C; and

(d) Revisions to the Final EIR/EIS – Reference Exhibit D.

9. The following exhibits are received in evidence on the effective date of this decision: Conservation Groups Exhibit C-15; Imperial Irrigation District Exhibit ID-4; Mussey Grade Exhibit MG-32; Powers Engineering Exhibit Powers-1; and Rancho Peñasquitos Exhibits R-9, R-10, R-11, R-12, R-13, and R-14.

10. The workpapers of the California Independent System Operator (CAISO) with the file names CAISO3 SD&LA v5.xls, CAISO3 SD&LA v5 less LCR case.xls, and CAISO3 SD&LA v4.xls are identified as CAISO Exhibit I-15 and received in evidence on the effective date of this decision.

11. CAISO's data request response to the Commission's environmental consultant, entitled "Information Request #2 to California Independent System Operator," as subsequently updated by CAISO to correct fuel oil emissions rates and then served on the parties to this proceeding by email on August 4, 2008, is identified as CAISO Exhibit I-16 and received in evidence on the effective date of this decision.

12. Pending motions are resolved as follows:

(a) All pending motions of CAISO for leave to file late and leave to submit additional testimony are granted;

(b) All pending motions to adopt transcript corrections are granted;

(c) The June 5, 2007 *Motion to Compel SDG&E to Upgrade its Import Capability at Miguel Substation* filed by Utility Consumer's Action Network (UCAN) is granted as specified herein and within 30 days of the effective date of this decision, SDG&E shall serve (but not file) a status report on all Commissioners, the Director of the Commission's Energy Division, and the service list for Application (A.) 06-08-010;

(d) The September 24, 2008 motion of Powers Engineering *Requesting Permission for Late Filing of Brief and Reply Brief* is granted;

(e) UCAN's June 5, 2007 Motion to Enjoin SDG&E from Entering Into a Permanent Cross-Trip Arrangement with CFE is denied as moot; and

(f) All motions or portions of motions that have not otherwise been resolved are denied as moot.

13. SDG&E shall take the necessary steps to institute a review of Path 44's rating and, within 60 days of the effective date of this decision, shall report on the status of that review and shall serve (but not file) the report on each Commissioner, the Director of the Commission's Energy Division, and the service list for A.06-08-010.

14. The issues in the *Assigned Commissioner and* Administrative *Law Judge's Scoping Memo and Ruling*, November 1, 2007, and *Revised Scoping Memo and Ruling of the Assigned Commissioner and Administrative Law Judge,* June 20, 2008, have been addressed and this proceeding is resolved for the purpose of compliance with Public Utilities Code Section 1705.1. However, the proceeding

remains open to address, as an adjudication, the issues raised by the *Assigned Commissioner's Revised Scoping Memo and Ruling Regarding Possible Rule 1.1 and Rule 8.3 Violations; Order to Show Cause*, August 1, 2008.

This order is effective today.

Dated ____________________________, at San Francisco, California.

APPENDICES A THRU F
ARE THE SAME AS IN
COMMISSIONER GRUENEICH'S
ALTERNATE AND THEY ARE
ACCESSIBLE AT

http://docs.cpuc.ca.gov/EFILE/ALT/93074.htm.

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated November 18, 2008, at San Francisco, California.

/s/ TERESITA C. GALLARDO
Teresita C. Gallardo