Rulemaking 12-03-014
Exhibit No.:
Witness: Neil Millar

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

TRACK 4 REBUTTAL TESTIMONY OF NEIL MILLAR ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

TRACK 4 REBUTTAL TESTIMONY OF NEIL MILLAR ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Neil Millar. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as the Executive Director, Infrastructure Development.

Q. Please briefly describe your employment and educational background.

A. I received a Bachelor of Science in Electrical Engineering degree at the University of Saskatchewan, Canada, and am a registered professional engineer in the province of Alberta.

I have been employed for over 30 years in the electricity industry, primarily with a major Canadian investor-owned utility, TransAlta Utilities, and with the Alberta Electric System Operator and its predecessor organizations. Within those organizations, I have held management and executive roles responsible for preparing, overseeing, and providing testimony for numerous transmission planning and regulatory tariff applications. I have appeared before the Alberta Energy and Utilities Board, the Alberta Utilities Commission, and the British Columbia Utilities Commission. Since November, 2010, I have been employed at the ISO, leading the Transmission Planning and Grid Asset departments.

Q. Have you previously testified before the Commission?

A. Yes, I presented rebuttal testimony in LTPP Track 1 on many of the same issues being raised again in Track 4.

Q. What is the purpose of your rebuttal testimony?

A. I will clarify the ISO's support for the development of preferred resources to help address needs created by the closure of the San Onofre Nuclear Generating Station (SONGS) and how the ISO's study methodology is supportive of developing these resources.

Further, numerous parties to this proceeding have taken issue with the ISO's study methodology and identification of residual resource needs in the absence of SONGS set out in Mr. Sparks' initial testimony. In this rebuttal testimony I will address topics raised by parties regarding the ISO's transmission planning studies and the joint agency Preliminary Reliability Plan for LA Basin and San Diego, as well as some recommendations for the Commission's consideration. Mr. Sparks will address topics raised by parties involving the technical aspects of the ISO's studies and application of the NERC/WECC reliability standards.

Finally, I will provide an update to the ISO's recommendations for this proceeding.

<u>Planning for Incremental Demand Response, Uncommitted Energy Efficiency, Uncommitted Combined Heat and Power, and Energy Storage</u>

Q. Several parties have taken issue with the ISO's study assumptions as opposing development of preferred resources (incremental demand response (DR), uncommitted energy efficiency (EE), uncommitted combined heat and power

(CHP) and energy storage). SCE's testimony suggests that the study supports only gas-fired generation, in contrast to SCE's studies and testimony. What is the ISO's position on these issues?

A. The ISO fully supports California's energy policy goals and the loading order and has been working diligently with state agencies to ensure that those goals are met while maintaining system reliability, as indicated in my testimony in Track 1.

The ISO's study approach is to model reasonable assumptions to assess residual needs for resources regardless of what type of resource supplies them. Informed decisions can then be made as to what resources should be authorized and procured. The ISO further supports the joint agency preliminary plan that includes a goal to procure 50% of those needs from preferred resources, and is also working to assist in the development of preferred resources.

The CPUC and other state agencies are in a position to ensure that those preferred resources are in fact developed, through the authorization of procurement or other actions, if the need is clearly identified.

Further, the ISO has published information that identifies the characteristics needed from preferred resources in order for those resources to meet local capacity needs. The ISO's goal is to ensure that demand response resources can meet operational requirements in transmission-constrained local areas where additional local capacity is needed. Unfortunately, demand response resources procured in the past have often not met these criteria.

If the ISO instead simply assumed much higher levels of preferred resource development, it would mask any potential system issues, state agencies and the industry would be ill informed as to how much of those additional requirements were actually needed to meet reliability requirements, they would also lack information on the necessary characteristics of the preferred resources, and California would risk reliability in the region.

Of course, as additional procurement of preferred resources with the necessary characteristics is identified, subsequent ISO studies will reflect those procurement decisions in future study cycles.

Q. Has the ISO followed through on its intentions expressed in Track 1 to assist with the development of characteristics for preferred resources?

A. Yes. Consistent with my testimony in Track 1, the ISO has developed a preliminary methodology to assess the necessary characteristics for preferred resources to address local capacity issues, and to proactively assist development of preferred resources as an alternative for meeting these needs. This is evolving through the ISO's 2013/2014 transmission planning cycle. The ISO released a discussion paper on September 8th, with a stakeholder call following up on September 18th. In addition, the initial application of that methodology was discussed in the most recent stakeholder consultation session on September 25th.

The ISO is also working to explore process changes to ensure that the preferred resources can be effectively utilized in the operating realm, particularly for those preferred resources that are dispatchable but use limited, such as demand response.

Q. Should changes be made to the Track 4 assumptions- purpose of Track 4?

A. No. As Mr. Sparks discusses in more detail, the assumptions (regarding preferred resources in particular) provided in the May 21, 2013 Revised Scoping Ruling are reasonable for assessing the residual needs in the local capacity areas; they also take into account procurement that the CPUC has already authorized. As I indicated earlier, additional preferred resources can be identified and authorized by the

CPUC, or otherwise taken into consideration beyond the already-assumed amounts to meet some portion of those residual needs without modifying the analysis already performed. Modifying input assumptions and repeating analysis at this time simply provides no additional value or information to the CPUC or industry.

Q. Mr. Woodruff, on behalf of the DRA, discusses silver bullets and grand plans, and suggests that the ISO believes it might have especially valuable transmission projects to propose. Does the ISO consider that a single solution exists to address the needs identified by the ISO?

A. No. The ISO has identified significant incremental needs in the LA Basin and San Diego that lend themselves to a basket of solutions, e.g. a balance of preferred resources, conventional resources, and possibly transmission. In that context, the ISO agrees in general with the summary of advantages and disadvantages associated with various resource choices set out in Mr. Woodruff's testimony.

The ISO has concluded that there are a number of transmission alternatives that warrant study and consideration, which is taking place in the 2013/2014 transmission planning cycle. Parties should not assume any particular outcome of that process.

While the ISO's 2013/2014 transmission planning process will provide enhanced input into future LTPP processes, the study results in the 2012/2013 planning process provided a frame of reference for the approximate magnitude of impact a significant transmission facility could provide, and a very high level cost estimate for a representative project. A local capacity reduction benefit of approximately 1000 MW was assessed for the representative transmission project, at a capital cost of between $1 to 2 billion.

Q. What role does the ISO give to the joint agency task force plan, the "Preliminary Reliability Plan for LA Basin and San Diego" referred to by Mr. Fagan (attached to Mr. Rogers' testimony) and presumably the "grand plan" referred to by Mr. Woodruff?

A. The joint agency task force plan describes the alignment of the ISO and state agency staff with regard to the scope of the issues and potential path forward to address reliability needs in light of the closure of SONG. Given the range of the issues being faced and the numerous proceedings and agencies affected, coordinated action is critical. The array of agencies and organizations with authority over aspects of the issues involved include the CPUC, CEC, ISO, State Water Resources Control Board, the South Coast Air Quality Management District, and probably others. Of course, the plan does not pre-empt agency processes such as CPUC proceedings and ISO stakeholder engagement and public process, including the ISO's transmission planning framework. But, the plan is an important indicator of the level of alignment around the need for prompt action to address reliability needs in the region.

Q. In this context, is there any reason that the CPUC should not consider the requests of SCE and SDG&E for authorization of additional procurement in this proceeding?

Given the importance of maintaining reliability in this heavily populated, urban area of California, and the complex array of actions necessary to meet the residual needs identified by the ISO, it is urgent for the Commission to authorize an all-source procurement for SCE and SDG&E for the amounts requested. This is much different, of course, than authorizing a comprehensive amount of procurement meant to address all the residual needs, which we advised against in Mr. Sparks' initial testimony.

Q. Several stakeholders have suggested that delays in the retirement of Once Through Cooling (OTC) generation should be considered as a means to address residual needs. Do you agree?

A. Delaying OTC retirements should not be considered as a means to meet residual needs for a number of reasons. First, planning and procurement should be based on the assumption that parties will comply with all applicable state, federal, and local regulations. Whether or not OTC compliance dates are changed is under the authority of the State Water Resources Control Board (SWRCB). Thus, delays to OTC compliance dates have not and should not be assumed in assessing future needs. Second, the existing OTC plants are inefficient, slow moving, and near the end of their economic life. Keeping them in place delays air quality improvements and slows modernization necessary to address changing reliability needs.

However, it is reasonable to explore OTC compliance delays if the timing alone would otherwise lead to a less ideal long term solution strictly due to slight differences in implementation timelines for preferred alternatives that could include DR, energy efficiency, storage, or transmission.

The ISO's Study Methodology: Transmission Planning Standards, the N-1-1 Contingency and Load-Shedding

Q. Many of the parties to this Track 4 proceeding, including Mr. Woodruff, have raised issues about the ISO's application of NERC/ WECC/ISO transmission planning standards embodied in the study methodology approved by the Commission in D.13-02-015 (Track 1 decision) and also in D.13-03-029 (SDG&E procurement decision). Do you believe that this topic and the ISO's study methodology in general are issues to be addressed in Track 4?

A. No. As discussed in Mr. Sparks' opening testimony, the issue has been reviewed and considered in the Track 1 proceeding. Mr. Sparks' rebuttal testimony also touches on his rebuttal testimony recently submitted in the Commission proceeding evaluating the need for the Pio Pico generation facility, Docket A.13-06-015. In that filing, the ISO also argues against accepting large amounts of load shedding as an acceptable long term transmission planning solution in highly urbanized areas of the ISO grid. This is consistent with ISO planning in all urbanized areas of the grid, including those in the SCE and PG&E service territories. I also touch on a number of issues raised in other parties' testimony below.

Q. Several parties have expressed concern about the validity of the ISO's application of the N-1-1 requirements in its planning standards. Is there any merit to this concern?

A. No. The ISO's application of the N-1-1 limiting contingency of the ECO-Miguel and Ocotillo-Suncrest circuits is consistent with the ISO's historical practices. In planning the needs of the system, the ISO's practice has been not to rely on significant volumes of load shedding to mitigate Category C contingencies in densely populated urban areas. As described in more detail in Mr. Sparks' testimony, the ISO relies on occasion on smaller blocks of load shedding, as well as larger blocks of load shedding on an interim basis until a permanent capital solution can put in place. Further, load shedding through SPS has been utilized effectively to achieve operational efficiencies where alternative sources are available to either restore load, or to take the place of relying on the load shedding as a mitigation if the operational risks are higher than normal (due to weather or fire conditions, for example). However, planning to rely on large blocks of urban load shedding with no alternative means of supply has not been the ISO's historical practice, nor has it been the current practice in assessing local capacity needs. The ISO also understands that this is consistent with the practices of most ISOs in the United States and Canada.

As Mr. Sparks' testimony indicates, load shedding was discussed in the Sunrise proceeding as an undesirable consequence of selecting the alternative route which, at that time, was classified as a simultaneous double circuit Category C outage.

The circumstances being considered today have evolved from the conditions discussed at that time. Clearly, the sensitivity of potentially relying on large blocks of urban load shedding (with no other available mitigation regardless of operating conditions) is higher today for a number of reasons supporting at least maintaining the current planning practices and not reducing them to a lower level. This is especially the case in San Diego, the eighth largest city in the US and second largest in California, with a high concentration of tourism and significant military facilities.

More recent outages in the area have also escalated customer reliability concerns, and highlighted the impact that larger outages have on customers – impacts that compound and reach beyond the sum of impacts otherwise felt due to individual customer outages.

The retirement of the SONGS has also significantly increased concerns for security in the area, making the system much more dependent on power flows into San Diego from the east. At the same time, there are tangible risks, fires in particular, that can impact both 500 kV circuits reaching into San Diego.

Further, as the industry plans for, and anticipates, a wider range of potential operating conditions in the future as the makeup of the resource fleet changes, it will be critical to ensure that reliability is maintained in the transition.

However, as Mr. Sparks' testimony describes in more detail, the application of these historical practices does not negate the significant benefits the Sunrise project has provided to the grid in enabling development of renewable generation and substantially reducing local capacity needs in the order of 1000 MW.

The ISO's Board of Governors is aware of the ISO's historic practices in regard to the consideration of N-1-1 contingencies. The ISO agrees that to ensure greater transparency, it would be best if these practices related to Category C contingencies are addressed as well in the ISO planning standards, and intends to conduct an open stakeholder process to augment its planning standards in the first half of 2014.

Q. Several stakeholders have suggested that detailed cost benefit analysis needs to be performed before accepting the ISO's position regarding protecting against the specific N-1-1 limiting contingency in the ISO analysis. Is this a practical approach?

A. The suggested approach of performing detailed cost benefit analysis in every case of considering reinforcement beyond the minimums established by NERC is not a practical consideration in all cases and not a practical consideration in this particular case. As I described in my Track 1 testimony, deterministic criteria have generally been adopted in transmission planning processes based on historical experience, in contrast to the probabilistic analysis used in generation planning scenarios. This has occurred largely because the number of combination of events that need to be studied in a more complex transmission network such as the LA Basin and San Diego systems cannot be fully assessed on a probabilistic basis due to both data limitations and limitations of analytical tools. There are cases where the number of combinations of potential system conditions are more limited, and a cost-benefit analysis can be employed and provide meaningful input into decision-making processes, but this is not universal. The ISO employs these methods where circumstances allow.

However, given the practical limitations associated with conducting a cost/benefit analysis for each Category C contingency, the ISO has therefore continued the historical practice of limiting the amount of load shed relied upon on a long term basis in densely populated urban areas and has employed cost/benefit analysis as a useful tool in cases where it is appropriate.

Q. At page 2 of his testimony, Mr. Powers suggests that LADWP plans only to the minimum NERC planning requirement and provides a system of higher reliability than SCE and SDG&E in referring to a referenced document prepared by LADWP. Can you respond to his assertions?

A. A plain read of the referenced document contradicts Mr. Powers' assertion that the LADWP system is planned to the minimum NERC standard level without additional criteria also being applied. To the contrary, the LADWP system relies on more than meeting the minimum NERC standards.

In addition to the NERC requirements, the LADWP document both refers to additional WECC requirements and provides a listing of additional LADWP requirements that are beyond and in addition to NERC and WECC requirements.[1] The report also details several load shedding arrangements that are being relied upon for double contingency Category C outages <u>until</u> a new facility is placed in service (comparable to the ISO's reliance on interim load shedding). The document further acknowledges additional actions being taken to mitigate a Category D contingency despite being beyond NERC requirements. (In that case, the installation of a load shedding arrangement is not required to meet Category D performance requirements.)[2]

Q. Mr. Fagan has suggested that load shedding could be an interim "bridge" until permanent solutions are implemented. Do you agree with this approach?

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[1] [1] See LADWP, 2012 Ten-Year Transmission Assessment (Dec.2012) at page 8. The weblink to this document can be found at footnote 7 of Mr. Powers' testimony.

[2] *Id.* at pages 2-3.

A. Yes. ISO historical practice has been to generally allow urban load shedding for Category C contingencies only for interim periods while mitigation is being deployed and as a last resort. There are two such load shedding arrangements currently in place, which have transmission projects underway to eliminate the need for the load shedding. In addition, the ISO very recently relied on load shedding in SCE's south Orange County area until the Del Amo-Ellis loop in project could be completed in the summer of 2012. A different load shedding arrangement was relied upon until the Barre-Ellis reconfiguration and the Johanna, Santiago and Viejo shunt capacitor bank projects could be completed in the summer of 2013.

Q. Based on the testimony presented in Track 4, should the Commission re-evaluate its prior decisions regarding the ISO's study methodology and the ISO's position load shedding for N-1-1 contingencies?

A. No. I have addressed a number of the issues raised in the testimony of others, and Mr. Sparks has addressed the other issues in more detail. None of the parties submitting testimony have presented any compelling basis for the Commission to change its use of the ISO's LCR methodology for determining local capacity needs for the LA Basin and the San Diego local areas in D.13-02-015 and D.13-03-029.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

ATTACHMENT 1

A.13-06-015
Application of San Diego Gas & Electric Company (U 902 E) to Fill Local Capacity Requirement Need Identified in D.13-03-029

Rebuttal Testimony of Robert Sparks on Behalf of the
California Independent System Operator Corporation
October 4, 2013

Application No.: A.13-06-015
Exhibit No.:
Witness: Robert Sparks

Application of San Diego Gas & Electric Company (U 902 E) to Fill Local Capacity Requirement Need Identified in D.13-03-029	Application 13-06-015 (Filed June 21, 2013)

REBUTTAL TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of the San Diego Gas & Electric Company (U902E) to Fill Local Capacity Requirement Need Identified in D.13-0-029	Application 13-06-015

REBUTTAL TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Robert Sparks. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as Manager, Regional Transmission.

Q. Please describe your educational and professional background.

A. I am a licensed Professional Electrical Engineer in the State of California. I hold a Master of Science degree in Electrical Engineering from Purdue University, and a Bachelor of Science degree in Electrical Engineering from California State University, Sacramento.

Q. What are your job responsibilities?

A. I manage a group of engineers responsible for planning the ISO controlled transmission system in southern California to ensure compliance with NERC, WECC, and ISO Transmission Planning Standards in the most cost effective manner. With the California transmission system undergoing a major transformation, there are significant uncertainties that must be considered. In particular, I have been involved in the studies conducted by the ISO to evaluate systems needs in light of the environmental requirements placed on once-through-cooling generating facilities by the State Water Resources Board and the absence of the San Onofre Nuclear Generating Station (SONGS).

Q. Have you provided testimony about local capacity needs in the San Diego area previously in other proceedings?

A. Yes. I submitted opening, supplemental and rebuttal testimony addressing the ISO's assessment of local area needs in San Diego in Docket A.11-05-023 which was based on the ISO's once through cooling studies developed during the 2011/2012 transmission planning process.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to some of the topics raised by the testimony of William Powers on behalf of Sierra Club, CA; California Environmental Justice Alliance (CEJA); Protect Our Communities (POC) and the testimony of David Peffer on behalf of POC.

Q. What are the issues that you intend to address in this testimony?

A. Both Mr. Powers and Mr. Peffer have made factually inaccurate statements about the ISO's LCR study methodology that underlies the 298 MW local capacity resource need established by the Commission in D.13-03-029. While I do not believe that the ISO's study methodology is an issue to be considered in this proceeding because it was extensively litigated and approved in D.13-03-029, the ISO is concerned that without a response, such incorrect information may be taken out of context and relied upon in other venues or proceedings. I will also address Mr. Power's testimony about intervening circumstances that he recommends should be taken into consideration by the Commission in deciding whether to approve the Pio Pico PPTA.

<u>Probabilistic versus Deterministic Transmission Planning Requirements</u>

Q. Mr. Powers and Mr. Peffer have characterized the ISO's contingency planning methodology as relying on a "highly improbable" and overly conservative reliability contingency in developing the local area needs in A.11-05-023. Was this topic addressed in A.11-05-023?

A. Yes. I provided rebuttal testimony explaining transmission planning requirements, responding to the witness sponsored by CEJA. I was extensively cross-examined on my testimony, and the ISO devoted a portion of its opening brief and reply brief to these topics. Contrary to Mr. Peffer's assertions at pages 12-14 of his testimony, I believe that the Commission had a very complete record upon which to rule on these issues in D.13-02-015. I am attaching these materials as exhibits to my testimony, and will include them in the record in this proceeding.

Q. Does the ISO's local capacity requirements (LCR) study methodology consider the probability that a reliability contingency will occur?

A. Not in the sense used by Mr. Powers at page 4 of his testimony. The contingencies and required system performance levels that are applied are based on the NERC transmission planning reliability criteria, as augmented by WECC regional standards and California-specific standards. These mandatory standards are deterministic, not probabilistic. Assumptions are made regarding load levels and system conditions prior to a disturbance and then specific disturbances are simulated to test modeled performance against performance requirement scales. In general, a broader range of system impacts are permissible for more extreme, and less likely, types of contingencies.

The deterministic test is exactly that – a test. It is a test that is developed through broad industry and stakeholder participation to arrive at an appropriate balance between reliability and cost. It is not an assessment of every possible operating condition and the anticipated system response to each possible operating condition.

This is an important distinction, because the probabilistic methodologies that are more common in system-wide resource adequacy analysis focus primarily on all possible combinations of generation outages, but for the most part assume an unconstrained and highly reliable transmission system. The two types of analyses have fundamental differences and applying probabilistic arguments to one possible transmission outage system condition without considering all other possible outage conditions is a fundamentally flawed application of the probabilistic study technique.

Q. What is the difference between a deterministic study and a probabilistic analysis?

A. A deterministic transmission planning study, used by the ISO for the OTC/LCR studies and its transmission planning studies, makes a number of idealized assumptions, and then tests the system performance following simulated contingencies, whether in the steady-state power flow analysis or dynamic stability analysis. The required performance for each level of contingency is established through years of industry-wide experience and stakeholder input, resulting in a testing methodology that has been adopted by NERC and FERC and provides consistent and acceptable system performance across the United States, Canada, and the interconnected portions of Mexico. Those performance levels differ for different broad categories of contingencies, recognizing the significantly different likelihood of occurrence for each of those categories of contingencies.

Probabilistic analysis, in contrast, sums the probabilities of a number of events, each with its own probability of occurring, occurring at a particular time or in combination and assesses the anticipated impacts of all of the potential events. System-wide resource adequacy analysis lends itself to this type of approach. Individual generators each have their unique performance characteristics, including the probability of forced outages, and the combined effect of the individual performance characteristics can be considered on a probabilistic basis.

Studying a transmission system on a probabilistic basis has not replaced deterministic assessments for a number of reasons. These include the complexity of needing to consider the individual performance of a significantly larger number of transmission and generation components, considering the interaction on the transmission system between those components, and also the wide range of operating conditions that could exist at any point in time. Also, and to some extent because of these complexities, there is no meaningful industry standard to compare forecast performance against, unlike the deterministic criteria adopted by NERC and WECC. Probabilistic techniques are emerging that can be applied to transmission system planning working in conjunction with deterministic analysis. To this point, however, these techniques have been utilized more frequently to assist in the selection of the optional alternative to address a reliability issue, or to consider the merits of transmission reinforcements to address economic or policy-related issues. Haphazardly or selectively applying probabilities of a particular event occurring in the midst of a deterministic analysis is not a probabilistic analysis –indeed it is neither. Arbitrary adjustments to exclude certain contingencies from analysis, as suggested in the referenced testimony, simply weaken and undermine the test being applied in the deterministic analysis.

Applying probabilities selectively, which would weaken the deterministic test, would be analogous to a medical student seeking to have his or her grades improved, by pointing out that the likelihood of being confronted with a particular disease or condition that was the subject of a test question is quite low, and therefore should be removed from the grading. It defeats the entire purpose of testing the integrity of the transmission system through a deterministic analysis, and fails to provide the comprehensive view of risk under a wide range of operating conditions that probabilistic analysis would provide.

Q. Was this information provided to the Commission in A.11-05-023?

A. Yes, I discussed deterministic versus probabilistic methodologies in my rebuttal testimony at pages 10-11, as well as the ISO's opening brief at pages 13-16, both of which are attached as exhibits to my testimony here.

Q. Has the Commission approved the ISO's LCR study methodology in other proceedings in addition to A.11-05-023?

A. Yes. The Commission made determinations in D.06-06-064 regarding the criteria and test contingencies, as the ISO discussed in its reply brief in A.11-05-023, pages 9-12 (attached). Furthermore, the Commission approves the ISO's annual LCR study each year for purposes of resource adequacy. The Commission also considered these issues in Track 1 of the current LTPP proceeding, R.12-03-014, and once again supported the ISO's study methodology in D.13-02-015.

<u>N-1-1 Planning Criteria and Load Shedding</u>

Q. Mr. Powers and Mr. Peffer have questioned the reasonableness of the ISO's transmission planning practices with regard to load shedding as a mitigation solution for the N-1-1 contingency in the San Diego local area. Was this issue also addressed in A.11-05-023?

A. Yes, the witnesses presented by CEJA and DRA made the same arguments that have been raised by Mr. Powers and Mr. Peffer. I addressed the topic of the N-1-1 reliability planning criteria in my rebuttal testimony in A.11-05-023 (pages 8-10, attached), and the ISO briefed the issue in its opening brief (pages 16-18, attached). The ISO provided the Commission with ample information about how engineers at the ISO develop mitigation solutions for the N-1-1 contingency and the circumstances under which load shedding is not a prudent planning option. The ISO's position is that load shedding in the densely populated San Diego area should not be used as a transmission planning tool for the N-1-1 NERC Category C contingency of the 500 kV lines between the Imperial Valley, Miguel and Suncrest substations. This is due to the significant amount of load that would be subject to load shedding, the sensitivity of urban loads to large blocks of shedding, the complexity of operating arrangements in the area, and the proximity of the particular transmission lines.

Q. Has either witness provided new factual information about the ISO's planning criteria that would cause the Commission to reconsider D.13-03-029?

A. No. In fact, Mr. Peffer in particular appears to be quite confused about NERC, WECC, and ISO planning standards and how LCR studies are conducted. His testimony should not cause the Commission to re-evaluate its previous decision establishing a need for 298 MW of local resources. Similarly, Mr. Powers' testimony simply repeats the argument raised by the witnesses in A.11-05-023 that the ISO should have used load shedding- in the highly urbanized San Diego area- as a mitigation solution in lieu of generation or other local resources (see Powers testimony, page 4).

Q. Mr. Peffer states that the ISO "switched" from a G-1/N-1 planning criteria to the more severe N-1-1 and that this "fundamental switch" was "revealed" for the first time in your Supplemental Testimony in A.11-05-023. Did the ISO

change from a G-1/N-1 standard to an N-1-1 standard for the San Diego area, as described by Mr. Peffer at pages 8 and 9 of his testimony?

A. No. Both the G-1/N-1 and the N-1-1 are part of the LCR criteria, and the most limiting test sets the requirements – in this case, the N-1-1 contingency. Mr. Peffer seems to conclude that when the ISO ceased to consider the even more demanding G-1/N-2 as the worst outage which then shifted the N-1-1 to being the worst outage, as described above, that the ISO had changed its standards and began applying a higher more demanding requirement . However, eliminating the test of the more onerous contingency was in response to a change in WECC criteria and not a change to ISO planning standards. Furthermore, the ISO's consideration of the N-1-1 as the most limiting contingency resulted in a less demanding test being the limiting condition.

Q. Can you briefly summarize the information provided in your Supplemental Testimony?

A. After performing a comprehensive contingency analysis of all contingencies required to be assessed in an LCR study, the ISO found that the G-1/N-2 contingency was demonstrated through the study results to be the worst contingency. As described in my supplemental testimony, prior to the change in the WECC criterion, the most limiting contingency for the determination of LCR needs in the San Diego area was the simultaneous outage of the 500 kV Sunrise Powerlink and the Imperial Valley-ECO 500 kV line overlapping with an outage of the Otay Mesa combined-cycle power plant (G-1/N-2). The limiting constraint for this contingency is the South of SONGS Separation Scheme. With the change to the WECC criterion, the most limiting contingency for San Diego sub-area becomes instead the loss of Imperial Valley-Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line (N-1-1).

Q. Why do you believe that load shedding is not appropriate under the circumstances of the loss of Sunrise followed by the loss of SWPL?

A. As I discussed in my rebuttal testimony, the history of transmission line outages due to fires and equipment failures in the area and the configuration of the system indicate that outage risks and consequences are high. The Imperial Valley substation is a major source of imported power for three different utilities: SDG&E, IID, and CFE. This is not only evidence of the criticality of this substation, but also the level of exposure to operational coordination issues and failures. Relying on load shedding as a primary mitigation measure is an indication that the system is being planned and operated at a very high stress level, and with very little margin for error. Based on this information, it is not prudent to plan and operate the Imperial Valley system with currently expected high outage risks and consequences at a very high stress level and with very little margin for error. In other words, relying on load shedding as part of the long-term plan leaves no allowance for unexpected circumstances such as generation retirements or higher load growth, other than additional load shedding which could lead to overly excessive amounts of load shedding. The ISO does not believe that load shedding should be used as a transmission planning tool for this particular contingency and for this densely populated area where - contrary to Mr. Peffer's testimony - widespread and possibly sustained outages could jeopardize public safety and have widespread economic consequences.

Q. Isn't load shedding permitted by NERC reliability standard TPL 003 in response to a Category C N-1-1 event?

A. Yes, and the ISO has special protection schemes (SPS) in place that employ some form of load shedding in small amounts on the sub-transmission system or for extreme category D contingencies. However, although NERC TPL 003 *permits* load shedding as a mitigation for an N-1-1 contingency, the standard does not *require* the ISO, as the Planning Coordinator, to approve an automatic load shedding SPS under all such circumstances and instead requires the Planning Coordinator to consider system design and expected system impacts in deciding whether an automatic load shedding SPS is appropriate.

Q. Is the ISO's position with respect to load shedding in highly urbanized areas under the N-1-1 contingency unique to SDG&E?

A. No. Similar to the San Diego area, the ISO does not use load shedding as a long term mitigation solution for the N-1-1 contingency in areas of dense population throughout the SCE and PG&E service territories as well. Changing this position for SDG&E would lead the ISO to make sweeping changes from current and historical practices for the entire ISO controlled grid. Furthermore, the ISO's position with respect to load shedding in highly urbanized areas is consistent with current practices in the rest of the ISOs and, in general, in much of the United States and Canada.

Q. Does the N-1-1 limiting contingency reduce the reliability benefits of the Sunrise Powerlink line below the 1000 MW reduction in LCR claimed as a benefit when the line was approved, as argued by Mr. Peffer at pages 9-11 of his testimony?

A. No. The 1000 MW benefit was based on increasing the existing import capability from 2500 MW to 3500 MW after an outage of either Sunrise or SWPL. At that time, the ISO assumed that the 3500 MW amount would be based on establishing a 3500 MW WECC path rating to replace the 2500 MW WECC Path 44 rating. Since that time the 1000 MW Sunrise WECC path rating has been eliminated as well as any notion of pursuing a 3500 MW WECC N-1 Path Rating. Although these path ratings would have helped ensure that changes within neighboring systems could not impact the capability of the ISO system, and provided reasonable margin for this urban load area which has only two reliable connections (SONGS and Imperial Valley) to the rest of the ISO and WECC, they also would limit the capability of the system. With Sunrise in-service the Imperial connection became more reliable, and the path ratings are not being pursued any further. Without the path rating limitations the N-1-1 is the most limiting contingency, and with only the N-1-1 considered, Sunrise provides more than 1000 MW of benefit. This information was shared by the ISO during the workshop for the San Diego procurement proceeding.

Q. Mr. Peffer accuses the ISO of a "lack of transparency" about its planning standards (testimony, page 12), noting specifically that the ISO objected to POC data requests on this subject. Do you agree that there is a lack of transparency regarding the ISO's reliability criteria?

A. No. As I have discussed above, and throughout the record in A.11-05-023, the N-1-1 limiting contingency for the San Diego area is firmly grounded in the LCR planning methodology and the NERC/WECC planning standards. It has been used for many years in the Commission's resource adequacy proceedings and is clearly described in numerous documents on the ISO's website. The N-1-1 issue was litigated in A.11-05-023 and resolved in D.13-03-029. For all of these reasons, the ISO objected to POC's data requests.

<u>**San Diego Local Capacity Area and Local Generation**</u>

Q. Mr. Peffer states that the ISO "wrongfully excluded" generation assets from the San Diego local area, thus overstating the LCR need (testimony, pages 5-7). Can you respond to this testimony?

A. Once again, Mr. Peffer misunderstands the ISO's LCR study methodology, and also has confused planning criteria with operational requirements. As I discussed in my supplemental testimony in A.11-05-023, the ISO studies identified two local capacity subareas in the SDG&E service territory: the San Diego LCR subarea and the IV-San Diego LCR area. From a transmission planning standpoint, the N-1-1 criteria discussed above is the most limiting contingency for the San Diego LCR subarea. The most limiting contingency in the Greater Imperial Valley-San Diego (IV-San Diego) area is described by the outage of 500 kV SWPL between Imperial Valley and N. Gila substations overlapping with an outage of the Otay Mesa combined-cycle power plant (603 MW). Generation at the Imperial Valley substation, such as La Rosita II and Sempra TDM is not effective at meeting the needs of the San Diego LCR subarea since that generation cannot flow into the area during the worst contingency. However, the generation at the Imperial Valley substation is effective at meeting the IV-San Diego LCR needs. Pio Pico is needed to meet the San Diego LCR subarea needs, and since the generation at Imperial Valley substation such as La Rosita II and Sempra TDM combined cycle projects (with generator ties to the Imperial Valley Substation) cannot meet the needs of this subarea, they are not substitutes for Pio Pico. Although from an operating standpoint, in order to protect against certain under frequency islanding situations, these generating units would be dispatched to meet the 25% internal generation requirement, as discussed in the FERC order Mr. Peffer describes in his testimony, this has nothing to do with the ISO's LCR study methodology, which does not consider islanding situations, and resource needs in the San Diego subarea identified in A.11-05-023.

<u>**Intervening Events Following D.13-03-029**</u>

Q. At pages 4-10 of his testimony, Mr. Powers suggests that the Commission should reconsider the local capacity need established in D.13-03-029 to take into account various changed circumstances since the decision was issued. Do you agree that the Commission should follow this course?

A. No, I do not. Mr. Powers has requested that Commission reconsider many of the study assumptions that were approved in D.13-03-029, thus necessitating that the studies be performed again so that new local resource needs can be identified. Using this approach will lead to never-ending studies with no conclusions because there will always be changed circumstances after a study is completed and decisions are rendered.

Q. Isn't the ISO evaluating local capacity needs in the San Diego and LA Basin areas in light of the SONGS retirement in Track 4 of the current LTPP, R.12-03-014?

A. Yes. The ISO's LCR studies underlying the resource needs identified in D. 13-03-029 did not take the SONGS retirement into account. The ISO's Track 4 studies have identified substantial needs in the LA Basin and San Diego that are in addition to the 298 MW approved for San Diego and the 1400-1800 MW approved for the LA Basin in Track 1. The ISO suggests that if preferred resources, energy storage and DG are developing at a rapid pace, as Mr. Powers suggests, the Commission can consider whether these resources can fill the residual needs identified by the ISO in Track 4.

<u>ISO Recommendation</u>

Q. What is the ISO's recommendation regarding the SDG&E request for approval of the Pio Pico PPTA?

A. Based on the ISO's local capacity studies, the Commission in D.13-03-029 determined there to be a 298 MW local need in the San Diego area, starting in early 2018. It is my understanding that the decision gave SDG&E the option of either re-submitting the Pio Pico and/or Quail Brush PPTA(s) with modifications to the commercial in-service dates to coincide with the retirement of the once-through-cooling generation, or issuing a new request for offers. Given the lead time needed for new generation permitting and construction, it would seem that conducting a new request for offers could adversely impact the commercial operation date of new resources responding to the request, ultimately impacting local reliability if the resource is not available after January 1, 2018.

Q. Would other resources, particularly preferred resources, also be able to fill the 298 MW need determined in D. 13-03-029?

A. Yes, if such resources provide the characteristics needed by the ISO to respond to local contingencies. However, as SDG&E witness Eekhout noted, the Commission took into account certain assumed levels of demand response and uncommitted energy efficiency that would be available to meet local resource needs, and reduced the ISO's study results to reflect these additional assumptions. The ISO agrees with SDG&E that it would not be prudent to assume that even greater levels of these preferred resources could supplant the need for a conventional gas-fired resource such as Pio Pico.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTACHMENT 1

R. Sparks Rebuttal Testimony
Pages 10-11

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Pages 13-16

not allowing load drop in the San Diego area is not reasonable," (Firooz testimony, pages 8- 9). Specifically, CEJA posed the following question:

> Does NERC, WECC, and/or CAISO reliability criteria prevent the use of controlled load drop for an N-1-1 transmission contingency? If so, where is this criteria documented? If not, what threshold does the CAISO use to determine when controlled load drop is acceptable mitigation and when it is not? Are there any limits on the amount of controlled load drop which is acceptable?

The CAISO responded:

> The ISO is required by NERC TPL 003 to plan its network so that it can be operated to supply projected customer demands for N-1-1 events regardless of their probability. *NERC Transmission Planning Standards allow the use of controlled load drop depending on system design and expected system impacts…*

The rest of the ISO's response provided more explanation as to why, under the specific system configuration and consistent with NERC TPL 003, the ISO would operate all available generation to avoid the need to shed load to mitigate the category C Sunrise/ECO-Miguel overlapping outage, for the reasons I discussed above. In other words, although NERC TPL 003 *permits* load shedding as a mitigation for an N-1-1 contingency, the standard does not *require* the ISO, as the Planning Coordinator, to approve an automatic load shedding SPS under all such circumstances and instead allows for the Planning Coordinator to consider system design and expected system impacts in deciding whether an automatic load shedding SPS is appropriate. Ms. Firooz seems to misunderstand both the planning standard and the ISO response to the CEJA data request, and has provided no basis for her conclusion that the ISO's planning decision to avoid a load shedding SPS for the Sunrise/ECO-Miguel N-1-1 is "unreasonable."

Q. Do you agree with Ms. Firooz's suggestion at pages 7- 8 of her testimony that considering the probability that a contingency will occur- which allegedly would result in lower costs for consumers- would not lower grid reliability?

A. Absolutely not. In the first place, the ISO is required to comply with NERC planning requirements, which are deterministic and not probabilistic. More importantly, Ms. Firooz has not conducted a complete probabilistic analysis so she has no basis for her conclusion that local area needs would be lower and that costs to consumers would therefore be lower. It is possible that a probabilistic analysis could result in higher local needs.

To briefly summarize the issue, deterministic criteria apply specific tests to the system – with specific assumptions regarding load level and the "worst" contingency as set out in the various disturbance classifications in the NERC standards. A probabilistic approach examines the probability of a wide range of outages under a wide range of conditions, and compares the results to a predetermined criteria related to the acceptable level of risk one is willing to take on a probabilistic basis.

Simply applying probabilities to the "worst case" scenario ignores all of the other potential events that could result in loss of reliable service, under a wide range of scenarios, providing no effective means to assess the robustness of the transmission system on a probabilistic basis or deterministic basis.

Q. DRA witness Fagan also takes issue with the ISO's position on load shedding, at pages 19-25 of his testimony. He notes that SDG&E has agreed to the use of controlled load drop under N-1-1 contingencies and intends to install a "safety net" that will shed load in the event of the sequential loss of two 500 kV lines. Do you agree that this "safety net" should be considered as a mitigation for the Category C contingency you described previously?

A. No. A safety net is only acceptable for a Category D outage. The safety net would need to be upgraded to a WECC approved SPS before it could be used for the N-1-1. However, as I explained above, the current transmission system design in the Imperial

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ISO used for an import capability and the 3500 MW San Diego area import level used by SDG&E is 414MW and should be added back into the LCR deficiency calculation, DRA witness Ghazzagh's determination of the local area resource requirement for 2020 under the high load scenario- 2713MW- is actually higher than the ISO's calculation for 2021 in the ISO base case. Thus, while the ISO cautions the Commission against using the "apples to oranges" approach to establish the import capability for purposes of LCR needs, the final conclusions as to the LCR needs reached by DRA and the ISO are not so far apart.[30]

CEJA witness Ms. Firooz also mixed apples and oranges by suggesting that the 3500MW import limit recommended by SDG&E should be increased by 730MW, based on the ISO's analysis. While it is rather difficult to follow and understand her analysis, Ms. Firooz seems to suggest that ISO's post-contingency import flow of 3230MW in 2021 should be increased by 1000MW to reflect the additional import capability provided by Sunrise (which would produce an import capability of 4230MW, or 730 MW higher than the 3500 MW used by SDG&E and DRA).[31] Her apparent assumption is incorrect. Ms. Firooz seems to have overlooked the fact that the ISO's post-contingency import flow is based on the N-1-1 contingency with Sunrise out of service, so that there were no Sunrise flows in the ISO's analysis that produced the 3230 MW flow limit. As noted above, the 3500 MW import capability was based on the G-1/N-1 contingency with only SWPL out of service, and with 604 MW of local generation out of service. Thus, Ms. Firooz's recommendation of a higher import limit lacks justification and is not consistent with any study methodology.

[30] Mr. Fagan's overall spreadsheet conclusions as to the LCR deficiencies for San Diego are dramatically different than the ISO's because of other assumptions that he adds to the spreadsheet analysis such as assumptions about uncommitted EE, incremental DR and others.
[31] Ex. 20, page 19.

IV. Intervener Concerns with the ISO's Study Methodologies and Assumptions are Misplaced.

In addition to the power flow and import capability issues addressed above, interveners DRA, NRDC and CEJA raised other issues with the ISO's LCR/OTC studies. For the most part, these parties argued that the ISO's assumptions in the base case renewable portfolio- the case upon which the ISO is basing its recommendations- are too conservative and do not reflect reasonable levels of demand response (DR), energy efficiency (EE), distributed generation (DG), combined heat and power (CHP) resources and energy storage. They have also questioned the ISO's use of a 1-in-10 load forecast and urge the Commission to adopt other mitigation solutions in lieu of local generation. CEJA witness Firooz also discussed other aspects of the ISO planning studies.

In essence, each intervener recommended the adoption of revised planning assumptions and non-generation mitigation solutions that, on paper, would substantially reduce the local capacity deficiencies identified by the ISO. As discussed below, these recommendations should be approached with great caution. The risks to grid reliability are too significant -- and the time frame for procuring needed flexible thermal generation is too short -- to allow for any errors in judgment. Furthermore, some of the intervener's proposals, if adopted for the Commission's procurement decisions, would require fundamental and unjustifiable changes in the ISO's LCR study methodology and could introduce substantial, inappropriate variations between transmission planning and resource procurement assumptions.

A. Load Forecasts and Planning Assumptions

1. <u>Probabilistic versus Deterministic Planning Studies</u>

CEJA witness Firooz begins her testimony by questioning the entire LCR methodology- and indeed, all of the ISO's transmission planning studies-with arguments that the deterministic approach to planning is "overly conservative" and produces results that are too expensive for the ratepayers.[32] According to Ms. Firooz, starting with the use of the 1-in-10 load forecast, which uses peak loads that are "not expected," and then layering on the NERC/WECC mandated planning requirements (which "probably" won't happen at peak load conditions) and the planning reserve margin requirements adopted by the Commission, dictates unnecessary mitigation solutions that are not needed. Ms. Firooz suggests that the Commission adopt a "probabilistic" approach to resource procurement decisions, concluding that this will not lead to reliability issues but will save the ratepayers money.

Not only are such suggestions beyond the scope of this docket, but Ms. Firooz did not conduct a probabilistic analysis of the transmission grid that would support her conclusions. Her discussion of this topic is based on mere observations regarding the likelihood that the most sever N-1-1 contingency might occur at the 1-in-10 system peak and ignores the cumulative probability of the other potential contingencies and system conditions that could also result in loss of reliable service. Furthermore, as Mr. Sparks noted, it is entirely possible that a full-blown probabilistic analysis could result in higher local needs.[33]

In contrast, the NERC/WECC mandatory planning standards are deterministic; meaning that the system is tested with specific assumptions regarding load level and appropriate contingency levels to design the system to a target reliability level. A

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[32] Ex. 20, pages 5-8.
[33] Ex. 27, page 11.

probabilistic analysis examines the individual probability of each contingency under a particular system condition over a wide range of scenarios. A deterministic criteria is similar to using one standard driving test for all drivers in California and a probabilistic criteria is similar to giving every driver an individualized test based on his or her expected driving plans. In this analogy it is difficult to predict whether the test failure rate would go up or down, or if the driving accident rate would go up or down, if the State switched from a standard driving test to individualized tests. Continuing with the analogy, while there may be some questions on the standard test that do not apply to many driving situations, this would not be a valid argument for lowering the passing score level. This is because the standard test is only a sample of potential questions that could have been asked, and the score is indicative of the knowledge level of the entire driver's handbook. Ms. Firooz's approach- which is to apply probabilities to the "worst case" under a deterministic evaluation- again mixes apples and oranges and is not an effective means by which to test the robustness of the system. Going back to the analogy, her argument is a little like finding one person and saying that since the test does not match his or her expected driving plans, the passing score for the test should be lowered for everyone.

2. Load Shedding as a Mitigation Solution

Both CEJA and DRA suggest that controlled load shedding in the event of an N-1-1 contingency should be viewed as an acceptable mitigation solution that would reduce the local capacity needs in San Diego; CEJA witness Firooz proposed dropping 378 MW and DRA witness Fagan proposed a 370 MW load drop.[34] Just to put these recommendations in perspective, this amount of load drop could equate to well over 300,000 homes.[35] To adopt the

[34] Ex. 17 (Fagan), page 12, table RF-3; Ex. 20 (Firooz), page 3, table 1.
[35] See Ex. 20, footnote 3 discussing an April 6, 2010 outage of 310 MW, which was 291,000 homes.

ATTACHMENT 2

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Pages 9-12

> in the area because with the large amount of renewable that we're expecting based on the renewable portfolio that we've studied…[15]

CEJA's statement that the "CAISO failed to evaluate the impact of four synchronous condensers that SDG&E proposed" appears to display a lack of understanding of the ISO's comprehensive transmission planning process and the testimony provided by the ISO.

D. The ISO's OTC Study is Consistent with the LCR Methodology and the Contingency Analysis Required by NERC/WECC Planning Standards.

CEJA has completely mischaracterized the ISO's local capacity area study methodology in an attempt to show that the ISO has engaged in a "backhanded attempt to increase procurement requirements" beyond those established by the Commission in D.06-06-064, the 2006 decision in which the Commission first addressed the LCR methodology.[16] This line of argument appears to be based on two general misperceptions: (1) that the ISO has "increased" the reserve margin by 2.5%, and (2) that the ISO has "failed to consider" operational solutions that would lower the LCR for San Diego.[17]

To begin with, while it is true that the ISO has never conducted a ten year local capacity technical study such as the OTC study, the OTC study is a "long-term LCR" study and it uses the same study methodology employed in the shorter term LCR studies described in Mr. Spark's initial testimony.[18] As discussed in the ISO's opening brief at pages 9-11, the ISO followed the study methodology for an LCR study, as described in

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[15] Tr. III, 539:15-540:7
[16] CEJA Opening Brief, page 11.
[17] *Id,* at pages 11-13.
[18] See Ex. 18, Attachment AA, page 213; Ex. 9, pages 2-6.

the 2013 Local Area Technical Study[19] and in the ISO's tariff.[20] It goes without saying that the LCR/OTC studies are conducted in accordance with NERC/WECC transmission planning standards.

Contrary to CEJA's assertions, the "2.5% reserve margin" is not related to the operational reserve requirements established by the Commission and was not unilaterally "added in" to the OTC study outside of the criteria used for an LCR/OTC study. Rather, the "2.5%" margin is a WECC transmission planning criteria that is followed as part of the LCR/OTC study methodology. Mr. Sparks explained this concept in response to questions from DRA about the OTC results table on page 3 of his supplemental testimony (Ex. 10).[21] Specifically, Mr. Sparks stated:

> …I also want to mention that [the] 2.5 percent margin…is required by the WECC or reliability criteria on top of the forecasted load. It is meant to be a margin for error because the studies are obviously not perfect.
>
> Q. And that criteria…is what you were just discussing with Ms. Behles a little earlier …the reserve margin?
>
> A. No, the reserve margin requirements are resource planning needs. The reactive power margin is more of a transmission planning need.
>
> And so there are two different problems. One is solved with reactive power or local resources in this case and is localized, very localized problem on the system. Resource adequacy is a much bigger picture. It is not necessarily a transmission issue. That is why they break them up into two disciplines, if you will.[22]
>
> ******
>
> As I mentioned earlier, the ISO is also a planning authority. So we are subject to the transmission planning standards. There are many standards. And so the transmission planning standards do need to be performed out to a 10 year horizon. And the WECC reactive power planning requirements specify this

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[19] Ex. 18, Attachment O
[20] See ISO tariff § 40.3
[21] Tr.III, 579:17-585:2.
[22] *Id.*at 580:24-581:20.

> 2.5 percent margin for Category C outages, and a 5 percent margin for Category B outages. And in a load pocket that means increasing the load…[23]

CEJA also cites the language of D.06-06-064 wherein the Commission selected the ISO's reliability planning Option 2, and argues that the ISO has not presented the Commission with "options" as part of the OTC study.[24] True, the description of the OTC study at Chapter 3 of the 2011/2012 Transmission Plan does not set forth the reliability planning options customarily set forth in the annual LCR study. However, since the issuance of D.06-06-064, the ISO has in fact consistently conducted its LCR studies in accordance with Option 2, as described at page 16 of the 2013 Local Capacity Technical Study[25]:

> Option 2 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (including those involving customer load interruption) developed and approved by the CAISO, in consultation with the PTOs…

Because the OTC study was conducted using the same criteria, the local capacity deficiencies were based on the Option 2 local capacity level. Further, as the ISO discussed extensively throughout the testimony and briefs in this proceeding, the ISO did in fact evaluate all "reasonable and feasible operating solutions," including load interruption, and concluded that additional local generation presented the most feasible mitigation solution. The OTC study is consistent with D.06-06-064 and the LCR studies that have been approved annually by the Commission since the issuance of that decision.

Besides misunderstanding the ISO's LCR study methodology, CEJA also appears to be confused about the NERC/WECC- required contingency analysis, which is the basis

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[23] *Id.*at 582:15-583:4.
[24] CEJA opening brief, page 12.
[25] Ex. 18, Attachment O

of the OTC study. The CEJA opening brief contains an entire section entitled "*CAISO Assumes that Sunrise Powerlink, SWPL, and the CFE Line Provide No Import Capability.*"[26] Apparently in support of this statement, CEJA entered into the record as Ex. 41 the pre- and post- import flows for two scenarios provided by the ISO in discovery. These are reproduced on page 15 of CEJA's opening brief. This table shows that after the most limiting N-1-1 contingency, which is the loss of an element of the Sunrise line followed by the loss of an element of SWPL, the parallel CFE transmission line will be disconnected. CEJA misses the obvious fact that the when these transmission line are lost to due electrical short circuit conditions, they must be removed from service. When this occurs, the parallel CFE transmission line must be protected from overload, which requires that it be removed from service as well. When these lines are removed from service, no power can flow through them. However, prior to this contingency these lines were carrying over 2600 MW of imported power. Until these lines are repaired by SDG&E, there can be no import flows on these major connections into San Diego. That is how a contingency study is conducted-- the ISO must mitigate a situation where substantial import flows into the local area have been cut off by a transmission outage.[27] This has nothing to do with the substantial benefits that Sunrise brings to the local area that CEJA describes. Contrary to CEJA's section heading, the benefits of Sunrise are assumed in the ISO's study methodology.

III. Credibility of the CEJA Testimony

CEJA witness Firooz made certain statements in the introduction and *curriculum vitae* sections of her written testimony which the ISO believed were unsustainable or

[26] CEJA Opening Brief pages 14-16.

[27] The ISO provided an explanation about import flows and CEJA's misunderstanding about the role of Sunrise in an N-1-1 contingency at page 13 of its opening brief.

ATTACHMENT 3

R. Sparks Rebuttal Testimony
Pages 8-10

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deliverability problems on the transmission system. The initiative also expedites the DG interconnection study process so that DG will not have to wait for a deliverability study to be completed if they site their DG at a location predetermined to be deliverable and if it is contracted with a load serving entity that has a DG deliverability allocation at that location. However, the ISO's DG initiative does not ensure that the DG will be developed. For planning purposes, the ISO must make reasonable assumptions about future DG development as previously discussed in this testimony.

<u>Load Shedding and Special Protection Schemes (SPS)</u>

Q. Please summarize the ISO's position on using SPS involving load shedding to meet reliability needs in the San Diego local area, as well as the interveners' testimony on this issue.

A. In my supplemental testimony, I stated that with the change in the WECC criterion, causing the Sunrise/IV-Miguel double outage to be reclassified as a Category D contingency, the most limiting contingency for the San Diego sub-area is the loss of the Imperial Valley-Suncrest 500 kV line followed by the loss of ECO- Miguel 500 kV line (N-1-1). While the change in categorization of the double outage did not change the ISO's local capacity area study methodology, the more severe G-1/N-2 contingency that previously had been studied conceptually assumed that an automatic load shedding SPS would be installed and available to prevent voltage collapse. I explained that with the more likely N-1-1 as the most limiting contingency, the ISO did not believe that it would be prudent planning to rely on an automatic load shedding SPS.

This is because the history of transmission line outages due to fires and equipment failures in the area and the configuration of the system indicate that outage risks and consequences are high. The Imperial Valley substation is a major source of imported power for three different utilities: SDG&E, IID, and CFE. This is not only evidence of the criticality of this substation, but also the level of exposure to operational coordination issues and failures. Relying on load shedding as a primary mitigation measure is an indication that the system is being planned and operated at a very high stress level, and with very little margin for error. Based on this information, it is not prudent to plan and operate the Imperial Valley system with currently expected high outage risks and consequences at a very high stress level and with very little margin for error. On the other hand, the ISO would rely on the load shedding SPS during extreme operating conditions beyond the N-1-1 contingency scenario considered in the OTC studies, that would otherwise require pre-contingency load shedding.

Both DRA (witness Fagan) and CEJA (witness Firooz) have argued that the ISO's approach to load shedding under an N-1-1 contingency is too conservative, and that the local capacity needs in San Diego would be lower if the ISO planned for automatic load shedding in the event of extreme circumstances or severe contingency events. As described below, these arguments are misplaced.

Q. Has Ms. Firooz accurately described the ISO's position with respect to load shedding as an N-1-1 contingency mitigation for the most limiting contingency for the San Diego area?

A. No. First, at page 7 of her testimony, Ms. Firooz broadly states that the ISO will not rely on load shedding in the San Diego area as mitigation for N-1-1 contingencies. That is not correct. My testimony focused specifically on load shedding as mitigation for the ECO-Miguel 500 kV line and Sunrise contingency and it is for this contingency that I believe it would not be prudent to rely on load shedding.

Ms. Firooz goes on to mischaracterize an ISO data request response on this topic by suggesting incorrectly that the ISO stated that it is not permitted to shed load for N-1-1 events and, based on that mischaracterization, she concludes that the ISO's "reason for not allowing load drop in the San Diego area is not reasonable," (Firooz testimony, pages 8- 9). Specifically, CEJA posed the following question:

> Does NERC, WECC, and/or CAISO reliability criteria prevent the use of controlled load drop for an N-1-1 transmission contingency? If so, where is this criteria documented? If not, what threshold does the CAISO use to determine when controlled load drop is acceptable mitigation and when it is not? Are there any limits on the amount of controlled load drop which is acceptable?

The CAISO responded:

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Q. Do you agree with Ms. Firooz's suggestion at pages 7- 8 of her testimony that considering the probability that a contingency will occur- which allegedly would result in lower costs for consumers- would not lower grid reliability?

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probabilistic analysis examines the individual probability of each contingency under a particular system condition over a wide range of scenarios. A deterministic criteria is similar to using one standard driving test for all drivers in California and a probabilistic criteria is similar to giving every driver an individualized test based on his or her expected driving plans. In this analogy it is difficult to predict whether the test failure rate would go up or down, or if the driving accident rate would go up or down, if the State switched from a standard driving test to individualized tests. Continuing with the analogy, while there may be some questions on the standard test that do not apply to many driving situations, this would not be a valid argument for lowering the passing score level. This is because the standard test is only a sample of potential questions that could have been asked, and the score is indicative of the knowledge level of the entire driver's handbook. Ms. Firooz's approach- which is to apply probabilities to the "worst case" under a deterministic evaluation- again mixes apples and oranges and is not an effective means by which to test the robustness of the system. Going back to the analogy, her argument is a little like finding one person and saying that since the test does not match his or her expected driving plans, the passing score for the test should be lowered for everyone.

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[34] Ex. 17 (Fagan), page 12, table RF-3; Ex. 20 (Firooz), page 3, table 1.
[35] See Ex. 20, footnote 3 discussing an April 6, 2010 outage of 310 MW, which was 291,000 homes.

recommendations of DRA and CEJA, the Commission would have to find that cutting off power to 300,000 homes is an acceptable outcome. This goes far beyond targeted load shedding in a limited area.

NERC planning standard TPL 003 permits load shedding for an N-1-1 contingency, but does not require the ISO, as the Planning Coordinator, to approve automatic load shedding under all circumstances. Rather, the planning standards allow for prudent engineering judgment taking into consideration system design and expected system impacts.[36] As Mr. Sparks explained, the history of the IV substation area includes outages due to fires and equipment failures, and the configuration of the system shows that outage risks are very high. This substation is a major source of imported power for three utilities: SDG&E, IID and CFE, which is evidence of the level of exposure to operational and coordination issues. In response to questions by CEJA, he stated:

> …All three of those systems rely on that point in the grid as one of their two major sources of imports in their systems. So it's a very critical piece of the system. And our concern is that if we rely on load shed, we're certainly overstressing that part of the system.[37]

At a later point Mr. Sparks added that it is not the ISO's position that automatic load shed would not be allowed for any of the "hundreds of overlapping contingencies (N-1-1) on the system." It is just that "there are some where it's okay and there are some where it is not,"[38] and this analysis must be done on a case by case basis. Ms. Firooz admitted that there is a host of engineering criteria that should be taken into account in determining whether controlled load shedding should be adopted as a mitigation solution, such as the design of the system,

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[36] Ex. 27, page 10.
[37] Tr.III, page 546.
[3838] *Id.*, page 550.

probability and severity of outages, and the existence of other special protection systems.[39] Thus, although Ms. Firooz clearly does not agree with the ISO's ultimate decision about load shedding, she provided no reasonable basis for disagreement with the engineering judgment that went into the analysis.

Similarly, Mr. Fagan offered no engineering basis for a load shedding scheme but pointed to SDG&E's consideration of a "safety net" as a mitigation solution for a Category C contingency. He further argued that the ISO should have performed a cost benefit analysis of the costs of a load shedding SPS versus procuring additional local generation. However, these two solutions are not substitutes for each other. Mr. Sparks explained that unlike load shedding, generation provides both local and system benefits, as well as renewable integration and reliability benefits for a marginal cost.[40] The wide-scale load shedding that would result from adoption of their proposals provides none of those benefits and only creates other problems.

3. Modeling Assumptions: Uncommitted EE, Incremental DR, Uncommitted CHP and Energy Storage

In addition to the other proposed reductions to the ISO's local deficiency findings, NRDC, CEJA and DRA all criticized the ISO's modeling assumptions regarding uncommitted EE and CHP, incremental DR and energy storage. They suggest that the ISO should have used assumptions from the planning standards used in the prior LTPP case (R.10-05-006). Specifically, these parties propose reductions in the ISO's local area requirements for 544 MW of uncommitted EE (DRA proposed an alternative 284 MW for "high need") and 302 MW of incremental demand response. CEJA and DRA also propose 64 MW of incremental

[39] Tr. III, pages 491-492.
[40] Ex. 27, page 12.

ATTACHMENT 2

A.11-05-023

Application of San Diego Gas & Electric Company (U 902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power

Supplemental Testimony of Robert Sparks on Behalf of the
California Independent System Operator Corporation
April 6, 2012

Page 3

Application No.: A.11-05-023
Exhibit No.: ________
Witness: Robert Sparks

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	Application 11-05-023

SUPPLEMENTAL TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

overlapping with an outage of the Otay Mesa combined-cycle power plant (G-1/N-2). The limiting constraint for this contingency is the South of SONGS Separation Scheme. With this change to the WECC criterion, the most limiting contingency for San Diego sub-area is the loss of Imperial Valley-Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line (N-1-1).

The table below shows the difference in study results between the two different limiting contingency scenarios.

LCR Area	Contingency	Limiting Constraint	Traject (MW)	Env (MW)	ISO Base (MW)	Time (MW)
San Diego	G-1/N-2 (Assuming load shed)	8000 Amp limit on P44	**LCR =2,883** OTC = 531* - 950**	**LCR =2,854** OTC = 231* - 650**	**LCR =2,864** OTC = 231* - 650**	**LCR =2,856** OTC = 421* - 840**
		7800 Amp limit on P44 (2.5% margin)	LCR =2,939** OTC = 520* - 939	LCR =2,922** OTC = 299* - 718	LCR =2,930** OTC = 299* - 718	LCR =2,911** OTC = 470* - 889
San Diego	N-1-1 (No load shed)	8000 Amp limit on P44	LCR =2,680 OTC = 318* – 737	LCR =2,625 OTC = 0* - 402	LCR =2,669 OTC = 218* - 637	LCR =2,633 OTC = 201* - 620
		7800 Amp limit on P44 (2.5% margin)	LCR =2,735 OTC = 373* – 792	LCR =2,702 OTC = 60* - 479	LCR =2,694 OTC = 243* - 662	LCR =2,691 OTC = 260* - 679
		Voltage Collapse (accounting for 2.5% margin)	**LCR =2,646 OTC = 311* – 730**	**LCR =2,524 OTC =0* - 300**	**LCR =2,663 OTC =211* - 630**	**LCR =2,553 OTC = 121* - 540**

* Lower OTC range value corresponds to the use of SDG&E-proposed generation included in the Long-Term Procurement Plan. The numbers in the table identified as OTC refer to an incremental local capacity need in the San Diego area driven by the loss of OTC generation in the San Diego area. This need could be met by repowering the existing OTC generation or by other new generation that is connected to an electrically equivalent location.

** Load curtailment of approximately 370 MW was simulated to achieve stability under G-1/N-2 contingency.

ATTACHMENT 3

2014 Local Capacity Technical Analysis
Final Report & Study Results

Pages 2 & 94

California ISO
Shaping a Renewed Future

2014
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 30, 2013

Below is a comparison of the 2014 vs. 2013 total LCR:

2014 Local Capacity Requirements

	Qualifying Capacity			2014 LCR Need Based on Category B			2014 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	70	173	243	145	0	**145**	195	0	**195**
North Coast / North Bay	150	771	921	623	0	**623**	623	0	**623**
Sierra	1288	762	2050	1414	0	**1414**	1803	285*	**2088**
Stockton	212	392	604	354	25*	**379**	446	255*	**701**
Greater Bay	1336	6280	7616	3747	0	**3747**	4423	215*	**4638**
Greater Fresno	318	2510	2828	1857	0	**1857**	1857	0	**1857**
Kern	613	64	677	421	14*	**435**	421	41*	**462**
LA Basin***	2242	9547	11789	10063	0	**10063**	10430	0	**10430**
Big Creek/ Ventura	1112	4206	5318	2156	0	**2156**	2250	0	**2250**
San Diego/ Imperial Valley***	200	4506	4706	3605	167*	**3772**	3605	458*	**4063**
Total	7541	29211	36752	24385	206	**24591**	26053	1254	**27307**

2013 Local Capacity Requirements

	Qualifying Capacity			2013 LCR Need Based on Category B			2013 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	55	162	217	143	0	**143**	190	22*	**212**
North Coast / North Bay	130	739	869	629	0	**629**	629	0	**629**
Sierra	1274	765	2039	1408	0	**1408**	1712	218*	**1930**
Stockton	216	404	620	242	0	**242**	413	154*	**567**
Greater Bay	1368	6296	7664	3479	0	**3479**	4502	0	**4502**
Greater Fresno	314	2503	2817	1786	0	**1786**	1786	0	**1786**
Kern	684	0	684	295	0	**295**	483	42*	**525**
LA Basin	4452	8675	13127	10295	0	**10295**	10295	0	**10295**
Big Creek/ Ventura	1179	4097	5276	2161	0	**2161**	2241	0	**2241**
San Diego	158	3991	4149	2938	0	**2938**	2938	144*	**3082**
Total	**9830**	**27632**	**37462**	**23376**	**0**	**23376**	**25189**	**580**	**25769**

10. San Diego-Imperial Valley Area

Area Definition

The transmission tie lines forming a boundary around the Greater San Diego-Imperial Valley area include:

1) Imperial Valley – North Gila 500 kV Line
2) Otay Mesa – Tijuana 230 kV Line
3) San Onofre - San Luis Rey #1 230 kV Line
4) San Onofre - San Luis Rey #2 230 kV Line
5) San Onofre - San Luis Rey #3 230 kV Line
6) San Onofre – Talega #1 230 kV Line
7) San Onofre – Talega #2 230 kV Line
8) Imperial Valley – El Centro 230 kV Line
9) Imperial Valley – Dixieland 230 kV Line
10) Imperial Valley – La Rosita 230 kV Line

The substations that delineate the Greater San Diego-Imperial Valley area are:

1) Imperial Valley is in North Gila is out
2) Otay Mesa is in Tijuana is out
3) San Onofre is out San Luis Rey is in
4) San Onofre is out San Luis Rey is in
5) San Onofre is out San Luis Rey is in
6) San Onofre is out Talega is in
7) San Onofre is out Talega is in
8) Imperial Valley is in El Centro is out
9) Imperial Valley is in Dixieland is out
10) Imperial Valley is in La Rosita is out

Total 2014 busload within the defined area: 5073 MW with 127 MW of losses resulting in total load + losses of 5200 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BORDER_6_UNITA1	22149	CALPK_BD	13.8	45.00	1	San Diego, Border		Market

the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

ATTACHMENT 4

California ISO Planning Standards
June 23, 2011

California ISO
Planning Standards

June 23, 2011

Table of Contents

I. Introduction

The California ISO (ISO) tariff provides for the establishment of planning guidelines and standards above those established by NERC and WECC to ensure the secure and reliable operation of the ISO controlled grid. The primary guiding principle of these Planning Standards is to develop consistent reliability standards for the ISO grid that will maintain or improve transmission system reliability to a level appropriate for the California system.

These ISO Planning Standards are not intended to duplicate the NERC and WECC reliability standards, but to complement them where it is in the best interests of the security and reliability of the ISO controlled grid. The ISO planning standards will be revised from time to time to ensure they are consistent with the current state of the electrical industry and in conformance with NERC Reliability Standards and WECC Regional Criteria. In particular, the ISO planning standards:

- Address specifics not covered in the NERC Reliability Standards and WECC Regional Criteria;
- Provide interpretations of the NERC Reliability Standards and WECC Regional Criteria specific to the ISO Grid;
- Identify whether specific criteria should be adopted that are more stringent than the NERC Reliability Standards and WECC Regional Criteria where it is in the best interest of ensuring the ISO controlled grid remains secure and reliable.

NERC Reliability Standards and WECC Regional Criteria:

The following links provide the minimum standards that ISO needs to follow in its planning process unless NERC or WECC formally grants an exemption or deference to the ISO. They are the NERC Transmission Planning (TPL) standards, other applicable NERC standards (i.e., NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant and San Onofre Nuclear Generating Station), and the WECC Regional Criteria:

http://www.nerc.com/page.php?cid=2|20

http://www.wecc.biz/Standards/WECC%20Criteria/Forms/AllItems.aspx

Section II of this document provides additional details about the ISO Planning Standards. Guidelines are provided in subsequent sections to address certain ISO planning standards, such as the use of new Special Protection Systems, which are not specifically addressed at the regional level of NERC and WECC. Where appropriate, background information behind the development of these standards and references (web links) to subjects associated with reliable transmission planning and operation are provided.

II. ISO Planning Standards

The ISO Planning Standards are:

1. Applicability of NERC Reliability Standards to Low Voltage Facilities under ISO Operational Control

The ISO will apply NERC Transmission Planning (TPL) standards, the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant and San Onofre Nuclear Generating Station, and the approved WECC Regional Criteria to facilities with voltages levels less than 100 kV or otherwise not covered under the NERC Bulk Electric System definition that have been turned over to the ISO operational control.

2. 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 TPL standards for single contingencies (TPL002). Supporting information is located within Section IV of this document.

3. Voltage Standard

Standardization of low and high voltage levels as well as voltage deviations across the TPL-001, TPL-002, and TPL-003 standards is required across all transmission elements in the ISO controlled grid. The low voltage and voltage deviation guideline applies only to load and generating buses within the ISO controlled grid (including generator auxiliary load) since they are impacted by the magnitude of low voltage and voltage deviations. The high voltage standard applies to all buses since unacceptable high voltages can damage station and transmission equipment. These voltage standards are shown in Table 1.

All buses within the ISO controlled grid that cannot meet the requirements specified in Table 1 will require further investigation. Exceptions to this voltage standard may be granted by the ISO based on documented evidence vetted through an open stakeholder process. The ISO will make public all exceptions through its website.

Table 1
(Voltages are relative to the nominal voltage of the system studied)

Voltage level	Normal Conditions (TPL-001)		Contingency Conditions (TPL-002 & TPL-003)		Voltage Deviation	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	TPL-002	TPL-003
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05	0.90	1.1	≤5%	≤10%

4. **Specific Nuclear Unit Standards**

The criteria pertaining to the Diablo Canyon Power Plant (DCPP) and San Onofre Nuclear Generating Station (SONGS), as specified in the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for DCPP and SONGS, and Appendix E of the Transmission Control Agreement located on the ISO web site at: http://www.caiso.com/docs/09003a6080/25/a3/09003a608025a3bd.pdf

5. **Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard**

A single module of a combined cycle power plant is considered a single contingency (G-1) and shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002). Supporting information is located in Section V of this document. Furthermore a single transmission circuit outage with one combined cycle module already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002) as established in item 1 above.

A re-categorization of any combined cycle facility that falls under this standard to a less stringent requirement is allowed if the operating performance of the combined cycle facility demonstrates a re-categorization is warranted. The ISO will assess re-categorization on a case by case based on the following:

a) Due to high historical outage rates in the first few years of operation no exceptions will be given for the first two years of operation of a new combined cycle module.
b) After two years, an exception can be given upon request if historical data proves that no outage of the combined cycle module was encountered since start-up.
c) After three years, an exception can be given upon request if historical data proves that outage frequency is less than once in three years.

The ISO may withdraw the re-categorization if the operating performance of the combined cycle facility demonstrates that the combined cycle module exceeds a failure rate of once in three year. The ISO will make public all exceptions through its website.

6. **Planning for New Transmission versus Involuntary Load Interruption Standard**

This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements. It does not address all circumstances under which load dropping is permitted under NERC and WECC planning standards.

1. No single contingency (TPL002 and ISO standard [G-1] [L-1]) should result in loss of more than 250 MW of load. This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to position the electric system for reliable operation in anticipation of the next worst contingency.
2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines “closed in” during normal operation.
3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more constraining.
4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure, through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

   To better understand the potential impact of the updated “planning for new transmission versus involuntary load interruption” standard, this standard will be considered a guideline for the first year that it is in effect in order to get an inventory of stations and transmission elements not in compliance and a cost impact of bringing them into compliance.

III. ISO Planning Guidelines

The ISO Planning Guidelines include the following:

1. New Special Protection Systems

As stated in the NERC glossary, a Special Protection System (SPS) is “an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition of faulted components to maintain system reliability.” In the context of new projects, the possible action of an SPS would be to detect a transmission outage (either a single contingency or credible multiple contingencies) or an overloaded transmission facility and then curtail generation output and/or load in order to avoid potentially overloading facilities or prevent the situation of not meeting other system performance criteria. A SPS can also have different functions such as executing plant generation reduction requested by other SPS; detecting unit outages and transmitting commands to other locations for specific action to be taken; forced excitation pulsing; capacitor and reactor switching; out-of-step tripping; and load dropping among other things.

The primary reasons why SPS might be selected over building new transmission facilities are that SPS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, SPS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, SPS is a commonly considered alternative to building new infrastructure in an effort to keep costs down when integrating new generation into the grid and/or addressing reliability concerns under multiple contingency conditions. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability. These reliability concerns necessarily dictate that guidelines be established to ensure that performance of all SPSs are consistent across the ISO controlled grid. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of existing transmission facilities while maintaining system reliability and optimizing operability of the ISO controlled grid. Needless to say, with the large number of generator interconnections that are occurring on the ISO controlled grid, the need for these guidelines has become more critical.

It needs to be emphasized that these are guidelines rather than standards. 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). This is to emphasize that best engineering practice and judgement will need to be exercised 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 SPS in all potential applications.

ISO SPS1

The overall reliability of the system should not be degraded after the combined addition of the SPS.

ISO SPS2

The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. In situations where the design of the SPS requires WECC approval, the WECC Remedial Action Scheme Design Guide will be followed.

ISO SPS3

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 minimum 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 revised as needed. In addition, the actual amount of generation that can be tripped is project specific and may depend on specific system performance issues to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts provided in this guide. The net amount of generation is the gross plant output less the plant's and other auxiliary load tripped by the same SPS.

ISO SPS4

For SPSs, the following consequences are unacceptable should the SPS fail to operate correctly:

A) Cascading outages beyond the outage of the facility that the SPS is intended to protect: For example, if a SPS were to fail to operate as designed for a single contingency and the transmission line that 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) Voltage instability, transient instability, or small signal instability: While these are rare 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.

ISO SPS5

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 SPS6

The SPS must be simple and manageable. As a general guideline:

A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS.

B) The SPS should not be monitoring more than 4 system elements or variables. A variable can be a combination of related elements, such as a path flow, if it is used as a single variable in the logic equation. Exceptions include:

   i. The number of elements or variables being monitored may be increased if it results in the elimination of unnecessary actions, for example: generation tripping, line sectionalizing or load shedding.

   ii. 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 or variables, then the new generation cannot materially increase the complexity of the existing SPS scheme. However, additions to an existing SPS using a modular design should be considered as preferable to the addition of a new SPS that deals with the same contingencies covered by an existing SPS.

C) 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.

D) An SPS should not require real-time operator actions to arm or disarm the SPS or change its set points.

ISO SPS7

If the SPS is designed for new generation interconnection, 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 SPS8

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. For example, the operation of SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back additional generation (or trip load if not already addressed under ISO SPS7 above) to bring the line loading within the line's four-hour or longer rating. This is intended to minimize real-time operator intervention.

ISO SPS9

The SPS needs to be agreed upon by the ISO and may need to be approved by the WECC Remedial Action Scheme Reliability Task Force.

ISO SPS10

The 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 SPS requirement would be to allow 8 initiating events rather than limiting the SPS to 6 initiating events until the identified system reinforcements are placed into service.

ISO SPS11

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

ISO SPS12

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 SPS13
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.

ISO SPS14
To ensure that the ISO's transmission planning process consistently reflects the utilization of SPS in its annual plan, the ISO will maintain documentation of all SPS utilized to meet its reliability obligations under the NERC reliability standards, WECC regional criteria, and ISO planning standards.

ISO SPS15
The transmission owner in whose territory the SPS is installed will, in coordination with affected parties, be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO SPS16 Generally, the SPS should trip load and/or resources that have the highest effectiveness factors to the constraints that need mitigation such that the magnitude of load and/or resources to be tripped is minimized. As a matter of principle, voluntary load tripping and other pre-determined mitigations should be implemented before involuntary load tripping is utilized.

ISO SPS17
Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO is required unless otherwise deemed unnecessary by the ISO. Specific telemetry requirements will be determined by the Transmission Owner and the ISO on a project specific basis.

IV. Combined Line and Generator Unit Outage Standards Supporting Information

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 TPL standards for single contingencies (TPL002).

The ISO Planning Standards require that system performance for an over-lapping outage of a generator unit (G-1) and transmission line (L-1) must meet the same system performance level defined for the NERC standard TPL-002. The ISO recognizes that this planning standard is more stringent than allowed by NERC, but it is considered appropriate for assessing the reliability of the ISO's controlled grid as it remains consistent with the standard utilized by the PTOs prior to creation of the ISO.

V. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard Supporting Information

Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard - A single module of a combined cycle power plant is considered a single (G-1) contingency and shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002).

The purpose of this standard is to require that an outage of any turbine element of a combustion turbine be considered as a single outage of the entire plant and therefore must meet the same performance level as the NERC TPL standard TPL-002.

The ISO has determined that, a combined cycle module should be treated as a single contingency. In making this determination, the ISO reviewed the actual operating experience to date with similar (but not identical) combined cycle units currently in operation in California. The ISO's determination is based in large part on the performance history of new combined cycle units and experience to date with these units. The number of combined cycle facility forced outages that have taken place does not support a double contingency categorization for combined cycle module units in general. It should be noted that all of the combined cycle units that are online today are treated as single contingencies.

Immediately after the first few combined cycle modules became operational, the ISO undertook a review of their performance. In defining the appropriate categorization for combined cycle modules, the ISO reviewed the forced outage history for the following three combined cycle facilities in California: Los Medanos Energy Center (Los Medanos), Delta Energy Center (Delta), and Sutter Energy Center (Sutter)[1]. Los Medanos and Sutter have been in service since the summer of 2001, Delta has only been operational since early summer 2002.

Table 2 below sets forth the facility forced outages for each of these facilities after they went into operation (i.e. forced outages [2]that resulted in an output of zero MWs.) The table demonstrates that facility forced outages have significantly exceeded once every 3 to 30 years. Moreover, the ISO considers that the level of facility forced outages is significantly above the once every 3 to 30 years even accounting for the fact that new combined cycle facilities tend to be less reliable during start-up periods and during the initial weeks of operation. For example, four of the forced outages that caused all the

[1] Los Medanos and Sutter have two combustion turbines (CT's) and one steam turbine (ST) each in a 2x1 configuration. Delta has three combustion turbines (CT's) and one steam turbine (ST) in a 3x1 configuration. All three are owned by the Calpine Corporation.

[2] Only forced outages due to failure at the power plant itself are reported, forced outages due to failure on the transmission system/switchyard are excluded. The fact that a facility experienced a forced outage on a particular day is public information. In fact, information on unavailable generating units has been posted daily on the ISO website since January 1, 2001. However, the ISO treats information regarding the cause of an outage as confidential information.

three units at Los Medanos to go off-line took place more than nine months after the facility went into operation.

Facility	Date	# units lost
Sutter[3]	08/17/01	No visibility
Sutter	10/08/01	1 CT
Sutter	12/29/01	All 3
Sutter	04/15/02	1 CT + ST
Sutter	05/28/02	1 CT
Sutter	09/06/02	All 3
Los Medanos[4]	10/04/01	All 3
Los Medanos	06/05/02	All 3
Los Medanos	06/17/02	All 3
Los Medanos	06/23/02	1CT+ST
Los Medanos	07/19/02	All 3
Los Medanos	07/23/02	1CT+ST
Los Medanos	09/12/02	All 3
Delta[5]	06/23/02	All 4
Delta	06/29/02	2 CT's + ST
Delta	08/07/02	2 CT's + ST

Table 2: Forced outages that have resulted in 0 MW output from Sutter, Los Medanos and Delta after they became operational

The ISO realizes that this data is very limited. Nevertheless, the data adequately justifies the current classification of each module of these three power plants as a single contingency.

VI. Background behind Planning for 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 certain 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 a specific single contingency. Historically, a wide variation among the PTOs has existed predominantly due to slightly differing planning and design philosophies. This standard is intended to provide a consistent framework upon which involuntary load interruption decisions can be made by the ISO when planning infrastructure needs for the ISO controlled grid.

[3] Data for Sutter is recorded from 07/03/01 to 08/10/02
[4] Data for Los Medanos is recorded from 08/23/01 to 08/10/02
[5] Data for Delta is recorded from 06/17/02 to 08/10/02

The overarching requirement is that implementation of these standards should not result in lower levels of reliability to end-use customers than existed prior to restructuring. As such, the following is required:

1. No single contingency (TPL002 and ISO standard [G-1] [L-1]) may result in loss of more than 250 MW of load. This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to protect for the next worst single contingency.

   This standard is intended to coordinate ISO planning standards with the WECC requirement that all transmission outages with at least 300 MW or more be directly reported to WECC. It is the ISO's intent that no single contingency (TPL002 and ISO standard [G-1] [L-1]) should trigger loss of 300 MW or more of load. The 250 MW level is chosen in order to allow for differences between the load forecast and actual real time load that can be higher in some instances than the forecast and to also allow time for transmission projects to become operational since some require 5-6 years of planning and permitting with inherent delays. It is also ISO's intent to put a cap on the footnote to the NERC TPL-002 that may allow radial and/or non-consequential loss of load for single contingencies.

2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines "closed in" during normal operation.

   This standard is intended to bring consistency between the PTOs' substation designs. It is not the ISO's intention to disallow substations with load below 100 MW from having looped connections; however it is ISO's intention that all substations with peak load above 100 MW must be connected through a looped configuration to the grid.

3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more stringent.

   This standard is intended to insure that the system is maintained at the level that existed prior to restructuring. It is obvious that as load grows, existing back-ties for radial loads (or remaining feed after a single contingency for looped substations) may not be able to pick up the entire load; therefore the reliability to customers connected to this system may deteriorate over time. It is the ISO's intention to establish a minimum level of back-up tie capability that needs to be maintained.

4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

It is ISO's intention to allow the build-up of transmission projects that are proven to have a positive benefit to ratepayers by reducing load drop exposure.

Information Required for BCR calculation: For each of the outages that required involuntary interruption of load, the following should be estimated:

- 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., week day 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.

The above information will be documented in the ISO Transmission Plan for areas where additional transmission reinforcement is needed or justified through benefit to cost ratio determination.

VII. Interpretations of terms from NERC Reliability Standard and WECC Regional Criteria

Listed below are several ISO interpretations of the terms that are used in the NERC standards that are not already addressed by NERC.

Combined Cycle Power Plant Module: A **combined cycle** is an assembly of heat engines that work in tandem off the same source of heat, converting it into mechanical energy, which in turn usually drives electrical generators. In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, one or more gas turbine generator(s) generates electricity and heat in the exhaust is used to make steam, which in turn drives a steam turbine to generate additional electricity.

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 PTO and the ISO subject to appropriate coordination and review with the relevant local, state, regional and federal regulatory authorities.

Entity Required to Develop Load Models: The PTOs, in coordination with the utility distribution companies (UDCs) and others, develop load models.

Entity Required to Develop Load Forecast: The California Energy Commission (CEC) has the main responsibility for providing load forecast. If load forecast is not provided by the CEC or is not detailed and/or specific enough for a certain study then the ISO, at its sole discretion, may use load forecasts developed by the PTOs in coordination with the UDCs and others.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. 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 more stringent 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 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.