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)

PHASE 2 OPENING BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES

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SUMMARY OF RECOMMENDATIONS

The Division of Ratepayer Advocates ("DRA") recommends that the California Public Utilities Commission ("Commission") take the following actions in this proceeding:

- Issue an interim decision declining to grant a certificate of public convenience and necessity ("CPCN") for the Sunrise Powerlink Transmission Project as proposed by San Diego Gas & Electric Company ("SDG&E") or other new Imperial Valley-San Diego Transmission Line ("IV-SD transmission line" or "IV-SD TL").

- Establish a timeline and conditions that must occur for a future finding of transmission line need, such as: (a) Imperial Valley-area renewables projects now under contract to SDG&E, such as Stirling Energy Systems, reaching certain development milestones, and (b) an additional showing in this docket by the California Independent System Operator ("CAISO") that reconciles the contradictions between the analysis of the local reliability impacts of a new IV-SD transmission line that it provided in this docket and the analyses provided in its two recent long-term LCR analyses.

- Allow SDG&E to secure efficient, cost-effective, combined-cycle generation, or other cost-effective, new in-basin resources, pursuant to

authorization already granted in the Long Term Procurement Plan ("LTPP") process.[1]

- Allow SDG&E to make a compliance filing that would trigger final review of a proposed project or other IV-SD TL based upon the above conditions.

In its decision in this proceeding, the Commission's only options are to grant or deny approval of a new IV-SD transmission line, and, if the Commission grants a CPCN, to select a route for SDG&E to pursue.[2]

The Commission cannot approve Sunrise, or another IV-SD transmission line alternative, on the assumption that it will solve SDG&E's local reliability challenges. Moreover, the purported benefits of a new IV-SD transmission line are based on the assumption that parties other than SDG&E will take future actions, particularly the CAISO, renewables developers, the Imperial Irrigation District and other Imperial Valley area developers. The Commission must continue to monitor local reliability issues regardless of what decision the Commission reaches in this case. For example, SDG&E is moving aggressively to address such issues by measures (such as local gas generation) that are virtually certain to solve the problem of local reliability.

Nor should the Commission act to achieve only minimal energy benefits. The Commission may wish to approve an IV-SD transmission line to advance California's renewables goals; however, it would be a very expensive investment. The Commission could allow development of the Environmentally Superior Southern Route Alternative based on SDG&E's securing agreements with the IID regarding IID system build-out for renewable and reliability benefits, or on Stirling Energy Systems' ("Stirling") meeting certain development milestones.

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[1] *See* Decision 07-12-052, p.114.

[2] Though the Commission's denial of a CPCN would trigger the provisions of D.07-12-052 that would enable SDG&E to procure additional resources to meet its local needs.

I. INTRODUCTION

In accordance with Rule 13.11 of the Commission's Rules of Practice and Procedure of the and with the procedural schedule established by presiding Administrative Law Judge ("ALJ") Steve Weissman, DRA hereby submits its opening brief in Phase 2 of the above-captioned proceeding, the application of SDG&E for a CPCN for the Sunrise Powerlink Transmission Project ("Sunrise").

DRA, a division of the Commission, is mandated by state law to represent the ratepayers of investor-owned utilities to obtain the lowest possible rates consistent with reliable and safe service levels.[3] DRA's interest in this proceeding is to determine if SDG&E's application satisfies the fundamental requirement for all CPCN applications, that it make a "showing that the present or future public convenience and necessity requires or will require such construction."[4]

In CPCN proceedings for major transmission lines, DRA traditionally focuses on issues relating to the determination of "need" for the proposed project, such as cost-effectiveness, long-term planning, and compliance with state policy and related Commission directives. DRA's focus in the instant proceeding is consistent with this traditional scope of review, which typically includes a "neutral" position on issues that are purely environmental in nature. However, given the contentiousness of the environmental issues in the Sunrise proceeding, the very nature of the controversies are spilling over into "need" issues. For example, a particular route alternative carries attributes that are different from those of other routes such as costs, legal appeals, actions by other regulatory agencies, right-of-way implications, timing and feasibility. Therefore, while DRA continues to take a neutral position regarding environmental issues, DRA has focused on certain attributes of the IV-SD transmission line alternatives.

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[3] *See* California Public Utilities Code section 309.5. All statutory references herein are to the California Public Utilities Code unless otherwise specified.

[4] Cal. Pub. Util. Code § 1001.

Moreover, the Phase 2 Scoping Memo established a direct link between the environmental issues and the need issues by requiring that the Phase 1 need analysis be updated in the context of the Draft Environmental Impact Report/Environmental Impact Statement ("EIR/EIS"). The Draft EIR/EIS selected eight feasible alternatives, evaluated each alternative's environmental impacts, compared the mitigation measures required, and provided a final ranking of the alternatives, in accordance with the requirements of the California Environmental Quality Act ("CEQA") and the National Environmental Quality Act ("NEPA"). Phase 2 testimonies were submitted by parties with varied interests – some solely focused on the environmental issues in the Draft EIR/EIS, and some whose interests related to both the environmental and the need issues.

The Sunrise application is premised on SDG&E's contention that the South Bay Power Plant ("SBPP" or "South Bay") will be retired by the end of 2009. However, as will be explained below, this assumption is flawed and should be accorded little or no weight by the Commission.

II. PROCEDURAL HISTORY and ISSUES

SDG&E filed its initial application on December 14, 2006, Application ("A.") 05-12-014. Because of deficiencies in that application, SDG&E filed an entirely new set of documents, characterized as an amended application, on August 4, 2006. The new application was identified as A.06-08-010. On August 9, 2006, in a ruling by the Chief ALJ, the two applications were consolidated. On January 11, 2007, in Decision ("D.") 07-01-008, A.05-12-014 was formally closed and its recorded was incorporated in its entirety into A.06-08-010. Phase 1 evidentiary hearings were held July 9-13, July 16-19, September 4-7, September 26-28, and October 3-4, 2007. Parties submitted opening briefs on November 9 and reply briefs on November 30, 2007.

The Administrative Law Judge's Ruling Setting the Schedule for Phase 2 was issued on December 11, 2007, and set forth the issues to be addressed in this second phase of the proceeding. The Draft EIR/EIS was published on January 3, 2008, with a public comment due date of April 11, 2008. Telephonic discovery conferences began on February 5, 2008. Public participation hearings were held in February and May 2008.

Parties served Phase 2 direct testimony on March 12 and rebuttal testimony on March 28, 2008. The fourth prehearing conference was convened on April 2, 2008. Phase 2 evidentiary hearings were held on April 7-9, April 14-18, April 21-25, April 28-May 2, and May 7, 2008.

III. THE PROPOSED PROJECT, ALTERNATIVES IN THE DEIR AND ROUTE ALTERNATIVES PROPOSED BY PARTIES

DRA defers to SDG&E to describe its Proposed Project, and to UCAN, RPCC and other parties to describe the route alternatives they propose. DRA also defers to the Draft EIR/EIS for descriptions of the alternatives contained therein. DRA notes, however, as to Sections A-E and G-J, subsections 4, regarding "effect on system reliability" and 5, regarding "effect on 'ability to deliver renewable energy to SDG&E customers,'" that it is DRA's understanding that these alternatives are electrically equivalent and at this time DRA makes no recommendation as to the specific routing that should be adopted if the Commission approves Sunrise.

As to Sections D-F, subsection 4 regarding "effect on system reliability," both SDG&E and the CAISO argue that the Environmentally Superior Southern Route Alternative ("ESSRA") should be considered significantly less reliable than either northern route because a Special Protection Scheme ("SPS") would need to be installed to guard against a potential "common mode" outage of both the ESSRA and the Southwest Powerlink ("SWPL") in the 36 miles of corridor they would share. SDG&E and the CAISO base this argument on a "finding" of the Western Electricity Coordinating Council ("WECC") that such a SPS would be necessary. The Commission should reject these arguments for several reasons:

1. In making its finding regarding the need for a SPS, the WECC relied entirely upon a study prepared by SDG&E, contrary to SDG&E's claims that the WECC conducted a "careful independent review."

2. The WECC's Reliability Performance Evaluation Work Group (RPEWG) stated: "[T]he robust line design showed Moderate Risk for 3 risks [sic] factors and High Risk

for 3 risk factors." However, the summary table in the SDG&E Study showed that of the eleven Risk Factors considered in assessing Robust Line Design, two were judged High Risk, two were judged Moderate Risk, and one was judged Moderate/High Risk. To contend instead that the analysis "showed Moderate Risk for 3 risk factors and High Risk for 3 risk factors" is absurd.

3. SDG&E and the CAISO also overstate the reliability concerns raised by the differences between a possible Category C or Category D designation. The differences in these designations do not indicate a difference between a transmission line that is reliable or not reliable, or even differences in reliability that are credibly quantifiable. Rather, the dividing line for the proposed Category D upgrade with cascading designation is an estimated greater than 300-year Mean Time Between Failure (MTBF) of an element. This is hardly the "significant" probability of an ESSRA failure cited in the CAISO's Phase 2 Direct Testimony.

Further, estimates of which assets will or will not exceed such a miniscule reliability threshold are extremely speculative. For example, in the SDG&E Study, SDG&E contended that both the Northern and Southern Routes would have MTBFs ranging from 21 to 928 years – which hardly leads to confidence in the precision of their data and statistical methods. Rather, decisions regarding the division between Category C and D conditions are based heavily on judgments. And, as noted above, the WECC's judgment in this matter is doubtful.

Moreover, the Draft EIR/EIS noted that other transmission corridors in the CAISO also have transmission lines located in close proximity. For example, 2,000 feet separate circuits on Path 15 and Path 66 in central California. And, if it is developed, the proposed Devers-Palo Verde #2 transmission line would be located within 130 feet of DPV1. The CAISO supported both of these projects before this Commission.[5]

[5] Exhibit D-101, pp. 13-16; *see also* Exhibit D-104.

IV. MATERIAL FACTUAL INACCURACIES OR DEFICIENCIES IN THE DRAFT EIR/EIS

DRA takes no position on this topic at this time.

V. THE ECONOMIC BENEFIT OF THE PROPOSED PROJECT, THE DEIR ALTERNATIVES, AND PARTY-PROPOSED ROUTE OPTIONS

A. Definition/description of baseline against which benefits for each alternative are compared

In preparing its case, SDG&E adopted the long-standing electric industry planning practice of comparing the value of Sunrise and various alternatives to a hypothetical "Combustion Turbine" (CT) build-out scenario that would meet minimum reliability standards. The "CT" alternative has long been used by the industry because building CTs has historically been the least-cost means of meeting reliability standards.

However, in this case, the most appropriate benchmark for analyzing Sunrise (or any other IV-SD TL) is the net cost of the best plausible alternative plan for meeting reliability needs, that is, an alternative plan that meets reliability needs *but also lowers customers' net costs below those of the CT alternative*.

B. Cost of Baseline

Please see V.C., below.

C. Net economic benefit of proposed project and alternatives relative to baseline (total NPV), consistent with "costs" in sections III.A-M.3

As this case and SDG&E's modeling and assumptions have evolved, the best plausible alternative to building a new IV-SD TL now features both new CTs in the near-term *and* the construction of a new "Combined Cycle" in San Diego in 2016. And, according to SDG&E's analysis, this "CT + CC" alternative is in fact virtually equivalent to the lowest cost IV-SD TL alternatives. And if SDG&E's analytic errors that inflate the value of the IV-SD TL options are corrected, the "CT + CC" alternative would likely be superior to any IV-SD TL.

The virtual equivalence of the "CT + CC" alternative was amply illustrated in SDG&E's own Exhibit SD-144, which showed that Alternative 4 (the ESSRA) and Alternative 6 (the Proposed Project) had Benefit-Cost Ratios (BCRs) of 1.08 and 1.07 compared to a "CT + CC" reference case. This finding is further illustrated in Exhibit U-113, which shows BCRs for the SDG&E's Enhanced Northern Route and Modified Southern Route of 1.08 and 1.01, respectively.

The benefits SDG&E is claiming for a new IV-SD TL have dropped dramatically from their filing of August 2006, and even from their final Phase 1 testimony provided in July 2007. As shown below, the BCRs shown in Exhibit SD-26 comparing Sunrise to either a CT reference case or a "CT + CC" reference case have fallen sharply to the BCRs now shown in SDG&E's Exhibits SD-142 and SD-144.

Lest the Commission see these slightly positive BCRs as being an indicator that a new IV-SD TL is clearly an economic investment, DRA reminds the Commission that SDG&E's economic case is still deeply flawed – despite its ongoing adoption of many corrections suggested by intervenors. Correction of the remaining deficiencies would reduce the BCRs of a new IV-SD TL below one.

Further, the comparison of BCRs based on a single gas price forecast does not reflect the likely hedging value that new CTs and CCs would offer SDG&E customers, that is, the ability to generate electricity at a lower cost when the market heat rate exceeds the heat rates of such units. (Exhibit D-66, p. ES-11).

The Fall of Sunrise's Benefit-Cost Ratio in SDG&E's Analyses

	Compared to Combustion Turbine Reference Case	Compared to Resource Plan with Combined Cycle	Sources:
Phase 1	1.91	1.48	1/ 2/
Phase 2	1.26	1.07	3/

1/ Exhibit SD-26, Table 5, Page 18.

2/ Sunrise BCR relative to Combined Cycle computed by dividing Case 201 (Sunrise) BCR of 1.91 by Case 204 (In-Area Combined Cycle Alternative) BCR of 1.29.

3/ Exhibit SD-142, Table 11-6 and Exhibit SD-144, Table 11-6

1. Summary of Range of Gross Benefits of a New IV-SD Transmission Line

The potential gross benefits of a new IV-SD transmission line are shown in the table below, for both a 2011 and a 2012 start date. The estimated benefits from each scenario for local reliability, energy and renewables benefits were added to yield various scenarios' total gross benefits.

Gross Benefits of New IV-SD Transmission Line[6]

		(levelized $2011MM) Benefit Scenarios:			
	IV-SD TL On-Line Date:	Low	Medium	High Without Stirling	High With Stirling
Benefits:	2011	30.5	132.6	255.0	309.1
	2012	29.0	125.6	245.7	299.0
LCR Scenario:		2. Minimal Relief	1. Immediate Benefits	4. Stirling Failure	3. Stirling Success

2. Benefit-Cost Ratios

Based on updated costs and the expansion of SDG&E's cost data in its direct testimony, DRA prepared estimates of the range of potential benefits of a new IV-SD transmission, shown in the table below for each IV-SD transmission alternative.

Range of Net Benefits and Benefit-Cost Ratios of

[6] Exhibit D-102, p.8.

New IV-SD Transmission Line Options[7]

(levelized $2011MM)

	Low	Medium	High Without Stirling	High With Stirling
2011 On-Line Dates				
Benefits:	30.5	132.6	255.0	309.1
Costs:				
Proposed Project		189.6		
ESNRA		311.5		
ESSRA		169.2		
ESSRA, As Adjusted		157.5		
Benefit-Cost Ratios:				
Proposed Project	0.2	0.7	1.3	1.6
ESNRA	0.1	0.4	0.8	1.0
ESSRA	0.2	0.8	1.5	1.8
ESSRA, As Adjusted	0.2	0.8	1.6	2.0
2012 On-Line Dates				
Benefits:	29.0	125.6	245.7	299.0
Costs:				
Proposed Project		195.3		
ESNRA		320.8		
ESSRA		174.3		
ESSRA, As Adjusted		162.3		
Benefit-Cost Ratios:				
Proposed Project	0.2	0.7	1.3	1.6
ESNRA	0.1	0.4	0.8	1.0
ESSRA	0.2	0.8	1.5	1.8
ESSRA, As Adjusted	0.2	0.8	1.6	1.9

The table shows that it is not clear that a new IV-SD TL will yield economic benefits. However, it is possible that either the Proposed Project or the ESSRA could provide net economic benefits should one or more of DRA's estimated "high" scenarios occur in conjunction with DRA's "medium" scenarios. It is unlikely the Environmentally Superior Northern Route Alternative ("ESNRA") would yield economic benefits because of its apparently significantly higher costs.

[7] Exhibit D-102, p.11.

The higher BCRs resulting from 2011 on-line dates in some scenarios are not an indication that an earlier implementation of an IV-SD transmission line would be beneficial. This analysis did not consider the additional costs that might – or might not – need to be incurred in 2011 to maintain San Diego area reliability. Rather, these figures can only be used to assess the relative value of IV-SD transmission line options to each other assuming they have the same on-line years.

In addition, the table shows that the ESSRA provides a higher estimated value than the Proposed Project, as acknowledged in SDG&E's testimony in Phase 2. Further, the ESSRA's value increases relative to the Proposed Project given DRA's adjustment to ESSRA cost estimates. The ESSRA thus appears to have the highest economic value based on the analytic rubric SDG&E has offered in this case.[8]

3. LCR Benefits

Given the ongoing uncertainty regarding an IV-SD transmission line's reliability benefits, DRA developed a new model for Phase 2 to estimate such benefits under four "San Diego LCR" scenarios, described below.[9]

To make its estimates of reliability benefits, DRA multiplied the MW changes in SDG&E customers' System RA and LCR obligations by estimates of the prices SDG&E customers would pay for various types of system and local capacity. Through 2015, DRA assumed customers would pay prices similar to current prices for System RA and San Diego local capacity. DRA assumed that Greater IV-SD local capacity would be priced at a five percent discount to San Diego local capacity. From 2025 forward, DRA assumed that the net prices of new combustion turbines ("CTs") – that is, the cost of building new CTs, less the peak energy revenues their owners would earn – would set the capacity prices for System RA, San Diego local, and Greater IV-SD local capacity. DRA based this "net new build" System RA price on a recent California Energy Commission ("CEC") study, and adjusted the price of Greater IV-SD and San Diego local capacity upward to reflect the likely more constrained building environment in those areas.

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[8] Exhibit D-102, pp. 11-12.

[9] DRA employed a different approach to estimating the reliability benefits of a new IV-SD transmission line than it did in Phase 1. In its Phase 1 analysis, DRA relied on SDG&E's local reliability cost model to prepare its estimates of Sunrise's reliability benefits. However, DRA did not in Phase 1 make quantitative estimates of the impact of alternative LCR scenarios, such as the possible designation of a new Greater IV-SD local area combined with a Stirling contract failure in the presence of a new IV-SD transmission line. Because DRA assessed some major new uncertainties in Phase 2, DRA's Low estimate of an IV-SD TL's LCR benefits is substantially lower than its Phase 1 Low estimate and DRA's High With Stirling scenario benefits are higher than DRA's Phase 1 High estimate.

Finally, between 2015 and 2025, DRA assumed capacity prices would rise log-linearly (that is, in equal annual percentages) between the market prices assumed in 2015 and "net new build" prices assumed in 2025.[10]

In response to SDG&E's direct testimony, DRA in its rebuttal testimony updated its estimates of the benefits of a new IV-SD TL. To estimate benefits consistent with SDG&E's approach, DRA extended the years considered to cover a period of 58 years instead of 40 years, increased the cost escalation rates and reduced the discount rate, and further reduced the benefits computed in the "Stirling Success" and "Stirling Failure" scenarios to reflect the even higher uncertainty surrounding these benefits in years 41 to 58. Specifically, DRA reduced the Stirling Success multiplier from 80 to 70 percent and the Stirling Failure multiplier from 50 to 40 percent. To estimate the impact of a delay in the construction of an IV-SD transmission line, DRA also computed local reliability benefits assuming the IV-SD transmission line's 58-year life would extend from 2012 to 2069.[11]

The "San Diego LCR" scenarios examined by DRA are as follow:

1. *Immediate Benefits (Medium Scenario):* In this scenario, SDG&E customers would quickly benefit by avoiding payment for 1,000 MW of San Diego area LCR obligations, though this benefit would be offset by increased payments for an additional 1,000 MW of System RA obligations. In addition, because of the quick realization of the benefits and their seeming likelihood, and the related local reliability operational costs that might be avoided by reducing reliance on existing San Diego area generators, DRA increased the computed value of this scenario by 50 percent.

2. *Minimal Relief (Low Scenario):* In this case, SDG&E customers would again benefit immediately by paying for 1,000 MW less of the San Diego LCR obligation. However, this benefit is offset by the need to pay for a new LCR obligation in the new GIV-SD local area, which will be exactly 1,000 MW more than the new San Diego obligation. Resources that can meet the current San Diego local need can also meet the GIV-SD local

[10] Exhibit D-101, pp. 23-24 and Appendix J.

[11] Exhibit D-102 pp.5-6.

need, but additional existing resources are also available to meet such GIV-SD area needs. However, DRA does not know whether the two additional generators that could meet a GIV-SD obligation – the La Rosita and TDM plants – are readily available to contract to provide such services or what terms and conditions they might seek if they are available. It is thus not clear there will be significant cost reductions for ratepayers. For this reason, DRA assumed in this scenario that the GIV-SD LCR price would only be modestly lower than the San Diego local capacity price. DRA did not make an adjustment to the benefits of this scenario.

3. *Stirling Success (High With Stirling Scenario):* In this scenario, the San Diego area LCR is again cut by 1,000 MW and the new GIV-SD LCR is again 1,000 MW greater than the original San Diego area LCR. However, in this case, 900 MW of new generation becomes available to meet this GIV-SD need over the next several years as Stirling succeeds at developing all of its solar-thermal capacity on schedule *at no additional expected cost to SDG&E customers*. This result would provide substantial benefits to SDG&E customers. The remaining amounts of new GIV-SD local need not met by Stirling, which eventually drops to only 100 MW, would still need to be met by other eligible local resources. The outcome of this scenario could be extremely favorable, though the actual achievement of this outcome will not be known for several years. Despite its potential value, this scenario is thus a much more speculative outcome that Scenario 1, as it relies on Stirling coming on-line on schedule and budget *and* continuing to operate at full capacity throughout the forecast horizon. Further, this scenario assumes Stirling's contracts are renewed after their twenty-year terms expires. To account for these uncertainties, the computed benefits of this scenario were reduced by twenty percent.

4. *Stirling Failure (High Without Stirling Scenario):* In this scenario, the San Diego LCR is again cut by 1,000 MW and a GIV-SD LCR is again instituted equal to the prior San Diego LCR. However, in this case, it is assumed that Stirling fails to deliver power pursuant to its contract. Instead, capacity to meet the GIV-SD need using the facilities of a new IV-SD TL is developed at later dates. Such resources could still include a delayed Stirling project or other renewables or conventional generators that connect directly to the IV substation. The realization of benefits in this scenario is very uncertain, as it may rely on future, as yet unidentified projects. Achieving the full estimated benefits of this scenario may also be difficult because, if Stirling fails, future developers may seek to capture in their pricing terms some of the benefits of meeting the GIV-SD LCR obligation. The benefits of this scenario were thus adjusted downward by 50 percent to reflect the substantial uncertainties of this scenario. The

benefits of this scenario obviously fall between those of Scenario 2, Minimal Relief, and Scenario 3, Stirling Success.[12]

The table below summarizes the reliability benefits of a new IV-SD transmission line for each of the above LCR scenarios.

Estimated Reliability Benefits of New IV-SD TL
for Local Capacity Requirements Scenarios[13]
($2011 MM)

		(levelized $2011MM) Benefit Scenarios:			
	IV-SD TL On-Line Date:	Low	Medium	High Without Stirling	High With Stirling
Benefits:	2011	8.6	47.1	62.6	116.7
	2012	8.2	44.3	62.7	116.0
LCR Scenario:		2. Minimal Relief	1. Immediate Benefits	4. Stirling Failure	3. Stirling Success

4. Energy Benefits

To estimate the energy benefits of each of the three IV-SD transmission line alternatives, DRA started with its original, Phase 1 estimates of Sunrise's energy benefits. However, given the recent steep rise in natural gas prices, DRA increased its Phase 1 estimates of an IV-SD transmission line's energy benefits by approximately 60 percent. This resulted in energy benefits ranging from a low of $20.0 million to a medium of $40.0 million to a high of $80.0 million. In this instance, DRA's High scenario does not distinguish between the "With" and "Without" Stirling scenarios.[14]

[12] Exhibit D-101, pp. 24-26.

[13] Exhibit D-102, p.6, Attachments A and B.

[14] Exhibit D-101, p.27.

Based on DRA's review of Phase 1 testimony on modeling issues, DRA is more convinced than ever that its prior criticisms of others' Gridview modeling – and SDG&E's in particular – are correct. DRA thus believes the Commission should give no weight to SDG&E's Gridview results and only limited credibility to the CAISO's Gridview results. DRA also continues to believe that its estimates of Sunrise's energy benefits submitted in its Phase 1 Direct Testimony are still the most reasonable submitted in this case.

In response to SDG&E's Phase 1 direct testimony, DRA adjusted its estimates of energy benefits to reflect the increase in the economic life of the IV-SD transmission line. DRA did so by adapting its estimates of levelized energy benefits, which were computed using a 40-year economic life, to reflect a 58-year economic life and SDG&E's new inflation and discount rate assumptions. First, DRA developed from its original estimate a 40-year stream of escalating energy benefits with the same present value as the 40-year stream of levelized benefits. DRA then assumed this stream of benefits would continue escalating at 2.5 percent per year through years 41 to 58. DRA then computed the levelized value of this 58-year stream of energy benefits. To assess the impact of a new IV-SD transmission line not being available until 2012, DRA again computed the levelized value over 58 years of a stream of energy benefits that starts in 2012 and ends in 2069.[15]

The estimated energy benefits of a new IV-SD transmission line, assuming both 2011 and 2012 start years, are summarized in the table below.

Estimated Energy Benefits of New IV-SD Transmission Line[16]

		(levelized $2011MM) Benefit Scenarios:		
	IV-SD TL On-Line Date:	Low	Medium	High
Benefits:	2011	21.0	42.0	84.1
	2012	20.0	40.0	80.0

VI. WILDFIRE CONSIDERATIONS

DRA takes no position on this topic at this time.

[15] Exhibit D-102, p.6.

[16] Exhibit D-102, p.7, Attachment C.

VII. COMPARISON OF THE PROPOSED PROJECT, THE DEIR ALTERNATIVES, AND PARTY-PROPOSED ROUTE OPTIONS

A. Ability to Provide System Reliability

DRA's analysis in this proceeding shows that a new IV-SD transmission line would not necessarily provide significant local reliability benefits to SDG&E and its customers. Neither SDG&E nor the CAISO has credibly refuted DRA's analysis. Therefore, the Commission should not assume that a new IV-SD transmission line such as Sunrise would definitively meet SDG&E's local reliability challenges in the coming years. Accordingly, the Commission's need determination in this proceeding cannot be based on the purported ability of Sunrise to provide system reliability benefits.

Of the various alternatives presented in the Draft EIR/EIS, the Commission's authority to grant a CPCN applies only to those options that would create a new IV-SD transmission line. Therefore, DRA's Phase 2 testimony focused on the three such alternatives: SDG&E's Proposed Project, the ESNRA, and the ESSRA. In particular, DRA examined the ability of a new IV-SD transmission line to maintain and enhance local reliability within SDG&E's service territory, one of the primary benefits that have been attributed to Sunrise if it is constructed. DRA found that none of the IV-SD transmission line alternatives would necessarily result in significant reliability benefits for SDG&E ratepayers.

1. The net impact on LCRs of a new Imperial Valley – San Diego transmission line is less than 1,000 MW.

SDG&E and the CAISO have claimed in this proceeding that its Proposed Project, and presumably the other two IV-SD transmission line alternatives described in the Draft EIR/EIS, would reduce SDG&E customers' local capacity requirements ("LCRs") by 1,000 MW. However, it is likely that when the CAISO performs its annual LCR study

for the SDG&E area in the presence of any IV-SD transmission, it will *not* find that a net 1,000 MW reduction in SDG&E customers' LCRs should be permitted.[17]

As DRA noted in Phase 1,[18] the CAISO issued a long-term LCR Study in October 2006 in which Sunrise yielded a 1,000 MW reduction in the "San Diego" local area LCRs in year 2011, but also created a new "Greater Imperial Valley – San Diego" ("Greater IV-SD") local area with LCRs equaling the San Diego area's *pre-Sunrise* LCR. This suggests that SDG&E customers would not see any reduction in their net LCR obligation and, as such, would still need to purchase just as much local capacity to meet local reliability needs in the presence of Sunrise.[19]

The CAISO issued another long-term LCR study in December 2007. This study yielded similar results about San Diego's local needs for the years of 2010 and 2012: though San Diego area LCRs seemingly drop by 1,000 MW because of the presence of Sunrise, the new Greater IV-SD area that is created has an LCR need exactly equal to the San Diego area's *pre-Sunrise* need. Again, therefore, SDG&E customers would not be relieved from purchasing even one fewer megawatt of LCR capacity.[20]

2. It is unclear whether La Rosita and TDM will be available to meet Greater IV-SD LCR needs.

Both CAISO studies mentioned additional generation units that interconnect directly with the Imperial Valley substation and could be used to meet Greater IV-SD area needs: the Intergen/Coral La Rosita and Sempra Termoelectrica de Mexicali ("TDM") plants. These units are apparently considered to lie within the Greater IV-SD local area but outside of the San Diego local area. However, DRA is not aware whether these specific plants are readily available to provide local reliability services to the

[17] Exhibit D-101, p.8.
[18] See, e.g., DRA Phase 1 Opening Brief, pp. 55-56.
[19] Exhibit D-101, pp. 8-9.
[20] Exhibit D-101, p.9

Greater IV-SD area, or under what terms and conditions the plants' owners would provide such services.[21]

3. It is uncertain whether and how much Stirling capacity will be available in 2010.

The CAISO overestimates the amount of solar thermal capacity that will be available in 2010. The CAISO's 2007 Long-Term LCR Study also identifies some other units as being available in the Greater IV-SD area in 2010: some 900 MW of solar thermal capacity. If such capacity were available to meet LCR needs in 2010, and was already under contract to SDG&E, much of the new Greater IV-SD need would be met at no additional expected cost to SDG&E customers. However, this assumption is wrong and cannot be used by the Commission in this proceeding. These units – apparently reflecting the 900 MW of solar thermal generating capacity that would interconnect directly to the IV substation that SDG&E has contracted from Stirling Energy Systems (Stirling) – will not be available at all in 2010 for purposes of meeting local needs. Rather, the first 300 MW could begin operations by the end of 2010, and thus might be available to meet 2011 LCRs. But the remaining 600 MW of Stirling capacity will not be available for some additional years.[22]

However, Stirling's ability to develop its resources and operate them successfully for the twenty-year life of its contract with SDG&E is uncertain. And if Stirling does not materialize on schedule, additional support of the GIV-SD area need may be obtained from other resources in either the existing San Diego local area or that might interconnect using the unique facilities of a new IV-SD TL. In particular, resources that "direct connect" to the IV substation (IV-DC resources) may apparently meet GIV-SD area need. Such support could come from the Stirling resource if it materializes at a later date, or possibly other renewable or conventional IV-DC generators. It is possible in the future

[21] Exhibit D-101, pp. 9-10.

[22] Exhibit D-101, p.10.

that resources might meet GIV-SD needs if they connect to other parts of a new IV-SD TL, such as the new 230 kV San Felipe substation proposed for the ESNRA. But the development of such resources in the event of a Stirling failure will take time and is a highly uncertain outcome.[23]

4. Range of IV-SD transmission line impacts on LCR

To illustrate the potential range of reliability benefits of a new IV-SD transmission line, DRA developed four "San Diego LCR" scenarios, described below.[24]

1. *Immediate Benefit:* In this scenario, the CAISO would find, contrary to its 2006 and 2007 Long-Term LCR Studies, that there is no need to create a new GIV-SD local area, or similar area, to supersede the existing San Diego local area. SDG&E customers would be relieved immediately of 1,000 MW of their existing San Diego LCR obligations. However, this obligation would be replaced with an offsetting 1,000 MW increase in the System Resource Adequacy obligation. DRA believes this scenario would be favorable for ratepayers and provide an immediate reduction in their LCR costs, driven mainly by the difference between San Diego LCR and System RA capacity costs.

2. *Minimal Relief:* In this scenario, the CAISO would find, consistent with its Long-Term LCR Studies, that there is a need to create a new Greater IV-SD local area to supersede the San Diego local area. SDG&E customers would again be relieved immediately of the need to procure 1,000 MW of local capacity to meet the San Diego area LCR obligation. However, this benefit is offset by a new Greater IV-SD LCR obligation exactly equal to the prior San Diego area LCR obligation, and SDG&E customers would still need to procure the same amount of local resources as before. Thus, SDG&E customers would effectively face an offsetting new 1,000 MW LCR obligation in the new Greater IV-SD local area. As discussed above, there might at least be some additional resources available to meet this need; however, DRA anticipates this to be a less valuable outcome for SDG&E ratepayers.

3. *Stirling Success:* This scenario is identical to Scenario 2, Minimal Relief, except that 900 MW of this Greater IV-SD LCR obligation is met within

[23] Exhibit D-101, p.10.

[24] Exhibit D-101, pp. 11-13.

the next decade *at no additional expected cost* by Stirling's success at performing pursuant to its existing contracts with SDG&E. The remaining amounts of Greater IV-SD local need, which drops to 100 MW, would still need to be met by eligible local resources. For this scenario, DRA assumes that Stirling delivers its first 300 MW at the end of 2010, its second 300 MW at the end of 2012, and its final 300 MW at the end of 2014. The outcome for SDG&E ratepayers of this scenario should be extremely valuable, though the ultimate success of this outcome will not be known for several years. Despite its potential value, it is thus a much more speculative scenario that Scenario 1, Immediate Benefits.

4. *Stirling Failure:* This scenario also develops as does Scenario 2, Minimal Relief, but Stirling fails to develop new resources on schedule. Instead, it is assumed that Stirling or another developer of conventional or renewable resources successfully develops IV-SD resources in 300 MW increments by the ends of 2012, 2015 and 2018. This outcome could still provide SDG&E customers substantial benefits, though likely lower than the benefits realized in Scenario 3. However, the emergence of this scenario is highly uncertain and will remain so until well into the next decade.

5. A new IV-SD transmission line would not necessarily lead to the retirement of the South Bay Power Plant.

The Sunrise application is premised on SDG&E's contention that the SBPP will be retired by the end of 2009. SDG&E contends that the aging facility will be forced to retire because of the terms and conditions of the lease agreement between the owners of plant and its landlord, the Port Authority of San Diego.

It is reasonable to assume, that if the SBPP retires, the 700 MW which are currently available to the local area under reliability-must-run ("RMR") contracts with the CAISO would disappear. For grid planning purposes, assuming N-1/G-1 conditions, 700 MW of firm local resources, (generation, transmission, or demand-side) would need to replace South Bay within the next several years.

However, the lease agreement does not appear to force the owners of the SBPP to retire the units. The lease does allow for an orderly transition between the existing SBPP

and a new, replacement, generation plant.[25] Presumably, the existing units are expected to operate, or at least be available, until *after* the new replacement plant is built and operating. The lease merely suggests that the transition is expected to occur during 2009.[26] If a new replacement plant has an expected online later than 2009, the same type of transition would be contemplated.[27]

An application for certification ("AFC") was filed by the owners of the SBPP for the South Bay Replacement Project ("SBRP"), a 600 MW combined cycle generating plant, in early 2007 at the California Energy Commission. Later in 2007, the AFC was withdrawn. The developers of the SBRP, the Port Authority, civic leaders from the City of Chula Vista, and other stakeholders, are discussing alternative sites to the one identified in the AFC, which would have been very close to the current SBPP.[28]

But based on the lease, the existing SBPP can remain available and operate until its replacement is developed.

The other player in the South Bay issue is the CAISO. Only the CAISO has the authority to remove the SBPP from RMR status.[29] If the CAISO takes such action, there is doubt as to whether the SBPP would be economically viable and would continue to operate. However, the CAISO presumably would not make such a decision until adequate resources are available to replace SBPP in the San Diego local area to ensure grid reliability. Hence, the Commission's decision on the Sunrise application would effectively lead to the shut down of the SBPP, but the Commission cannot control the potential development of the new SBRP in the Sunrise proceeding.

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[25] *See* Phase 1 oral testimony of South Bay Replacement Project ("SBRP") witness Ali Amarali, RT 2369 (Sept. 28, 2007).

[26] *See* SBRP/Amarali, RT 2352-2370.

[27] *See* SBRP/Amarali, RT 2369.

[28] See http://www.energy.ca.gov/sitingcases/southbay/documents/index.html.

[29] *See* SBRP/Amarali, RT 2364.

The CAISO has made seemingly contradictory statements regarding the events that would have to occur before it would remove the RMR designation from the existing SBPP, which DRA believes would very likely trigger SBPP's retirement.[30] For example, the CAISO has apparently made public statements stating that the development of Sunrise may not be sufficient for the CAISO to allow the SBPP to be retired.[31] On January 28, 2008, CAISO President and Chief Executive Officer Yakout Mansour sent a letter to the Mayor of Chula Vista regarding the events that would have to occur before the CAISO would agree to remove the RMR designation. This letter contains yet additional information on the CAISO's views on this matter.[32]

DRA recognizes that, unlike some other CAISO public statements, the January 28 Letter does seem generally consistent with the CAISO's position in this case that the construction of the Sunrise Powerlink would trigger the CAISO's removal of the RMR designation from the SBPP, provided at least one other likely pre-cursor also occurs, such as the completion of the Otay Mesa Energy Center ("OMEC"). However, the January 28 Letter makes two additional statements that are worth noting. First, the letter says that the occurrence of only two out of three conditions would be sufficient for the CAISO to end the SBPP's RMR designation: the completion of OMEC, the completion of the Sunrise Powerlink, and/or the completion of new peakers that SDG&E has under contract. The January 28 Letter thus seems to state that Sunrise itself is not truly necessary to remove the SBPP must-run designation in the near future.[33]

In addition, the January 28 Letter refers to two additional development projects that DRA had not heard mentioned before in this context: the completion of the new Silvergate 230 kV substation and related upgrades (expected in December 2008) and the "Baja Norte natural gas interconnection (scheduled for January 2008)." DRA confirmed

[30] *See* Exhibit D-101, pp. 18-19. *See also* Exhibit D-66, DRA Phase 1 Direct Testimony, p. 19 and Appendix B, for a discussion of the pre-conditions to a retirement of SBPP.
[31] Exhibit D-101, pp. 18-19.

[32] Exhibit D-102, p.25, Attachment I.

[33] Exhibit D-102, pp. 25-26.

from the CAISO's *2008 Transmission Plan* that the completion of the new Silvergate 230 kV substation is expected by December of this year, though a possibly-related development (the loop-in of a transmission line to the Silvergate 69 kV switchyard) is not scheduled for completion until June 2009. But the information in the CAISO's *2008 Transmission Plan* is consistent with the January 28 Letter.[34]

However, it remains unclear what the January 28 Letter means by the "Baja Norte natural gas interconnection," much less why the CAISO should consider it in assessing reliability in the San Diego load pocket. Although the impending completion and operation of Sempra LNG's Energía Costa Azul ("ECA") Liquefied Natural Gas ("LNG") terminal may affect availability of natural gas in Baja California and the Southwestern United States, it is not clear to DRA that the completion of ECA and related efforts will expand gas deliverability into the San Diego area. Further, to DRA's knowledge, this is the first time the CAISO has opined on the necessity of particular gas delivery facilities as being necessary to meet the San Diego local reliability criterion.[35] The CAISO's witness on this subject, Robert Sparks, did not appear to have personal knowledge of the specific attributes of the so-called "Baja Norte natural gas interconnection issue," or whether expansions of other natural gas facilities would be required to increase gas deliverability into San Diego sufficiently to allow the CAISO to remove the RMR designation from South Bay.[36]

6. SDG&E and the CAISO's reliability cost modeling data and assumptions are deeply flawed and should be accorded no weight.

Both SDG&E and the CAISO in Phase 2 have continued to use deeply flawed means to estimate "reliability" benefits in the presence of the Proposed Project and its alternatives. In particular, both assume that competition among generating units will

[34] Exhibit D-102, p.26.

[35] Exhibit D-102, p.26.

[36] *See* CAISO/Sparks, RT 5373-78; *see also* Exhibit D-90.

yield significant savings in the fixed costs paid to RMR units that must be contracted to meet local reliability criteria. However, the savings due to such purported "competition" are grossly overestimated. In the case of RMR units located in the San Diego local reliability area, such competition will be ineffective because RMR units will not likely survive for long without contracts providing them full coverage of their fixed costs. The CAISO has also grossly overestimated the amount of "RMR operational costs" that a new IV-SD TL or other alternatives might avoid. And in the case of RMR units located in the Los Angeles Basin ("LA Basin"), the CAISO has again grossly overestimated the potential savings in the fixed costs paid to RMR units.[37]

a) SDG&E and CAISO Modeling of San Diego Area RMR Units Implausible

Both SDG&E and the CAISO assume that the costs paid to San Diego area RMR units still assumed needed under various alternative scenarios will fall substantially due to the "competition" created when new transmission into the San Diego area is added. DRA does not dispute that "competition" can be a positive influence on ratepayers' behalf in many cases. However, a simple review of the performance characteristics of most San Diego RMR units shows that such units likely have no other means of earning sufficient revenues to remain in operation unless they have contracts that provide them full recovery of their fixed costs. Their only realistic alternative – recovering their fixed costs from some form of market transaction for electric energy – are not plausible given these units' acknowledged inefficiencies. This is particularly true for the units that SDG&E divested in the 1990s, which comprise 1,822 MW of capacity, all of which is currently needed to meet the San Diego local reliability criterion.[38]

The table below presents data regarding the operation of the SDG&E-divested units over the past two years. The table shows that all SDG&E-divested units have low

[37] Exhibit D-102, p.17.
[38] Exhibit D-102, pp. 17-18.

capacity factors for "Market Transactions" – and that some sell no energy at all in "Market Transactions." Instead, these units run primarily to provide reliability services. But making market transactions will be necessary for such units to survive financially if they do not have full cost recovery contracts.[39]

[39] Exhibit D-102, pp. 18-19.

SDG&E-Divested Units' Operations in 2006-2007

	Capacity (MW)	Total hours each RMR Unit was operated	Total Energy each RMR Unit produced	Total Energy each RMR Unit sold in Market Transactions 1/	Total hours each RMR Unit was dispatched as an RMR Unit	Total hours each RMR Unit was **NOT** dispatched as an RMR Unit	Percent of Hours RMR Unit operated as other than RMR Unit	Capacity Factor of Energy Sold in Market Transactions (%)
				2006				
Encina 1	106	1,582	50,445	20,935	1,425	157	1.8	2.3
Encina 2	103	2,420	83,102	35,955	2,183	237	2.7	4.0
Encina 3	109	2,574	114,267	59,400	2,430	144	1.6	6.2
Encina 4	299	5,637	457,132	297,712	5,580	57	0.7	11.4
Encina 5	329	5,357	503,657	251,427	5,178	179	2.0	8.7
Encina CT	14	110	758	0	13	97	1.1	0.0
Cabrillo II, El Cajon GT	13	72	860	0	53	19	0.2	0.0
Cabrillo II, Kearney 1 CT	15	57	627	0	16	41	0.5	0.0
Cabrillo II, Kearney 2A-D CTs	55	109	2,729	0	58	51	0.6	0.0
Cabrillo II, Kearney 3A-D CTs	57	157	5,782	0	86	71	0.8	0.0
Cabrillo II, Miramar 1A-B CTs	33	269	2,374	0	61	208	2.4	0.0
South Bay, Unit 1	145	6,756	384,385	129,674	6,756	0	0.0	10.2
South Bay, Unit 2	149	6,326	353,566	81,681	6,237	89	1.0	6.3
South Bay, Unit 3	174	2,287	129,761	43,160	2,266	21	0.2	2.8
South Bay, Unit 4	221	1,475	92,891	30,723	1,136	339	3.9	1.6
South Bay, CT	13	40	454	0	16	24	0.3	0.0
				2007				
Encina 1	106	1,341	60,347	4,140	598	743	8.5	0.4
Encina 2	103	908	41,497	4,440	509	399	4.6	0.5
Encina 3	109	1,772	81,468	18,440	1,014	758	8.7	1.9
Encina 4	299	2,764	207,100	100,061	2,566	198	2.3	3.8
Encina 5	329	3,511	333,614	166,439	3,209	302	3.4	5.8
Encina CT	14	206	1,409	0	55	151	1.7	0.0
Cabrillo II, El Cajon GT	13	122	1,489	0	80	42	0.5	0.0
Cabrillo II, Kearney 1 CT	15	66	752	0	33	33	0.4	0.0
Cabrillo II, Kearney 2A-D CTs	55	169	6,403	0	124	45	0.5	0.0
Cabrillo II, Kearney 3A-D CTs	57	168	6,212	0	114	54	0.6	0.0
Cabrillo II, Miramar 1A-B CTs	33	152	3,654	0	112	40	0.5	0.0
South Bay, Unit 1	145	2,721	168,510	73,927	2,241	480	5.5	5.8
South Bay, Unit 2	149	3,045	181,411	50,670	2,343	702	8.0	3.9
South Bay, Unit 3	174	3,719	237,907	164,259	3,317	402	4.6	10.8
South Bay, Unit 4	221	1,837	150,954	24,205	803	1,034	11.8	1.3
South Bay, CT	13	179	1,847	0	95	84	1.0	0.0
Column ID:	A	B	C	D	E	F	G	H
Source:	SDG&E 8/4/06 Testimony, Table II-3, pp. II-44 to -47.	*2006 RMR Reporting Requirements*, CAISO, 3/9/2007, available at http://www.caiso.com/1b9c/1b9cca2f2def0.pdf *2007 RMR Reporting Requirements*, CAISO, 3/7/2008, available at http://www.caiso.com/1f83/1f8385b6713c0.pdf				= B - E	= 100 x F / 8,760	= 100 x D / (A x 8,760)

NOTE: 1/ "DA" added to this box for 2007 report; may indicate some market transactions made in "hour ahead" or "real time" modes.

Despite the obvious non-competitiveness of these resources, the CAISO and SDG&E assume that these units' owners will be willing to settle for RMR contracts that pay well less than full cost recovery. This is not a credible assumption. The Commission should discount these parties' reliability cost modeling results. In addition, SDG&E and the CAISO also assume that these units can be "mothballed" if they do not receive any contract and be available to return to service as needed in future years. This is also a deeply questionable assumption. It assumes that these assets' owners will be willing to continue to pay the costs of maintaining these units on the off-chance they might receive a full cost recovery contract in some unknown future year. DRA instead believes a more

realistic assumption is that once these units no longer receive full cost recovery contracts, they will be retired.[40]

b) CAISO RMR Operating Cost Data Badly Dated

The CAISO has also been assuming that substantial amounts of RMR operational costs can be avoided by new transmission serving San Diego. However, the CAISO uses as its base assumption a total potential annual cost to SDG&E customers of $60 million per year. This figure is quite dated and likely grossly overstates the level of such costs in San Diego now, and hence the level of such costs that could be avoided by a new IV-SD TL.

Based on CAISO oral testimony in Phase 1, DRA believes the source of the $60 million figure was apparently the "Net Pre-dispatch Costs ($M)" for SDG&E shown in Table 6.5 of the CAISO Department of Market Monitoring's ("DMM's") 2005 *Annual Report, Market Issues and Performance*, published in April 2006.[41] This page, which is provided as Attachment F, shows that total CAISO "Net Pre-dispatch Costs" in 2005 were $157 million. However, the same DMM report regarding 2006 showed that such "Net Pre-Dispatch Costs" for the entire CAISO fell to only $88 million, a substantial decline from the CAISO's total for 2005. The similar page of this report is provided as Attachment G (though it does not provide data at the same level of detail as the 2005 report). It is doubtful that SDG&E experienced $60 million of such costs if the entire CAISO reported only $88 million of such costs. Given that the highly-efficient Palomar Energy Center – the first modern-vintage combined cycle plant to operate in the San Diego area – began operations around March 30, 2006, it is likely that such costs fell dramatically in 2006. The completion of the similarly-efficient Otay Mesa Energy Center in 2009 should further reduce such costs. The San Diego-area RMR operating

[40] Exhibit D-102, pp. 19-20.

[41] *See* CAISO/Sparks, RT 2027:16-2029:3.

cost assumptions the CAISO has used in its post-2010 reliability cost modeling are thus highly suspect.

c) CAISO Data for Fixed Costs of Los Angeles Basin RMR Units Is Wrong

In Phase 1, the CAISO developed a new "Late Filed" model to assess the reliability benefits of Stirling and its alternatives. In Phase 2, the CAISO also used its Late Filed model to prepare its analysis. One key assumption of that model is that the various alternatives will also affect local reliability costs in the LA Basin. DRA has questioned whether some key assumptions of this model will be valid in the near future.[42]

Moreover, the price for RMR units in the LA Basin that the CAISO is assuming has no basis in fact and is likely wildly wrong. The CAISO assumes for its reliability benefits analyses that the maximum fixed costs for RMR units in the San Diego area was $46.21/kW-yr in 2006 dollars, which DRA believes was based on average RMR fixed capacity payments in San Diego in 2005. However, the CAISO also assumes that LA Basin RMR units will also be paid the price of $46.21/kW-yr in 2006 dollars, that is, that RMR units will be able to receive the maximum price in both the LA Basin and the San Diego load pocket.[43]

However, the same data source that was evidently used to estimate San Diego area RMR fixed costs also suggests LA Basin RMR fixed costs should be dramatically lower. As shown in the table below, the average LA Basin RMR cost for the year 2005 was only $14/kW-yr, or less than one-third of the average San Diego RMR fixed cost.

Recorded 2005 RMR Fixed Capacity Payments
for Los Angeles Basin and San Diego Load Pockets

[42] S*ee* Exhibit D-101, pp. 19-21.
[43] Exhibit D-102, pp. 21-22.

Row ID:	Variable	Units	SDG&E	SCE	Source:
A	Fixed Option Payments	($MM)	94	29	1/
B	RMR Capacity	(MW)	2,008	2,059	2/
C	RMR Fixed Capacity Payments	($/kW-yr)	46.81	14.08	1000 x A / B

Sources: 1/ Table 6.5 (p. 6-10) of CAISO Department of Market Monitoring Market Issues and Performance, published April 2006, provided as Attachment F.

2/ Sum of "Retained Designations" and "Terminations" from September 2, 2005 memo to CAISO Board of Governors regarding proposed 2006 RMR designations (p. 15). This excerpt is provided as Attachment H.

The CAISO clearly has a basis for assuming that San Diego area fixed capacity payments were $46.21/kW-yr in 2005. However, the CAISO had no basis for assuming that LA Basin RMR prices should be the same. This fundamental flaw in the CAISO's data is one more reason the Commission should reject the CAISO's reliability benefit projections.[44]

7. Summary of Project Alternatives' LCR Impacts

The table below summarizes the potential impacts on LCRs of the various options available to meet San Diego local reliability criteria.

Major Options Subject to Commission Influence
for Meeting San Diego Local Reliability Criteria[45]

Alternative	Reduction in Net Local Capacity Requirements of SDG&E Customers (MW)	Comments
Transmission:		
o New Imperial Valley – San Diego Transmission Line	0 – 1,000	Multiple estimates of a new IV-SD TL's contribution to local reliability submitted in this case
o TE/VS Transmission Line	500 – 1,000	o Currently pending before Commission in A.07-10-005 o Multiple estimates of TE/VS's contribution to local reliability also

[44] Exhibit D-102, p.22.

[45] Table from Exhibit D-101, page 33, with additional information (on first line) regarding IV-SD transmission line.

		submitted in this case[46]
o Path 44 Upgrade	300	SCE involvement and WECC Path Rating process may cause lengthy implementation period[47]
Generation:		
o 2010-2012 Long-Term RFO	10s to 100s	o SDG&E likely still negotiating with bidders to develop new local generation o Conventional generation could add "tens" to "hundreds" of MW of local capacity per project
o Renewables RFOs	1s to 10s	o SDG&E issues renewables RFOs annually[48] o Renewables projects would likely add local capacity in MW increments of "ones" to "tens"
o Future RFOs	10s to 100s	o The Commission can direct SDG&E to issues RFOs in the future to meet various needs, including local capacity needs
Non-Wires and "Short Wires" Alternatives:		
Various	10s to 100s	o Several initiatives to reduce or manage demand and develop local generation underway[49] o Local reliability contributions may come in small MW increments, though cumulative contributions could range to the "hundreds"

B. Ability to Facilitate Renewable Energy

In Phase 1, the CAISO developed a model to estimate the post-2005 incremental costs of meeting California's RPS objectives with and without the development of the Proposed Project.[50] The model is premised upon the following key assumptions: (1) The Proposed Project (or IV-SD transmission line alternative) would enable a significant

(continued from previous page)

[46] *See* Exhibit D-101, pp. 16-17.

[47] *See* Exhibit D-101, p.34.

[48] *See* Exhibit D-101, pp. 34-37.

[49] *See* Exhibit D-101, p.37.

amount of renewable resource development in the Imperial Valley that would otherwise have to be purchased from elsewhere; and (2) renewable energy for RPS compliance would be procured from renewable energy clusters or zones in California and in the rest of the WECC in an economically rational manner (i.e., lower cost resources are purchased first).[51]

DRA, with the objective of updating its benefit-cost estimates and of shedding light on particular questions of relevance to this proceeding, has made modifications to the CAISO's RPS compliance model and new estimates of RPS compliance benefits for the IV-SD transmission line alternatives. DRA used, as a starting point, the version of the RPS compliance model that the CAISO produced as part of its workpapers for the new analysis it introduced into its Phase 1 Opening Brief.[52] DRA made changes to the model to include consideration of line losses and wind integration costs, and updated the renewable energy and transmission cost assumptions. DRA then updated its estimates to be consistent with the new assumptions SDG&E introduced in its Phase 2 direct testimony.[53]

The renewables benefits of an IV-SD transmission line as estimated by DRA are summarized in the table below.

Imperial Valley-San Diego Transmission Line
RPS Compliance Benefits (levelized 2011$ MM)[54]

(continued from previous page)

[50] CAISO Exhibit I-2, pp. 46-70.

[51] Exhibit D-99, p.3.

[52] See CAISO Phase 1 Opening Brief, Nov. 9, 2007, pp. 70-73.

[53] Exhibit D-99, pp. 3-5; Exhibit D-100, p.11.

[54] Exhibit D-100, p.12.

	IV-SD TL On-Line Date:	(levelized $2011MM) Benefit Scenarios: Low	Medium	High
Benefits:	2011	0.9	43.5	108.3
	2012	0.9	41.4	103.0

C. Estimated Cost

DRA compared the estimated range of gross benefits to the estimated costs of the three IV-SD transmission alternatives. DRA used SDG&E's estimates of each alternative's levelized revenue requirements, including costs for "mitigation" and "capital replacement." DRA also prepared an extra ESSRA scenario cost to test the importance of seemingly anomalous cost estimates for the ESSRA by reducing the levelized costs of the ESSRA by eight percent.[55]

These cost estimates are summarized in the table below in levelized annual figures of millions of 2010 dollars, as SDG&E provided the data in its testimony and workpapers.

Estimated Levelized Revenue Requirements of New IV-SD TL

(levelized $2010MM)

Row ID:		Proposed Project	ESSRA	ESNRA	Formula:	Source:
	Assumed On-Line Dates	2011	2012	2012		SDG&E Phase 2 Direct Testimony (3/25), Table 11.5, footnotes c/ and d/ (p. 11.18)
A	Revenue Requirements	160	150	280	Input	Sunrise Rev Req Results Summary - Proposed Errata.xls, cells C, F and E 13.
B	Adjustments					
C	- Mitigation	18	13	17	Input	SDG&E Phase 2 Direct Testimony (3/25), Table 11.12 (p. 11.35)
D	- Capital Replacement	7	7	16	Input	
E	Subtotal	25	20	33	C + D	
F	**Total Revenue Requirements**	**185**	**170**	**313**	**A + E**	
G	Adjustments to ESSRA		12		7.8% x A	DRA Phase 2 Rebuttal Testimony, Volume 1 of 3, Appendix A.
H	**Adjusted ESSRA Total Rev Reqs**		**158**		**F - G**	

DRA made some other adjustments to these data to enable it to compare them to its estimated benefits. First, DRA computed the levelized costs of each IV-SD transmission line alternative for a different on-line date, i.e., DRA computed the levelized costs of the Proposed Project assuming a 2012 on-line year and the levelized costs of the

ESNRA and ESSRA assuming a 2011 on-line year. To make these adjustments, DRA increased the estimated costs of the Proposed Project by three percent and reduced the estimated costs of the two Environmentally Superior routes by three percent.

DRA then converted these estimated costs by on-line year – which were all in levelized millions of 2010 dollars – to 2011 dollars by increasing each estimate by 2.5 percent, which is the estimate of underlying inflation SDG&E is using to convert "real" to "nominal" dollars.

The table below presents the levelized annual revenue requirements DRA used to assess the potential value of each of the IV-SD TL alternatives.

Levelized Revenue Requirements of New IV-SD TL Options for Differing On-Line Years, and Adjusted to $2011MM[56]

		Costs in $2010MM for Different On-Line Year		Costs in $2011MM for Each On-Line Year	
Alternative	Costs in $2010MM	2011	2012	2011	2012
Proposed Project	185		190.6	189.6	195.3
ESNRA	313	303.9		311.5	320.8
ESSRA	170	165.0		169.2	174.3
ESSRA, As Adjusted	158	153.7		157.5	162.3
Comments		Costs adjusted by three percent (half a year's escalation or de-escalation) to reflect earlier or later on-line years.		Costs escalated by 2.5 percent to convert $2010MM to $2011MM, per SDG&E escalation assumptions in Attachments 11-2 to 11-13 of Phase 2 Direct Testimony.	

D. Ability to Provide an Economic Benefit

Please see Section V.C., above.

E. Feasibility of Obtaining Necessary Approvals and Construction

DRA takes no position on this topic at this time.

F. Environmental Impact

DRA takes no position on this topic at this time.

(continued from previous page)

[55] Exhibit D-102, pp. 8-9.

[56] Exhibit D-102, p.9.

G. Expandability

DRA takes no position on this topic at this time.

VIII. EMF

DRA takes no position on this topic at this time.

IX. COST CAP

Please see DRA's Phase 1 Opening Brief, at pages 22-23.

X. OTHER

DRA has no other issues it wishes to raise at this time. DRA reserves the right to respond in its reply brief to any issues raised by other parties in their opening briefs.

XI. CONCLUSION

For the reasons set forth above, DRA respectfully requests that the Commission adopt DRA's recommendations in this proceeding.

Respectfully submitted,

/s/ MARION PELEO

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May 30, 2008

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document "**PHASE 2 OPENING BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES**" in **A.-06-08-010**.

A copy was served as follows:

[**X**] **BY E-MAIL**: I sent a true copy via e-mail to all known parties of record who have provided e-mail addresses.

[ ] **BY MAIL**: I sent a true copy via first-class mail to all known parties of record.

Executed in San Francisco, California, on the **30th** day of **May**, **2008**.

/s/ MARION PELEO

Marion Peleo

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address and/or e-mail address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

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