Attachment 1

Tower Placement, Data Information Tables and Location Information

Clarification

Note on the symbols used, referenced in the "Legend," on the following computer generated tower Plan and Profile Sheets:

1. "Spotting Constrain" is more accurately "Spotting Constrain<u>t</u>" (added "t"). The final letter was omitted due to computer program limitations. Spotting constraints represent road crossings which were identified on aerial photos and assumed for tower spotting. Survey data for final line design should provide information of all obstacles where no structure should be spotted.
2. References to various color lines, and the lines themselves are computer embedded reference codes and should not be used for any purpose.

Documents supporting the ability of Talega-Escondido/Valley Serrano 500 kV Interconnect to reduce the local capacity requirement (LCR) for San Diego 1,100 MW

In response to the contention by CAISO that the Talega-Escondido/Valley Serrano 500 kV Interconnect (TE/VS) proposed by The Nevada Hydro Company (TNHC) cannot produce more than a 625 MW reduction in the local capacity requirement (LCR) for San Diego, there are three items to be considered.

1. The CAISO's record of the Sunrise CPCN Phase II hearings

CAISO witness Robert Sparks, in his testimony for Phase II of the Sunrise Project CPCN hearings, in his response to the question, "Why is it incorrect to assume that TE/VS would reduce LCR by 1000 MW?", states,

> *"In its Phase I testimony, the CAISO calculated the reliability benefits of TE/VS (alone and in combination with the LEAPS hydro generation) and determined that the project would reduce LCR by 500 MW in the San Diego area. The Nevada Hydro Company (TNHC), the TE/VS proponent, did not agree with this conclusion but did not provide any credible analysis that would cause CAISO to change the 500 MW determination. However, following the conclusion of Phase I, the Energy Division requested that the CAISO re-evaluate the ability of TE/VS to reduce LCR taking into account the operation of the phase shifters. The CAISO has undertaken this additional analysis."*

Then Mr. Sparks was asked, "What were the results of the CAISO's additional analysis?" His answer was,

> *"Based on power flow studies with the phase shifters set to force the TE/VS line flow to 1,000 MW, the CAISO determined that TE/VS could reduce LCR by up to 625 MW in the San Diego area."*

In a confidential document supplied to the Sunrise proceeding by CAISO on March 14, 2008, Mr. Sparks provided a spreadsheet which shows the basis of his conclusion that the ability of TE/VS-LEAPS to reduce SDG&E's LCR is limited to 625 MW. This spreadsheet, and Mr. Sparks testimony may be found in Exhibit1.

It should be noted that the basis, shown at the top of that spreadsheet, is the use of "G-1/N-1-1" conditions. That is, the planning criteria upon which the 625 MW limit is based is the loss of a generator, then the loss of a transmission element and then the loss of another transmission element. This is inconsistent with CAISO's own planning criteria, which is "G-1/N-1", the loss of a generator and then loss of a transmission element. The CAISO planning criteria are shown Section II, item 3 on page 4 of the document "California ISO Planning Standards", dated February 7, 2002, attached as Exhibit 2. The

“Category B” conditions mentioned there are shown on page 24 of the WECC document, “Reliability Criteria”, dated August 2002, attached as Exhibit 3. Because of the misapplication of its own criteria, the conclusion CAISO presents is incorrect.

2. The inclusion of a thorough analysis of the capabilities of TE/VS by TNHC

The presentation by TNHC of a thorough analysis to support the minimum capability of at least a 1,000 MW LCR reduction was provided by TNHC in its Phase II testimony in the Sunrise proceedings. This analysis for Phase II was provided in support of the testimony of Mr. Fred Depenbrock on behalf of TNHC. Further, on pages 5 to 7 of Mr. Depenbrock’s Phase 2 Rebuttal Testimony, he outlines the perceived errors that caused both the CAISO and SDG&E to draw the conclusion that they provided in their testimony. This Phase 2 testimony and supporting documents are presented as Exhibit 4 in this submission.

3. The analysis of the capabilities and limitations of the SDG&E system in the summer of 2012

An analysis of the southern California system for the summer of 2012 was conducted by Mr. Depenbrock. The analysis was conducted using a WECC load flow case for summer heavy load conditions in 2012. The case was provided by WECC with both the Palo Verde-Devers II 500 kV line and the Sunrise Powerlink 500 kV line in service. These were removed and the TE/VS-LEAPS Project added, but with the LEAPS generation turned off.

Tests were made of combinations of G-1 and N-1 contingency combinations, and flow diagrams showing critical G-1, N-1 conditions are attached. The most critical G-1/N-1 combination continues to be the loss of Otay Mesa combined cycle generation and the loss of the Imperial Valley-Miguel 500 kV line. However, to show that the TE/VS Project performs adequately, G-1/N-1 tests were conducted for major elements of the Project as well. This analysis shows that TE/VS is capable of supplying 1,100 MW to the SDG&E system, thus reducing the LCR by 1,100 MW. These load flow cases are presented in Exhibit 5.

Exhibits

Exhibit 1

Robert Sparks (CAISO) Testimony
and
Confidential Workpapers

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 DIRECT TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR

Nancy Saracino, General Counsel
Judith B. Sanders, Counsel
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
151 Blue Ravine Road
Folsom California 95630
Tel. (916) 351-4400
Fax. (916) 608-7296
Email: jsanders@caiso.com

Jeffrey P. Gray
DAVIS WRIGHT TREMAINE LLP
Suite 800
505 Montgomery Street
San Francisco, CA 94111-6533
Tel. (415) 276-6500
Fax. (415) 276-6599
Email: jeffgray@dwt.com

Attorneys for the CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

March 12, 2008

I. INTRODUCTION

Q. Please state your name, title and employer.

A. My name is Robert Sparks, Lead Regional Transmission Engineer at the California Independent System Operator Corporation (CAISO). My qualifications have been previously provided at Attachment A to the CAISO Initial Testimony Part I, submitted in Phase 1 of this proceeding on January 26, 2007.

Q. Are you the same Robert Sparks who provided testimony in Phase 1?

A. Yes.

Q. On whose behalf are you submitting this Phase 2 initial testimony?

A. I am submitting this testimony on behalf of the CAISO.

Q. What is the purpose of your Phase 2 testimony?

A. It is my understanding that the November 1, 2006 and December 11, 2007 Scoping Rulings set forth the specific areas that will be examined in Phase 2. Accordingly, my testimony will address the following issues: (1) material factual inaccuracies or deficiencies in the draft environmental impact report/environmental impact statement (DEIR/EIS); and (2) the effect of project alternatives to Sunrise on system reliability and the ability to deliver renewable energy to SDG&E and CAISO customers. A cost-benefit analysis of the project alternatives will be presented primarily by Dr. Ren Orans, Managing Partner of Energy and Environmental Economics, Inc. (E3).

Q. How is your testimony organized?

A. The DEIR/EIS presents an analysis of the Sunrise Powerlink Project (Sunrise) as proposed by San Diego Gas & Electric Company (SDG&E) and 27 alternatives to the project, and ranks the seven environmentally superior alternatives.[1] The DEIR/EIS also analyzes a No Project/No Action Alternative. My testimony focuses on issues related to the environmentally superior alternatives and the No Project Alternative.

Q. Please summarize the key conclusions in your testimony.

A. With respect to the alternatives identified in the DEIR/EIS as environmentally superior , only Sunrise would meet all of the project objectives identified in the DEIR/EIS. As discussed below, the CAISO has identified material factual inaccuracies with respect to the other alternatives identified as environmentally superior in the DEIR/EIS and has a number of concerns regarding the ability of these alternatives to ensure electric reliability, reduce energy costs, and increase access to much needed renewable generation.

II. ADDITIONAL BACKGROUND FOR PHASE 2 TESTIMONY

Q. Please describe your understanding of the project objectives used in the DEIR/EIS to evaluate Sunrise and proposed alternatives to the project.

A. The DEIR/EIS notes that the California Public Utilities Commission (CPUC) and Bureau of Land Management have identified three "basic project objectives" which the DEIR/EIS uses to screen project alternatives. These three project objectives are:

1. To maintain reliability in the delivery of power to the San Diego region;
2. To reduce the cost of energy in the region; and
3. To accommodate the delivery of renewable energy to meet State and federal renewable energy goals from geothermal and solar resources in the Imperial Valley and wind and other resources in San Diego County.[2]

[1] DEIR/EIS at ES-2 - ES-4.

In particular, the DEIR/EIS notes that Project Objective 1 includes the SDG&E objective that the project provide transmission facilities with a voltage level and transfer capability necessary to meet anticipated load growth "through a total San Diego area import capability of at least 4,200 MW (all lines in service) and 3,500 MW (under G-1, N-1 contingency conditions)."[3] As the CAISO discussed in its Phase 1 testimony, this translates into a reduction in the Local Capacity Requirements (LCR) in the San Diego area of 1,000 MW. Thus, to satisfy Project Objective 1, an alternative must be able to reduce or contribute to meeting the San Diego LCR by 1,000 MW.

Q. Is it your understanding that the expected in-service date for Sunrise has changed since Phase 1 concluded?

A. Yes. It is my understanding that, as a result of delays in the issuance of the DEIR/EIS, SDG&E now expects the in-service date for Sunrise to be 2011.

III. ENVIRONMENTALLY SUPERIOR ALTERNATIVES

1. New In-Area All-Source Generation Alternative

Q. Please describe your understanding of the New In-Area All-Source Generation alternative (All-Source Generation Alternative).

A. The DEIR/EIS describes the All-Source Generation Alternative as providing approximately 1,000 MW of in-area generation consisting of one natural-gas fired combined cycle (*i.e.*, base load) power plant, four natural-gas fired peaking power plants, and a combination of wind, solar photovoltaic (PV) and biomass/biogas renewable generation facilities.

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[2] DEIR/EIS at ES-20.
[3] DEIR/EIS at Ap.1-20.

Q. Please describe the base load generation included in the All-Source Generation Alternative.

A. The DEIR/EIS identifies three base load generation projects within San Diego and assumes that one of these three projects "can feasibly be built by 2010."[4] Based on this assumption, the DEIR/EIS provides that "at least" 620 MW of "incremental firm on-peak [base load] capacity" can be expected by 2010.[5] The three base load generation projects identified in the DEIR/EIS are: (1) the South Bay Replacement Project (nominal capacity 620 MW); (2) the San Diego Community Power Project being developed by ENPEX (nominal capacity 750 MW); and (3) the Encina Power Plant Repowering (nominal capacity 540 MW).

Q. Do you have any concerns with the conclusion that at least one of these projects can feasibly be built as assumed in the DEIR/EIS and thus provide local generation capacity to help meet San Diego LCR?

A. Yes. I believe there are significant questions regarding whether the South Bay Replacement Project and ENPEX project will be built. In addition, the Encina project should not be expected to provide the amount of net incremental capacity that the DEIR/EIS seems to assume the project will provide. Thus, I do not believe it is prudent to rely upon these base load generation projects as described in the DEIR/EIS in evaluating the All-Source Generation Alternative.

With respect to the South Bay Replacement Project, the CAISO was notified by letter from the project developer dated October 19, 2007 that it was unable to secure site

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[4] DEIR/EIS at Ap.1-325.
[5] DEIR/EIS at Ap.1-326 (Table Ap.1-15).

control for the project, had elected not to proceed with executing a Large Generator Interconnection Agreement, and was no longer pursuing development of the project. A copy of the October 19 letter is attached to my testimony at Attachment A. As a result, the South Bay Replacement Project's interconnection request was removed from the CAISO's interconnection queue. In addition, the DEIR/EIS notes that in October 2007 the application for certification (AFC) with the California Energy Commission (CEC) was withdrawn for the project.[6] Given the time necessary to acquire site control (particularly in light of the difficulties the South Bay Replacement Project has already experienced with this issue), obtain necessary regulatory approvals (which can take a year or more), and complete construction (which can take several years), I do not believe it is reasonable to assume that the South Bay Replacement Project can feasibly be built in the next several years, even if the project's developer resumed development activities immediately. In any event, at the present time, it appears unlikely that the South Bay Replacement Project will be built at all.

The CAISO also has several concerns with respect to the ENPEX project. As an initial matter, the DEIR/EIS notes that the development status of the project is unclear. Specifically, ENPEX has not submitted an AFC to the CEC.[7] Thus, there is no indication that ENPEX is moving forward with the development of the project at this time. Moreover, for the CAISO's grid planning purposes, only generation projects that are under construction are considered when assessing the need for transmission system additions in 5 year planning cases. For 10-year planning cases, only generation projects

[6] DEIR/EIS at Ap.1-325, note 29.
[7] DEIR/EIS at Ap.1-332

that are under construction or have received regulatory approval are modeled in the study area.[8] Thus, because the ENPEX has not received regulatory approval, for planning purposes the CAISO does not assume that the ENPEX project will be online within the next 5-10 years (2013 - 2018).

Even without considering CAISO's grid planning assumptions, there are significant questions regarding when the project could be timely completed even if ENPEX were to submit an AFC for the project soon. Given the permitting and construction times I mentioned above, I question whether it is reasonable to expect that the ENPEX project could be constructed within the time period assumed in the DEIR/EIS. It is also my understanding that the City of Santee opposes the ENPEX project, which could further delay or perhaps prevent construction should ENPEX move forward with developing the project. The CPUC's own decision calls into question to assumption in the DEIR/EIS about the timing of construction of the ENPEX project. In its recent long-term procurement decision, the CPUC found that "[s]even years is a reasonable time to develop[, permit and construct] new generation and to avoid 'just-in-time' procurement."[9]

The Encina project is much further along in the permitting process than the ENPEX project and a decision from the CEC on an AFC for the Encina project is expected any time.[10] The Encina project, however, is a repowering project, meaning that it will simply

[8] *See* "Generation Assumptions for Grid Planning Studies." This document can be found at http://www.caiso.com/docs/2001/06/25/20010625134406100.pdf
[9] Decision 07-12-052, mimeo at 277 (Finding of Fact 40).
[10] *See* Carlsbad-NRG, Docket No. 07-AFC-6, http://www.energy.ca.gov/sitingcases/all_projects.html.

replace a portion of existing capacity (specifically, existing steam boiler Units 1, 2 and 3)[11] with new capacity, resulting in a net increase in capacity of only approximately 220 MW – not the entire 540 MW nameplate capacity for the project. My Phase 1 testimony in this proceeding, includes a table showing a capacity deficiency in San Diego beginning in 2010 and continuing through 2020.[12] In calculating this capacity deficiency, I assumed that the existing Encina power plant (Net Qualified Capacity 960 MW) is not retired. In other words, for purposes of calculating the need for Sunrise, the CAISO assumes the existing Encina power plant is still operating and providing capacity needed to help meet the San Diego LCR. Thus, even assuming that the Encina repowering project is built, the project would not result in a net 540 MW increase in available local generation capacity to meet SDG&E's LCR as the DEIR/EIS apparently assumes; it would only result in a net increase of approximately 220 MW..

Based on the above, I do not believe it would be prudent planning practice to rely upon the South Bay Replacement Project, the ENPEX project, or the Encina repowering project when evaluating the All-Source Generation Alternative.

Q. Please describe the natural-gas fired peaking power plants included in the All-Source Generation Alternative.

A. The DEIR/EIS identifies four specific peaking power plant projects within San Diego resulting from SDG&E's 2008 Peaker request for offers ("RFO") and assumes that these projects will be online in 2008.[13] Based on this assumption, the DEIR/EIS provides that 250 MW of "incremental firm on-peak [new or expanded peaker] capacity" can be

[11] DEIR/EIS at Ap.1-334.
[12] CAISO Ex. I-6 at 39 (Table 5).
[13] *See* DEIR/EIS at C-78; Ap.1-335.

expected by 2010.[14] The four peaker projects considered by the DEIR/EIS are located at: (1) Miramar substation (49 MW); (2) Pala substation (99 MW); (3) Margarita substation (99 MW); and (4) Borrego Springs substation (15 MW).[15] In addition, the DEIR/EIS identifies four other peaker projects that could be online by 2010 if the four specific peaker projects resulting from SDG&E's 2008 Peaker RFO are not fully developed to achieve the 250 MW target.[16]

Q. Do you have any concerns with the conclusion that 250 MW of incremental firm on-peak capacity can be provided by new or expanded peakers as assumed in the DEIR/EIS?

A. Yes, I have concerns regarding whether these peaker projects will result in 250 MW of incremental firm, on-peak capacity as assumed in the DEIR/EIS.

As an initial matter, I note that 138 MW of the 198 MW of capacity the DEIR/EIS assumes for the peaker projects located at the Pala (99 MW) and Margarita (99 MW) substations were already assumed to be on-line in 2008 for purposes of the CAISO's Phase 1 LCR analysis.[17] Thus, at most, the Pala and Margarita projects would seem to contribute only an additional 50 MW of on-peak capacity above what the CAISO has already assumed for these projects in Phase 1. However, that based on information in the CAISO's generation interconnection queue, the amount of generation under development at these locations may actually be only 100 MW – not 198 MW. This represents a 38 MW *decrease* in the amount of local capacity that the CAISO assumed would be

[14] DEIR/EIS at Ap.1-326 (Table Ap.1-15).
[15] DEIR/EIS at Ap.1-335 – 1-336.
[16] *See* DEIR/EIS at Ap.1-336 – 1-337.
[17] *See* CAISO Ex. I-6 at 39 (Table 5).

operating in its Phase 1 LCR analysis and a 98 MW *decrease* in the amount of peaker generation the DEIR/EIS assumes will be built as a result of SDG&E's 2008 Peaker RFO.

With respect to other peaker projects identified in the DEIR/EIS that could potentially make-up this shortfall, it is unclear whether any of these projects will actually be constructed. As the DEIR/EIS notes, no public information is available for the Kearney Mesa peaker or the Escondido peaker expansion projects, and the CEC provides no information on the status of these projects.[18] The Chula Vista Peaker expansion project has filed an AFC with CEC but, without a power purchase agreement, it is unclear whether the project will be constructed. Thus, there is little evidence to suggest that these peaker projects will go forward. This, in turn raises significant questions regarding whether these projects should be relied upon when evaluating the All-Source Generation Alternative.

Q. Please describe renewable generation included in the All-Source Generation Alternative.

A. Renewable generation included in the All-Source Generation Alternative consists of:

- Approximately 200 MW (nameplate) of wind power located in the Crestwood Summit/Boulevard area by 2010 with an additional 200 MW (nameplate) by 2016. For reliability accounting purposes, this equates to 48 MW by 2010 and an additional 48 MW by 2016.[19]

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[18] DEIR/EIS at Ap.1-336 – 1-337.
[19] DEIR/EIS at Ap.1-312 (Table Ap.1-13); Ap.1-317 – 1-318.

- Approximately 50 MW (both nameplate and for reliability accounting purposes) of biomass or landfill gas generation by 2010 with an additional 50 MW by 2016.[20]
- Approximately 210 MW (nameplate) of solar photovoltaic ("PV") to be installed on unidentified residential and commercial buildings by 2010. For reliability accounting purposes, this equates to 105 MW by 2010, reduced to 84.5 MW by 2016.[21]
- Approximately 300 MW (nameplate) of solar thermal to be developed near Borrego Springs by 2016. For reliability accounting purposes, this equates to 240 MW by 2016.

Assuming all of these resources are constructed within the time frames noted in the DEIR/EIS, nameplate capacity in the San Diego area would increase 460 MW by 2010 and 969 MW by 2016. For reliability accounting purposes, this equates to 203 MW in 2010 and 520.5 MW in 2016.[22]

Q. Do you have any concerns with the conclusion that renewable resources will provide 203 MW of incremental firm on-peak capacity by 2010 and/or 520.5 MW by 2016 as assumed in the DEIR/EIS?

A. Yes. Given the challenges in developing large scale renewable energy projects and the fact that some of the renewable projects identified in the DEIR/EIS do not have sites and/or are currently not being developed, I believe it would be extremely risky to rely upon the renewable generation projects identified in the DEIR/EIS in evaluating the All-Source Generation Alternative.

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[20] DEIR/EIS at Ap.1-312 (Table Ap.1-13); Ap.1-318 – 1-321.
[21] DEIR/EIS at Ap.1-312 (Table Ap.1-13); Ap.1-313 – 1-317; Ap.1-337.
[22] DEIR/EIS at Ap.1-312 (Table Ap.1-13).

For instance, with respect to potential solar thermal generation, the DEIR/EIS notes that no developers have identified sites in the Borrego Springs area that could accommodate a 300 MW solar thermal project.[23] The DEIR/EIS notes that to build 300 MW of solar thermal nameplate capacity approximately 1,500 acres of land would be needed.[24] Moreover, even if such a large site could be found, interconnecting such generation would require substantial additions or upgrades to the transmission infrastructure, including at least 40 miles of additions or upgrades from Borrego Springs to the closest existing 230 kV or 138 kV substation, as well as downstream upgrades beyond the existing 230 kV or 138 kV substation.

Potential wind resources also raise concerns regarding the ability to provide incremental firm on-peak capacity as assumed in the DEIR/EIS. As an initial matter, the DEIR/EIS notes that 400 MW of wind generation would require 2,000 acres of land in the San Diego area, which would seem to present significant land acquisition and permitting challenges. Significant transmission infrastructure would also be needed to interconnect new wind resources to the grid. Furthermore, as I discuss below with respect to the No Project Alternative, there are serious deliverability issues associated with new wind generation in the Crestwood area identified in the DEIR/EIS.

In order to achieve 210 MW of solar PV nameplate capacity, the DEIR/EIS notes that more than 26,649 residential and 85 commercial installations would need to occur each

[23] DEIR/EIS at Ap.1-312.
[24] DEIR/EIS at Ap.1-313.

year.[25] This is 25,000 more residential and 36 more commercial installations than currently occur each year. Moreover, the DEIR/EIS notes that developing 210 MW of solar PV capacity would require approximately 500 workers per year installing individual PV systems throughout San Diego county over a three year period.[26] Given this massive undertaking, it is questionable whether the amount of solar PV assumed to be online in the DEIR/EIS is achievable.

2. New In-Area Renewable Generation Alternative

Q. Please describe your understanding of the New In-Area Renewable Generation Alternative (Renewable Generation Alternative).

A. The Renewable Generation Alternative consists of the same renewable resources that the DEIR/EIS identifies for the renewable portion of the All-Source Generation Alternative.

Q. Do you have any concerns regarding the assumptions and conclusions in the DEIR/EIS related to the Renewable Generation Alternative?

A. Yes. For the reasons I previously discussed with respect to the renewable portion of the All-Source Generation Alternative, there is little evidence at this time to suggest that the renewable generation projects identified in the DEIR/EIS will be developed and constructed. Thus, I do not believe it is prudent to rely upon the renewable generation projects identified in the DEIR/EIS in evaluating Renewable Generation Alternative.

However, even if the CPUC were to assume that these renewable resources could be timely built, the associated capacity would not meet Project Objective 1 (reduce the San Diego LCR by 1,000 MW) because they would only provide 203 MW. As a result, I do

[25] *See* DEIR/EIS at Ap.1-313.
[26] DEIR/EIS at Ap.1-313 – 1-317.

not believe the Renewable Generation Alternative represents a feasible or reasonable alternative to Sunrise.

3. LEAPS Transmission-Only (TE/VS) Alternative

Q. Please describe your understanding of the LEAPS Transmission-Only Alternative ("TE/VS Alternative").

A. The DEIR/EIS describes the TE/VS Alternative as including only the transmission components of the LEAPS combined project (generation and transmission) and modifications to the existing SDG&E Talega-Escondido 230 kV transmission lines to accommodate the interconnection of the new 500 kV line and northern substation. The new 500 kV line would be constructed along the same corridor as the LEAPS Project, but no reservoir or pumped storage generation would be built.[27]

Q. Did the CAISO study a "transmission only" LEAPS alternative in Phase 1 of this case?

A. Yes. As explained in the CAISO Initial Testimony Part V, the CPUC Energy Division requested that the CAISO evaluate the reliability and economic impacts of the TE/VS project, both with the LEAPS pumped hydro storage facility as merchant generation,[28] and without the pumped hydro storage facility, in several different alternative scenarios.[29] The results of these studies were presented in Table 49 of the CAISO's Part V testimony. The CAISO's Phase 1 testimony also described its study assumptions for analyzing the LCR benefits of TE/VS on both the San Diego and LA basins.[30]

[27] DEIR/EIS at Ap.1-259.
[28] *See* CAISO/Ex. I-5 at 37-50 (Cases ED5 and ED6).
[29] *See* CAISO/Ex. I-5 at 10-36 (Cases ED1, ED2, ED3 and ED4).
[30] CAISO/Ex. I-6 at 17-25.

Q. Is the TE/VS Alternative evaluated in the DEIR/EIS the same project that the CAISO studied at the request of the Energy Division?

A. Based on my review of the project descriptions found at pages C-68-69 and A.1-259 of the DEIR/EIS, it is the same project that the CAISO studied.

Q. Has the CAISO identified any deficiencies or material factual inaccuracies with the evaluation of the TE/VS Alternative in the DEIR/EIS?

A. Yes, the CAISO has identified two factual inaccuracies in the evaluation. First, the DEIR/EIS incorrectly assumes that TE/VS would provide the same reliability benefits to the SDG&E area that Sunrise provides.[31] Second, the DEIR/EIS incorrectly concludes that TE/VS would "partially" achieve the objective of delivering renewable generation from the Imperial Valley and the Salton Sea areas.

Q. Please describe the first area of CAISO concerns with the DEIR/EIS evaluation of TE/VS.

A. As I note above, to satisfy Project Objective 1, an alternative must be able to reduce the San Diego LCR by 1,000 MW. The DEIR/EIS describes TE/VS as having a designed capacity of 1,300 MW to 1,600 MW.[32] No further explanation was provided, so for purposes of my testimony, I assume that the DEIR/EIS equates this designed capacity with the ability of TE/VS to reduce LCR. This is an incorrect assumption.

Q. Why is it incorrect to assume that TE/VS would reduce LCR by 1,000 MW?

A. In its Phase 1 testimony, the CAISO calculated the reliability benefits of TE/VS (alone and in combination with the LEAPS hydro generation) and determined that the project would reduce LCR by 500 MW in the San Diego area. The Nevada Hydro Company

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[31] *See e.g.*, DEIR/EIS at Ap.1-260.
[32] DEIR/EIS at C-69; A.1-260.

(TNHC), the TE/VS proponent, did not agree with this conclusion but provided no credible analysis that would cause the CAISO to change the 500 MW determination. However, following the conclusion of Phase 1, the Energy Division requested that the CAISO re-evaluate the ability of TE/VS to reduce LCR taking into account the operation of phase shifters. The CAISO has undertaken this additional analysis.

Q. What were the results of the CAISO's additional analysis?

A. Based on power flow studies with the phase shifters set to force the TE/VS line flow to 1,000 MW, the CAISO determined that TE/VS could reduce LCR by up to 625 MW in the San Diego area. This increase still does not bring TE/VS to the level of Sunrise in terms of reliability benefits, and it certainly is nowhere near the 1,300-1,600 MW level assumed in the DEIR/EIS. Nonetheless, because the CAISO has modified its reliability benefits assumptions for TE/VS, the CAISO has updated its net benefits analysis using the 625 MW LCR reduction amount in each of the scenarios analyzed in Phase 1 that included the TE/VS line. This updated analysis is set forth in Dr. Oran's Phase 2 direct testimony. As Dr. Orans explains, assuming TE/VS provides greater LCR reductions, the net benefits of the project in some scenarios are slightly increased, but decrease under other scenarios.

Q. Why does the CAISO consider the LCR reduction assumed for the TE/VS Alternative in the DEIR/EIS to be a material factual inaccuracy?

A. The reliability benefits provided by Sunrise are a key component of the proposed project. In my opinion, any alternatives to the project that are to be considered by the CPUC must provide the same level of reliability benefits - not just a portion of them. The CAISO has studied the TE/VS line and has concluded that Sunrise and TE/VS are not equal in many respects, in particular the ability of each line to reduce LCR. Even with the modification to the TE/VS analysis that I describe above, TE/VS does not meet the reliability objective identified by the DEIR/EIS as a method for screening project alternatives.

Q. **What is the CAISO's second area of concern with respect to the TE/VS Alternative?**

A. In order to meet Project Objective 3 (delivery of renewable energy), an alternative must promote SDG&E's ability to meet state and federal renewable energy requirements by facilitating access to sources of solar and geothermal energy in the Imperial Valley and Salton Sea areas. However, the DEIR/EIS acknowledges that this objective cannot be met by either of the TE/VS alternatives. Rather, the DEIR/EIS provides that the renewable energy objective will be met only "partially" because the ability of TE/VS to access renewables is dependent upon the completion of the Green Path North project, in conjunction with Southern California Edison's (SCE) second Devers-Palo Verde 500 kV line (DPV2).[33]

The fact that TE/VS cannot provide access to Imperial Valley and Salton Sea renewables by itself is consistent with the CAISO's study results in Phase 1. When TE/VS was studied on a stand- alone basis (ED1: CAISO Base Case + TE/VS), the renewable benefits were very similar to the South Bay Repower (In-Basin Generation) scenario. Because TE/VS alone does not provide direct access to renewables, the ED1 scenario results in negative net benefits compared to Sunrise, even with the modified import capability factored into the analysis.

[33] DEIR/EIS at Ap.1-258.

Q. Do you agree with the DEIR/EIS that the TE/VS Alternative could provide indirect access to renewable generation in these areas?

A. No, this is not a reasonable conclusion. The DEIR/EIS assumes that the combination of the Devers-Palo Verde and PVD2 lines in the SCE territory, together with TE/VS, "could allow for the importation of low cost conventional generation from the Blythe area or the Palo Verde hub in Arizona, thereby freeing capacity on the existing SWPL [Southwest Power Link] to import renewable power from the Imperial Valley."[34] This idea may sound appealing, but unfortunately interconnected electric power systems do not work this way. Power flow from the Blythe area or the Palo Verde hub into the CAISO control area would naturally flow through both the Devers Substation and Miguel Substation. The TE/VS phase shifters are ineffective at regulating the flow through Miguel substation because the parallel Path 44 (south of SONGS) is not controllable.

Q. Why does the CAISO consider the DEIR/EIS conclusions about the ability of the TE/VS Alternative to provide access to renewable generation to be a deficiency in the DEIR/EIS?

A. Similar to the reliability benefits discussed above, it is the CAISO's opinion that a feasible alternative to Sunrise must be able to provide the same access to renewable generation and renewable benefits. TE/VS clearly does not meet this objective unless other projects, the implementation of which are uncertain and not within the control of the CPUC, are considered in combination with TE/VS. It is not reasonable for the CPUC to consider TE/VS to be a comparable alternative to Sunrise under these circumstances, and the DEIR/EIS determination that this alternative meets the screening criteria for project alternatives is incorrect.

[34] DEIR/EIS at Ap.1-258.

4. Southern Route Alternative 4 and Northern Route Alternative 5

Q. Please describe your understanding of DEIR/EIS Alternative 4 and DEIR/EIS Alternative 5

A. According to the DEIR/EIS, DEIR/EIS Alternative No. 4 is the Interstate 8 Alternative with Modified Route D Alternative and three segment route options. It is my understanding that this alternative is collocated with SWPL for 36 miles in an area of lower fire risk. DEIR/EIS Alternative No. 5 consists of 75 miles of the proposed project and 8 route options with segments of the route underground through the Anza-Borrego Desert State Park.[35]

Q. Did the CAISO evaluate these alternatives in Phase 1?

A. Yes. Aspen Environmental Group requested that the CAISO perform reliability studies for these alternatives. Based on the above descriptions, it appears that DEIR/EIS Alternative No. 4 is comparable to the Aspen 10 alternative, and DEIR/EIS Alternative No. 5 is comparable to the Aspen 1 alternative.[36] The CAISO determined that both of these alternatives performed electrically similar to Sunrise. However, in my Phase 1 testimony, I also described concerns with DEIR/EIS Alternative 4 (Aspen 10) to the extent that portions of the route would be in a common corridor with SWPL.

Additionally, I pointed out that neither DEIR/EIS Alternative 4 (Aspen 10) nor DEIR/EIS Alternative 5 (Aspen 1) provide the option value of a potential 500 kV network

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[35] DEIR/EIS at ES-3-4.

[36] *See* CAISO Ex. I-3 at 61-64; CAISO Ex. I-5 at 77-81 for discussion of the reliability and electrical aspects of these alternatives.

connection to resource areas to the north, such as Tehachapi. In contrast, Sunrise provides this future expansion option.[37]

Q. Are you aware of any additional information that would impact the determination that both DEIR/EIS Alternative 4 and DEIR/EIS Alternative 5 can meet reliability objectives?

A. Yes. As I previously indicated, DEIR/EIS Alternative 4 is in the same corridor as SWPL for 36 miles. In contrast, DEIR/EIS Alternative 5 and Sunrise as proposed by SDG&E are in the same corridor as SWPL for approximately 4 miles. According to the Western Electricity Coordinating Council (WECC), this creates a difference in system reliability. WECC recently determined that the risk of a common corridor outage of both 500 kV lines (DEIR/EIS Alternative 4 and the existing SWPL) was significant and would require a remedial action scheme designed to trip up to 1,000 MW of load in the San Diego area and up to 2,000 MW of generation in the Imperial Valley area in order to protect against this risk. On the other hand, for DEIR/EIS Alternative 5 and Sunrise, the WECC recently determined that there is not a significant risk of a common corridor outage. Thus, according to WECC's determination, there is no significant risk of load shedding associated with Sunrise or DEIR/EIS Alternative 5, but there is a significant risk of load shedding with DEIR/EIS Alternative 4.

4. LEAPS Generation and Transmission Alternative

Q. What are the CAISO's concerns with respect to the LEAPS Generation and Transmission Alternative ("TE/VS + LEAPS Alternative")?

[37] CAISO Ex. I-5 at 81.

A. The CAISO's concerns with this alternative are the same as I discuss above with respect to the TE/VS Alternative. The TE/VS + LEAPS Alternative meets neither the reliability objective nor the access to renewables objective for all of the same reasons that the TE/VS Alternative does not meet these objectives.

Q. In your opinion, should the TE/VS + LEAPS Alternative be considered by the CPUC as an alternative to Sunrise?

A. No. The TE/VS + LEAPS alternative does not meet the Sunrise reliability and access to renewable generation objectives discussed in this testimony. However, this does not mean that TE/VS + LEAPS cannot provide operational benefits. Once Sunrise is built, TE/VS + LEAPS has the potential to provide the 500 kV connectivity that I discussed above and access to renewable generation resources to the north as I discussed in my Phase I testimony. In the future, as electric utilities are required to achieve increasingly higher renewable energy targets, the CAISO may find a need for bidirectional transfers between the SCE and SDG&E systems to integrate the intermittent sources of wind and solar resources in Imperial County and Kern County. TE/VS could perform this function.

5. No Project Alternative

Q. Please describe the No Project Alternative.

A. It is my understanding that an evaluation of a No Project Alternative is a required part of the environmental review process that provides the CPUC with a scenario that is likely to occur if Sunrise is not approved. The No Project Alternative is described at pages C-144-152 of the DEIR/EIS. Table C-4 displays the elements of this alternative, including demand-side actions (primarily increased solar PV and distributed generation) and supply-side generation and transmission actions.[38] The generation supply-side resources are the same as those included in the first two environmentally superior alternatives (*i.e.*, All-Source Generation Alternative and Renewable Generation Alternative). On the transmission supply-side, Table C-4 identifies the TE/VS alternatives, Path 44 Upgrades and Mexico Light. Previously my testimony addressed the CAISO's concerns with both the all-source and renewable generation alternatives, as well as the TE/VS alternatives. If Sunrise is not approved, the CAISO does not believe that these alternatives will satisfy SDG&E's reliability needs or provide sufficient access to renewable generation to meet renewable generation requirements.

Q. Does the CAISO have additional concerns with the No Project Alternative?

A. Yes. The DEIR/EIS includes Path 44 Upgrades and Mexico Light as transmission projects that are likely to be pursued if Sunrise is not approved, and that would "help to ensure that San Diego meets the reliability criteria in the absence of the Proposed Project."[39] Both of these projects were proposed by UCAN in Phase 1 as options that would provide sufficient infrastructure for importing renewables into San Diego. At the request of UCAN, the CAISO studied these transmission upgrades as part of numerous alternative scenarios, and found that both options caused reliability and economic concerns on the CAISO and CFE systems.[40] Based on the CAISO Phase I testimony, these "transmission projects" should not have been included in the No Project Alternative as possible actions that would provide the same level of reliability or access to renewable benefits as Sunrise without considering the costs of mitigating the reliability, economic, and environmental concerns associated with these alternatives.

[38] DEIR/EIS at C-147.
[39] DEIR/EIS at C-150 - C-151.
[40] *See e.g.*, CAISO Ex. I-6 at 54-57.

Q. Does the CAISO have additional information that would impact the supply-side generation assumptions included in the No Project Alternative?

A. Yes. Recently an 1,150 MW dispatch limit has been established that is expected to be applied to all generation connected to the Imperial Valley substation, if more than 1,150 MW is connected to that substation. At a minimum, this would mean that any generation connected to Imperial Valley Substation above 1,150 MW would not be deliverable for Resource Adequacy capacity counting purposes. This limit appears to be needed to protect the CFE system without increased reliance on the cross tripping scheme.

The 700 MW stability limit established by the studies described in the CAISO's Phase 1 testimony would still apply to generation connected to the Imperial Irrigation District system. It is not clear how this or other reliability limits would apply to generation connected to the Imperial Valley bus now that the CAISO has established this dispatch limit that would apply for all hours of the year and for all generation on that bus.

Q. Can you provide an example of how this 1,150 MW dispatch limit will impact proposed wind projects located in Mexico?

A. Yes. As an example, Sempra Generation recently filed for approval with the Department of Energy to build transmission facilities across the U.S.-Mexico border to interconnect 1,250 MW of wind generation from La Rumarosa to SWPL. For the purposes of this response, I am assuming that this generation would be connected to a new 500 kV substation ("Windsub") between Imperial Valley and Miguel. The existing Imperial Valley to Miguel 500 kV line would be looped into Windsub to create an Imperial Valley to Windsub 500 kV line and a Windsub to Miguel 500 kV line. Therefore, an outage of the Windsub to Miguel line would leave Windsub radially connected to the Imperial Valley 500 kV bus via the Imperial Valley to Windsub line. As a result, all generation connected to Windsub would be subject to the 1,150 MW dispatch limit described above. In other words, without Sunrise or something like it, all generation at the Windsub and Imperial Valley substations, combined, would be subject to an 1,150 MW dispatch limit.

At the present time, there is already about 1,070 MW of generation attached to the Imperial Valley substation. Thus, even if the Sempra wind generation is interconnected to the new substation, no more than 80 MW can be counted for Resource Adequacy purposes due to the dispatch limit.

Furthermore, any time there was enough wind for full 1,250 MW of production, then 100 MW of wind and 1,070 MW of highly efficient combined cycle generation would be curtailed. More importantly, a reliability analysis would be expected to result in finding that the 1,250 MW proposed project cannot be reliably connected and operated without Sunrise or a similar upgrade.

Q. Will the dispatch limit at the Imperial Valley substation have the same impact on the interconnection of renewable generation described in the No Project Alternative?

A. Yes. The No Project Alternative, as well as the Renewable Generation Alternative, assume that without Sunrise, new wind generation will be developed in the Crestwood-Boulevard area. The DEIR/EIS provides that the in-area wind generation component would require a new switchyard, a new 500 kV substation and a transmission line interconnecting the generation to SWPL.[41] This proposed generation would be similarly situated to the 1,250 MW Sempra project because the new substation would also be subject to the 1,150 MW limit. Accordingly, even if the wind generation in the San Diego area interconnected at the new substation as envisioned in the DEIR/EIS, no more than 80 MW of the generation could be counted for Resource Adequacy purposes.

Q. What other factual inaccuracies and deficiencies has the CAISO identified with respect to the No Project Alternative?

A. The Path 44 upgrades and Mexico Light scenario should not have been included as transmission-side actions for the reasons addressed above and in the CAISO's Phase 1 testimony. Additionally, given the dispatch limitation on generation currently connected at the Imperial Valley substation that is now in effect, new renewable generation being interconnected to SWPL or the Imperial Valley substation is less likely to occur in the absence of Sunrise, Alternative 4 or Alternative 5 and should not be assumed.

Q. Does this conclude your direct testimony?

A. Yes.

[41] DEIR/EIS at C-73.

Attachment A

Exhibit 2

California ISO Planning Standards

PLANNING STANDARDS

February 7, 2002

Table of Contents

I. Introduction

The purpose of this document is to specify the Planning Standards that will be used in the planning of ISO Grid transmission facilities. The primary principle guiding the development of the ISO Grid Planning Standards is to develop a consistent reliability standards for the ISO grid that will maintain or improve the level of transmission system reliability that existed with the pre-ISO planning standards.

The ISO Tariff specifies:

> "After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs, will work to develop a consistent set of reliability criteria for the ISO Controlled Grid which the TOs will use in their transmission planning and expansion studies or decisions."[1]

The ISO Tariff specifies in several places that the facilities that are to be added to the ISO Grid are to meet the Applicable Reliability Standard, which is defined as follows:

> "The reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC."[2]

These ISO Grid Planning Standards fill the role of the "consistent set of reliability criteria" in the above tariff language. To facilitate the development of these Standards, the ISO formed the ISO Grid Planning Standards Committee (PSC), which includes representation from all interested market participants. One of the primary roles of the PSC is to periodically review the ISO Grid Planning Standards and recommend changes as necessary. In recognition of the need to closely coordinate the development of the ISO Grid with neighboring electric systems both inside and outside of California, the approach taken by the PSC is to utilize regional (WSCC) and continental (NERC) standards to the maximum extent possible. These ISO Grid Planning Standards build off of, rather than duplicate, Standards that were developed by WSCC and NERC. The PSC has determined that the ISO Grid Planning Standards should:

- Address specifics not covered in the NERC/WSCC Planning Standards.
- Provide interpretations of the NERC/WSCC Planning Standards specific to the ISO Grid.
- Identify whether specific criteria should be adopted that are more stringent than the NERC/WSCC Planning Standards.

The following Section details the ISO Grid Planning Standards. Also attached are interpretations of the terms used by NERC and background information behind the development of these standards.

[1] ISO Tariff, October 13, 2000, Section 3.2.1.2, Original Sheet No. 144.
[2] ISO Tariff, October 13, 2000, Appendix A, Original Sheet No. 303.

II. ISO Grid Planning Standards

The ISO Grid Planning Standards include the following:

1. **NERC/WSCC Planning Standards -** The standards specified in the NERC/WSCC Planning Standards unless WSCC or NERC formally grants an exemption or deference to the ISO.

2. **Specific Nuclear Unit Standards -** The criteria pertaining to the Diablo Canyon and San Onofre Nuclear Power Plants, as specified in Appendix E of the Transmission Control Agreement.

3. **Combined Line and Generator Outage Standard -** A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies.

4. **New Transmission versus Involuntary Load Interruption Standard**

   A. Involuntary load interruptions are not an acceptable consequence in planning for ISO Planning Standard Category B disturbances (either single contingencies or the combined contingency of a single generator and a single transmission line), unless the ISO Board decides that the capital project alternative is clearly not cost effective (after considering all the costs and benefits). In any case, planned load interruptions for Category B disturbances are to be limited to radial and local network customers as specified in the NERC Planning Standards.

   B. Involuntary load interruptions are an acceptable consequence in planning for ISO Planning Standard Category C and D disturbances (multiple contingencies with the exception of the combined outage of a single generator and a single transmission line), unless the ISO Board decides that the capital project alternative is clearly cost effective (after considering all the costs and benefits).

   C. In cases where the application of Standards 4A and 4B would result in the elimination of a project or relaxation of standards that would have been built under past planning practices, these cases will be presented to the ISO Board for a determination as to whether or not the projects should be constructed.

5. **San Francisco Greater Bay Area Generation Outage Standard -** Before conducting Grid Planning studies for the San Francisco Greater Bay Area, the following three units should be removed from service in the base case:

   - One 50 MW CT in the Greater Bay Area but not on the San Francisco Peninsula.
   - The largest single unit on the San Francisco Peninsula.
   - One 50 MW CT on the San Francisco Peninsula.

   The case with the above three units out of service should be treated as the “system normal” or starting base case (NERC Category A) when planning the system. Traditional contingency analysis, based on the standards specified in the NERC, WSCC (including voltage stability), and ISO standards (such as single line outage, single generator outage etc), would be conducted on top of this base condition. The one exception is that when screening for the most critical single generation outage, only units that are not on the San Francisco peninsula should be considered. Similarly, when examining multiple unit outages, at least one of the units considered should not be on the San Francisco Peninsula.

This standard is intended to apply to system planning studies and not system operating studies. In addition, this standard has not been designed to be used to determine Reliability Must-Run generation requirements. The RMR standards are intentionally developed separately from the Planning Standards.

It is recognized that it may require several years to add the facilities to the system that are necessary to allow the system to meet this standard. The amount of time required will depend on the specific facility additions this standard generates.

III. ISO Grid Planning Guides for New Generator Special Protection Systems

As stated in the NERC/WSCC Planning Standards, the function of a Special Protection System (SPS) is to: "detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance." In the context of new generation projects, the primary action of a SPS would be to detect a transmission outage (either a single or credible multiple contingency) or an overloaded transmission facility and then trip or run back generation output to avoid potential overloaded facilities or other criteria violations. The alternatives to a SPS are pre-contingency generation curtailment or new transmission facilities.

The primary reasons why a SPS might be selected over new transmission facilities are that a SPS can normally be implemented much more quickly and for a much lower cost. In addition, a SPS can increase the utilization of the existing transmission facilities and make better use of scarce transmission resources. Due to these advantages, a SPS is an alternative commonly proposed as a cost-effective method of integrating new generation into the grid while maintaining system reliability. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of a SPS, there can be increased exposure to potential criteria violations, transmission outages can become more difficult to schedule, and the system can become more difficult to operate. If there are a large number of SPSs, it may become difficult to assess the interdependency of these SPSs on system reliability. It is these reliability concerns that have led to the development of the additional guides in this document concerning the application of SPS. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of the existing transmission facilities while maintaining system reliability and operability. The need for these guides has become more critical as a result of the large number of new generators that are currently planning to connect to the ISO Grid.

It needs to be emphasized that these are guides rather than standards. This is to emphasize that judgement will need to be used by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of a SPS in all potential applications.

<u>California ISO New Generator SPS Guides</u>

ISO G1. The overall reliability of the system should not be degraded after the combined addition of the SPS and the generator.

ISO G2. The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. To meet this requirement, the SPS may need to be fully redundant.

ISO G3. The SPS must be fully automatic, including arming, as much as practical.

ISO G4. The total net amount of generation tripped by a SPS for a single contingency cannot exceed the ISO's largest single generation contingency (currently one Diablo Canyon unit at 1150 MW). The total net amount of generation tripped by a SPS for a double contingency cannot exceed 1400 MW. This amount is related to the maximum amount of spinning reserves that the ISO has historically been required to carry. The quantities of generation specified in this standard represent the current upper limits for generation tripping. These quantities will be reviewed periodically and may increase or decrease. In addition, the actual amount of generation that can be tripped is project specific and may depend on the reliability criteria violations to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts shown in this guide. The net amount of generation is the gross plant output less the load (plant and other) tripped by the same SPS.

ISO G5. For SPSs designed to protect against single contingency outages, the following consequences are normally unacceptable should the SPS fail to operate correctly (even for a fully redundant SPS):

A) **C**<u>ascading outages beyond the outage of the facility that the SPS is intended to protect:</u> For example, if a SPS were to fail to operate as designed for a single contingency and the line the SPS was intended to protect were to trip on overload protection, then the subsequent loss of additional facilities due to overloads or system stability would not be an acceptable consequence.

B) <u>Voltage instability, transient instability, or small signal instability:</u> While these are rarely concerns associated with the addition of new generation, the consequences can be so severe that they are deemed to be unacceptable results following SPS failure.

These restrictions apply to single contingency outages and not double contingency outages due to the much higher probability of occurrence of single contingency outages.

ISO G6. Close coordination of SPS is required to eliminate cascading events. All SPS in a local area (such as SDG&E, Fresno etc) and grid-wide need to be evaluated as a whole and studied as such.

ISO G7. The SPS must be simple and manageable. Generally, there should be no more than 4 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS and the SPS should not be monitoring the loading on more than 4 system elements. The exception is that if the new SPS is part of an existing SPS that is triggered by more than 4 local contingencies or that monitors more than 4 system elements, then the new generation cannot materially increase the complexity of the existing SPS scheme. Generally, the SPS should only monitor facilities that are connected to the plant or to the first point of interconnection with the grid. Monitoring remote facilities may add substantial complexity to system operation and should be avoided, if possible.

ISO G8. The SPS may not include the involuntary interruption of load. Voluntary interruption of load paid for by the generator is acceptable. The exception is that the new generator can be added to an existing SPS that includes involuntary load tripping. However, the amount of involuntary load tripped by the combined SPS may not be increased as a result of the addition of the generator.

ISO G9. Action of the SPS shall limit the post-disturbance loadings and voltages on the system to be within all applicable ratings and shall ultimately bring the system to within the long-term (4 hour or longer) emergency ratings of the transmission equipment or to the loading levels that would exist on the system prior to the addition of the new generator. For example, the operation of a SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back generation to bring the line loading to be within the line's 4 hour or longer rating.

ISO G10. The SPS should not run-back or trip existing Reliability Must-Run generators unless there is no plausible expectation that the ISO would call upon such generators for reliability purposes during the periods where the SPS would be armed.

ISO G11. The SPS needs to be approved by the ISO and may need to be approved by the WSCC Remedial Action Scheme Reliability Task Force.

ISO G12. The CA-ISO, in coordination with affected parties, may relax SPS requirements as a temporary bridge to system reinforcements. Normally this bridging period would be limited to the time it takes to implement a specified alternative solution. An example of a relaxation of a SPS requirement would be to allow 6 initiating events rather than limiting the SPS to 4 initiating events.

ISO G13. The ISO will consider the expected frequency of operation in its review of SPS proposals.

ISO G14. In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies).

ISO G15. The actual performance of existing and new SPS schemes will be documented by the transmission owners and periodically reviewed by the ISO and other interested parties so that poorly performing schemes may be identified and revised.

ISO G16. All SPS schemes will be documented by the owner of the transmission system where the SPS exists. The generation owner, the transmission owner, and the ISO shall retain copies of this documentation. To facilitate transmission system studies, documentation will be made available to others upon request to the ISO.

ISO G17. Normally, the transmission owner, in coordination with affected parties, will be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO G18. Generally, the generating units tripped by the SPS should be highly effective in reducing the loadings on the facilities of concerns.

ISO G19. Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO will normally be required. Specific telemetry requirements will be determined on a project specific basis.

IV. Interpretations of NERC/WSCC Planning Standard Terms

Listed below are several of the terms that are used in the NERC Planning Standards which members of the PSC have determined require clarification. Also provided below are ISO interpretations of these terms:

Bulk Electric System: The ISO Bulk Electric System refers to all of the facilities placed under ISO control.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTOs and the ISO subject to appropriate coordination and review with the relevant state, local, and federal regulatory authorities and WSCC. The PTOs develop annual transmission plans, which the ISO reviews. Both the ISO and PTOs have the ability to identify transmission upgrades needed for reliability.

Entity Required to Develop load models: The TOs, in coordination with the UDCs and others, develop load models.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. The PSC decided that for studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level. The more stringent requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. Having a higher standard for local areas will help minimize the potential for interruption of end-use customers.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified in the ISO Grid Coordinated Planning Process and corresponding operating procedures are in place when required.

Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

V. Background behind the New Transmission versus Involuntary Load Interruption Standard

For practical and economic reasons, all electric transmission systems are planned to allow for some involuntary loss of firm load under some contingency conditions. For some systems, such a loss of load may require several contingencies to occur while for other systems, loss of load may occur in the event of specific single contingencies. Historically, there has been a wide variation in approaches exists among the California ISO PTOs. One PTO may allow involuntary loss of load following a specific type of contingency while another PTO would build a project to prevent loss of load for the same type of contingency. This standard is intended to lead to the elimination of these inconsistencies and also to provide the information needed to help ensure that the ISO is making cost effective transmission system additions.

This standard is also a change in the approach the ISO uses in planning from primarily deterministic planning standards[3] toward probabilistic planning standards. It is the general belief of the PSC that this trend will be an improvement in that it will provide additional information for the ISO and others to use when making decisions associated with making improvements to the grid. It is the intent of the PSC that the implementation of these principles should not result in lower levels of reliability to end-use customers than existed prior to restructuring.

To implement this standard, the following process will be used:

1) Identification of Reliability Concerns: As part of the PTO's annual transmission expansion plans, each PTO will identify those ISO Category B outages that would require the involuntary interruption of load either as a result of the system configuration (i.e., such as for a radial system) or because interrupting load was necessary to meet the ISO Grid Planning Standards.

2) Information Gathering: For each of the ISO Category B outages that required involuntary interruption of load, the PTOs will estimate the following:

- The maximum amount of load that would need to be interrupted
- The duration of the interruption
- The annual energy that would not be served or delivered
- The number of interruptions per year
- The time of occurrence of the interruption (e.g., weekday summer afternoon)
- The number of customers that would be interrupted
- The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural)
- Value of Service or Performance Based Ratemaking assumptions concerning the dollar impact of a load interruption

3 An example of a purely deterministic standard is the following: There should be no more than 200 MW of load loss for a double contingency.

The above information will be documented in the PTO's Transmission Expansion Plans. Using this information, the PTOs and other interested stakeholders can estimate the benefit to the end-use customers of reducing the likelihood of interruption.

3) PTO Recommendations: As part of the evaluation of alternatives in the PTO's Five-Year Transmission Expansion Plans, the PTOs will propose either projects or operating procedures[4] to be the appropriate solution to address identified reliability criteria violations. The PTOs shall also provide their rationale for selecting either an operating procedure or a project.

4) Cost-Benefit Estimates: The PTO will estimate the costs[5] and benefits of projects to remedy the reliability concerns identified in 1) above. In addition to developing new projects, the PTOs will review currently approved projects to determine if they would still propose to construct those projects or propose an alternative solution.

For cases where the PTO has proposed an operating procedure that involves the interruption of load to be the appropriate solution, the PTOs will estimate the following:

- The future frequency and duration of outages for impacted substations
- The historical frequency and duration of outages for impacted substations
- The communities served by these substations

5) Notification: All of the above information will be provided to the stakeholders as part of the Transmission Expansion Plan prior to an ISO decision to accept or reject PTO-proposed involuntary load dropping in lieu of transmission reinforcement. The information will be made available in a timely manner so that customers can intervene before the ISO Board if they desire.

One way the information could be provided would be to develop a table such as the following:

<u>Projected and Historical Reliability Data for Single Contingencies that can Result in Load Interruptions</u>

Case	Area Affected		Possible Future Outage Without Project		Possible Future Outage With Project	
	Substations, Feeders, And Peak MW	Communities	Frequency	Duration	Frequency	Duration

[4] The proposed operating procedures shall be in sufficient detail in concept and application so as to allow review and approval in principle in lieu of upgrade projects.
[5] Project costs may need to be handled as confidential information.

6) ISO Review and Approval: The ISO, with input from the PTOs and other stakeholders, will review the PTO's five-year plans and determine whether to adopt the PTO's proposed projects or operating procedures[6]. The final ISO approved plan will be distributed to the stakeholders.

7) Periodic Reevaluation: Cases where it has been decided by the ISO Board to plan for involuntary load interruptions rather than a project (transmission, generation, or load reduction) will be re-evaluated every three years or more frequently if merited by load growth or system changes or if the reliability in that area has significantly deteriorated.

[6] Proposed operating procedures will be reviewed by the ISO to determine whether they can be reasonably implemented.

VI. Background behind the San Francisco Greater Bay Area Generation Outage Standard

On June 14, 2000, rolling blackouts were initiated in the San Francisco Bay area to protect against the potential for voltage collapse. The major reason behind the need to implement rolling blackouts was the large number of generating units that were forced out of service on that day. The problem had not been uncovered in the planning studies for the area because the current ISO Grid Planning Standards only require that a single generating unit be assumed out of service in combination with the most critical transmission line. As a result of the June 14, 2000 rolling blackouts, the ISO Grid Planning Standards Committee was tasked with reviewing the ISO Grid Planning Standards to determine whether they need to be revised.

As a result of this review, the ISO Grid Planning Standards Committee determined that, while the normal standard of planning for one generating unit in combination with one transmission line out is adequate for most of the ISO Grid, it is inadequate for the greater San Francisco Bay area. In the Bay area, there is an unusually large concentration of generating units (more than 30) which increases the likelihood that more than one unit could be forced out of service at a given time. In addition, the historical forced outage rates for the units in the Bay area are significantly higher than the industry averages for similar units resulting in a higher probability of such multiple outage occurrences. The higher forced outage rates are at least partially due to the age of the units. Based on this information, and discussion at six stakeholder meetings where a variety of approaches to potential new standards were considered, the San Francisco Greater Bay Area Generation Outage Standard was developed.

While this proposed standard only applies to the San Francisco Bay Area, the ISO Grid Planning Standards Committee will periodically review various areas of the ISO Grid to determine if additional specific standards are warranted to address issues unique to those areas.

The ISO Grid Planning Standards Committee will review this standard periodically. This review will require forced and scheduled outage data for all generating units in the area.

The following tables provide the statistical basis for the work that has been completed by the ISO Grid Planning Standards Committee. This data was provided by PG&E and is based on outage data available to PG&E during their ownership of the units prior to the formation of the CAISO. It is assumed for this analysis that outage data will be similar under the present ownership of the units. For a description of how the data was compiled or computed, please refer to the original report that was prepared by Anatoliy Meklin of PG&E. The report is entitled “STATISTICAL ANALYSIS OF SIMULTANEOUS FORCED OUTAGES IN BAY AREA” and dated October 31, 2000.

Table 1. Forced Outage Data for Bay Area Generators

Name	MW	T2 - hours between forced outages		T1 - hours of forced outages	
		Mean	Standard deviation	Mean	Standard deviation
OAKLND 1	55	2130	1978	521	1150
OAKLND 2	55	4804	6612	306	649
OAKLND 3	55	4352	4399	29	17
ChevGen1	54	1475	1032	25	18
ChevGen2	54	1475	1032	25	18
PDEFCT2	199	1475	1032	25	18
PDEFCT1	199	1475	1032	25	18
PDEFST1	280	1475	1032	25	18
PTSB 1	170	1720	2078	79	75
PTSB 2	170	2448	1986	622	1925
PTSB 3	170	1520	1549	570	873
PTSB 4	170	2307	2048	153	138
PTSB 5	325	1798	2389	262	373
PTSB 6	325	4596	3773	67	48
PTSB 7	710	3252	6196	147	131
MOSS 5	750	2735	1416	64	35
MOSS 6	750	1626	1970	94	94
C.COS 6	340	1930	1522	429	1365
C.COS 7	340	1158	843	41	57
POTRERO3	210	3090	3156	212	186
POTRERO4	52	4705	6151	253	242
POTRERO5	52	13090	6869	75	35
POTRERO6	52	5596	9842	47	41
HNTRS P2	108	2047	1961	129	160
HNTRS P3	108	3207	4253	76	51
HNTRS P4	170	3165	4511	130	146
HNTRS P1	52	7856	7498	55	31
GLRY COG	130	1445	1010	55	38
FMC CT	52	1445	1010	55	38

Table 2. NERC Forced Outage Data for Selected Types of Units

Unit Type	MW Trb/Gen Nameplate	# of Units	Unit-Years	FOF (%)	Assuming 6 outages per year	
					T2 - hours between forced outages	T1 – hours of forced outages
FOSSIL	All Sizes	1,532	7,126	3.82	1408	56
All Fuel Types	1-99	351	1,486	3.18	1417	47
	100-199	426	2,016	3.45	1413	51
	200-299	171	825	3.68	1410	54
	300-399	147	717	5.07	1390	74
	400-599	262	1,250	4.29	1401	63
	600-799	127	602	4.22	1402	62
	800-999	34	165	3.48	1413	51
	1000 Plus	14	65	5.78	1379	85
Gas Primary	All Sizes	466	1,965	3.58	1412	52
	1-99	145	554	3.53	1412	52
	100-199	147	624	3.61	1411	53
	200-299	47	211	2.31	1430	34
	300-399	41	188	4.33	1401	63
	400-599	63	296	3.92	1407	57
	600-799	20	81	4.27	1401	63
	800-999	3	11	1.50	1442	22
Gas Turbine	All Sizes	768	3,475	3.84	1408	56
	20-49	251	1,161	5.60	1382	82
	50 Plus	318	1,386	2.12	1433	31
Comb. Cycle	All Sizes	58	242	1.50	1442	22

Table 3. Probabilities of Simultaneous Forced Outages of Generators
(Actual Greater Bay Area Data)

# of generators in forced outage	% of year	% of year if in peak
>=1	91	8.1
>=2	68	6.2
>=3	40	3.7
>=4	17	1.6
>=5	6	0.6

Observations:

- One out of 30 generators is unavailable 91 % of time
- The probability of simultaneous forced unit outages is very high and two units are unavailable 68% of the time
- The coincident forced outage of 5 generators could occur for 520 hours/year or 52 peak-hours/year.
- The probability of having 5 generators forced out of service in the Greater Bay Area is 20 times higher using actual historical data than it would be if the units had typical NERC forced outage rates as shown in Table 4.

Table 4. Probabilities of Simultaneous Forced Outages of Generators
(NERC Data)

# of generators in forced outage	% of year	% of year if in peak
>=1	67	5.8
>=2	28	2.4
>=3	8.3	0.72
>=4	1.59	0.15
>=5	0.22	0.03

Observations:

- The lower generator forced outage rates in the NERC data result in a much lower probability for multiple unit outages.

Table 5. Probabilities of Simultaneous Forced Outages of Megawatts (Using Actual Data).

Unavailable MW	% of year	% of year <u>if in peak</u>	occurrences/year	occurrences/year <u>if in peak</u>
in forced outage			(as result of a forced outage event with loss of >100 MW)	(as result of a forced outage event with loss of >100 MW)
>=100	88.2	7.7	60.44	5.55
>=200	74.9	6.4	54.31	4.8
>=300	66.2	5.65	49.93	4.48
>=400	48.3	4.07	40.30	3.71
>=500	42.6	3.56	35.92	3.30
>=600	28.8	2.4	26.28	2.53
>=700	20.7	1.69	20.15	2.07
>=800	15.2	1.21	20.15	1.59
>=900	10.8	0.92	12.26	1.31
>=1000	8.0	0.69	9.64	1.05
>=1100	5.5	0.46	7.01	0.61
>=1200	4.0	0.34	5.26	0.44
>=1300	2.7	0.21	3.50	0.32
>=1400	1.8	0.12	2.63	0.22
>=1500	0.9	0.07	1.75	0.16
>=1600	0.6	0.04	0.88	0.11

Note: Peak hours make up about 8.8% of the year.

Exhibit 3

WECC Reliability Criteria

Western Electricity Coordinating Council

RELIABILITY CRITERIA

PART I - NERC/WECC PLANNING STANDARDS

PART II - POWER SUPPLY ASSESSMENT POLICY

PART III - MINIMUM OPERATING RELIABILITY CRITERIA

PART IV - DEFINITIONS

PART V - PROCESS FOR DEVELOPING AND APPROVING WECC STANDARDS

AUGUST 2002

WESTERN ELECTRICITY COORDINATING COUNCIL

NERC/WECC PLANNING STANDARDS

PART I

Contents

Table I. Transmission Systems Standards — Normal and Contingency Conditions

Category	Contingencies: Initiating Event(s) and Contingency Element(s)	Elements Out of Service	System Limits or Impacts: Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading[c] Outages
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B – Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:						
	1. Generator	Single	A/R	A/R	Yes	No[b]	No
	2. Transmission Circuit	Single	A/R	A/R	Yes	No[b]	No
	3. Transformer	Single	A/R	A/R	Yes	No[b]	No
	Loss of an Element without a Fault.	Single	A/R	A/R	Yes	No[b]	No
	Single Pole Block, Normal Clearing[f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C – Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]:						
	1. Bus Section	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	2. Breaker (failure or internal fault)	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]: 4. Bipolar (dc) Line	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Fault (non 3Ø), with Normal Clearing[f]: 5. Any two circuits of a multiple Circuit towerline[g]	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 6. Generator 7. Transmission Circuit 8. Transformer 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No

D [e] – Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [f]: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of-way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. • May involve substantial loss of customer demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may or may not achieve a new, stable operating point. • Evaluation of these events may require joint studies with neighboring systems.

Footnotes to Table I.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria

Exhibit 4

TNHC Phase 2 Testimony and study supporting at least 1,000 MW import capability of the TE/VS Project

(Designated Confidential)

Exhibit 5

Power flow cases supporting 1,100 MW import capability of TE/VS under G-1 / N-1 conditions

SCE Net MW Ties = -9149.1 MW

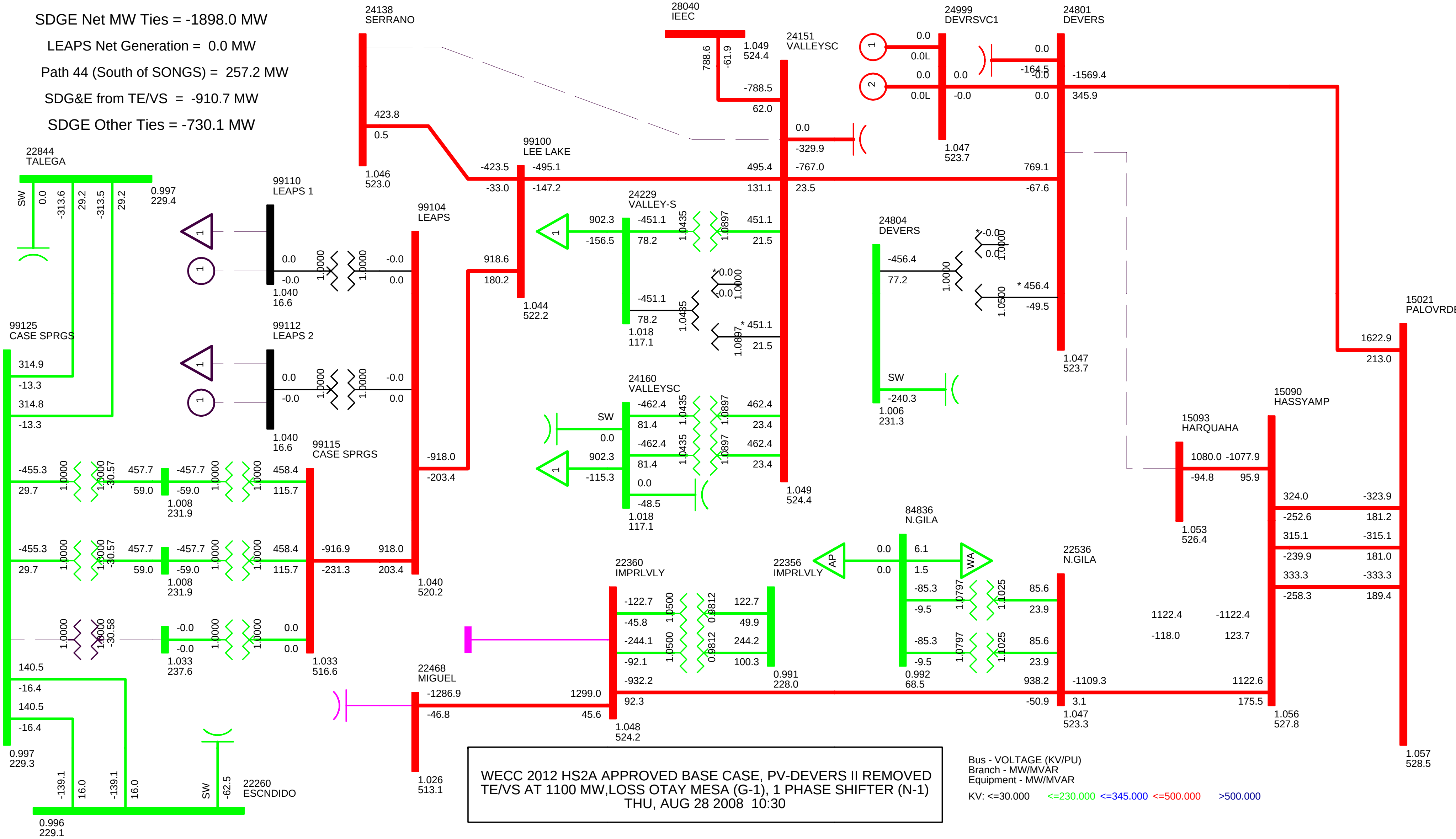
SDGE Net MW Ties = -1898.0 MW

LEAPS Net Generation = 0.0 MW

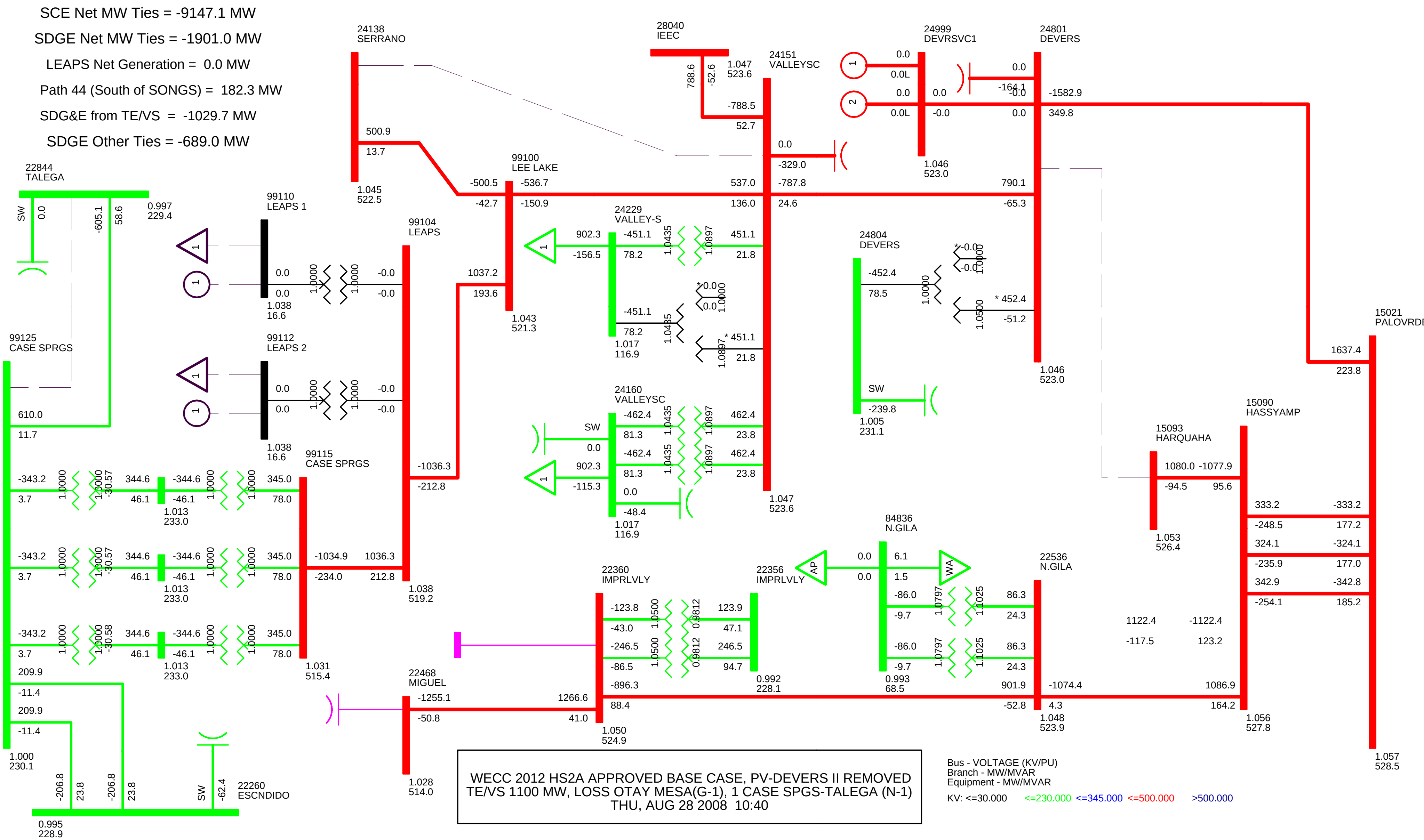
Path 44 (South of SONGS) = 257.2 MW

SDG&E from TE/VS = -910.7 MW

SDGE Other Ties = -730.1 MW



WECC 2012 HS2A APPROVED BASE CASE, PV-DEVERS II REMOVED
TE/VS AT 1100 MW,LOSS OTAY MESA (G-1), 1 PHASE SHIFTER (N-1)
THU, AUG 28 2008 10:30


SCE Net MW Ties = -9147.1 MW
SDGE Net MW Ties = -1901.0 MW
LEAPS Net Generation = 0.0 MW
Path 44 (South of SONGS) = 182.3 MW
SDG&E from TE/VS = -1029.7 MW
SDGE Other Ties = -689.0 MW
24138 SERRANO
1.045 522.5
28040 IEEC
1.047 523.6
24151 VALLEYSC
24999 DEVRSVC1
1.046 523.0
24801 DEVERS
1.046 523.0
22844 TALEGA
0.997 229.4
99110 LEAPS 1
1.038 16.6
99100 LEE LAKE
1.043 521.3
99104 LEAPS
1.038 519.2
24229 VALLEY-S
1.017 116.9
24804 DEVERS
1.005 231.1
15021 PALOVRDE
1.057 528.5
99125 CASE SPRGS
1.000 230.1
99112 LEAPS 2
1.038 16.6
24160 VALLEYSC
1.017 116.9
1.047 523.6
15090 HASSYAMP
1.056 527.8
15093 HARQUAHA
1.053 526.4
99115 CASE SPRGS
1.031 515.4
1.013 233.0
84836 N.GILA
0.993 68.5
22360 IMPRLVLY
1.050 524.9
22356 IMPRLVLY
0.992 228.1
22536 N.GILA
1.048 523.9
22468 MIGUEL
1.028 514.0
22260 ESCNDIDO
0.995 228.9
WECC 2012 HS2A APPROVED BASE CASE, PV-DEVERS II REMOVED
TE/VS 1100 MW, LOSS OTAY MESA(G-1), 1 CASE SPGS-TALEGA (N-1)
THU, AUG 28 2008 10:40
Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
KV: <=30.000 <=230.000 <=345.000 <=500.000 >500.000

SCE Net MW Ties = -8584.4 MW

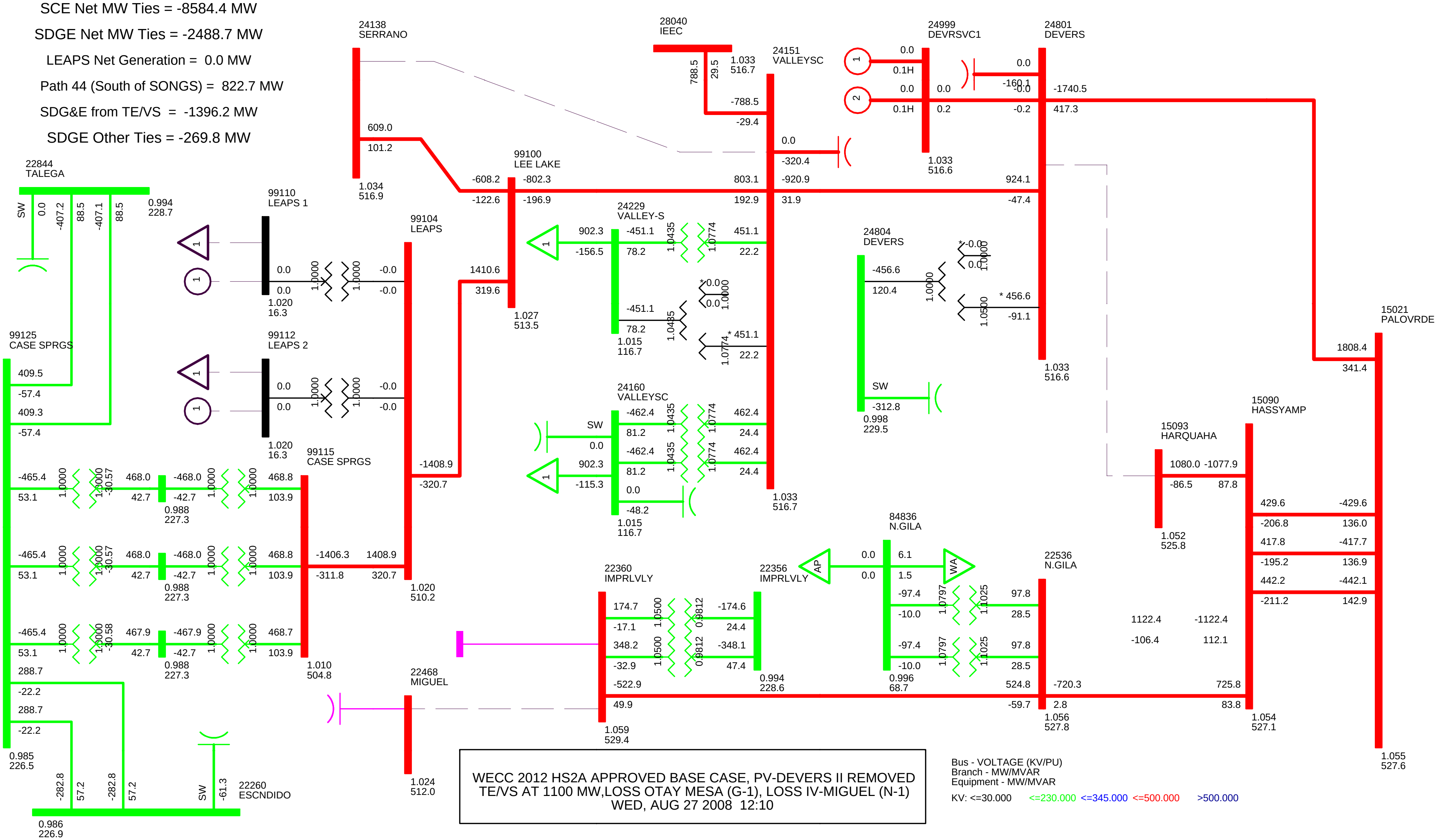
SDGE Net MW Ties = -2488.7 MW

LEAPS Net Generation = 0.0 MW

Path 44 (South of SONGS) = 822.7 MW

SDG&E from TE/VS = -1396.2 MW

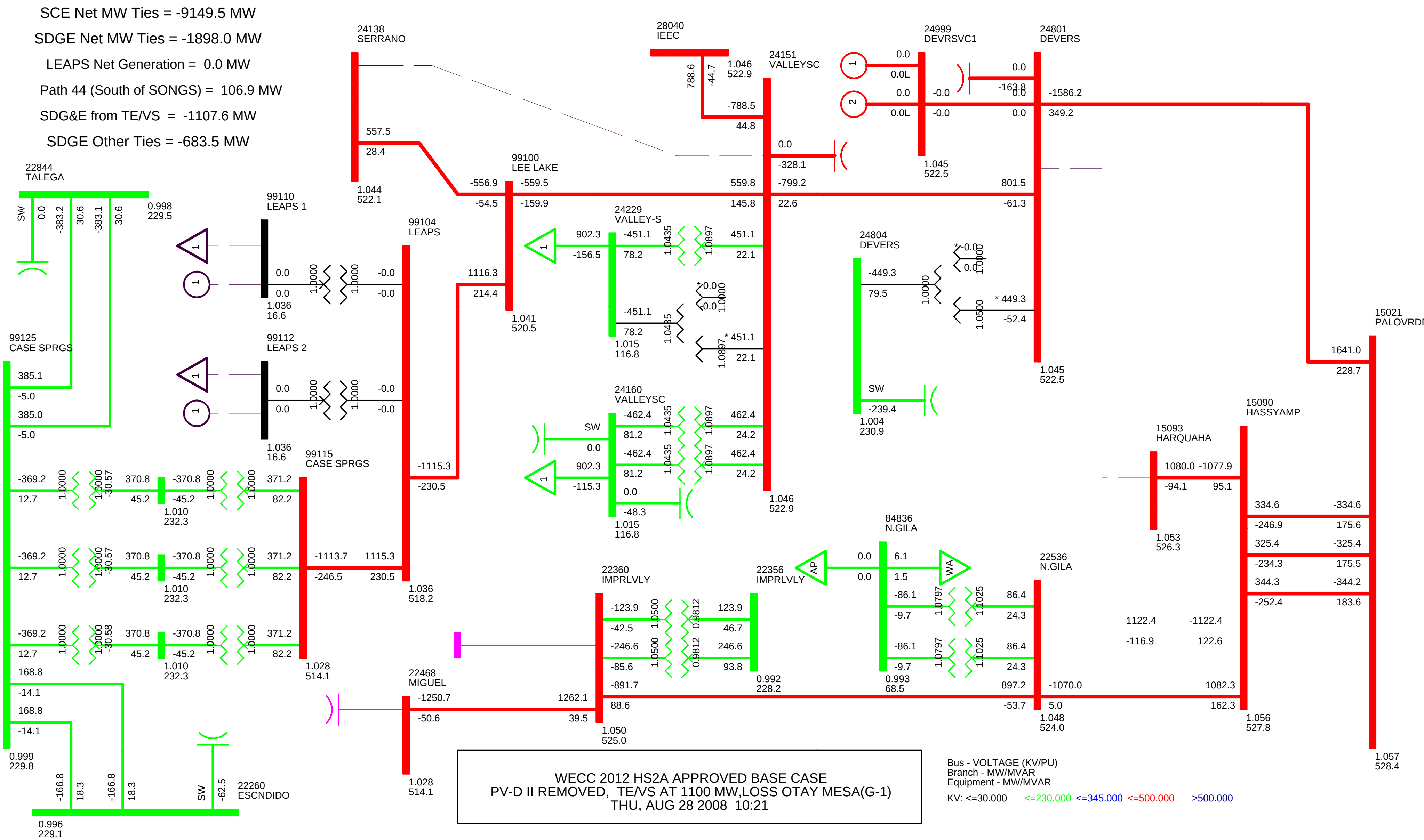
SDGE Other Ties = -269.8 MW



WECC 2012 HS2A APPROVED BASE CASE, PV-DEVERS II REMOVED
TE/VS AT 1100 MW,LOSS OTAY MESA (G-1), LOSS IV-MIGUEL (N-1)
WED, AUG 27 2008 12:10

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR

KV: <=30.000 <=230.000 <=345.000 <=500.000 >500.000


SCE Net MW Ties = -9149.5 MW
SDGE Net MW Ties = -1898.0 MW
LEAPS Net Generation = 0.0 MW
Path 44 (South of SONGS) = 106.9 MW
SDG&E from TE/VS = -1107.6 MW
SDGE Other Ties = -683.5 MW
22844 TALEGA
24138 SERRANO
28040 IEEC
24151 VALLEYSC
24999 DEVRSVC1
24801 DEVERS
99110 LEAPS 1
99104 LEAPS
99100 LEE LAKE
24229 VALLEY-S
24804 DEVERS
15021 PALOVRDE
99125 CASE SPRGS
99112 LEAPS 2
24160 VALLEYSC
15093 HARQUAHA
15090 HASSYAMP
99115 CASE SPRGS
84836 N.GILA
22360 IMPRLVLY
22356 IMPRLVLY
22536 N.GILA
22468 MIGUEL
22260 ESCNDIDO
WECC 2012 HS2A APPROVED BASE CASE
PV-D II REMOVED, TE/VS AT 1100 MW,LOSS OTAY MESA(G-1)
THU, AUG 28 2008 10:21
Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
KV: <=30.000 <=230.000 <=345.000 <=500.000 >500.000

SCE Net MW Ties = -9248.0 MW

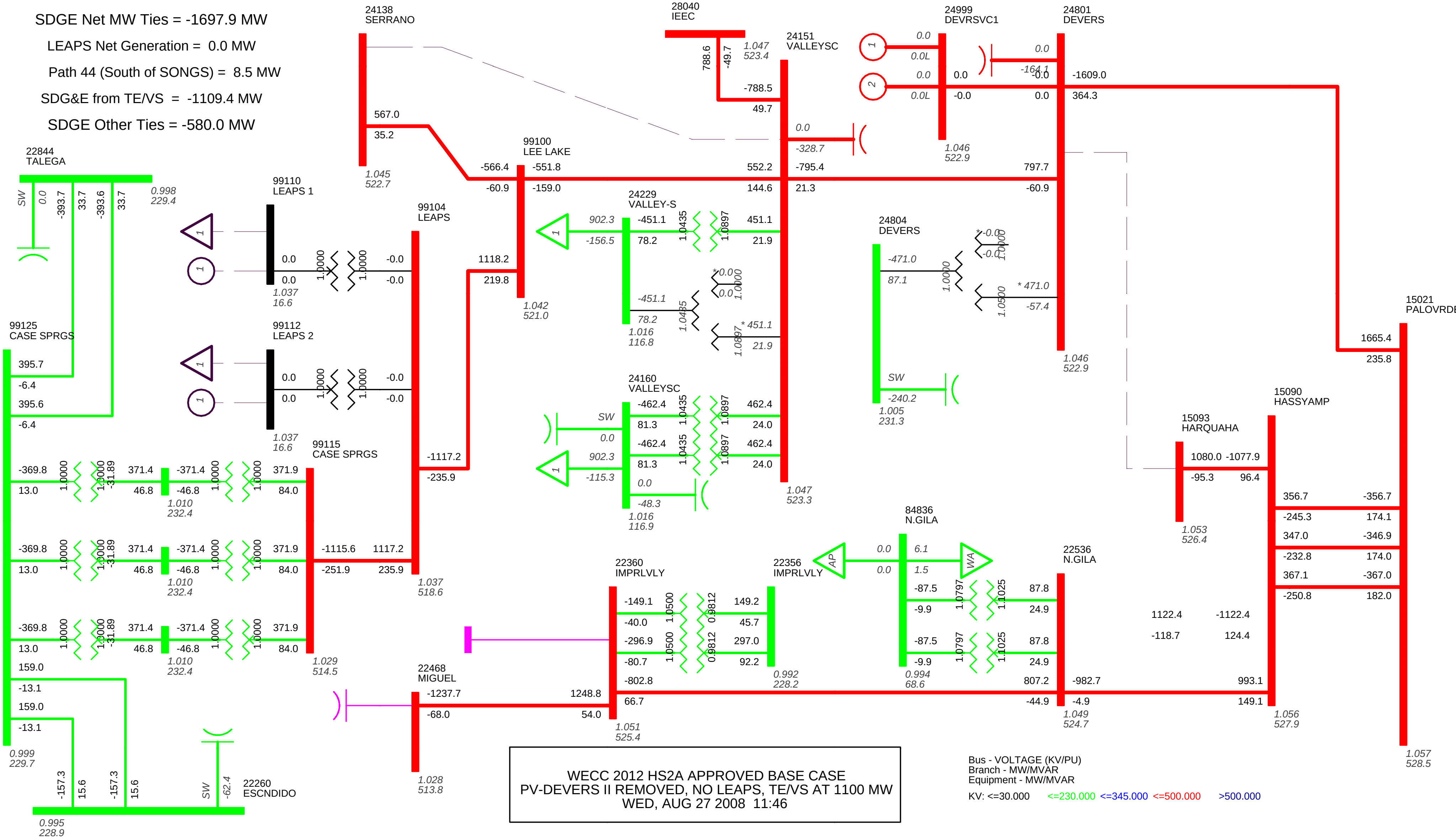
SDGE Net MW Ties = -1697.9 MW

LEAPS Net Generation = 0.0 MW

Path 44 (South of SONGS) = 8.5 MW

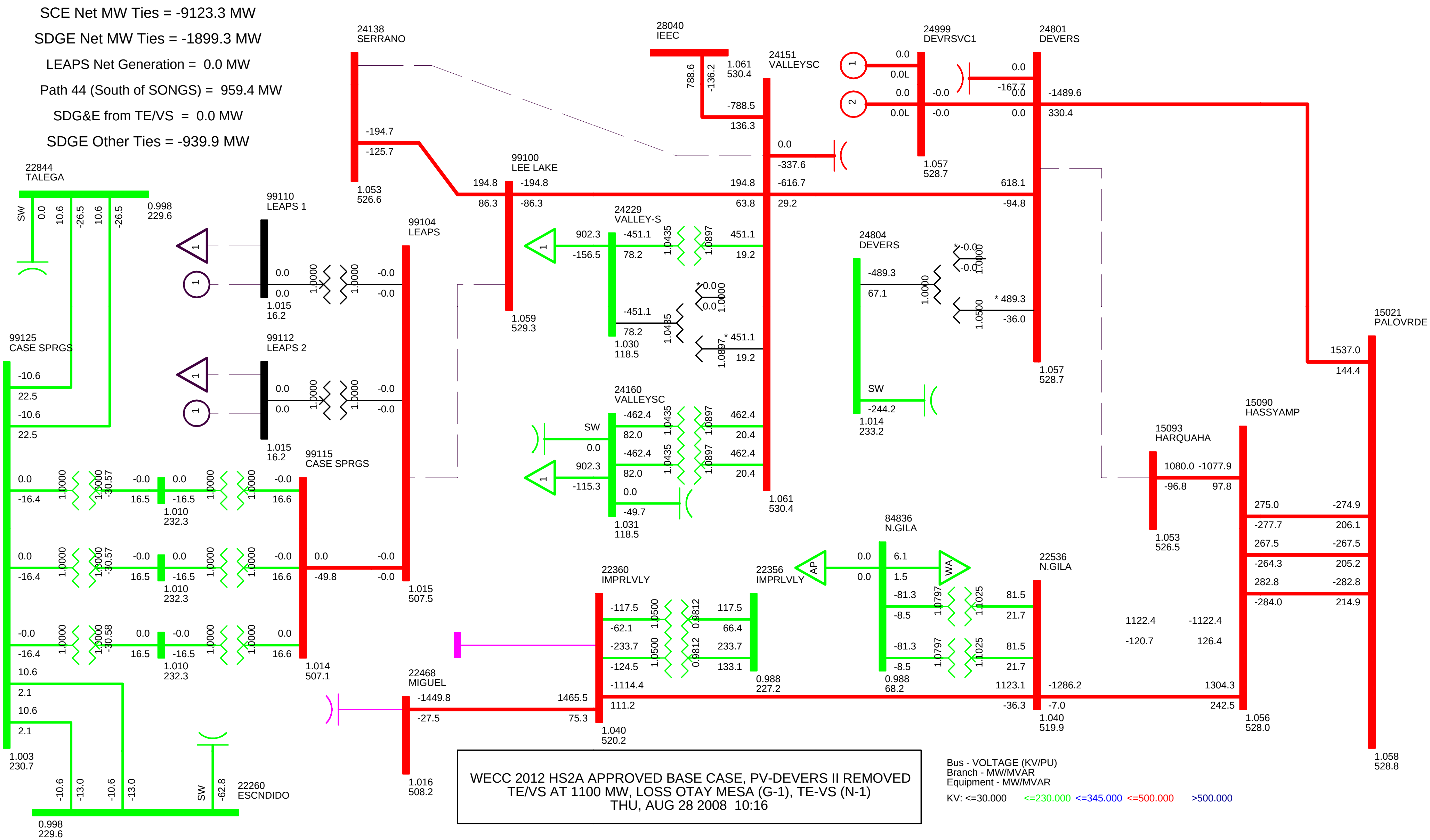
SDG&E from TE/VS = -1109.4 MW

SDGE Other Ties = -580.0 MW



WECC 2012 HS2A APPROVED BASE CASE
PV-DEVERS II REMOVED, NO LEAPS, TE/VS AT 1100 MW
WED, AUG 27 2008 11:46

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
KV: <=30.000 <=230.000 <=345.000 <=500.000 >500.000



SCE Net MW Ties = -9123.3 MW
SDGE Net MW Ties = -1899.3 MW
LEAPS Net Generation = 0.0 MW
Path 44 (South of SONGS) = 959.4 MW
SDG&E from TE/VS = 0.0 MW
SDGE Other Ties = -939.9 MW
24138 SERRANO
28040 IEEC
24151 VALLEYSC
24999 DEVRSVC1
24801 DEVERS
22844 TALEGA
99110 LEAPS 1
99104 LEAPS
99100 LEE LAKE
24229 VALLEY-S
24804 DEVERS
15021 PALOVRDE
99125 CASE SPRGS
99112 LEAPS 2
24160 VALLEYSC
15090 HASSYAMP
15093 HARQUAHA
99115 CASE SPRGS
84836 N.GILA
22360 IMPRLVLY
22356 IMPRLVLY
22536 N.GILA
22468 MIGUEL
22260 ESCNDIDO
WECC 2012 HS2A APPROVED BASE CASE, PV-DEVERS II REMOVED
TE/VS AT 1100 MW, LOSS OTAY MESA (G-1), TE-VS (N-1)
THU, AUG 28 2008 10:16
Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
KV: <=30.000 <=230.000 <=345.000 <=500.000 >500.000