BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of	)	Application No. 06-08-010
San Diego Gas & Electric Company	)	(Filed August 4, 2006)
(U-902) for a Certificate of Public	)	
Convenience and Necessity for the	)	
Sunrise Powerlink Transmission Project.	)	

INITIAL TESTIMONY OF THE

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

PART 1

Anthony J. Ivancovich
Assistant General Counsel – Regulatory
Judith B. Sanders
Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
916-351-4400 - office
916-608-7296 – facsimile
jsanders@caiso.com

Dated: January 26, 2007

1. INTRODUCTION AND TESTIMONY OVERVIEW

Q. Please state your names, titles, employer and qualifications.

A. Our names are Armando J. Perez, Vice President of Planning and Infrastructure Development for the California Independent System Operator (CAISO), Robert Sparks, Lead Regional Transmission Engineer at the CAISO, and Dr. Ren Orans, Managing Partner of Energy and Environmental Economics, Inc. (E3). Our qualifications are provided at Attachment 1 to this testimony.

Q. On whose behalf are you submitting this testimony?

A. We are submitting this testimony on behalf of the CAISO.

Q. What is the purpose of your testimony?

A. The overall purpose of this initial testimony is to sponsor study results and recommendations of the CAISO regarding the Sunrise Powerlink Transmission Project (Sunrise) proposed by the San Diego Gas & Electric Company (SDG&E). Specifically, this initial testimony is being filed in response to the November 1, 2006 Assigned Commissioner/ALJ Scoping Ruling that directed the CAISO to submit testimony regarding its assessment of the project, including:

1) Information supplementing its evaluation of the proposed project with a more complete evaluation of wires and non-wires alternatives;

2) A more complete evaluation of the interaction between Sunrise and the LEAPS and Tehachapi projects;
3) An explanation of how these additional factors impact the CAISO's assessment of the costs and benefits of Sunrise based on the Transmission Economic Assessment Methodology (TEAM).

Thus, with this initial testimony, we will:

- Sponsor the July 28, 2006 "CAISO South Regional Transmission Plan for 2006 Findings and Recommendation on the Sun Path Project" (CSRTP Report) that has been submitted by SDG&E as part of its application for a Certificate of Convenience and Necessity (CPCN) for the Sunrise project;[1] and
- Address the reference (i.e., base) case development and study assumptions that we used in conducting the initial analyses for the CSRTP Report and the modifications that have been made for the purposes of our further evaluations, including comparisons of these assumptions to those used in the CSRTP Report and in SDG&E's August 4, 2006 analysis; and the results of the alternative studies that have been completed so far.

The November 1, 2006 Scoping Ruling also requested that the CAISO and SDG&E jointly prepare an exhibit providing a comparison of our respective computer models, methodologies, critical assumptions, scenarios, sensitivity cases

[1] The CSRTP Report can be found at Appendix I-1 to Volume 2 of the SDG&E testimony filed in this proceeding on August 4, 2006. That report refers to Sunrise as "Sun Path", reflecting the combination of the Sunrise Powerlink portion of the project with the Green Path portion.

and results. That comparison has been completed; and the joint exhibit (Joint Exhibit A) is attached to this testimony and to SDG&E's supplemental testimony. The CAISO and SDG&E were also encouraged to file joint testimony, where appropriate, but time did not allow us to engage in that process and still be able to complete our testimony and alternative studies by January 26, 2007.

Q. Does the CAISO intend to submit additional testimony in this proceeding?

A. Yes, we do. As explained in our January 8, 2007 Motion for Extension of Time to Complete Studies (Motion for Extension), it was simply impossible for the CAISO to evaluate all of the project alternatives submitted by the parties in time for the January 26, 2007 testimony filing date. In addition, Dr. Orans will file Part II of this initial testimony on February 16, 2007, which will provide further evidence on the reasonableness of the economic assessment portion of the results reported below.

Q. Please describe the alternative scenarios that will be addressed in this testimony.

A. The CAISO agreed to complete its studies of the following scenarios and address the results in this testimony:

1) A revised base case reflecting the updated Devers-Palo Verde 2 plan of service, updates to the maximum capacity of the existing combustion turbines (CTs) and updates to the 2015 demand forecasts;

2) Assessment of the revised base case with Sunrise;
3) Assessment of the revised base case with the LADWP Green Path North project and the Lake Elsinore Advanced Pump Storage (LEAPS) project;
4) Assessment of the revised base case assuming that the South Bay generation facility has been repowered with a new 620-MW combined cycle generating facility.

2. THE CAISO'S INITIAL EVALUATION OF SUNRISE

Q. Please describe the CAISO's reliability concerns with the San Diego area?

A. The CAISO recognizes that SDG&E's service area is short of local generation and has insufficient transmission connection to the rest of the state as well as surrounding areas. SDG&E is a net importer of power and meets its energy needs by importing power from southern California, Arizona and Mexico. Reliability constraints limit SDG&E's ability to import additional power into the San Diego area over the next few years and have raised the concerns that SDG&E may not be able to reliably serve its customers in 2010 and beyond.

Q. Is there anything that is unique about the transmission infrastructure used to serve load in San Diego in comparison to the transmission service for the rest of the State?

A. California is a net importer of power and imports about 25% of its energy needs from outside the state. The main arteries for imports are:

- Three 500 kV AC lines and one bi-pole 500 kV DC transmission line that link the Pacific Northwest to California, and
- Six 500 kV lines crossing the Colorado River which, along with six parallel lower voltage transmission lines, link Arizona and Nevada to California.

Out of the four high capacity transmission lines originating in the Pacific Northwest and six crossing the Colorado River, all but one terminate in Southern California Edison's and LADWP's service areas nearing and around the Los Angeles area.

Similar to the rest of the state, SDG&E is also a net importer of power. However, there are no direct 500 kV connections between Pacific AC or DC Intertie systems and the SDG&E service area. SDG&E has only a single 500 kV transmission line, the Southwest Power Link (SWPL), which connects it to Arizona through the Imperial Irrigation District (IID).

Q. Are these southern California transmission capacity concerns that you have identified the reason that SDG&E presented Sunrise to the CAISO for evaluation?

A. Yes. SDG&E believes that Sunrise would help lower the costs of complying with the existing reliability standards and facilitate their need to procure 20% renewable generation by 2010. As early as 2003, SDG&E had identified in its long term transmission plans that it needs a high voltage transmission line to access renewable energy projects in southern California and to promote SDG&E's ability to import lower cost energy sources. In January 2006, SDG&E presented the project to the CAISO for its evaluation in accordance with its tariff and transmission planning procedures. Sunrise was combined with the two other southern California transmission projects, Tehachapi and LEAPS, for stakeholder study as part of the CSRTP group. The CAISO assessed the project for both economic and reliability benefits, as described in Sections 4 and 6 of the CRSTP Report. Project alternatives were also considered as part of the study process (see Section 5 of the CSRTP Report).

Q. What conclusions were drawn by the CAISO after the initial reliability and economic assessments were completed?

A. The CAISO Staff Memorandum to the Board of Governors, dated July 28, 2006,[2] succinctly summarized the study findings:

- Sunrise facilitates compliance by SDG&E and other California utilities with the state renewable portfolio standard (RPS) by providing access to the CAISO control area for planned renewable resources in the Salton Sea and other areas in Imperial Valley without curbing economic imports to California;

---

[2] This Memorandum can be found on CAISO's website at: http://www.caiso.com/1841/1841be8d118b0.pdf.

- Sunrise provides positive net economic value for the CAISO ratepayers as its benefit outweighs its cost; and
- Sunrise solves San Diego's known import limit reliability problem for 2010 and beyond without introducing new reliability concerns.

These benefits are considered by the CAISO Staff to be the "three-legged stool" supporting its recommended approval of the project, and they also served as the standard for its review and evaluation of the project alternatives described in the CSRTP Report. In particular, the results of the CAISO's reliability and economic studies indicated that Sunrise would provide a cost-efficient means by which SDG&E and other electricity retailers can meet state law requirements to procure 20% of their retail energy requirements from renewable sources by 2010. Access to the geothermal renewable resources projected to be developed in the Salton Sea/Imperial Valley area is particularly important because such renewable facilities augment the "mix" of resources required to promote grid reliability.

Q. Has the CAISO had an opportunity to review and update its initial assessments of Sunrise?

A. Yes, we have. As discussed above, the CAISO has been asked by the Commission to continue its evaluation of Sunrise by updating its findings with respect to the interaction of Sunrise with Tehachapi and LEAPS and also by considering alternative scenarios proposed by the parties. To accomplish these tasks, we analyzed the parties' recommendations and concluded that certain adjustments should be made to the pre-project base case used in the CSRTP Report. Additionally, the Tehachapi plan of service has been updated; and therefore the Tehachapi project has been included in the base case and the alternative scenarios. Finally, the CAISO has made certain adjustments to the assumptions used in its TEAM methodology, thereby producing an updated economic assessment. The details and results of the CAISO's continued evaluation are described in the remainder of this testimony.

3. THE CAISO'S CONTINUED EVALUATION OF SUNRISE

Q. What is the objective of the CAISO's continued evaluation?

A. As discussed above, the objective of this continued evaluation is to fulfill the promise made in CAISO's Motion for Extension to file testimony by January 26, 2007 for the following studies:

1) Development of a base case (without Sunrise) that reflects updated information on demand forecasts, Devers-Palo Verdes 2 plan of service, revised maximum capacity of existing combustion turbines (CTs) in the SDG&E area, and SDG&E's long-term procurement plan.

2) Analysis of Scenario 1: Base Case with addition of LADWP's Green Path North Project and the Nevada Hydro Company's LEAPS Project.[3] For the sake of concise exposition, this scenario will also be referred to as the (Green Path + LEAPS) case.
3) Analysis of Scenario 2: Base Case with addition of South Bay Repowering Project. The existing South Bay Power Plant is assumed to be off-line.
4) Analysis of Scenario 3: Base case with addition of the Sunrise.

In doing so, this testimony presents the updated results, explains the methodology and input assumptions used to obtain those results, and compares this testimony's methodology, input assumptions and results to those in the CSRTP Report. Finally, the testimony proposes an independent review of this testimony, to be filed on February 16th, so as to ensure the reasonableness of its findings.

Q. What are the key findings?

A. Similar to the findings set forth in the CSRTP Report, the key findings of our continued evaluation are as follows. First, Sunrise is expected to remedy the foreseeable reliability problems in the San Diego area for a period of approximately ten years in addition to compensating for the retirement of South Bay power plant. Second, Sunrise will facilitate SDG&E's compliance with its

[3] For the purposes of this evaluation, the LEAPS project includes the transmission and the pumped storage portions of the proposal. The CAISO notes that there has been no "wires" only proposal presented by The Nevada Hydro Company to the CAISO for analysis.

legislated RPS target of 20% by 2010 and the likely RPS target of 33% by 2020 of its electricity sales. Third, Sunrise is expected to reduce the CAISO consumers' electricity expenditure by $87M/year in 2015 when compared to the base case that assumes the project's absence and minimal new development of renewable energy in the Salton Sea area and IID service territory.[4] Hence, Sunrise is cost-effective from the perspective of CAISO consumers. Finally, there are many factors that differentiate the analysis described in this testimony, the CSRTP Report, and the SDG&E most recent (01/19/07) submission.[5] Notwithstanding these differences, Sunrise is shown to be cost-effective using a set of unbiased and plausible assumptions that define the base case and its alternatives.

Q. What is the CAISO's plan to validate the reasonableness of these findings?

A. The CAISO has been working with Dr. Ren Orans of E3 to develop the results presented here. His involvement is instrumental in the CAISO's updated economic analysis of Sunrise. Dr. Orans will file his supplemental testimony by February 16, 2006, offering his review of the reasonableness of the findings.

Q. How is the remainder of this testimony organized?

A. It is organized as follows:

---

4 The total benefits of Sunrise are expected to be approximately $250 million and the costs are $163 million in 2015.

5 As noted above, Joint Exhibit A contains a comparison between the latest (01/19/07) SDG&E and CAISO analysis of both reliability and economics of the Sunrise Project.

- Section 4 presents the methodology used by the CAISO to obtain the updated results in this testimony. It states the transmission planning problem faced by the CAISO. It also defines the variables that enter into the problem, so as to ensure a clear understanding of the CAISO's approach to evaluate Sunrise. It describes the empirical implementation of the CAISO's methodology. Finally, it compares the methodological differences between the current analysis of costs and benefits and the approach used in the CSRTP Report.
- Section 5 presents the input assumptions used here and indicates important differences from those used in the CSRTP Report.
- Section 6 reports the reliability results from the CAISO's promised studies. It then compares the results to those in the CSRTP Report.
- Section 7 reports the cost-effectiveness results from the CAISO's promised studies and compares these results to those in the CSRTP Report.
- Section 8 describes the non-quantifiable benefits of Sunrise and general conclusions that can be drawn from this continued evaluation.

4. METHODOLOGIES USED IN THE ECONOMIC AND RELIABILITY STUDIES.

Q. Are there any differences in the methodology used to evaluate the reliability impacts and benefits of the CAISO's updated base case and the scenarios described in the CAISO 1/08/07 Motion?

A. No. For all of the evaluations, the CAISO performed the following analyses:

- Power flow studies of the power grid under normal conditions;
- Transient stability studies of the power grid's ability to absorb the initial electrical shock of loss of one or more elements, and
- Post-transient studies of the power grid's electrical sustainability after absorbing the initial shock of the contingency.

Q. What methodology did the CAISO use to measure the net economic benefits of Sunrise?

A. The CAISO continues to rely on its TEAM methodology described in a July 2004 report[6] (TEAM Report) to calculate the benefits and costs of Sunrise, as well as a number of feasible alternatives. This methodology is endorsed in a recent CPUC opinion (p.2):[7] "The CAISO's work in developing its Transmission Economic Assessment Methodology (TEAM) has advanced the state of the art in economic

---

[6] *Transmission Economic Assessment Methodology*, July 2004, CAISO, CA: Folsom.

[7] *Opinion of Methodology for Economic Assessment of Transmission Projects* D.06-11-018, Mailed 11/14/07, Investigation. 05-06-041, CPUC CA: San Francisco

evaluations of transmission projects. We agree with and adopt many aspects of the CAISO's TEAM approach."

Q. Has the TEAM methodology been used to evaluate other CPCN applications in California?

A. Yes. It has been used to evaluate the Devers-Palo Verdes 2 project's benefits for California and regionally across the WECC. These benefits are differentiated by consumers, producers and transmission owners.

The benefits are based on nodal market prices under locational marginal pricing (LMP) and an assumed producer bidding strategy. These nodal prices reflect a constrained least cost dispatch in a network model of the WECC grid, subject to constraints such as generation and transmission capacity availability and laws of physics that govern power flows. The Commission finds merit in the TEAM in a 12/22/06 proposed decision, stating (p.27):[8] "The fact that the relationships among the energy benefits found by the parties are logical provides some assurance both that the CAISO's "LMP Only" and "LMP +Contract Path" estimates bracket actual energy benefits and that the more simplistic modeling underlying the SCE and DRA analyses may be reasonably reliable."

---

[8] *Proposed Decision of ALJ Terkeurst*, Application 05-04-015 (Mailed 12/22/2006), CPUC, CA: San Francisco.http://www.cpuc.ca.gov/EFILE/PD/63163.pdf

Q. How did the CAISO use TEAM to evaluate Sunrise ?

A. We used TEAM's benefit framework (TEAM Report, pp.ES-5-6) to find a resource plan that would minimize the expected electricity expenditure paid by CAISO consumers over a forecast period, subject to the following constraints: (a) reliability standards of CAISO and WECC; and (b) the mandated RPS target of 20% by 2010 and the likely RPS target of 33% by 2020.

Q. Is the TEAM approach consistent with the CPUC's adopted cost-effectiveness analysis of non-transmission programs?

A. Yes. The least-expenditure approach in the TEAM methodology is consistent with the Ratepayer Impact Measure ("RIM") test defined in Chapter 3 of the *California Standard Practice Manual (SPM): Economic Analysis of Demand-Side Programs and Projects*, first adopted by the CPUC in 1983 and later updated in 2001.[9]

Q. Please define "customer bill" in the Sunrise context.

A. Based on the TEAM's benefit framework (TEAM Report, pp.ES-5-6), customer bill is the electricity expenditure paid by CAISO consumers for a feasible

---

[9] Available at http://www.cpuc.ca.gov/static/energy/electric/energy+efficiency/rulemaking/spm.doc, the SPM (p.13) states: "The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels."

resource plan that satisfies the reliability and RPS constraints. Electricity expenditure is defined to be the present value (or its annual levelized equivalent) sum of: (a) CAISO loads times nodal prices; (b) RPS compliance cost; (c) reliability compliance cost; (d) new transmission cost (if any); less the sum of (e) generation profit of investor-owned-utilities ("IOU"); (f) refund from the CAISO for line loss over-collection under LMP; and (g) congestion revenue received by transmission owners.

All cost variables in the electricity expenditure are based on the concept of utility avoided costs. Fixed costs such as the returns on and of past investments that cannot be avoided by a resource plan (e.g., transmission construction or generation expansion) do not enter into the expenditure calculation. To the extent that these fixed costs are common in all the resource plans to be considered, their exclusion does not alter the plans' cost rankings. The least-expenditure plan would still be the optimal plan, even if the fixed costs were to be included in the expenditure computation.

Q. Is this customer bill definition qualitatively identical to the one used by SDG&E?

A. Yes, it is. In particular, Chapter 4 of SDG&E's August 4, 2006 application states (p.VI-4): "The difference in energy bills for consumers within the CAISO control area between the reference case and the Sunrise case, is a measure of the grid efficiency savings created by the addition of the Sunrise Powerlink."

However, the expenditure and the associated benefit estimates reported here are numerically different from those in SDG&E's 01/19/07 submission. At present, we cannot attribute each of the numerical differences to each individual difference in input assumptions, including definition of the reference case, load forecast, natural gas price forecast, RPS compliance cost, , etc. Joint Exhibit A describes the differences and compares the numerical results for each category of benefits.

Q. Please define the value of CAISO loads priced under LMP.

A. It is the sum of CAISO loads priced at the applicable nodal prices found under LMP. Solved by a constrained optimal dispatch algorithm (i.e., the GridView program used in the CSRTP and SDG&E's 01/19/07 Submission), nodal prices are the node- and time-specific marginal generation costs (including marginal line losses) to meet nodal loads, without violating the grid's physical constraints (e.g., transmission and generation capacities available and laws of physics that govern power flows). A transmission capacity expansion reduces the average LMP level because it helps relieve capacity constraints and reduces line losses.[10] Moreover, if new transmission improves access to less expensive generation sources, it further reduces the value of CAISO loads priced under LMP.

[10] A feasible dispatch before transmission expansion remains feasible after transmission expansion. Hence, if the post-expansion dispatch differs from the pre-expansion dispatch, the former must be less costly than the latter under the assumption of optimal dispatch.

Even though market power may exist (as was assumed by the CSRTP and SDG&E's 08/04/06 Submission), the nodal prices used here assume marginal-cost-based bidding by competitive generators.[11] The competitive bidding assumption implies that the results reported herein are free from the potential criticism of "inflated" costs that may arise under the assumption of market power abuse, one that partly depends on the effectiveness of regulatory surveillance of and sanction against non-competitive generator behavior.[12]

The competitive bidding assumption also reflects the fact that IOUs are required by the CPUC to procure 90% of their summer peaking needs plus reserves a year in advance in the forward market.[13] The CAISO believes that the forward market is reasonably competitive, with prices tracking market expectation of future spot prices.[14] Hence, competitive nodal prices are better suited for the Sunrise evaluation than non-competitive prices.

Q. Please define "RPS compliance cost."

---

[11] The TEAM Report (p.ES-3) recognizes market power mitigation benefit of transmission expansion in the presence of market power mitigation measures (e.g., price cap, automatic mitigation procedure, and long-term contracting). For this Sunrise evaluation, the CAISO excludes the market power mitigation benefit for being conservative in its economic assessment. However, the CAISO plans to include this benefit as warranted in other TEAM applications.

[12] For a discussion on the regulatory effort by the Federal Energy Regulatory Commission (FERC), see Helman, U. "Market power monitoring and mitigation in the US wholesale power markets," *Energy* 2006; 21: 877-904.

[13] http://www.cpuc.ca.gov/word_pdf/NEWS_RELEASE/33555.pdf; http://www.cpuc.ca.gov/static/energy/electric/ab57_briefing_assembly_may_10.pdf

[14] This rationale is used by the long-term market price projection in a CPUC-sponsored avoided cost estimation project, see Baskette, et al. op cit.

A. RPS compliance cost is the incremental payment by CAISO consumers due to RPS compliance by SDG&E, PG&E and SCE. This per MWh payment is the difference between (a) renewable energy's per MWh all-in cost, including the necessary transmission and connection costs, and (b) the LMP prices. To the extent that new transmission improves access to less expensive renewable energy, it helps reduce RPS compliance cost.

All renewable generation contracts are assumed to be cost-based, with a competitive return for merchant-owned units and a regulated return for IOU-owned units. The cost-based assumption obviates the need to compute producer profits under alternative renewable energy mixes. It removes the sensitivity of RPS compliance cost to new renewable generation ownership (i.e., merchant vs. IOU plants).

Q. Please define "reliability compliance cost."

A. Reliability compliance cost is the cost incurred by SDG&E to comply with (a) the reliability standards of the CAISO and WECC; and (b) the Commission's 15%-17% local capacity requirement (LCR).[15] To determine compliance, the CAISO uses the same approach in the reliability analysis found in Chapter 4 of the CSRTP Report.

[15] The LCR requirement is to be met by January 1, 2008, see http://www.cpuc.ca.gov/static/energy/electric/ab57_briefing_assembly_may_10.pdf

Reliability compliance cost may arise because meeting the RPS targets may still leave SDG&E capacity short. Two examples illustrate this point:

- Example 1: No new transmission construction. In this example, SDG&E would procure renewable energy from sources that are available in the new line's absence. It would then buy sufficient CTs and local generation capacity contracts similar to reliability-must-run contracts (RMR) to meet the reliability standards and LCR. Both the CTs and local capacity contracts are assumed to be cost-based, with a competitive return for merchant-owned units and a regulated return for the IOU units. The cost-based assumption obviates the need to compute producer profits under alternative reliability compliance plans. The same assumption removes the sensitivity of reliability compliance cost to new CT ownership (i.e., merchant vs. IOU plants).
- Example 2: New transmission being put in place. In this example, SDG&E would procure resources that now include those made available by the new transmission line (e.g., renewable baseload units in Imperial Valley). If reliability compliance is fully met by renewable energy procurement, its cost is zero because the cost is already part of the RPS compliance cost. However, if reliability compliance is only partially met by renewable energy procurement, it has a positive cost, reflecting additional capacity purchases to satisfy the reliability standards and LCR. The capacity purchase is assumed to be cost-based, obviating the need to compute producer profits under alternative reliability compliance plans.

Q. Please define “new transmission cost.”

A. New transmission cost is the increase in the transmission bill of CAISO consumers, as described in the CSRTP Report (p.20).

Q. Please define “profit of IOU-owned generation.”

A. In accordance with the TEAM Report (p.ES-5), the profit of IOU-owned generation is the net revenue (= revenue - variable cost) made by IOUs’ retained generation ("URG") (e.g., nuclear and hydro units). Because the net revenue is passed through to the IOU customers, a positive (negative) value reduces (raises) electricity expenditure.

Q. Please define “line loss over-collection.”

A. Line loss over-collection is the difference between (a) the line loss revenue collected under LMP that sets nodal prices based on marginal line losses; and (b) the revenue that would be collected under average cost pricing. As the over-collection reduces the transmission access charge (TAC) of CAISO consumers, it is a subtraction to the electricity expenditure.

Q. Please define “congestion cost revenue”.

A. Congestion cost revenue results from LMP, which sets transmission congestion cost as the price difference between the point of delivery (POD) for electricity withdrawal and point of receipt (POR) for electricity injection.[16] Consistent with the TEAM Report (p.ES-5), this revenue reduces the TAC of CAISO consumers; and therefore it is a subtraction to the electricity expenditure.

Q. Please state the CAISO's base case resource plan.

A. The base case resource plan is the default option required to meet the reliability and RPS constraints absent the Sunrise facilities. The option assumes the existing South Bay Power Plant to be off-line. It uses new CTs inside the San Diego local area in addition to RMR contracts to resolve the reliability problem in San Diego. It assumes that SDG&E would comply with the RPS by procuring renewable resources available in Sunrise's absence.

Q. When defining this base case resource plan, what is the CAISO's assumption on renewable energy development in the absence of Sunrise?

A. The CAISO assumes that absent Sunrise, the renewable energy development in the Salton Sea area would be less than the level necessary to materially lower energy costs for California's electricity consumers. This is because the lack of transmission implies that the generation capacity from the area's renewable energy output would not meet the CAISO's deliverability requirements and therefore would not count towards meeting the CPUC and CAISO's Resource

---

[16] This congestion cost revenue computation is not likely to be materially affected by the CAISO's sale of financial transmission rights (FTR) for two reasons. First, the FTR revenue is offset by the congestion cost revenue not paid by FTR holders. Second, under the efficient market hypothesis, the FTR price for a POD-POR pair tracks the expected congestion cost.

Adequacy Requirements. It is unlikely that renewable energy developers will make the necessary billions of dollars in financial commitments without new transmission investments that would facilitate their access to markets outside of the Salton Sea/Imperial Valley area. Absent Sunrise, these developers would face potential curtailments in the event of contingency and potentially prohibitive levels of congestion charges that could be expected to grow with increased development.

Q. What have you assumed about the costs of RPS compliance absent Sunrise?

A. The base case assumes that the incremental cost of complying with the RPS standards without Sunrise is the same as the cost of compliance with Sunrise.

Q. Are there additional differences between the base case definitions used in this updated analysis and the one used in the CSRTP Report?

A. Yes there are. A complete list of the differences between the two base cases is described in Section 5.

Q. Please define "cost-effectiveness" in the context of the CAISO's continued evaluation of Sunrise.

A. As discussed in the TEAM Report, a resource plan's net benefit (NB) is its expenditure less the base case's expenditure. A resource plan is said to be cost-effective relative to the base case plan if its NB is positive. A resource plan is said to be least-cost if it has the largest NB among all the plans considered.

The cost-effectiveness analysis of the base case and alternative plans uses the computation process in Chapter 6 of the CSRTP Report. To derive the electricity expenditure, however, the process has been modified to account for RPS compliance cost and line loss over-collection.

Q. How does the CAISO compute RPS compliance cost?

A. The RPS compliance cost is defined as the difference between (a) the renewable energy procurement cost; and (b) the procured amount of renewable energy valued at LMP prices.

The renewable energy procurement cost is estimated for each resource plan:

- Base case plan. The CAISO assumes that the IOUs, including SDG&E, would procure renewable energy from a set of resources that are expected to be available without Sunrise, the Green Path Project, or the LEAPS Project.
- Alternative 1 (Scenario 1 on p.7 of the CAISO's Motion). The CAISO assumes that the IOUs, including SDG&E, would procure renewable energy from a set of resources that are expected to be available with the Green Path Project and the LEAPS Project in place but not the Sunrise Project.
- Alternative 2 (Scenario 2 on p.7 of the CAISO's Motion). Since this alternative is the base case modified by the South Bay Repowering Project,

the CAISO assumes that the IOUs, including SDG&E, would procure renewable energy from a set of resources that are expected to be available without Sunrise, Green Path Project, or the LEAPS Project.

- Alternative 3 (Scenario 1 on p.7 of the CAISO's Motion). The CAISO assumes that the IOUs, including SDG&E, would procure renewable energy from a set of resources that are expected to be available with Sunrise in place but not the Green Path Project and the LEAPS Project.

Q. How does the CAISO compute line loss over-collection?

A. Marginal line loss is about twice the size of average line loss. Valuing total line loss under LMP overstates the total line loss cost to be recovered from electricity consumers. Hence, there is a line loss over-collection, the difference between the value based on marginal cost pricing and the one based on average cost pricing. The line loss over-collection is calculated as the total WECC customer load payments less WECC generation receipts less congestion charges. The line loss over-collection is allocated to CAISO customers based on their share of annual customer load payments.

Q. Is the methodology used here different than the one in the CSRTP Report?

A. There is no methodological difference in the reliability analysis between this testimony and the CSRTP. However, the following table indicates differences in the cost-effectiveness methodologies.

Table 4.1: Cost-effectiveness methodology comparison: Current methodology vs. CSRTP Report

Current methodology	CSRTP Report	Remarks
Only one base case, defined to be the default option of meeting the reliability and RPS constraints.	Three scenario-specific base cases, each of which is "no Sunrise", see Figure 6.1	The current methodology clarifies what the single base case is.
The electricity expenditure definition includes RPS compliance cost and line loss over-collection.	The electricity expenditure definition does not explicitly consider RPS compliance cost and line loss over-collection.	The current methodology offers a comprehensive expenditure definition that can incorporate differences in RPS compliance costs related to specific transmission investments
Nodal price estimation assumes competitive bidding.	Nodal price estimation assumes possible market power abuse (p.55).	The current methodology focuses on cost-based expenditure estimation, not one that may be influenced by non-competitive prices.
The price for new generation (e.g., CT for reliability and renewable energy) is assumed to be cost-based, including a competitive return for a merchant unit and regulated return for a utility-owned unit.	There is no explicit accounting for the return on and of investment in new generation. Hence, the generation profit to be credited to consumers depends on the assumption of IOU generation ownership.	The current methodology removes the cost-effectiveness results' sensitivity to new generation ownership.
The line loss over-collection is now part of the expenditure estimation.	There is no explicit accounting for the possible line loss over-collection.	The current methodology recognizes that marginal cost pricing of line loss revenue may result in excess revenue collection.

5. INPUT ASSUMPTIONS

Q. Please describe the key input assumptions used to develop the updated results in this testimony.

A. Based on the base case in the CSRTP Report, the updated base case assumes a 2015 Heavy Summer and is revised to include modifications described in Section 4. The updated base case also includes the Tehachapi transmission project.[17] The key updated input assumptions include the following:

1. Updated load forecast for the PTO's:
   - **SDG&E Planning Area**. The CAISO now uses the latest load forecast in SDG&E's Long Term Procurement Plan (LTPP). The updated SDG&E's 1-in-10 year heat wave load forecast is 5,289 MW, which includes Uncommitted Energy Efficiency, Distributed Generation for customer use, and California Solar Rooftop PV.
   - **SCE Planning Area**. The CAISO uses the CEC's load forecast (as available from June 2006), subtracts 675 MW as an adjustment to include the California Solar Initiative (CSI) Rooftop PV. The updated 1-in-10 year heat wave load for SCE is 27,173 MW in 2015, calculated as follows:

[17] The Tehachapi Transmission Project is modeled in the updated base case because the CAISO Board of Governors approved this project at the January 24, 2007 meeting.

Total SCE Planning Area Load = 27,543 MW + 305 MW

Pasadena load – 675 MW PV rooftop = 27,173 MW

In addition, DWR pump load in SCE area will be adjusted to 506 MW as forecasted by the CEC.

- **PG&E Planning Area**. The CAISO uses PG&E's load forecast that reflects the corresponding forecast load in Northern California (conforming + pump load in PG&E = 28,519 MW) when Southern California load peaks, subtracts 675 MW PV rooftop, then add pump load (conforming -675 MW + pump load in PG&E = 27,848 MW.
- **LADWP Planning Area**. There's no need to change the load forecast from LADWP 2006 Integrated Resource Plan (6597 MW for 2015), as was modeled in the CSRTP Report

2. Updated PVD2 Plan of Service:

   The updated base case includes the Devers – Valley No. 2 500kV line, along with the model for the PVD2 500kV line from Harquahala – Devers and modifications of the electrical characteristics of the West of Devers 230kV lines.

3. Path 42 Upgrade:

   The CAISO models Path 42 upgrade at 1500 MW for the updated Sunrise Power Link case and the LADWP's (Green Path + LEAPS) Project case.

4. Renewable generation:

The CAISO models a total of new 2500 MW of renewable (1600 MW new merchant geothermal generation and 900 MW of solar generation at Imperial Valley Substation) for the updated Sunrise case and the (Green Path + LEAPS) case. For the updated base case and the South Bay Repower case, no new merchant renewable generation in the Salton Sea area is modeled due to the area's insufficient transmission capacity.

5. Verification of Pmax for CT's in San Diego per SDG&E's 12/11/2006 LTPP:

The CAISO has done the verification in its definition of the updated base case and the alternative cases.

Other key input assumptions remained the same as in the CSRTP Report. In particular, the Otay Mesa combined cycle generation facility (561 MW) was assumed out of service for the base case largest G-1 contingency. The updated base case assumes that absent the construction of the Sunrise line, very few new renewable resources would be developed in the Salton Sea basin. This assumption makes the updated base case significantly different than the one in the CSRTP Report, as shown in the table below. Specifically, the CSRTP assumed that the profit increases (i.e., the change in producer surplus) from the Salton Sea renewable resources would accrue to CAISO consumers. The updated analysis assumes that renewable resources are purchased through long-term cost-based contracts and profit changes do not flow to CAISO customers. The key assumptions defining the updated base case and the one in the CSRTP Report are listed in the table below.

Table 5.1: Base case comparison: Current study vs. CSRTP Report

Updated base case in the **current study**	Reference cases in Figure 6.1 of the **CSRTP**
The customer perspective counts consumer benefits for TAC participating utilities: IOUs, Anaheim, Azusa, Banning, Pasadena, Riverside, and Vernon. The adjustment is small (2.4% reduction).	The customer perspective counts benefits for all customers in the CAISO zones in which the IOUs are located. This includes publicly owned utilities that are not TAC participants (e.g., the City of Palo Alto and Silicon Valley Power).
Consumer surplus benefits are offset by any change in excess loss payments. The LMP modeling of nodal prices assumes that losses are billed on a marginal losses basis. This leads to over-collections that would be returned to customers through a credit or charge reduction. The excess loss costs are returned to customers on a GWH share basis.	Not included.
Based on the updated reliability study reported in Section 6, 711MW of CTs are installed in the San Diego area to meet reliability needs The levelized capital cost of the CT units are now included as a cost in the reference case.	No CT capital costs included.
CT levelized cost = $78/kW-yr ($2006) based on CAISO 2005 Annual Report on Market Issues and Performance, pp. 2-33 to 35).	Not used
Changes in local capacity contract requirements are valued at an average cost of $46.21/kW-yr ($2006)	Changes in local capacity contract requirements are valued at an average cost of $43/kW-yr ($2006)
The Path 42 upgrade is in place	No path 42 upgrade
Tehachapi contain 4500MW of renewable resources	Same
Salton Sea contains no new renewable resources in the absence of the Sunrise Project.	1600MW of geothermal and 900MW of solar are in the Salton Sea area, even though the Sunrise Project is not built.
Wind, geothermal, and solar energy	All margin from renewable energy sale

are purchased through long term cost-based contracts that recover both capital and variable costs. As a result, there is no producer surplus to be passed to CAISO participating ratepayers	(= revenue at LMP – variable costs) is passed to CAISO participating ratepayers
The contract cost of wind, geothermal, and solar energy are 66, 86, and 120 $/MWh ($2015)	Did not consider contract costs
Additional renewable resources needed to meet the aggregate IOU RPS requirement will be procured at a cost of $89.3/MWh	Did not consider contract costs
RA market costs = $27/kW-yr ($2006) based on Table 2.11 of CAISO 2005 Annual Report on Market Issues and Performance. These cases did not require the use of RA market costs.	Not needed, given assumption of no RA capacity contracts to replace the terminated RMR contracts
Inflation is 2% per year	Same
Nominal discount rate is 8.18%	Same

Q. Please state the key input assumptions used to develop the alternative cases in this testimony

A. The alternative cases follow the TEAM methodology, using the assumptions listed in Table 5.2 below. Because of our primary interest in the Sunrise case, the case appears in the first column of Table 5.2, even though it has been referred to as Alternative 3 in Section 3. The description of Alternatives 2 and 1 appear in the next two columns.

Table 5.2: Input assumptions for the alternative cases in the current study

Alternative 3: Sunrise (Scenario 3 on p.7 of the CAISO's Motion)	Alternative 2: South Bay (Scenario 2 on p.7 of the CAISO's Motion)	Alternative 1: Green Path + + LEAPS (Scenario 1 on p.7 of the CAISO's Motion)
Transmission Project Cost = $1.114 billion ($2006)	Transmission interconnection and upgrade costs = $63.4 million ($2006)	Transmission project cost = $1.350 billion ($2006)
The present value revenue requirement of the transmission projects is 1.59 times the direct cost of the project, based on CSRTP (p.64)	Same as Sunrise	Same as Sunrise
Transmission project provides 1000MW of increased import capability.	No transmission project	Transmission project reduces the local capacity requirement by approximately 700 MW
1600MW of geothermal and 900MW of solar are added in the Salton Sea Area	No additional renewable resources in the Salton Sea area.	1600MW of geothermal and 900MW of solar are added in the Salton Sea Area
No new CT's are required to meet reliability in 2015.	106 MW of CTs are required in San Diego area in 2015	No new CT's are required to meet reliability in 2015.
No CT transmission cost.	$4M/year of levelized generation-related transmission costs for the CT.	No CT transmission cost.
Contracts to meet local capacity requirements are reduced by approximately 300MW. The reduction is priced at $46.21/kW-yr ($2006), the average historical RMR cost.	Contracts to meet local capacity requirements are approximately 300increased by 620 MW.	No reduction in local capacity contract payments from the base case.
RA capacity is purchased at a cost of $27 per kW-yr ($2006) to "firm up" renewable energy imports as needed. None are needed for the Sunrise case.	Same as the Sunrise case	Same as the Sunrise case
No remediation cost.	No remediation cost.	Remediation and reactive support = $65M ($2006).

		The levelized revenue requirement of this investment is $10M/year ($2015)

Q. Please compare the key input assumptions used here to those in the SDG&E 01/26/07 update.

A. The input assumption comparison is in Joint Exhibit A.

6. RELIABILITY RESULTS

Q. Please summarize the results from the reliability analysis of the updated base case and three alternative cases listed in Section 3.

A. Table 6.1 summarizes the reliability results under the CAISO's G-1/N-1 criteria for 2015 Heavy Summer. These results lead to the following observations:

- For the updated base case, an additional 711 MW of CTs (or other local resources) would be necessary to serve load and maintain SDG&E's existing non-simultaneous import limit (NSIL) of 2500 MW.
- For the Sunrise case (i.e., Alternative 3 in Table 5.2), the 711 MW of CTs are not required because in-area resource needs would be met by imports.
- For the South Bay Repowering case (i.e., Alternative 2 in Table 5.2), there is still a need for 106 MW of CTs necessary to meet SDG&E's existing NSIL.
- For the (Green Path + LEAPS) case (i.e., Alternative 1 in Table 5.2), the initial results under G-1/N-1 contingencies produced a Divergent Result; in other words, the G-1/N-1 contingencies would result in a reactive deficient condition that could lead to voltage instability under this scenario. To mitigate this reliability concern, we added 630 MVAR of Static Var Compensator (SVC) at Talega 230 kV Substation, at a cost of about $65M based on the CAISO's experience with similar projects.[18] Finally, tripping of 130 MW of generation from the Salton Sea would be needed to mitigate the overload on the Coachella-Midway 230kV lines.

[18] This amount of reactive power requirement is an estimate and does not include optimization of the size as well as the location.

Table 6.1: Reliability assessment results for 2015 Heavy Summer by case

All the cases below include the Tehachapi Transmission Project

	2015HS Sunrise Powerlink (All-Lines In Service)	2015HS Sunrise Powerlink (N-1 Condition***)	2015HS South Bay Re-power (All Lines In Service) (CT's are added as necessary)	2015HS South Bay Re-power (N-1 Condition*) (CT's are added as necessary)	2015HS Green Path North + LEAPS (All-Lines In Service)	2015HS Green Path North + LEAPS (N-1 Condition*)	2015HS Reference Case (All Lines In Service) (CT's are added as necessary)	2015HS Reference Case (N-1 Condition*) (CT's are added as necessary)
CONTINGENCY	**G-1: Otay Mesa**	**G-1:Otay Mesa N-1: IV-Miguel**	**G-1: South Bay**	**G-1:South Bay N-1: IV-Miguel**	**G-1: Otay Mesa**	**G-1:Otay Mesa N-1: IV-Miguel**	**G-1: Otay Mesa**	**G-1:Otay Mesa N-1: IV-Miguel**
SDG&E LOAD (MW)	5289	5289	5289	5289	5289	5289	5289	5289
SDG&E INTERNAL GENERATION (MW)	2270	2270	2831	2831	2270	2270	2270	2270
SDG&E SYSTEM LOSSES (MW)	89	134	87	148	86	178	86	192
TOTAL SDG&E IMPORT (MW)	**3108**	**3153**	**2545**	**2606**	**3105**	**3197**	**3105**	**3211**
Surplus / (Deficient) (MW)	**892**	**347**	**305**	**(106)**	**895**	**3**	**(255)**	**(711)**
Total Import Capability (MW)	4000	3500	2850	2500	4000	3200 ****	2850	2500

NOTE:
This table presents a thermal analysis justification for the need of the subject import line.
This table is not intended as a rigorous import analysis or verification of any import limits.

* SPS for Cross Tripping of the Imperial Valley - La Rosita 230kV Line helps preventing internal 230kV CFE system from being overloaded.
** G-1 of Otay Mesa, System Re-adjustment in base cases. The contingency analysis includes an N-1 on the Imperial Valley - Miguel 500kV line (N-1).
*** No need for Cross Trip SPS (Post Sun Path Project Scenario).
**** For the Green Path North + LEAPS Project, to mitigate the divergent solution for the IV-Miguel 500kV line contingency, we need to include: ~ 630 MVAR SVC at Talega 230kV. In addition, we also need to drop ~ 130 MW of generation from Salton Sea to mitigate line overload on the Coachella - Midway 230kV lines. The 3200 MW non-simultaneous limit above is an estimate at this time.

Q. Did the CAISO also conduct additional power flow analyses for the base case and the alternative scenarios?

A. Yes, we did. The CSRTP Report provides the results of Post-Transient and Stability studies performed on the 2010 Heavy Summer Pre-Project and 2010 HS Sun Path Project Scenarios. As promised in the January 8, 2007 Motion for Extension, the CAISO has performed these same studies on the 2015 Heavy Summer case for all four scenarios. The results of these studies have identified similar reliability issues as those in the CSRTP report. However, for the simultaneous loss of two Nuclear generating units, which are traditionally the most severe contingencies from a voltage stability perspective, the 2015 case appears to have reactive issues beyond the study area that need to be resolved. The CAISO will continue to work on resolving these issues and report back on its final resolution. It is not expected that the resolution of this issue will be pivotal in the project recommendation.

Q. What conclusions can be drawn from the preceding reliability study results?

A. The conclusions are as follows:

- Relative to the updated base case, the Sunrise case shows that SDG&E's import capability will improve by about 1000MW.
- For the (Green Path + LEAPS) case, SDG&E's import capability will improve by 700 MW. To further increase this case's import capability, additional reactive support will be needed, as the SDG&E system is "leaning" on SCE system under the loss of the SWPL line.
- For the South Bay Repowering case, there will be no import capability improvement.

Q. Please compare these updated results to those in the CSRTP Report.

A. The reliability assessment results are found at pages 36- 43 of the CSRTP Report. Table 6.1 above is analogous to Table 4.2 on page 38, and the results shown in the CSRTP's Table 4.2 are very similar to the results of our updated base case (2015HS Pre-project), base case plus Sunrise (2015HS Sun Path Project) and the 2015HS South Bay Repower sensitivity study. The table shows the total load and generation in the SDG&E area and required amount of imports into the area needed to meet the load. The import level "Total SDG&E Import (MW)" shown was produced using the 2015 HS power flow model and includes transmission system losses. This import level is then compared to the previously established import limit, "Total Import Capability (MW)" If the "Total SDG&E Import (MW)" exceeds the "Total Import Capability (MW)" the area has insufficient local capacity to reliably meet the local demand.

Q. Please compare these results those in the SDG&E 01/26/07 Submission.

A. This comparison is in Joint Exhibit A.

7. COST-EFFECTIVENESS RESULTS

Q. Please summarize the results from a cost-effectiveness analysis of the updated base case and the three alternative resource plans listed in Section 3.

A. Table 7.1 shows the benefits using the CAISO's updated assumptions in the familiar format used in the CSRTP. With exception of the Total WECC production cost reduction, which is from the perspective of all WECC participants, all benefits reflect the perspective of CAISO consumers.

Table 7.1: Annual energy and reliability benefit (loss) for Year 2015 in millions of 2015 dollars

Benefit Description	Sunrise	South Bay	Greenpath	July 2006 Equivalent
Total CAISO IOU Generator Surplus	$ (93.99)	$ (12.11)	$ (87.26)	Table 6.4
Total CAISO Consumer Payment Reduction (Increase)	$ 231.48	$ 32.57	$ 245.84	Table 6.4
Total CAISO PTO Transmission Congestion Revenue Gain (Loss)	$ 9.22	$ (2.37)	$ 1.95	Table 6.4
Total CAISO Energy Benefit (Loss)	$ 146.71	$ 18.10	$ 160.53	Table 6.4
RMR Savings	$ 17	$ (34)	$ -	Table 6.14
Total Benefits	**$ 163.28**	**$ (16.14)**	**$ 160.53**	Table 6.15
Total WECC Production Cost Reduction (Increase)	$ 756.83	$ 11.30	$ 731.97	Table 6.4

Table 7.2 shows the benefits and costs that include the additional components in Table 5.1 for the CAISO's updated analysis. Specifically, this updated analysis includes an adjustment for the return of excess loss payments (line 4) and benefits for the reduction in reliability costs other than RMR payments (lines 6 though 10). Moreover, this analysis recognizes that the cost of renewable resources will have a significant impact on CAISO consumers, so those costs are presented in lines 15 and 16. The benefits are calculated as a difference in costs between two cases. For example, Table 7.2 estimates that the base case costs consumers $12,594 million in 2015. The Sunrise case costs consumers $12,507 million which is an $87 million benefit to consumers. South Bay and Green Path + LEAPS are estimated to provide $49 and $36 million benefits to consumers, respectively.

Table 7.2: Total project costs and benefits for Year 2015 in 2015 nominal million dollars per year

		A	B	C	D	E	F	G
	Summary of 2015 Benefits	Base	Sunrise		South Bay		Green Path + LEAPS	
		Cost	Cost	Benefit	Cost	Benefit	Cost	Benefit
	IOU Customer Payments ($M/yr)							
1	Customer Payments from Gridview	16,183	15,952	231	16,151	33	15,937	246
2	Less CAISO congestion cost (reduces TAC)	(104)	(113)	9	(102)	(2)	(106)	2
3	Less URG Margin (reduces URG balancing acct)	(4,253)	(4,159)	(94)	(4,241)	(12)	(4,166)	(87)
4	Less IOU excess loss payments (returned to load)	(758)	(751)	(6)	(753)	(5)	(752)	(5)
5	**Subtotal Energy Benefit**			**140**		**13**		**155**
	Reliability Costs							
6	San Diego LCR Costs	156	140	17	191	(34)	156	-
7	Cost of New CTs for in-area reliability	66	-	66	10	56	-	66
8	Transmission cost for new CTs	27	-	27	4	23	-	27
9	Remediation cost to provide reactive support	-	-	-	-	-	10	(10)
10	RA Costs to replace CTs and RMR contracts	-	-	-	-	-	-	-
11	**Subtotal Reliability Benefit**			**110**		**45**		**84**
12	**Total Energy and Reliability Benefits**			**250**		**58**		**239**
	Transmission Cost							
13	**Levelized Cost of Transmission**	-	163	**(163)**	9	**(9)**	198	**(198)**
14	**Subtotal including Transmission Cost**	11,317	11,231	**87**	11,268	**49**	11,276	**41**
	Renewable Resource Costs							
15	Contract cost of renewable generation in GridView	841	1,297	(456)	841	0	1,297	(456)
16	Cost/credit for renewable shortfall/excess	436	(21)	456	436	(0)	(15)	451
17	**Total with Transmission & Renewable Costs**	12,594	12,507	**87**	12,545	**49**	12,558	**36**

Q. Can a snap-shot view of cost-effectiveness in 2015, as shown in Table 7.2, be a reasonable assessment of a transmission project with very long life?

A. Yes, we believe that the 2015 analysis provides a reasonable approximation of the economic benefits provided by the alternatives. However, Dr. Orans will test this assumption with in his supplemental testimony.

Q. Using the Table 7.2, please summarize the cost-effectiveness results for the Sunrise case when compared to the updated base case.

A. The benefits and costs of the Sunrise Case are as follows:

a. Energy Benefits.

The Sunrise case adds transmission, effecting access to and development of renewable resources in the Salton Sea. This leads to lower LMP nodal prices and less operation hours for generation units with high marginal fuel cost. The resulting total impact of $140M/year (2015 dollars) on CAISO customers has the following components:

- The CAISO customers see a reduction of $231M/year due to lower prices in their payment for CAISO loads.
- The utility owned and contracted units have lower profit because of lower prices and less output. The $94M/year profit reduction increases CAISO customer bills by the same amount.
- Congestion cost revenue rises slightly ($9 M/year), which under the TEAM methodology, reduces CAISO customer benefits.

- The CSRTP does not consider the over-collection of line loss payments under LMP, even though this over-collection should be returned to CAISO customers. In this testimony, the Sunrise case is found to have lower line loss than the updated base case; and hence, its over-collection shrinks by $6 M/year, raising the CAISO customer bills by the same amount.

b. Reliability Costs

The Sunrise case adds approximately 1000MW of import capability into San Diego. The increased capability eliminates the need for the updated base case's new CTs and associated local transmission in the San Diego Area, and reduces the LCR in the area. The CT capacity eliminated is 711MW, yielding an annual cost savings of $66M for the plants and $27M for the associated transmission. The Sunrise case also allows San Diego to reduce approximately300 MW of the amount of capacity that it must contract with to meet its LCR. Based on the average 2006 RMR capacity payments of $46.21/kW-yr ($2006), the ensuing benefit is $17M/year in 2015 dollars. The total reliability benefit is $110M/year.

c. Transmission Cost

The Sunrise project is assumed to cost $1.114 billion in 2006 dollars. After adjusting the costs to revenue requirement levels, and levelizing over 41 years, the annual cost of the project is $163 million.

d. Resource Adequacy (RA) Compliance Cost

We assume that there is no change in RA costs with the Sunrise alternative.

e. RPS Compliance Cost

Valuing CAISO loads at the LMP prices does not account for the CAISO's cost-based contract assumption in the implementation of RPS compliance. The renewable resource costs shown in

Table 7.2 reflect the cost difference between forecasted power contract costs and LMP payments made to the renewable generators (the "above LMP" cost). There are two scenarios to consider:

- Insufficient renewable resources to meet the RPS requirement. In this scenario, additional resources are assumed to be purchased at a cost of $36.9/MWh above the LMPs. This corresponds to a contract cost that is the same as the cost of buying renewable energy from the Salton Sea area. This scenario applies to the base case and South Bay repowering case.
- Surplus renewable energy beyond what is needed for RPS compliance. In this scenario, the surplus is assumed to be sold at its contract price, yielding a per MWH cost savings equal to the average difference between the renewable contract and LMP prices. This scenario applies to the Sunrise case and the Green Path + LEAPS cases,, but the amount of renewable energy surplus is minor.

For this scenario, we assume that additional renewable resources have the same contract cost as the Salton Sea resources. Therefore, there is no change in RPS compliance cost between the Sunrise and base case. The potential change in benefits due to changes in renewable resource costs is explored later in this testimony.

f. Net Benefit

The energy and reliability benefits of the Sunrise alternative total $250 M/year in 2015 dollars. Subtracting the levelized transmission cost of $163M/year results in a net benefit of $87M/year. There is no adjustment for above LMP cost of renewable resources.

Q. Using the Table 7.2, please summarize the cost-effectiveness results for the South Bay Repowering case when compared to the updated base case.

A. The benefits and costs of the South Bay Repowering Case are as follows:

a. Energy Benefits

The South Bay Repowering case adds a large local generator resource, but does not significantly alter the transmission grid, or increase San Diego's import capability. The reduction in customer payments due to lower LMPs is \$33M/year, and the change in utility and contracted generation margin is only \$12M/year. Finally, the changes in congestion costs and excess line loss payments are \$2M/year and \$5M/year decreases, respectively. The total energy benefit is \$13M/year.

b. Reliability Costs

The South Bay Repowering case reduces the need for new CT's in the area from 711MW in the updated base case to 106MW, providing plant and transmission cost savings of \$79M/ year. SDG&E, however, must contract with the South Bay plant for local capacity, at a cost of \$34M/year based on the 2006 RMR payments. The net effect is a benefit of \$45M/year.

c. RA Compliance Cost

We assume that no adjustment is required.

d. RPS Compliance Cost

The renewable resources available in the South Bay Repowering case are the same as in the base case. Hence, there is no change in RPS compliance cost compared to the base case.

e. Net Benefit

The total energy and reliability benefits of the South Bay Repowering alternative are \$58 M/year in 2015 dollars. Subtracting the levelized transmission interconnection cost of

$9M/year results in a net benefit of $49M/year. There is no adjustment for RPS compliance cost.

Q. Using the Table 7.2, please summarize the cost-effectiveness results for the (Green Path + LEAPS) case when compared to the updated base case.

A. The benefits and costs of this case are as follows:

a. Energy Benefits

The (Green Path + LEAPS) case expands renewable resources in the Salton Sea area, and provides an alternate transmission configuration to the Sunrise. The reduction in customer payments due to lower LMPs is $246 M/year, comparable to the Sunrise case. Similarly, the new generation and transmission configuration results in lower margins for the utility owned and contracted generation, which reduces the energy benefits by $87 M/year. The changes in congestion costs increase energy benefits by $2 M/year. The changes in excess loss payments reduce energy benefits by $5 M/year. The total energy benefit is $155M/year.

b. Reliability Costs

This case eliminates the updated base case's 711MW of new local CT's in 2015, providing plant and transmission cost savings of $93M/year. Remediation and reactive support, however, will be required at an additional cost of $10M/year. Moreover, San Diego's need for contracts to meet its LCR remains at the updated case's level, so there is no benefit for the LCR component. The total reliability benefit is $84M/year.

c. RA Compliance Cost

As with the Sunrise case, we assume that there is no change in cost for RA compliance.

d. RPS Compliance Cost

As with the Sunrise case, because we assume that additional renewable resources have the same contract cost as the Salton Sea resources, there is no adjustment for the above LMP cost of renewable resources.

e. Transmission Cost

This case's project is assumed to cost $1.35 billion in 2006 dollars. After adjusting the costs to revenue requirement levels, and levelizing over 41 years, the annual cost of the project is $198 million.

f. Net Benefit

The (Green Path + LEAPS) case has energy and reliability benefits of $ 239 M/year in 2015 dollars. Subtracting the levelized transmission interconnection cost of $198M/year results in a net benefit of $41M/year. There is no adjustment for the above LMP cost of renewable resources.

Q. In light of the difference in the updated analysis and the CSRTP (see Table 5.1), please discuss the impact of renewable energy costs on the estimation of net benefit.

A. Renewable energy procurement has two impacts on the net benefits:

- The renewable resources have costs that vary depending on the technology and location of the resource. If the new resources can be procured at costs lower (higher) than alternative sources, then there is positive benefit (cost) to consumers.
- There is an effect of long-term contracts on consumer surplus. Our analysis assumes that utilities sign long- term cost-based contracts for renewable energy. Under the LMP market structure, any differences between LMP payments to generators and contract prices are trued up through financial arrangements between the buyer and consumer. Therefore, to

the extent that LMPs decline for generators, which is anticipated with the addition of new low variable cost renewable resources, consumers will make higher true-up payments to the contracted generators. The true-up payments can partially erode the consumer benefits of the transmission upgrade.

Q. What is the effect of new transmission on renewable energy production in the Salton Sea area?

A. Both the Sunrise and (Green Path + LEAPS) alternatives provide access to new renewable resources in the Salton Sea area. Based on the estimates produced by GridView under the various transmission alternatives, Table 7.3 below shows the WECC-wide renewable energy output in 2015 from wind, geothermal, and solar thermal resources. This table shows that both the Sunrise and (Green Path + LEAPS) transmission investments are expected to increase 15 TWh of generation from geothermal and solar thermal resources.

Table 7.3 Renewable Resource Output in 2015 (GWh)

	Base Case and South Bay	Sunrise and Greenpath + LEAPS	Difference
Wind	20,589,634	20,589,634	(0)
Geothermal	20,014,858	34,031,059	14,016,201
Solar Thermal	2,388,999	3,915,156	1,526,157
Total	42,993,491	58,535,848	15,542,358

Q. In the updated analysis, how did the CAISO compute the RPS compliance cost?

A. Our computation uses the following steps:

- Step 1: Determine the state's total renewable energy requirement Assuming that the equivalent of 75% of the non-IOU California utilities would be purchasing renewable energy to voluntarily meet the 20% RPS requirement, the total renewable output produced by qualified renewable resources would need to reach 57,836 GWh.[19]

- Step 2: Determine if the RPS requirement is met in the following two scenarios:
  - New transmission in place, as in the Sunrise and (Green Path + LEAPS) cases. We find the RPS requirement is met in these cases.
  - No new transmission, as in the updated base case and South Bay Repowering case. Without renewable energy from the Salton Sea area, these two cases would need an additional 14,843 (57,836-42,993) GWh of renewable energy.
- Step 3: Develop the per MWh all-in cost for renewable energy bought to comply with the RPS target. The all-in cost of renewable energy would include the capital and operating cost of the renewable resource, plus transmission costs net of any energy and reliability benefits from the transmission work. Given time and resource limitations, we have made the following simplifying assumptions:
  - The renewable energy purchased to make up the 14,843 GWh shortfall would have the same mix of geothermal and solar energy shown in the difference column in Table 7.3.[20]
  - The all-in levelized costs of Salton Sea resources are as follows: wind \$66/MWh, geothermal \$86/MWh and Solar thermal \$120/MWh.[21] The weighted average cost is \$89.3/MWh.

---

[19] Based on GridView output of California Generation and 2004 sales by utilizes in California from EIA.

[20] A rigorous analysis would require assumptions on resource siting, transmission upgrades, and then require numerous GridView runs to evaluate the economic impacts of the incremental resources.

[21] These values are taken from the central estimates of the levelized cost of energy for different renewable technologies in the 2005 report "Achieving a 33% Renewable Energy Target," prepared for the CPUC by the Center for Resource Solutions, See p.44. These costs do not include transmission or integration costs.

  - Given the uncertainties surrounding renewable energy development, we postulate that the per MWh renewable cost for procuring the 14,843 GWh shortfall can be: (a) Low cost of \$81.2/MWh: 10% below \$89.3/MWh; (b) Same cost at \$89.3/MWh; and (c) High cost of \$98.3/MWh: 10% above \$89.3/MWh.

- Step 4: Find the per MWh cost of RPS compliance, the difference between the all-in cost for renewable energy and the average LMP price. Using the high case of\$98.3/MWh all-in cost and an average LMP of \$52.4/MWh,[22] the RPS compliance cost for the make-up renewable energy would be \$45.8/MWh. For the low case, an all-in cost of \$81.2/MWh results in an RPS compliance cost of \$28.8/MWh.

Q. What is the impact of the RPS compliance cost on net benefits?

A. Table 7.4 shows the total net benefits to CAISO consumers in 2015 by alternative resource plan and per MWh RPS compliance cost. This table indicates the following ranges of total net benefits when compared to the updated base case:

- Sunrise. The net benefit varies from -\$14M/year to \$197M/MWh. Hence, so long as the per MWh compliance cost is not 10% below the all-in levelized costs of Salton Sea resources , the project is likely cost-effective.
- South Bay Repowering. As the updated base case and South Bay case have the same renewable costs, the South Bay Repowering case's net benefit remains the same over the range of per MWh RPS compliance costs.

[22] We recognize that LMPs would likely change with the addition of make-up renewable resources. As we do not have GridView studies for alternate configurations, we assume that the generation LMPs with make-up renewable resources would be the same as the LMPs in the Sunrise case.

- (Green Path + LEAPS). The net benefit varies from -$60M/year to $141M/MWh. Hence, so long as the per MWh compliance cost is not 10% below the all-in levelized costs of Salton Sea resources, the project is likely cost-effective.

Although the above findings are driven entirely by a set of plausible procurement cost assumptions, they demonstrate that except for the case of low per MWh RPS compliance cost, Sunrise produces the largest amount of net benefits.

Table 7.4: Net benefits under alternate incremental renewable resource cost assumptions

	Per MWh RPS compliance cost range		
	Low (-10%)	No Change	High (+10%)
All-in renewable energy cost ($/MWh)	81.2	89.3	98.3
Above LMP cost ($/MWh)	28.8	36.9	45.8
Net Benefits ($M/year) (2015 dollars)			
Sunrise	$ (14)	$ 89	$ 197
South Bay Repowering	$ 49	$ 49	$ 49
(Green Path + LEAPS)	$ (60)	$ 41	$ 151

Q. What is the CAISO's plan to refine the RPS compliance cost?

A. The CAISO intends to refine the per MWh RPS compliance cost with a study based on estimates of an actual renewable energy development plan, including the cost of the plan, estimates of transmission costs, and energy and capacity values to California consumers. The findings from this study will be filed in Dr. Oran's supplemental testimony on February 16, 2007.

Q. Please compare these results to those in the CSRTP Report.

A. Table 6.15 of the CSRTP shows $187.96M in benefits for 2015 in 2006 dollars. Converting to 2015 dollars using a 2% inflation rate results in $224M/year of benefits. The corresponding value from this study is $250M/year. Hence, these two benefit estimates are similar, despite the significant input assumption differences between the updated base case and the cases in the CSRTP Report.

Q. Please compare these results those in the SDG&E 01/26/07 Update.

A. SDG&E estimates total energy and reliability benefits of $289.4M for 2015 (in 2015 dollars). The corresponding value from this study is $250M/year. As shown in Joint Exhibit A, the SDG&E case shows lower energy benefits, but higher reliability benefits.

8. NON-QUANTIFIABLE BENEFITS AND CONCLUSIONS.

Q. Does Sunrise provide other benefits that were not quantified as part of the reliability and economic assessments described in this testimony?

A. Yes, it does. The TEAM methodology contemplates non-quantifiable benefits associated with transmission projects.[23] . Such benefits associated with Sunrise were identified at pages 66-69 of the CSRTP Report, including:

- Providing much needed long-term improvement of an aging transmission infrastructure.
- Providing options for future expansion and “insurance” against unexpected high load growth in San Diego.
- Enabling more options for future strategic interconnections and ultimately the expansion of import capability.
- Facilitating the replacement of aging power plants in the San Diego area.

[23] *Opinion of Methodology for Economic Assessment of Transmission Projects*, *id*, 66.

- Encouraging local generation to repower and become more efficient by decreasing or eliminating SDG&E's dependence on CAISO backstop (RMR) contracts.
- Facilitating connection to the desirable types of renewable resources being developed in the Salton Sea area. Among renewable types, geothermal and solar are the most desirable type resources since they are both predictable and sustainable. These types of resources facilitate the operation of the power grid as well as the wholesale markets. From an operational perspective, the renewables at the Salton Sea are arguably "low hanging fruit";
- Replacing natural gas fired plants and therefore reduces both NOX emissions and Green House Gas effects. Less reliance on natural gas is beneficial to California since it diversifies its supply portfolio and reduces the State's exposure to the volatilities that are associated with the gas markets.

Q. What conclusions can be drawn from the economic and reliability studies described in this testimony?

A. Similar to the conclusion reached in the CSRTP Report, Sunrise appears to be the most cost effective means for achieving access to renewable generation and reliability goals identified at the beginning of this testimony. Furthermore, the CAISO's continued evaluation of Sunrise has refined our estimates of the energy and reliability benefits, but has not produced any information that changes our earlier conclusions that Sunrise will provide substantial net benefits to CAISO consumers. Our sensitivity analysis shows that unless there is a feasible alternative with 10 percent lower net costs of renewable procurement, the Sunrise project has the largest net benefits of the alternatives considered to date.

Nonetheless, the CAISO still has work to do and the results presented by this continued evaluation should be further analyzed. For example, the (Green Path + LEAPS) case provides access to the Salton Sea/Imperial Valley renewables, with energy and reliability benefits that are less than those of Sunrise.

The CAISO has more alternatives to evaluate in the upcoming months, and during this process will continue to refine its study methodologies and inputs. Once all of the studies have been completed, the CAISO will be in a better position to offer its final conclusions and recommendations.

Q. Does this conclude your Initial Testimony, Part 1?

A. Yes, it does.

ATTACHMENT 1

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)

PART I INITIAL TESTIMONIES OF

ARMANDO J. PEREZ
ROBERT SPARKS
DR. REN ORANS

SUBMITTED ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Anthony J. Ivancovich,
Assistant General Counsel - Regulatory
Judith B. Sanders,
Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
(916) 351-4400 - telephone
(916) 608-7222 - facsimile

January 26, 2007

STATEMENT OF QUALIFICATIONS OF
ARMANDO PEREZ

Q. Please state your name and business address.

A. My name is Armando (Armie) Perez and my business address is 151 Blue Ravine Road, Folsom, California 95630.

Q. Briefly describe your duties and responsibilities at the CAISO.

A. I am responsible for the review and approval of the yearly transmission plan that includes the PTO expansion plans (including, of course, SDG&E's request for evaluation of Sunrise), generator interconnection requests, determining reliability must-run (RMR) generation and LCR requirements to comply with RMR/LCR criteria, transmission maintenance activities and network computer applications including the State Estimator.

Q. Please summarize your educational and professional background.

A. I am a Senior Member of the Institute of Electrical and Electronic Engineers and am a registered Professional Electrical Engineer in the state of California. I have over 35 years of experience in electrical engineering, operations engineering , and transmission planning. Prior the coming to the ISO in 1997, I contributed in various capacities at Southern California Edison, fulfilling the position of Manager of Transmission Planning during my last years there. I have also been very active within the WECC and NERC organizations, including chairing WECC's Technical Studies and Reliability Subcommittees, WECC's Planning Coordination Committee, and NERC's Planning Standards Subcommittee.

Q. Does this conclude your statement of qualifications?

A. Yes, it does.

Q. Please state your name and business address.

A. My name is Robert Sparks and my business address is 151 Blue Ravine Road, Folsom, California, 95630.

Q. Briefly describe your duties and responsibilities at the CAISO.

A. One of my primary job responsibilities is to work with CAISO PTOs, state agencies, and Stakeholders to create a comprehensive long- term transmission expansion plan that is compatible with the long term resource plans of the load serving entities for California to ensure that facilities are in place as needed to economically provide wholesale electric service and to meet applicable reliability criteria. I became involved with the Sunrise evaluation process in late December 2006.

Q. Please summarize your educational and professional background.

A. I receive a Master of Science degree in Electrical Engineering from Purdue University in August 1989, and a Bachelor of Science degree in Electrical Engineering from California State University, Sacramento in June 1988. Immediately after graduation I joined PG&E's Transmission Planning Department and worked on California-Oregon Transmission Project design refinement studies, and QF interconnection studies. From March 1994 until November 1997 I worked in PG&E's System Operations Department initially as a Lead Operations Engineer and later as a Supervising Power System Engineer. In November 1997 I joined the California ISO as a Grid Planning Engineer. From December 2001 to August 2002 I worked for FPL Energy as the West Coast

Transmission Manager for transmission related issues associated with their various generation projects in the WECC. I rejoined the ISO in September 2002. I have over 16 years experience in electric transmission system planning and operations and am a registered Professional Engineer in the State of California.

Q. Does this conclude your statement of qualifications?

A. Yes, it does.

Ren Orans

ren@ethree.com 415.391.5100 ext. 312

Dr. Orans founded the consulting firm Energy and Environmental Economics (E3) in 1993. The firm specializes in energy economics and has nationally recognized experts in the fields of electricity pricing, integrated resource planning and regulatory theory and finance. Dr. Orans heads the electricity pricing practice for E3.

ENERGY & ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA

Managing Partner 1993 – Present

Dr. Orans' work in utility pricing and planning is centered on the design and use of area- and time-specific costs for electric utilities. The first successful application was conducted for Pacific Gas and Electric Company in their 1993 General Rate Case. Using costs developed by Dr. Orans, PG&E became the first electric utility to use area and time specific costing in its ratemaking process. This seminal work led to detailed area costing applications in pricing, marketing and planning for Wisconsin Electric Company, Niagara Mohawk Power Company, Public Service of Indiana, Kansas City Power and Light, Central and Southwest Utilities, Philadelphia Electric Company, Tennessee Valley Authority and Ontario Hydro. This work has been formalized in Dr. Orans' Dissertation, Area-Specific Costing for Electric Utilities, A Case Study of Transmission and Distribution Costs (1989) and a more recent NARUC report revising the California Standard Practice Guidelines for Evaluating DSM programs (2000).

Dr. Orans expertise in utility planning is complemented by his practical working experience at Pacific Gas and Electric Company (PG&E), where he was responsible for designing their electric utility rates between 1981 to1985. He has relied on this background, along with his published papers to provide expert testimony on transmission pricing on behalf of BC Hydro (1996, 1997 and 2004, 2005), Ontario Power Generation (2000) and Hydro Quebec (2001, 2006). Dr. Orans has also testified in stranded asset cases before the British Columbia Utilities Commission and the Texas PUC on behalf of BC Hydro and Central Power and Light, respectively. Dr. Orans was also PG&E's expert witness for avoided generation costs in their most recent rate case (2005) and is currently sponsoring testimony on electric rate design for both Hawaiian Electric Company and Lower Valley Energy.

DEPARTMENT OF ENERGY Washington, DC
NATIONAL RENEWABLE ENERGY LABORATORY 1992 – 1993
ELECTRIC POWER RESEARCH INSTITUTE

Lead Consultant

Developed new models to evaluate small-scale generation and DSM placed optimally in utility transmission and distribution systems.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA

Research and Development Department 1989 – 1991

Developed an economic evaluation method for distributed generation alternatives. The new approach shows that targeted, circuit-specific, localized generation packages or targeted DSM can in some cases be less costly than larger generation alternatives. Developed the evaluation methodology that led to PG&E's installation of a 500KW photovoltaic (PV) facility at their Kerman substation. This is the only PV plant ever designed to defer the need for distribution capacity.

ELECTRIC POWER RESEARCH INSTITUTE Palo Alto, CA
1988 – 1992

Developed the first formal economic model capable of integrating DSM into a transmission and distribution plan; the case study plan was used by PG&E for a $16 million pilot project that was featured on national television.

DEPARTMENT OF ENERGY Washington, DC
1989 – 1990

Lead consultant on a cooperative research and development project with the People's Republic of China. The final product was a book on lessons learned from electric utility costing and planning in the United States.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Corporate Planning Department 1989 – 1992
Lead consultant on a joint EPRI and PG&E research project to develop geographic differences in PG&E's cost-of-service for use in the evaluation of capital projects. Developed shared savings DSM incentive mechanisms for utilities in California.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Rate Department Economist 1981 – 1985
Responsible for the technical quality of testimony for all electric rate design filings. Also responsible for research on customers' behavioral response to conservation and load management programs. The research led to the design and implementation of the first and largest residential time-of-use program in California and a variety of innovative pricing and DSM programs.

Education

STANFORD UNIVERSITY Palo Alto, CA
Ph.D. in Civil Engineering

STANFORD UNIVERSITY Palo Alto, CA
M.S. in Civil Engineering

UNIVERSITY OF CALIFORNIA Berkeley, CA
B.A. in Economics

Refereed Papers

1. *Orans, R., Woo, C.K., Horii, B., Moore, J., "CPP as default rate: fair or folly?" Electricity Journal, Forthcoming.*

2 *Lusztig, C., P. Feldberg, R. Orans and A. Olson (2005) "A survey of transmission tariffs in North America," Energy-The International Journal.*

3 *Woo, C.K., A. Olson and R. Orans (2004), "Benchmarking the Price Reasonableness of an Electricity Tolling Agreement," Electricity Journal, 17:5, 65-75.*

4 *Orans, R., Woo, C.K., Clayton, W. (2004) "Benchmarking the Price Reasonableness of a Long-Term Electricity Contract," Energy Law Journal, Volume 25, No. 2.*

5 *Orans, R., Olson, A., Opatrny, C., Market Power Mitigation and Energy Limited Resources, Electricity Journal, March, 2003.*

6 *Chow, R.F., Horii, B., Orans, R. et. al. (1995), Local Integrated Resource Planning of a Large Load Supply System, Canadian Electrical Association.*

6 *Feinstein, C., Orans, R. (1995) "The Distributed Utility Concept," The Annual Energy Review,1988.*

7 *Woo, C.K., R. Orans, B. Horii and P. Chow (1995), "Pareto-Superior Time-of-Use Rate Options for Industrial Firms," Economics Letters.*

8 *Woo, C.K., B. Hobbs, Orans, R. Pupp and B. Horii (1994), "Emission Costs, Customer Bypass and Efficient Pricing of Electricity," Energy Journal, 15:3, 43-54.*

9 *Orans, R., C.K. Woo, R. Pupp and I. Horowitz (1994), "Demand Side Management and Electric Power Exchange," Resource and Energy Economics, 16, 243-254.*

10 *Pupp, R., C.K.Woo, R. Orans, B. Horii, and G. Heffner (1995), "Load Research and Integrated Local T&D Planning," Energy - The International Journal, 20:2, 89-94.*

11 *Woo, C.K., R. Orans, B. Horii, R. Pupp and G. Heffner (1994), "Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," Energy - The International Journal, 19:12, 1213-1218.*

12 *Orans, R., C.K. Woo and B. Horii (1994), "Targeting Demand Side Management for Electricity Transmission and Distribution Benefits," Managerial and Decision Economics, 15, 169-175.*

13 *Orans, R., C.K. Woo and R.L. Pupp (1994), "Demand Side Management and Electric Power Exchange," Energy - The International Journal, 19:1, 63-66.*

14 *Orans, R., Seeto, D., and Fairchild, W., (1985), "The Evolution of TOU Rates," Pergamon Press*

Research Reports

1. Orans, R. Olson, A., Integrated Resource Plan for Lower Valley Energy, December, 2004.

2. *Orans, R., Woo C.K., and Olsen, Arne, Stepped Rates Report, prepared for BC Hydro and filed with the BCUC, May, 2003.*

3. *Orans, R., Woo, C.K, and B. Horii (1995), Impact of Market Structure and Pricing Options on Customers' Bills, Report submitted to B.C. Hydro.*

4 *Horii, B., Orans, R., Woo, C.K., (1994) Marginal Cost Disaggregation Study, Report submitted to PSI Energy.*

5 *Woo, C.K., L. Woo and R. Orans (1995), Rationing and Area-Specific Generation Costs, Report submitted to Pacific Gas and Electric Company.*

6 *Orans, R., C.K. Woo and C. Greenwell (1994), Designing Profitable Rate Options Using Area- and Time-Specific Costs, Report No. TR-104375, Electric Power Research Institute.*

7 *Singer, J., Orans, R., Energy Efficiency Lending, A Business Opportunity for Fannie Mae, Report submitted to Fannie Mae.*

8 *Orans, R., Feinstein, C. et. al., (1993), Distributed Utility Valuation Study, submitted to the Electric Power Research Institute, the National Renewable Energy Laboratory, and PG&E.*

9 *Orans, R., Pupp, R., (1993), Menomonee Falls Case Study, Submitted to Wisconsin Electric Power Corporation.*

10 *Orans, R. and C.K. Woo (1992), Marginal Cost Disaggregation Study, Report submitted to Wisconsin Electric Power Corporation.*

11 *Orans, R., C.K. Woo, J.N. Swisher, B. Wiersma and B. Horii (1992), Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District, Report No. TR-100487, Electric Power Research Institute.*

12 *Orans, R., Swisher, J., Duane, T., (1989), Lessons Learned from U.S. Electric Utilities, Prepared for the Department of Energy for the Peoples Republic of China.*

13 *Orans, R., Area-Specific Marginal Costing for Electric Utilities: A Case Study of Transmission and Distribution Costs (1989) PhD Thesis, Stanford University.*

14 *Orans, R., (1987)The Risk of Sales Forecasts: Controllable through Indexation and Careful Disaggregation, Submitted to Stanford University and Pacific Gas and Electric Company.*

15 *Woo, C.K. and R. Orans (1983), Transferability of Other Utilities' Time of Use Experiments to PG&E's Service Schedule D-7, Pacific Gas and Electric Company Reports filed with the California Public Utilities Commission.*

Conference Papers

1 *Orans, R. Evaluating Generating Resources based on a Eqivalent Reliability Methodology, 2nd Annual Resource Planning Symposium, January, 2004, Vancouver, Canada.*

2 *Martin, J., Orans, R., Knapp, K., "DG Economics and Distribution Rate Design" (2000), Western Electric Power Institute, Distributed Generation and the Utility Distribution System Conference, March 22-23, Reno, NV.*

3 *Orans, R. (1997), "Getting the Transmission Prices Right," Facilitating Cross Border Trade, New Mexico.*

4 *Orans, R. (1997), "Deregulation on the Mainland, What is Happening and What is Not, PCEA Conference, Hawaii.*

5 *Swisher, J., Orans, R., (1995), "A New Utility DSM Strategy Using Intensive Campaigns Based on Area Specific Costs," ECEEE 1995 Summer Study.*

6 *Orans, R., Greenwell, C., (1995), "Designing Profitable Rate Options Using Area and Time-Specific Costs," Prepared for EPRI, Annual DSM Review, Dallas, Texas.*

7 *Orans, R, Integrated Local Area Planning, (1995), Prepared for NELPA and presented in Calgary.*

8 *Orans, R., Local Area Planning for Profit, "Annual Review of Distributed Resource Studies," Prepared for EPRI, Lake George, New York.*

9 *Orans, R., C.K. Woo, B. Horii and R. Pupp, (1994), "Estimation and Applications of Area- and Time-Specific Marginal Capacity Costs," Proceedings: 1994 Innovative Electricity Pricing, (February 9-11, Tampa, Florida) Electric Research Power Institute, Report TR-103629, 306-315.*

JOINT EXHIBIT A

Exhibit A

Joint SDG&E/CAISO Exhibit
Comparing the Analyses of the Sunrise Powerlink
Conducted by SDG&E in Support of its January 26, 2007 Supplemental Testimony
and by the CAISO in Support of its January 26, 2007 Testimony

The November 1, 2006 *Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling* directs SDG&E and the CAISO to

> "develop a jointly-sponsored exhibit that provides a comparison between their respective assessment methodologies, computer models, critical assumptions, scenarios, sensitivity cases, and results. This exhibit shall identify any and all significant differences between the two assessments, and discuss the sensitivity of the results to each of these differences." (page 11)

1.0 SDG&E's Assessment Methodology

SDG&E's assessment of the Sunrise Powerlink is comprised of two principle components, a reliability assessment and an economic assessment. The reliability assessment includes technical analysis whereby the Sunrise Powerlink and transmission alternatives are subjected to contingencies, assuming stressed system conditions, as prescribed by applicable NERC, WECC and CAISO reliability criteria. The technical analysis includes thermal powerflow studies, post transient voltage analysis, and transient stability analysis. The results of the technical analysis are used to define the plan of service for the Sunrise Powerlink and transmission alternatives, as well as to identify import capabilities into the San Diego area given these plans of service.

SDG&E's economic assessment follows the CAISO's Transmission Economic Assessment Methodology (TEAM). It is designed to identify the relative economic benefits to CAISO consumers of adding the Sunrise Powerlink in comparison to other transmission, generation and demand management alternatives. For purposes of comparison, SDG&E's supplemental testimony employs an in-area gas turbine build out reference case. SDG&E projects the costs, both variable and fixed, associated with the gas turbine reference case, the Sunrise Powerlink case, and each of the alternatives cases, over the life-cycle of the respective projects and alternatives. The costs for the Sunrise Powerlink case, and each of the alternatives cases, are compared to the costs for the in-area gas turbine reference case to develop relative levels of estimated benefits.

The economic assessment estimates benefits and costs in four major categories.

(1) Grid efficiency benefits which are essentially the net affect on CAISO consumers' commodity charges after accounting for the market clearing price for electricity, the CAISO utility-owned producer surplus which is returned to CAISO consumers, and CAISO congestion rents which are also credited to CAISO consumers. Grid efficiency benefits are computed by comparing the results for the gas turbine reference case to the results for the Sunrise Powerlink and alternatives.

(2) Reliability Must Run (RMR) contract savings capture the affect on the costs that are incurred to mitigate the ability of generators in defined load pockets—the San Diego area in this case—to exercise undue local market power. While RMR contracts are likely to be phased-out in the future, above-market costs will nonetheless still be incurred to mitigate the ability of generators in load pockets to exercise undue local market power. The RMR analysis employed for SDG&E's supplemental testimony is used as a proxy methodology for estimating these costs. RMR contract savings are computed by comparing the results for the gas turbine reference case to the results for the Sunrise Powerlink and alternatives.

(3) Avoided capacity costs represent the fixed costs of the new in-area gas turbines included in the reference case that will not have to be built if the Sunrise Powerlink or any of the other alternatives is put in place.

(4) The fixed costs of the Sunrise Powerlink and each of the alternatives studied. Where the alternative under consideration does not meet the San Diego area local reliability requirements (application of the CAISO's G-1/N-1 reliability criteria assuming one-in-ten year (90/10) peak load conditions), in-area gas turbines are added to close the reliability gap. The fixed costs of these gas turbines are added to the fixed costs of the alternative under consideration.

The levelized total savings associated with the first three categories is then divided by the levelized fixed costs associated the last category to compute the respective benefit/cost ratios for the Sunrise Powerlink and alternatives.

2.0 CAISO's Assessment Methodology

The CAISO's assessment methodology is generally consistent with SDG&E's. In its role of reviewing and approving the project, however, the CAISO has the objective to validate and verify the plan of service and the benefits of the proposed project.

The first part of the CAISO verification process is a reliability analysis, similar to the one done by SDG&E. This analysis has two steps:

- Step 1: Simulate the reliability problem identified by SDG&E and estimate the magnitude of the reliability deficiency. This is done by analyzing the reference

case without the Sunrise Powerlink project and any other mitigation projects not currently planned.
- Step 2: Test if the proposed project can adequately resolve the identified reliability problem. This process was repeated for the alternative scenarios.

The second part of the CAISO verification process is an economic analysis. The CAISO continues to rely on its Transmission Economic Assessment Methodology (TEAM) approach to estimate the benefits and costs of the Sunrise Powerlink project and other feasible alternatives. As such, the CAISO also uses the GridView model to compute nodal market prices under a range of scenarios.

The key differences between the CAISO's approach and SDG&E's are as follows:

1. SDG&E assumes the presence of new renewables located in the Salton Sea and Imperial Valley areas in both the base case (SDG&E's in-area gas turbine reference case) and Sunrise Powerlink cases. In contrast, the CAISO's base case does not model the presence of new renewables in these areas because the CAISO assumed that without Sunrise Powerlink, these resources would not be developed to a significant level. The CAISO's comparison of base case and Sunrise Powerlink cases will show larger energy benefits than SDG&E's analysis. This is because in the CAISO's analysis the combination of the transmission project plus the new low variable cost generation resources in the with Sunrise Powerlink case results in lower consumer costs than in the CAISO's base case where it is assumed the renewable resources would not be developed. SDG&E's analysis, in contrast, assumes these low variable cost renewable resources are available in both the base case and in the with Sunrise Powerlink case. The CAISO's analysis also includes a RPS compliance cost, expressed as a $/MWh adder. The cost adder is the estimated per MWh difference between the renewable contract costs and the LMP payments received by the renewable energy producers.
   - Although both SDG&E and the CAISO assume sufficient CT capacity to maintain reliability in their base cases, there is a difference in their estimation methods relating to transmission system resistive losses, and 29 MW of demand response that was assumed by SDG&E but not the CAISO.
2. Both SDG&E and the CAISO dispatch renewable resources based on their variable costs. The margin (= LMP revenue – total variable cost) from renewable energy production was treated the following way. The CAISO assumed that the renewable resource generators have cost-based contracts that include competitive returns for merchant units and regulated returns for utility-owned units. As these contracts are assumed to be paid for by electricity consumers in California, there is no renewable energy profit to offset the bills of electricity consumers, even if all of the renewable generation units are owned by utilities. SDG&E treated renewable generation resources the same way as other merchant generation. However, SDG&E modeled higher operational costs for the geothermal resources compared with the costs assumed by the CAISO.
3. The CAISO analysis has separate estimates for the RPS compliance cost [by resource plan. SDG&E's analysis does not.

The estimated benefits and costs in the CAISO's evaluation can also be categorized into the same four major categories used by SDG&E, with the addition of a fifth category for the incremental cost of RPS compliance.

(1) Grid efficiency benefits reflect a resource plan's net dollar effect, relative to the reference case, on CAISO consumers' commodity charges. The computation accounts for the CAISO loads at market clearing nodal prices, producer surplus from the CAISO utility-owned generators and CAISO congestion rents which are also returned to CAISO consumers. However, the CAISO excludes energy benefits that might flow to loads of non-CAISO consumers (e.g., SMUD). Also, the CAISO offsets a portion of the grid energy benefits due to the fact that customers would receive a credit or refund to reflect the difference between marginal and average losses.

(2) The cost to meet local capacity requirements are calculated with and without Sunrise in place. The CAISO uses average 2006 Reliability Must Run (RMR) contract payments as a proxy for the local capacity requirement contract costs.

(3) Avoided capacity costs represent the capital costs of the new in-area gas turbines (both plant cost and transmission interconnection and reconfiguration costs) included in any case that requires additional in area generation beyond what is already in place.

(4) The capital costs of the Sunrise Powerlink and each of the alternatives studied are the same as those proposed by SDG&E.

(5) Incremental cost to meet RPS standard for CA utilities with and without the Sunrise project.

3.0 Computer Models used by SDG&E

The technical analysis conducted by SDG&E used General Electric's PSLF Version 15.1 to perform the contingency analysis required by NERC, WECC and the CAISO.

To estimate the grid efficiency benefits associated with the addition of the Sunrise Powerlink and alternatives, SDG&E performed hourly simulations of the entire WECC electric system (all generation, load, and transmission elements within the WECC) for three years (2010, 2015 and 2020). SDG&E used ABB's GridView model, version 3.4, to conduct these simulations. SDG&E used strategic bid mark-ups in the GridView calculations to reflect the potential for independent power producers' to bid their output above each unit's respective variable operating cost.

No other specialized "models" were used in SDG&E's economic analysis although numerous Excel spreadsheets were developed to capture simulation results, interpolate and extrapolate benefits, and to project the revenue requirements associated with the various capital investments.

4.0 Computer Models used by the CAISO

The CAISO's technical analysis uses General Electric's PSLF Version 15.1 to perform the contingency analysis required by NERC, WECC and the CAISO.

To estimate the grid efficiency benefits associated with the addition of the Sunrise Powerlink and alternatives, the CAISO uses ABB's GridView model, version 3.5 to perform hourly simulations of the entire WECC electric system (all generation, load, and transmission elements within the WECC) for three years (2010, 2015 and 2020). In contrast to the SDG&E assumptions, in the latest studies, the CAISO did not assume any bid mark-ups from the generation units. The July 28, 2006 *CAISO South Regional Transmission Plan for 2006 (CSRTP-2006), Findings and Recommendation on the Sun Path Project* (CSRTP report) provided an estimate of the sensitivity of this parameter on the overall benefits of the Sunrise project.

No other specialized "models" are in the CAISO's economic analysis, although the CAISO applies Excel to capture simulation results, interpolate and extrapolate benefits, and project the revenue requirements associated with the various capital investments.

As was mentioned above, in the grid efficiency benefits calculations, the CAISO used version 3.5 of the ABB GridView program, and SDG&E used an earlier version 3.4. In version 3.5, ABB improved the algorithms for optimizing the operation of pump-storage-generation plants. With this optimization option, the Pumped storage (PS) dispatch is determined by a local LMP price curve; the pump storage plants primarily are pumping at low price, and generating at high price. The generation and pumping are optimized based on forecast Locational Marginal Prices (LMPs) that would be paid when the pumped-storage-generation facilities are in generating mode and charged when the facilities are in a pumping mode. In version 3.5, improvements have been made for calculating the forecast LMP price curve. The change between those two versions represents a fine-tuning of the pump-storage-generation dispatch logic for optimization purposes. The SDG&E and CAISO models of the pump-storage-generation facilities use different parameters; the CAISO model had the latest updates recommended by ABB. The CAISO will continue to review the pump-storage-generation modeling assumptions with SDG&E and ABB.

5.0 Key Assumptions Underlying SDG&E's Supplemental Testimony

5.1 Load Growth

San Diego area – SDG&E used "the most recent Commission-adopted…base case forecasts of loads…" This is the CEC's updated San Diego area load forecast for year 2007, which was made in June, 2006, extrapolated through year 2020 as directed by the Commission in its September 25, 2006 document entitled

ATTACHMENT A, 2006 Long-Term Procurement Plan Filing Outline, Draft 9/20/2006.

Remainder of WECC – SDG&E used the regional load forecasts for year 2015 as contained in the WECC economic database (vintage January, 2006). Loads for years 2010 and 2020 were estimated using regional load growth rates contained in the WECC's 2005 ten-year plan.

<u>5.2 Energy Efficiency Impacts in the San Diego Area</u>
SDG&E's Supplemental Testimony assumes the energy efficiency impacts incorporated in SDG&E's December 11, 2006 *EXHIBITS, 2007-2016 LONG-TERM PROCUREMENT PLAN* (LTTP) filing are consistent with the assumptions used by the CEC to update the year 2007 demand forecast. The energy efficiency impacts are based on the Commission's targets for 2010 through 2013 as adopted in D.04-09-060.

<u>5.3 Distributed Generation Impacts in the San Diego Area</u>
SDG&E's Supplemental Testimony includes the Distributed Generation (DG) impacts incorporated in SDG&E's December 11, 2006 LTTP filing. These impacts are based on the Commission direction provided in D.04-12-048, which, in ordering paragraph 11, requires utilities to "adhere to the directives for reflecting DG estimates in load forecasting consistent with D.01-04-050 and D.04-10-035…"

<u>5.4 Demand Response Impacts in the San Diego Area</u>
SDG&E's Supplemental Testimony includes the committed demand response program impacts (29 MW) that the CAISO counts as contributing to the San Diego area local reliability requirements. SDG&E has also evaluated a sensitivity, which adds the projected impacts of SDG&E's Automated Metering Infrastructure (AMI) program. The AMI program, if approved by the Commission, is expected to subsume the impacts of the Commission's adopted 5% demand response target.

<u>5.5 California Solar Initiative (CSI) Impacts in the San Diego Area</u>
SDG&E's Supplemental Testimony includes projected impacts of the 3000 MW CSI within the San Diego area. SDG&E assumes that upon full implementation the CSI could reduce peak loads in the San Diego area by 150 MW.

<u>5.6 Resource Additions</u>
San Diego area – SDG&E used the committed resource additions for the San Diego area as shown in SDG&E's December 11, 2006 LTTP.

Remainder of WECC – SDG&E used the WECC economic database (vintage January, 2006) for new resource additions through year 2015. For year 2020 SDG&E estimated new resource additions by assuming installed conventional generating capacity would grow by the amount of load growth between year 2015 and 2020 plus 16% to account for planning reserve margins. The technology and geographic dispersion of this new conventional generating capacity was based on the new generation additions contained in WECC's 2005 ten-year plan for the period 2005 through 2014.

SDG&E has also adjusted the type of new resource additions shown in the WECC economic database for the Palo Verde area. The WECC economic database contains 2700 MW of new resource additions in the Palo Verde area. This total is comprised of 1500 MW of new gas turbine generating capacity and 1200 MW of new combined cycle generating capacity. Consistent with the CAISO's July 28, 2006 CSRTP report, SDG&E has changed the amount of new combined cycle generating capacity in the Palo Verde area to 2500 MW and the amount of new gas turbine generating capacity to 200 MW. The total of new resource additions in the Palo Verde area remains at 2700 MW.

5.7 Resource Retirements

SDG&E's Supplemental Testimony uses the resource retirement assumptions embedded in the WECC economic database (vintage January, 2006). In addition, SDG&E's Supplemental Testimony assumes the existing South Bay power plant (702 MW) is retired at the end of year 2009.

5.8 Renewable Resource Goals

California has adopted the goals that 20% of the state's retail energy requirements in year 2010, and 33% by year 2020, will be met with renewable energy. SDG&E, as a load serving entity, has the responsibility to meet its proportional share of this goal with respect to its bundled customer load. The Company expects to meet these goals but is concerned about the cost of doing so were the Sunrise Powerlink not built.

For purposes of the economic analysis conducted for the Sunrise Powerlink, SDG&E assumes the same quantity, mix, location and timing of renewable resource additions in all cases including the in-area gas turbine reference case. This approach simplifies the analysis because there is no need to speculate about how California renewable resource goals will be met without the Sunrise Powerlink.

The quantity, mix, location and timing of the renewable resource additions assumed by SDG&E for the Sunrise Powerlink Supplemental Testimony are a combination of the additions shown in the WECC economic database (vintage January, 2006) outside of the Imperial Valley, additional amounts of new geothermal generating capacity as identified by the Imperial Valley Study Group for the Imperial Valley, and anticipated solar thermal generating capacity in the Imperial Valley as reflected in purchased power contracts signed by SDG&E (and related options).

The quantity, mix, location and timing of the renewable resource additions in the Imperial Valley assumed by SDG&E for purposes of its Supplemental Testimony is as follows: 785 MW of geothermal additions by year 2010 and another 1000 MW between years 2010 and 2015; 300 MW of solar thermal additions by year 2010 and another 600 MW between years 2010 and 2015; and 21 MW of wind generating capacity by year 2010. SDG&E assumed no incremental renewable resource additions in the Imperial Valley between the years 2015 and 2020.

5.9 Transmission Additions

SDG&E incorporated the new transmission additions included in the WECC economic database (vintage, January, 2006), plus other transmission upgrades internal to the Imperial Irrigation District (IID) system identified by the Imperial Valley Study Group (IVSG) that would be associated with the expected development of new geothermal resources in the Imperial Valley.

The analysis conducted in support of SDG&E's supplemental testimony also assumes the ratings of the Navajo-Crystal and El Dorado-Moenkopi 500 kV lines will be raised above currently announced levels. This rating increase is based on high levels of congestion observed on these lines. SDG&E believes that given the high levels of congestion, it is reasonable to assume that projects will be initiated to increase the ratings of these lines.

5.10 San Diego Area Transmission Limits

For each case studied by SDG&E from an economic perspective, an estimate of the maximum amount of power which can be imported into the San Diego area under two conditions has been developed. The first condition is the all-lines-in-service contingency condition (N-0), which provides the maximum imports that can be reliably accommodated *in anticipation of* the most severe contingency (normally the outage of the Imperial Valley-Miguel 500 kV line). This import capability is used in the simulations that identify, for each case studied, the hourly economic results from least cost dispatch of the entire WECC grid.

The second condition is the G-1/N-1 contingency condition which provides the maximum imports that can be reliably accommodated following the outage of the largest in-area generator (G-1), the outage of the most critical transmission element (normally the outage of the Imperial Valley-Miguel 500 kV line which is the N-1 contingency), and the system readjusted *in anticipation of* the next most severe contingency. This import capability is used to identify, for each case studied, the quantity of in-area generation that needs to be added in order to satisfy the CAISO's G-1/N-1 reliability criteria assuming one-in-ten year ("90/10") weather conditions.

Tables 1 through 6 show the N-0 and G-1/N-1 San Diego area import capabilities for the case 200 and case 201 studied by SDG&E.

SDG&E has also modeled the effects of the Miguel area import nomogram and has included limitations on the outlet capability from Miguel substation. The Miguel area import nomogram relates maximum flows into Miguel substation on the Imperial Valley-Miguel 500 kV line to the quantity of generation directly connected to Imperial Valley substation. This nomogram allows more imports into Miguel substation when more directly-connected generation at the Imperial Valley is on-line. SDG&E has also modeled the 1900 MW outlet capability of Miguel substation. This limit is established by a number of line, transformer and bus limitations on the Miguel substation outlet facilities.

5.11 WECC Regional Fuel Prices

The regional fuel prices used in the hourly economic simulations performed by SDG&E for its Supplemental Testimony are, with one exception, those contained in the WECC economic database (vintage January, 2006) for year 2015. These fuel prices include both coal and natural gas. SDG&E understands that the fuel prices in the January, 2006 WECC economic database are in constant year 2005$. SDG&E has assumed that the constant dollar fuel prices in years 2010 and 2020 will be the same as in year 2015.

The one exception to use of the fuel prices contained in the WECC economic database is that SDG&E modified certain of the regional gas prices to reflect the published gas transportation rate between the Arizona border and the San Diego area. The WECC economic database reflects an approximate $0.20/MMBTU average annual price difference (Arizona gas prices being $0.20/MMBTU lower than San Diego area gas prices). The published gas transportation rate is $0.435/MMBTU. Using the published gas transportation rate, SDG&E has developed revised natural gas prices for the WAPA L.C., IID, Mexico, San Diego, SCE, LADWP, PG&E, Sierra, and Nevada regions.

5.12 Heat Rates for Gas- and Coal-Fired Generation

SDG&E's Supplemental Testimony uses the heat rates included in the WECC economic database (vintage January, 2006) for gas- and coal-fired generators, with the exception of the older gas-fired boiler units in California and the new vintage of combined cycle units throughout the WECC. SDG&E has replaced the incorrect heat rates contained in the WECC economic database for the older gas-fired boiler units in California, with the heat rates shown in the CEC's aging power plant study (the result of this replacement is reduced fuel conversion efficiency).

In addition, SDG&E has replaced the heat rates contained in the WECC economic database for the newer vintage of combined cycle units with heat rates more typical of actual operating experience (the result of this replacement is increased fuel conversion efficiency).

5.13 San Diego Area RMR Costs

The RMR costs included in SDG&E's supplemental testimony are based on an assessment of which in-area merchant generators would need to be subjected to contracts in order to mitigate their ability to exercise undue local market power (or, equivalently, to provide a revenue stream sufficient to keep the units from retiring thereby aggravating other units' ability to exercise undue market power). The above-market costs of these contracts are estimated based on a unit-specific analysis that relies on historical as well as projected information.

6.0 Key Assumptions Underlying the CAISO's January 26, 2007 Testimony

The Load Growth, Energy Efficiency, Distributed Generation, and CSI assumptions used by the CAISO were the same as those used by SDG&E. However, the CAISO did not perform a sensitivity analysis on SDG&E's AMI program. In addition, CSI impacts on the PG&E and SCE systems were also included in the CAISO analysis. It is expected that the CSI impacts in the PG&E and SCE systems would slightly reduce the benefits of the proposed Sunrise Powerlink project.

In the energy benefit calculations, the SDG&E and CAISO assumptions regarding new generation additions were largely the same. The main exceptions is that all of the CAISO cases included new wind (4350 MW) and thermal (612 MW) generation in the Tehachapi area modeled together with the associated transmission upgrades recently approved by the CAISO and the SDG&E cases did not model any new wind generation in Tehachapi. This assumption for Tehachapi wind generation was consistent across the four cases run by the CAISO for its testimony filed on January 26, 2007. Assuming that there will be no wind generation in Tehachapi would make Sunrise project benefits higher than if there were Tehachapi wind generation.

The other renewable resource difference is that the CAISO assumed that without the Sunrise transmission project or other major transmission projects in the area, new development of renewable resources in the Salton Sea and Imperial Valley areas would be severely limited. Therefore, in the updated base case no new renewable generation was added to the Salton Sea and Imperial Valley areas. Instead, the CAISO's base case assumes that renewable development would occur elsewhere at some currently unknown location. Given the uncertainty of the alternative locations, the alternative renewable generation was not explicitly modeled in the analysis.

Resource Retirement assumptions were the same for both the CAISO and SDG&E analyses.

Generally the assumptions on Transmission Additions are common between the CAISO and SDG&E. However, the CAISO leaves the ratings of the Navajo-Crystal and El Dorado-Moenkopi 500 kV lines at the currently announce levels. This difference leads to more congestion on these facilities in the CAISO results than in the SDG&E results, possibly reducing the quantified benefits of the proposed Sunrise project in the CAISO analysis. Constraints on these facilities, which would operate in parallel with the proposed Sunrise project, could potentially limit the combined simultaneous transmission flows from Arizona and Nevada to Southern California. With these constraints removed, it is possible to have more combined economic power transfers, raising the benefits of the Sunrise Powerlink project. In other words, the combined benefits of both upgrades (Sunrise Powerlink and the parallel facilities discussed above) could be higher than the simple sum of the benefits of Sunrise Powerlink alone and the upgraded parallel facilities alone.

The CAISO assumptions on the fuel prices are different from the SDG&E assumptions. The CAISO used the fuel prices based on an assumed natural gas cost of $7/MMBTU at Henry Hub. All fuel prices used by the CAISO were the same as were used in the WECC database. SDG&E has modified gas prices and had higher differential between gas prices in California and Arizona. In the SDG&E cases, the cost of gas in all California areas, as well as in Nevada, Sierra, Mexico and southern Colorado was increased by 3.4% compared with the prices used by the CAISO. This created $0.435/MMBTU price differential between Southern California and Arizona versus $0.20/MMBTU differential used in the CAISO cases and in the WECC database. Such difference in gas prices raised Sunrise's benefits in the SDG&E case.

The CAISO used the heat rate assumptions from the latest WECC database. These assumptions were developed in August 2006. SDG&E used the heat rate assumptions from the January 2006 version of the database, but corrected errors in the California gas-fired boiler heat rates by using the heat rates based on the CEC's aging power plant study. Also, SDG&E changed the heat rates for the newer vintage of combined cycle units to reflect their own operating experience to about 7100 BTU/kWh at full load. The updated heat rates in the latest WECC database also corrected some errors and used the more refined data. As a result, there was significant difference in the heat rates for some generators, mainly in the first and second blocks. It is not clear what impact it might have on the benefits of the Sunrise project.

For the economic analysis, the CAISO assumed that CT's could be installed at a cost of $78/kW-yr ($2006), plus the CT-related transmission costs identified by SDG&E in their base case. Local capacity requirement costs are assumed to be avoidable at a savings of $46.21/kW-yr ($2006).

7.0 Scenarios and Sensitivity Cases

Reliability Assessment Scenarios (SDG&E)

- Sunrise Powerlink
- Mexico Light
- SONGS Light
- LEAPS
- Second SWPL
- LADWP Greenpath North

Reliability Assessment Scenarios (CAISO)

The following reliability scenarios were run for 2015 only:

- Reference Case (with only planned transmission and generation)
- Sunrise Powerlink
- South Bay Repowering
- Green Path North and LEAPS

Economic Assessment Scenarios (SDG&E)

- Case 200 (base in-area gas-turbine reference case)
- Case 230 (low demand in-area gas-turbine reference case)
- Case 240 (in-area gas turbine/AMI COMBO reference case)
- Case 220 (in-area gas-turbine reference case without bid mark-ups)

- Case 201 (with Sunrise Powerlink case)
- Case 204 (in-area combined cycle generation alternative)

- Case 203 (Talega-Escondido/Valley-Serrano – Lake Elsinore Advanced Pumped Storage (LEAPS) project transmission alternative)

- Case 208 (LADWP/IID Green Path North project transmission alternative)
- Case 209 (ENPEX Combined Cycle generation alternative)
- Case 210 (South Bay Combined Cycle generation alternative)
- Case 211 (Mexico-lite/AMI COMBO integrated wires/non-wires alternative)
- Case 212 (New 500 kV line parallel to SWPL transmission alternative)
- Case 221 (Sunrise Powerlink without bid mark-ups)
- Case 231 (Sunrise Powerlink with low demand)
- Case 241 (Sunrise Powerlink/AMI COMBO)

Economic Assessment Scenarios (CAISO)

The following economic assessment scenarios were run for 2015 only:

- Reference Case (with gas-turbines need to meet local capacity requirements)
- Sunrise Powerlink
- South Bay Repowering (with gas-turbines need to meet local capacity requirements)
- Green Path North and LEAPS

8.0 SDG&E / CAISO Comparison Tables – Assumptions and Results

Table A-1: Year 2010 (Case 200 – In area gas turbine reference case)

Reliability	SDG&E 1/26/07 filing	CAISO 1/26/07 filing	Comments/Discussion
SDG&E Area 2010 Surplus / (Deficiency)	33 MW	N/A	280 MWs of CT Generation has been added
SDG&E 's 2010 Load Forecast (90/10) unadjusted	5071 MW	N/A	
Uncommitted Energy	106 MW	N/A	
Distributed Generation	69 MW	N/A	
California Solar Initiative (CSI)	10 MW	N/A	
Resource Additions	See Section 5.6	N/A	
Resource Retirements Assumed South Bay Retired	See Section 5.7 Yes – 2009	N/A	
Import (N-0) All lines in service	2850 MW	N/A	
Import (G-1/N-1)	2500 MW	N/A	
WECC Load 2010	175,506 MW	N/A	Gridview, Non-coincident Peak
Renewables Assumptions w/ associated transmission upgrades	See Sections 5.8 & 5.9 Yes	N/A	

Table A-2: Year 2015 (Case 200 – In area gas turbine reference case)

Reliability	SDG&E 1/26/07 filing	CAISO 1/26/07 filing	Comments/Discussion
SDG&E Area 2015 Surplus / (Deficiency)	40 MW	(711 MW deficiency met with in-area CTs)	513 MW of CT Generation has been added
SDG&E 's 2015 Load Forecast (90/10) unadjusted	5438 MW	5438 MW	
Uncommitted Energy Efficiency	332 MW	332 MW	
Distributed Generation	74 MW	74 MW	
California Solar Initiative (CSI)	150 MW	150 MW	
Resource Additions	See Section 5.6	See Section 6	
Resource Retirements Assumed South Bay Retired	See Section 5.7 Yes – 2009	See Section 6 Yes – 2009	
Import (N-0) All lines in service	2850 MW	2850 MW	
Import (G-1/N-1)	2500 MW	2500 MW	
WECC Load 2015	190,506 MW		Gridview, Non-coincident Peak
Renewables Assumptions w/ associated transmission	See Sections 5.8 & 5.9	See Section 6	

upgrades	Yes		

Table A-3: Year 2020 (Case 200 – In area gas turbine reference case)

Reliability	SDG&E 1/26/07 filing	CAISO 1/26/07 filing	Comments/Discussion
SDG&E Area 2020 Surplus / (Deficiency)	4 MW	N/A	839 MW of CT Generation has been added
SDG&E 's 2020 Load Forecast (90/10) unadjusted	6224 MW	N/A	
Uncommitted Energy Efficiency	566 MW	N/A	
Distributed Generation	79 MW	N/A	
California Solar Initiative (CSI)	150 MW	N/A	
Resource Additions	See Section 5.6	N/A	
Resource Retirements Assumed South Bay Retired	See Section 5.7 Yes – 2009	N/A	
Import (N-0) All lines in service	2850 MW	N/A	
Import (G-1/N-1)	2500 MW	N/A	
WECC Load 2020	207,096	N/A	Gridview, Non-coincident Peak
Renewables Assumptions w/ associated transmission upgrades	See Sections 5.8 & 5.9 Yes	N/A	

Table A-4: Year 2010 (Case 201 – Sunrise Powerlink Case)

Reliability	SDG&E 1/26/07 filing	CAISO 1/26/07 filing	Comments/Discussion
SDG&E Area 2010 Surplus / (Deficiency)	753 MW	N/A	0 MWs of CT Generation has been added
SDG&E 's 2010 Load Forecast (90/10) unadjusted	5071 MW	N/A	
Uncommitted Energy Efficiency	106 MW	N/A	
Distributed Generation	69 MW	N/A	
California Solar Initiative (CSI)	10 MW	N/A	
Resource Additions	See Section 5.6	N/A	
Resource Retirements Assumed South Bay Retired	See Section 5.7 Yes – 2009	N/A	
Import (N-0) All lines in service	4200 MW	N/A	
Import (G-1/N-1)	3500 MW	N/A	
WECC Load 2010	175,506 MW	N/A	Gridview, Non-coincident Peak
Renewables Assumptions w/ associated transmission upgrades	See Sections 5.8 & 5.9 Yes	N/A	

Table A-5: Year 2015 (Case 201 – Sunrise Powerlink Case)

Reliability	SDG&E 1/26/07 filing	CAISO 1/26/07 filing	Comments/Discussion
SDG&E Area 2015 Surplus / (Deficiency)	527 MW	300 MW	0 MW of CT Generation has been added
SDG&E 's 2015 Load Forecast (90/10) unadjusted	5438 MW	5438 MW	
Uncommitted Energy Efficiency	332 MW	332 MW	
Distributed Generation	74 MW	74 MW	
California Solar Initiative (CSI)	150 MW	150 MW	
Resource Additions	See Section 5.6	See Section 6	
Resource Retirements Assumed South Bay Retired	See Section 5.7 Yes – 2009	See Section 6 Yes – 2009	
Import (N-0) All lines in service	4200 MW	4000 MW	
Import (G-1/N-1)	3500 MW	3500 MW	
WECC Load 2015	190,506 MW	186,308 MW	Gridview, Non-coincident Peak
Renewables Assumptions w/ associated transmission upgrades	See Sections 5.8 & 5.9 Yes	See Section 6	

Table A-6: Year 2020 (Case 201 – Sunrise Powerlink Case)

Reliability	SDG&E 1/26/07 filing	CAISO 1/26/07 filing	Comments/Discussion
SDG&E Area 2020 Surplus / (Deficiency)	165 MW	N/A	0 MW of CT Generation has been added
SDG&E 's 2020 Load Forecast (90/10) unadjusted	6224 MW	N/A	
Uncommitted Energy Efficiency	566 MW	N/A	
Distributed Generation	79 MW	N/A	
California Solar Initiative (CSI)	150 MW	N/A	
Resource Additions	See Section 5.6	N/A	
Resource Retirements Assumed South Bay Retired	See Section 5.7 Yes – 2009	N/A	
Import (N-0) All lines in service	4200 MW	N/A	
Import (G-1/N-1)	3500 MW	N/A	
WECC Load 2020	207,096	N/A	Gridview, Non-coincident Peak
Renewables Assumptions w/ associated transmission upgrades	See Sections 5.8 &5.9 Yes	N/A	

Economic Comparison Tables

Table A-7: Year 2010, 2015, & 2020 (Case 200 vs. Case 201)

Economics Assumptions	SDG&E 1/26/07 filing	CAISO 1/26/07 filing	Comments/Discussion
2010 SDG&E Load Forecast (50/50) Adjusted for Uncommitted Energy Efficiency, DG, and CSI	4659 MW	N/A	
2010 SDG&E Energy Forecast Adjusted for Uncommitted Energy Efficiency, DG, and CSI	22748 MWh	N/A	
2015 SDG&E Load Forecast (50/50) Adjusted for Uncommitted Energy Efficiency, DG, and CSI	4848 MW	4732 MW	
2015 SDG&E Energy Forecast Adjusted for Uncommitted Energy Efficiency, DG, and CSI	23814 MWh	23961 MWh	
2020 SDG&E Load Forecast (50/50) Adjusted for Uncommitted Energy Efficiency, DG, and CSI	5166 MW	N/A	
2020 SDG&E Energy Forecast Adjusted for Uncommitted Energy Efficiency, DG, and CSI	25351 MWh	N/A	
Socal Gas Price, ave	$7.13/MMBtu ($2005)	$6.89/MMBtu ($2005)	
Gas Price Diff (Socal – AZ)	$0.435/MMBtu	$0.20/MMBtu	
Renewables	See Section 5.8 & 5.9	See section 6	SDG&E Included IV Geothermal and Stirling Solar
RESULTS			
2010 Benefit (nominal)		N/A	
Energy Benefits	$80.2 M	N/A	
RMR Benefits	$71.7 M	N/A	
Avoided Gas Turbine Rev Req	$42.1 M	N/A	
Avoided GT XMSN Rev Req	$14.8 M	N/A	
2015 Benefit (nominal)			
Energy Benefits	$106.5 M	140 M	
RMR Benefits	$88.9 M	17 M	
Avoided Gas Turbine Rev Req	$67.2 M	66 M	
Avoided GT XMSN Rev Req	$26.8 M	27 M	
2020 Benefit (nominal)		N/A	
Energy Benefits	$206.4 M	N/A	
RMR Benefits	$96.9 M	N/A	

Avoided Gas Turbine Rev Req	$108.1 M	N/A	
Avoided GT XMSN Rev Req	$45.7 M	N/A	
Benefit (levelized) 2010-2049			
Energy Benefits	$179.7 M	N/A	
RMR Benefits	$100.9 M	N/A	
Avoided Gas Turbine Rev Req	$66.7 M	N/A	
Avoided GT XMSN Rev Req	$29.3M	N/A	
Total Benefits	$376.6 M	N/A	
Total Costs (Sunrise Transmission Revenue Requirement)	$156.1 M	N/A	
Benefit/Cost Ratio	2.41/1	N/A	

Table A-8: Year 2010, 2015, & 2020 (Case 200 vs. Case 208 (Green Path North))

Economics **<u>Assumptions</u>**	SDG&E 1/26/07 filing	CAISO 1/26/07 filing	Comments/Discussion
2010 SDG&E Load Forecast (50/50) Adjusted for Uncommitted Energy Efficiency, DG, and CSI	4659 MW	N/A	
2010 SDG&E Energy Forecast Adjusted for Uncommitted Energy Efficiency, DG, and CSI	22748 MWh	N/A	
2015 SDG&E Load Forecast (50/50) Adjusted for Uncommitted Energy Efficiency, DG, and CSI	4848 MW	4732 MW	
2015 SDG&E Energy Forecast Adjusted for Uncommitted Energy Efficiency, DG, and CSI	23814 MWh	23961 MWh	
2020 SDG&E Load Forecast (50/50) Adjusted for Uncommitted Energy Efficiency, DG, and CSI	5166 MW	N/A	
2020 SDG&E Energy Forecast Adjusted for Uncommitted Energy Efficiency, DG, and CSI	25351 MWh	N/A	
Socal Gas Price, ave	$7.13/MMBtu ($2005)	$6.89/MMBtu ($2005)	
Gas Price Diff (Socal – AZ)	$0.435/MMBtu	$0.20/MMBtu	
Renewables	See Sections 5.8 & 5.9	See section 6	SDG&E Included IV Geothermal and Stirling Solar
<u>RESULTS</u>			
2010 Benefit (nominal)		N/A	
Energy Benefits	$61.6 M	N/A	
RMR Benefits	$0 M	N/A	
Avoided Gas Turbine Rev Req	$42.1 M	N/A	
Avoided GT XMSN Rev Req	$92.6 M	N/A	

2015 Benefit (nominal)			
Energy Benefits	$107.4 M	155 M	
RMR Benefits	$0 M	0 M	
Avoided Gas Turbine Rev Req	$67.2 M	66 M	
Avoided GT XMSN Rev Req	$89.6 M	27 M	
2020 Benefit (nominal)			
Energy Benefits	$23.6 M	N/A	
RMR Benefits	$0 M	N/A	
Avoided Gas Turbine Rev Req	$108.1 M	N/A	
Avoided GT XMSN Rev Req	$97.5 M	N/A	
Benefit (levelized) 2010-2049			
Energy Benefits	$54.9 M	N/A	
RMR Benefits	$0.2 M	N/A	
Avoided Gas Turbine Rev Req	$66.7 M	N/A	
Avoided GT XMSN Rev Req	$29.3 M	N/A	
Total Benefits	$151.1 M	N/A	
Total Costs	$150.6 M	N/A	
Benefit/Cost Ratio	1.00/1	N/A	

Table A-9: Year 2010, 2015, & 2020 (Case 200 vs. Case 210 (South Bay Combined Cycle Alternative))

Economics Assumptions	SDG&E 1/26/07 filing	CAISO 1/26/07 filing	Comments/Discussion
2010 SDG&E Load Forecast (50/50) Adjusted for Uncommitted Energy Efficiency, DG, and CSI	4659 MW	N/A	
2010 SDG&E Energy Forecast Adjusted for Uncommitted Energy Efficiency, DG, and CSI	22748 MWh	N/A	
2015 SDG&E Load Forecast (50/50) Adjusted for Uncommitted Energy Efficiency, DG, and CSI	4848 MW	4732 MW	Difference is due to method for applying CSI adjustment
2015 SDG&E Energy Forecast Adjusted for Uncommitted Energy Efficiency, DG, and CSI	23814 MWh	23961 MWh	Difference is due to method for applying CSI adjustment
2020 SDG&E Load Forecast (50/50) Adjusted for Uncommitted Energy Efficiency, DG, and CSI	5166 MW	N/A	
2020 SDG&E Energy Forecast	25351 MWh	N/A	

Adjusted for Uncommitted Energy Efficiency, DG, and CSI			
Socal Gas Price, ave	$7.13/MMBtu ($2005)	$6.89/MMBtu ($2005)	
Gas Price Diff (Socal – AZ)	$0.435/MMBtu	$0.20/MMBtu	
Renewables	See Sections 5.8 & 5.9	See section 6	SDG&E Included IV Geothermal and Stirling Solar
RESULTS			
2010 Benefit (nominal)			
Energy Benefits	$93.6 M	N/A	
RMR Benefits	$12.2 M	N/A	
Avoided Gas Turbine Rev Req	$42.1 M	N/A	
Avoided GT XMSN Rev Req	$14.8 M	N/A	
2015 Benefit (nominal)			
Energy Benefits	$71.4 M	$13 M	
RMR Benefits	($5.4) M	(-34) M	
Avoided Gas Turbine Rev Req	$67.2 M	56 M	
Avoided GT XMSN Rev Req	$26.8 M	23 M	
2020 Benefit (nominal)			
Energy Benefits	$54.8 M	N/A	
RMR Benefits	($6.1) M	N/A	
Avoided Gas Turbine Rev Req	$108.1 M	N/A	
Avoided GT XMSN Rev Req	$45.7 M	N/A	
Benefit (levelized) 2010-2049			
Energy Benefits	$69 M	N/A	
RMR Benefits	($3) M	N/A	
Avoided Gas Turbine Rev Req	$66.7 M	N/A	
Avoided GT XMSN Rev Req	$29.3 M	N/A	
Total Benefits	$162 M	N/A	
Total Costs	$121 M	N/A	
Benefit/Cost Ratio	1.34/1	N/A	

CERTIFICATE OF SERVICE

I hereby certify that I have served, by electronic and United States mail, a copy of the foregoing Initial Testimony of The California Independent System Operator Corporation, Part 1 to each party in Docket No. A.06-08-010

Executed on January 26, 2007 at Folsom, California.

/s/ Charity N. Wilson
Charity N. Wilson
An Employee of the California
Independent System Operator

WILLIAM TULLOCH
28223 HIGHWAY 78
RAMONA, CA 92065

WALLY BESUDEN
SPANGLER PEAK RANCH, INC
PO BOX 1959
ESCONDIDO, CA 92033

LINDA A. CARSON
ANZA-BORREGO FOUNDATION
PO BOX 2001
BORREGO SPRINGS, CA 92004

JOHN GRISAFI
PO BOX 310125
GUATAY, CA 91931

JOETTA MIHALOVICH
11705 ALDERCREST POINT
SAN DIEGO, CA 92131

LYNDA KASTOLL
BUREAU OF LAND MANAGEMENT
1661 SOUTH 4TH STREET
EL CENTRO, CA 92243

ABBAS M. ABED
NAVIGANT CONSULTING, INC.
aabed@navigantconsulting.com

ANDREW B. BROWN
ELLISON, SCHNEIDER & HARRIS, LLP
abb@eslawfirm.com

AUDRA HARTMANN
LS POWER GENERATION
ahartmann@lspower.com

G. ALAN COMNES
CABRILLO POWER I LLC
alan.comnes@nrgenergy.com

PATRICIA C. SCHNIER
barbschnier@yahoo.com

BREWSTER BIRDSALL
ASPEN ENVIRONMENTAL GROUP
bbirdsall@aspeneg.com

Billie C. Blanchard
CALIF PUBLIC UTILITIES COMMISSION
bcb@cpuc.ca.gov

BRIAN T. CRAGG
GOODIN MACBRIDE SQUERI RITCHIE & DAY LLP
bcragg@gmssr.com

BONNIE GENDRON
bgendron@nethere.com

BRADLY S. TORGAN
CALIFORNIA DEPT. OF PARKS & RECREATION
btorgan@parks.ca.gov

CARRIE DOWNEY
HORTON KNOX CARTER & FOOTE
cadowney@san.rr.com

CAROLYN A. DORROH
RAMONA COMMUNITY PLANNING GROUP
carolyn.dorroh@cubic.com

CASE ADMINISTRATION
SOUTHERN CALIFORNIA EDISON COMPANY
case.admin@sce.com

LAUREL GRANQUIST
celloinpines@sbcglobal.net

CALIFORNIA ENERGY MARKETS
cem@newsdata.com

CENTRAL FILES
SAN DIEGO GAS & ELECTRIC
centralfiles@semprautilities.com

STEVE/CAROLYN ESPOSITO
cesposit@sdcoe.k12.ca.us

CLAY E. FABER
SOUTHERN CALIFORNIA GAS COMPANY
cfaber@semprautilities.com

CLARE LAUFENBERG
CALIFORNIA ENERGY COMMISSION
Claufenb@energy.state.ca.us

BRIAN KRAMER
colobiker@gmail.com

CONNIE BULL
conniebull@cox.net

PAUL RIDGWAY
cpuc@92036.com

CRAIG ROSE
THE SAN DIEGO UNION TRIBUNE
craig.rose@uniontrib.com

CAROLYN MORROW
GOLIGHTLY FARMS
Csmmarket@aol.com

DAHVIA LOCKE
COUNTY OF SAN DIEGO
Dahvia.Locke@sdcounty.ca.gov

DAVID W. CAREY
DAVID CAREY & ASSOCIATES, INC.
dandbcarey@julianweb.com

DANIEL SUURKASK
WILD ROSE ENERGY SOLUTIONS, INC.
daniel@wildroseenergy.com

DARELL HOLMES
SOUTHERN CALIFORNIA EDISON
darell.holmes@sce.com

DAVID LLOYD
CABRILLO POWER I, LLC
david.lloyd@nrgenergy.com

DAVID BRANCHCOMB
BRANCHCOMB ASSOCIATES, LLC
david@branchcomb.com

DARRELL FREEMAN
ddfreeman@yahoo.com

DAVE DOWNEY
NORTH COUNTY TIMES
ddowney@nctimes.com

DENIS TRAFECANTY
COMMUNITY OF SANTA YSABEL & RELATED COMM
denis@vitalityweb.com

David Ng
CALIF PUBLIC UTILITIES COMMISSION
dhn@cpuc.ca.gov

DAVID HOGAN
CENTER FOR BIOLOGICAL DIVERSITY
dhogan@biologicaldiversity.org

DIANE I. FELLMAN
FPL ENERGY, LLC
diane_fellman@fpl.com

DIANE J. CONKLIN
MUSSEY GRADE ROAD ALLIANCE
dj0conklin@earthlink.net

DAVID KATES
DAVID MARK AND COMPANY
dkates@sonic.net

DIANA LINSDAY
ANZA-BORREGO FOUNDATION & INSTITUTE
dlindsay@sunbeltpub.com

DAVID MARCUS
dmarcus2@sbcglobal.net

DONNA TISDALE
BOULEVARD SPONSOR GROUP
donnatisdale@hughes.net

DAVID T. KRASKA
PACIFIC GAS AND ELECTRIC COMPANY
dtk5@pge.com

DON WOOD SR.
PACIFIC ENERGY POLICY CENTER
dwood8@cox.net

DAVID VOSS
dwvoss@cox.net

BOB & MARGARET BARELMANN
ecp@ixpres.com

J.A. SAVAGE
CALIFORNIA ENERGY CIRCUIT
editorial@californiaenergycircuit.net

ELIZABETH EDWARDS
RAMONA VALLEY VINEYARD ASSOCIATION
edwrdsgrfx@aol.com

CALIFORNIA ISO
e-recipient@caiso.com

FREDERICK M. ORTLIEB
CITY OF SAN DIEGO
fortlieb@sandiego.gov

E. GREGORY BARNES
SAN DIEGO GAS & ELECTRIC COMPANY
gbarnes@sempra.com

JOHN&PHYLLIS BREMER
gecko_greens@juno.com

GLENN E. DROWN
gedrown@mindspring.com

EDWARD GORHAM
WESTERNERS INCENSED BY WRECKLESS ELECTRI
gorhamedward@cox.net

GREG SCHUETT
gregschuett@mac.com

MARY ALDERN
COMMUNITY ALLIANCE FOR SENSIBLE ENERGY
hikermomma1@yahoo.com

HARVEY PAYNE
RANCHO PENASQUITOS CONCERNED CITIZENS
hpayne@sdgllp.com

HENRY ZAININGER
ZAININGER ENGINEERING COMPANY, INC.
hzaininger@aol.com

LOUIS NASTRO
lnastro@parks.ca.gov

DEMIAN DORRANCE
inbox858-cvcc@yahoo.com

IRENE STILLINGS
SAN DIEGO REGINONAL ENERGY
Irene.stillings@sdenergy.org

JACK BURKE
SAN DIEGO REGIONAL ENERGY OFFICE
jack.burke@sdenergy.org

JAMES H. CALDWELL JR.
PPM ENERGY, INC.
james.caldwell@ppmenergy.com

JUSTIN AUGUSTINE
THE CENTER FOR BIOLOGICAL DIVERSITY
jaugustine@biologicaldiversity.org

JASON YAN
PACIFIC GAS AND ELECTRIC COMPANY
jay2@pge.com

JENNIFER PORTER
SAN DIEGO REGIONAL ENERGY OFFICE
jennifer.porter@sdenergy.org

JULIE L. FIEBER
FOLGER LEVIN & KAHN LLP
jfieber@flk.com

JALEH (SHARON) FIROOZ, P.E.
ADVANCED ENERGY SOLUTIONS
jfirooz@iesnet.com

JUDY GRAU
CALIFORNIA ENERGY COMMISSION
jgrau@energy.state.ca.us

HEIDI FARKASH
JOHN & HEIDI FARKASH TRUST
jhfark@pacbell.net

JIM BELL
jimbellelsi@cox.net

JEDEDIAH J. GIBSON
ELLISON, SCHNEIDER & HARRIS LLP
jjg@eslawfirm.com

JOHN W. LESLIE
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
jleslie@luce.com

Joe Como
CALIF PUBLIC UTILITIES COMMISSION
joc@cpuc.ca.gov

JOSEPH RAUH
RANCHITA REALTY
joe@ranchitarealty.com

JUDITH B. SANDERS
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
jsanders@caiso.com

JUILE B. GREENISEN
LATHAM & WATKINS LLP
juile.greenisen@lw.com

KELLY FULLER
k.d.fuller@sbcglobal.net

KARL HIGGINS
HIGGINS & ASSOCIATES
karlhiggins@adelphia.net

KEN BAGLEY
R.W. BECK
kbagley@rwbeck.com

KEVIN WOODRUFF
WOODRUFF EXPERT SERVICES, INC.
kdw@woodruff-expert-services.com

W. KENT PALMERTON
WK PALMERTON ASSOCIATES, LLC
kent@wkpalmerton.com

GLENDA KIMMERLY
kimmerlys@yahoo.com

KAREN NORENE MILLS
CALIFORNIA FARM BUREAU FEDERATION
kmills@cfbf.com

KEVIN O'BEIRNE
SAN DIEGO GAS & ELECTRIC COMPANY
ko'beirne@semprautilities.com

KEITH RITCHEY
kritchey@san.rr.com

Keith D White
CALIF PUBLIC UTILITIES COMMISSION
kwh@cpuc.ca.gov

LAWRENCE LINGBLOOM
SENATE ENERGY/UTILITIES & COMMUNICATION
lawrence.lingbloom@sen.ca.gov

DONALD C. LIDDELL
DOUGLASS & LIDDELL
liddell@energyattorney.com

LON W. HOUSE
WATER & ENERGY CONSULTING
lonwhouse@waterandenergyconsulting.com

MICHAEL P. CALABRESE
CITY ATTORNEY'S OFFICE
mcalabrese@sandiego.gov

MICHEL PETER FLORIO
THE UTILITY REFORM NETWORK (TURN)
mflorio@turn.org

MICHAEL J. GERGEN
LATHAM & WATKINS LLP
michael.gergen@lw.com

MATTHEW JUMPER
SAN DIEGO INTERFAITH HOUSING FOUNDATION
mjumper@sdihf.org

MARY KAY FERWALT
mkferwalt@yahoo.com

MARC PRYOR
CALIFORNIA ENERGY COMMISSION
mpryor@energy.state.ca.us

MRW & ASSOCIATES, INC.
mrw@mrwassoc.com

Marcus Nixon
CALIF PUBLIC UTILITIES COMMISSION
mrx@cpuc.ca.gov

MICHAEL SHAMES
UTILITY CONSUMERS' ACTION NETWORK
mshames@ucan.org

MICHAEL S. PORTER
PACIFIC GAS AND ELECTRIC COMPANY
mspe@pge.com

MICHAEL L. WELLS
CALIFORNIA DEPARTMENTOF PARKS&RECREATION
mwells@parks.ca.gov

Nicholas Sher
CALIF PUBLIC UTILITIES COMMISSION
nms@cpuc.ca.gov

NORMAN J. FURUTA
FEDERAL EXECUTIVE AGENCIES
norman.furuta@navy.mil

NANCY PARINELLO
nparinello@gmail.com

MICHAEL PAGE
oakhollowranch@wildblue.net

PETER SCHULTZ
OLD JULIAN CO.
oldjulianco@integrity.com

PAT/ALBERT BIANEZ
patricia_fallon@sbcglobal.net

DAN PERKINS
ENERGY SMART HOMES
perkydanp@yahoo.com

PAUL G. SCHEUERMAN
SHEUERMAN CONSULTING
PGS@IEEE.org

PHILLIPPE AUCLAIR
phiha@astound.net

CHRISTOPHER P. JEFFERS
polo-player@cox.net

PAM WHALEN
pwhalen2@cox.net

Robert Elliott
CALIF PUBLIC UTILITIES COMMISSION
rae@cpuc.ca.gov

RORY COX
rcox@pacificenvironment.org

AARON QUINTANAR
RATE PAYERS FOR AFFORDABLE CLEAN ENERGY
rcox@pacificenvironment.org

REBECCA PEARL
ENVIRONMENTAL HEALTH COALITION
rebeccap@environmentalhealth.org

RICHARD W. RAUSHENBUSH
LATHAM & WATKINS LLP
richard.raushenbush@lw.com

RICHARD LAUCKHART
GLOBAL ENERGY
rlauckhart@globalenergy.com

EILEEN BIRD
sanrocky@aol.com

SARA FELDMAN
CA STATE PARKS FOUNDATION
sara@calparks.org

Steven A. Weissman
CALIF PUBLIC UTILITIES COMMISSION
saw@cpuc.ca.gov

SCOT MARTIN
scotmartin478@msn.com

SCOTT J. ANDERS
UNIVERSITY OF SAN DIEGO - LAW
scottanders@sandiego.edu

PAUL BLACKBURN
SIERRA CLUB, SAN DIEGO CHAPTER
sdenergy@sierraclubsandiego.org

SEPHRA A. NINOW
SAN DIEGO REGIONAL ENERGY OFFICE
sephra.Ninow@sdenergy.org

SUSAN FREEDMAN
SAN DIEGO ASSOCIATION OF GOVERNMENTS
sfr@sandag.org

Scott Logan
CALIF PUBLIC UTILITIES COMMISSION
sjl@cpuc.ca.gov

JOHN RAIFSNIDER
skyword@sbcglobal.net

SUSAN LEE
ASPEN ENVIRONMENTAL GROUP
slee@aspeneg.com

LARA LOPEZ
soliviasmom@cox.net

STEPHEN ROGERS
srogers647@aol.com

SUZANNE WILSON
swilson@pcta.org

TOM BLAIR
CITY OF SAN DIEGO
TBlair@sandiego.gov

Traci Bone
CALIF PUBLIC UTILITIES COMMISSION
tbo@cpuc.ca.gov

Terrie D. Prosper
CALIF PUBLIC UTILITIES COMMISSION
tdp@cpuc.ca.gov

TOM GORTON
BORREGO SUN
tgorton@cableusa.com

THOMAS A. BURHENN
SOUTHERN CALIFORNIA EDISON
thomas.burhenn@sce.com

THOMAS ZALE
BUREAU OF LAND MANAGEMENT
Thomas_Zale@blm.gov

TOM MURPHY
ASPEN ENVIRONMENTAL GROUP
tmurphy@aspeneg.com

Thomas Flynn
CALIF PUBLIC UTILITIES COMMISSION
trf@cpuc.ca.gov

EPIC INTERN
EPIC/USD SCHOOL OF LAW
usdepic@gmail.com

MARTHA BAKER
VOLCAN MOUNTAIN PRESERVE FOUNDATION
vmp@sbcglobal.net

BILLY BLATTNER
SAN DIEGO GAS & ELECTRIC COMPANY
wblattner@semprautilities.com

RON WEBB
webron7@yahoo.com

WILLIE M. GATERS
williegaters@earthlink.net

OSA L. WOLFF
SHUTE, MIHALY & WEINBERGER, LLC
wolff@smwlaw.com

SHERIDAN PAUKER
SHUTE,MIHALY & WEINBERGER LLP
wolff@smwlaw.com

PHILLIP &ELIANE BREEDLOVE
wolfmates@cox.net

Scott Cauchois
CALIF PUBLIC UTILITIES COMMISSION
wsc@cpuc.ca.gov

SCOTT KARDEL
PALOMAR OBSERVATORY
PO BOX 200
PALOMAR MOUNTAIN, CA 92060