The ISO received comments on the Draft 2013-2014 Transmission Plan February 12, 2014 Stakeholder Meeting from the following:

1. Bay Area Municipal Transmission group (BAMx)
2. California Large Energy Consumers Association
3. California Public Utilities Commission
4. CalPeak Power
5. Clean Coalition, Natural Resources Defense Council and Environmental Defense Fund
6. Duke America Transmission Company
7. Duke-American Transmission Company and Hunt Power
8. Duke Energy
9. EnerNOC, Inc.
10. Imperial Irrigation District (IID)
11. LS Power Development, LLC
12. MidAmerica Transmission and Pinnacle West Capital Corporation
13. Office of Ratepayer Advocates
14. Pacific Gas and Electric
15. San Diego Gas & Electric
16. Sempra US Gas and Power
17. Sierra Club and California Environmental Justice Alliance
18. Southern California Edison
19. Southwest Transmission Partners, LLC
20. Transmission Agency of Northern California
21. The Nevada Hydro Company
22. The Vote Solar Initiative
23. Trans Bay Cable LLC
24. City of Victorville

Comments that were submitted on the Draft 2013-2014 Transmission Plan Appendix D for the San Francisco Peninsula Extreme Event along with the ISO responses are captured in a separate comment matrix which is posted on the ISO's Market Participant Portal

Copies of the comments submitted are located on the *2013-2014 Transmission planning process* page at: http://www.caiso.com/planning/Pages/TransmissionPlanning/2013-2014TransmissionPlanningProcess.aspx under the 2013-2014 transmission plan heading.

The following are the ISO's responses to the comments.

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<tr><th>No</th><th>Comment Submitted</th><th>ISO Response</th></tr>
<tr><td>1</td><td>Bay Area Municipal Transmission group (BAMx)
Submitted by: Barry Flynn, Robert Jenkins and Pushkar Wagle</td><td></td></tr>
<tr><td>1a</td><td>Reliability Assessment
Below we provide some comments and questions on the transmission projects that are recommended for approval by the CAISO based on the Reliability Assessment.
Mesa Loop-In
As we have stated in our comments dated October 10, 2013, the Mesa Loop-In project is presented as a mitigation to address two different T-1-1 (C3) contingencies. Loss of a 500/220 kV transformer is very rare. WECC published data indicate a failure rate of about one in 27 years (compared to once in seven months for a transmission line)2.
That would suggest that the probability of the independent overlapping loss of two transformers would be extremely rare. Therefore, before concluding that the appropriate mitigation for this extremely unlikely and rare event is the construction of a $550M-$700M transmission expansion, consideration should be given to less expensive measures including fire walls between transformers, system spares in addition to the on-site spare and utilizing customer interruption as a backstop measure. Since customer interruption is allowed under WECC and NERC standards for Level C events and is the mitigation used on the CAISO grid for rare, but much more likely events, it should be considered for this extremely unlikely event/overlapping contingencies.
The Appendix C (2013/2014 ISO Reliability Assessment - Study Results) of the Draft Plan identifies additional reliability issues in the SCE LA Basin area that could presumably be addressed by Mesa Loop-In along with the remaining Group I transmission projects. As we elaborate in our comments on the “Southern California Reliability Assessment,” there are potentially additional competing alternative mitigation measures available to address those issues besides building new expensive transmission projects.</td><td>As we stated in our response to BAMx’s previous comments dated October 10, 2013, the Mesa Loop-In Project is recommended as one element of the post- SONGS solution that is needed to:
address the post 2020 thermal loading violations that are identified in the LA Metro Area as presented in Section 2.7.6 (Los Angeles Metro Area) of the draft plan and the corresponding sections in Appendix B and Appendix C
alleviate the increased overall loading on transmission facilities in the LA Metro and San Diego areas resulting from the retirement of SONGS and OTC generation as well as longer term load growth and
reduce the amount of new local capacity needed to replace retired generation as discussed in Section 2.6 (Southern California Bulk Transmission System Assessment) of the draft plan.
The post-2020 loading violations identified in the LA Metro area in Section 2.7.6 of the draft transmission plan based on Track 1 assumptions are included below for quick reference:
<u>2023 Summer Peak</u>
Barre–Lewis 230 kV line under a Category B (L-1) and multiple Category C (L-1/L-1) contingencies
Vincent 500/230 kV #1 Bank under multiple Category B (L-1) and Category C (L-2, T-1/T-1) contingencies
Barre–Villa Park 230 kV line under multiple Category C (L-1/L-1) contingencies
Serrano–Villa Park #1 & #2 230 kV lines under multiple Category C (L-2) contingencies
Lewis–Villa Park 230 kV line under a Category C (L-2) contingency
Mira Loma 500/230 kV #1 & #2 Banks under a Category C (T-1/L-1) contingency
Chino–Mira Loma # 3 230 kV line overload under a Category C (T-1/T-1) contingency
Serrano 500/230 kV Banks overload under multiple Category C (T-1/L-1, T-1/T-1) contingencies</td></tr>
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		Please see Table 2.7-13 on page 123 of the draft transmission plan, which provides the loading results with and without Mesa Loop-in based on Track 4 assumptions, for effectiveness of the Mesa-Loop-in Project in alleviating the loading of transmission facilities in the LA Metro area for the long term. In addition to being very effective in alleviating the long-term loading concerns in the LA Metro area noted above and its benefits in reducing local capacity needed to mitigate the critical SDGE L-1-1 contingency, the Mesa Loop-In Project is supported by shorter lead times, higher regulatory certainty regarding the timing of its development, and the benefit of not requiring new transmission rights of way. As noted below, the ISO does not consider it feasible to pursue transmission options involving significant new rights of way, when reasonable and viable options to meet the needs are available without requiring new rights of way.
1b	Henrietta 230 kV breaker-and-a-half Upgrade The Draft Plan3 mentions a *Henrietta 230 kV breaker-and-a-half Upgrade* project, which entails "Reconfiguring the existing 230 kV buswork to a breaker-and-a-half configuration to improve substation reliability." This project is expected to cost more than $50M, and will require a BoG approval. However, the Draft Plan does not provide any justification for the recommendation for this project. Moreover, this project was not presented in the February 12th Stakeholder meeting. We request that the CAISO not recommend this project for approval in the 2013-14 Plan without a more detailed project justification and proper stakeholder review.	The ISO has updated the Transmission Plan to correct several references to the Henrietta project and reflect the discussion in Appendix B that the ISO is not seeking approval of this project in the 2013-2014 Transmission Plan and will continue to monitor in future planning cycles as indicated in Appendix B of the plan.
1c	Midway-Kern PP #2 230 kV Line The CAISO's Draft Plan recommends this project, which entails reconductoring and unbundling the existing Midway-Kern PP 230 kV line into two circuits and looping one of the new circuits into the Bakersfield substation. The stated reason for the reconductoring is to match the rating of the rest of the circuit into which it is looped. Is it possible to avoid reconductoring of the 12-mile segment of the line going into Bakersfield substation by terminating both of the circuits into Bakersfield Substation at Kern PP? If so, would that allow the CAISO to postpone reconductoring the Midway-Kern #1 line? In the Final Transmission Plan, please clarify why reconductoring was selected over looping the 230 kV into Kern PP.	The alternative of terminating the two new circuits supplying Bakersfield at Kern PP was considered and would require half to a mile of new double circuit 230 kV line and would require either new or modifications to existing rights-of-way in addition to expanding the Kern PP 230 kV bus to accommodate the two new line terminations. The interconnecting of Bakersfield directly to Kern PP would not have eliminated the need for the reconductoring of the unbundled Midway-Kern #1 230 kV double circuit line. With this the alternative of looping Bakersfield into the Midway-Kern PP #2 230 kV line was selected as it provides higher level of reliability for the Bakersfield substation as opposed to a double radial supply directly from Kern PP.

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1d	Morgan Hill Area Reinforcement Project The CAISO's Draft Plan recommends this project, which entails constructing a new 230/115 kV substation, Spring Substation, west of the existing Morgan Hill Substation. The CAISO has recommended this project to increase the reliability of the Morgan Hill area by adding a new source into the area. According to the CAISO, the new 115 kV source will avoid potential electric load interruptions for most of the Morgan Hill and Gilroy area, following the loss of the Metcalf-Morgan Hill and Metcalf-Llagas 115 kV double circuit tower line (Category C5). The CAISO planning standard 6.1 indicates that up to 250MW of load can be dropped for a category B event.4 What is the CAISO policy for loss of load for a category C event? If there is no such loss of load policy for category C, then a Benefit to Cost ratio (BCR) should be calculated to justify a transmission project.5	Section 6.1 is in reference to radial load supplied from multiple substations. The ISO assesses the potential of load shedding for Category C contingencies as a part of the analysis. In this case the N-1-1 and N-2 contingency results in load of load at both the Morgan Hill and Llagas substations and it also trips off approximately 300 MW of generation in the area. This results in loss of supply to the entire Morgan Hill area. In addition the loss of the one of the 115 kV supply lines and the Gilroy Generation 115 kV line results in thermal and voltage violations. The addition of the Spring station brings additional 115 kV supply to the Morgan Hill to address the loss of load and thermal and voltage violations in the area. In addition the reinforcement of the 115 kV system in the Morgan Hill area reduces the overload on the remaining Metcalf 230/115 kV banks which result following an outage of two Metcalf 230/11k kV banks.
1e	Description of RAS BAMx appreciates CAISO's development of the Table 3.3-1 in the Draft Plan, which summarizes the recommendations for each SPS reviewed and updated as a part of the 2013-2014 transmission planning process. BAMx believes this table can be improved by providing more details on these SPSs in the Revised Transmission Plan such as, the type and amount of generation or load tripping allowed under the SPS.	The ISO will consider adding this information in future planning cycles.
1f	Southern California Reliability Assessment BAMx supports the rapid progress that has been made in understanding the electric system performance and needs without the San Onofre Nuclear Generating Station (SONGS) and the Once-Through Cooling (OTC) generating units in southern California. While recognizing it is a difficult task, BAMx appreciates the coordination with other State Agencies that has occurred. We especially appreciate the standardization of assumptions across the CPUC Track 4 Long Term Procurement Proceeding (LTPP) and the CAISO Transmission Planning Process, as well as bringing the description of the residual reliability need to a common basis to facilitate the comparison of alternatives. The CAISO has also made great strides in advancing the efforts to identify characteristics and locations of preferred resources, which can be used to most effectively provide for an electrical grid for the LA Basin and San Diego that complies with the State's Loading Order. We recognize this as an early effort in this area and highly encourage the CAISO to build upon this early effort in future analysis.	

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	BAMx also supports the CAISO restraint in not seeking to identify transmission improvements to address the entire residual reliability need in this initial cycle so that future iterations in local resource procurement and demand side programs can be considered. It is important to recognize that there are backstops available to preserve reliability to the area in the event local supply and/or demand side solutions do not fully materialize. Such backstops include potential extension of the OTC unit compliance dates with SWRCB requirements, extension of the economic life of the non-OTC units currently assumed to retire, extending the reliance on the San Diego SPS, SCE's proposed backstop generation siting, etc. Such backstops allow for measured steps to be taken with respect to transmission expansion to help avoid excessive ratepayer impacts.	The ISO acknowledges that there are several alternatives that could be pursued as short term mitigations or "backstops" should authorized procurement of resources or planned and approved system reinforcement may be delayed. However, these mitigations are not acceptable long term solutions and cannot be relied upon to defer indefinitely developing and implementing long term solutions.
	As an extension of the CAISO's efforts to coordinate with State Agencies, we encourage the CAISO to reevaluate the candidate transmission projects with full consideration of the final decision on CPUC LTPP Track 4 procurement.7 The transmission planning process would benefit from closer coordination between the CPUC and the CAISO The CAISO has already decided to defer the recommendation of some transmission projects to a later date with the possibility that the CAISO management may come to the CAISO BoG after March 2014 and propose these transmission additions as amendments to the 2013-14 Transmission Plan. The CAISO should consider the final decision on the Track 4 proceeding, which should be available shortly, before recommending transmission solutions. This will also allow the CAISO to perform further analysis and to resolve some issues surrounding the projects proposed in the current Draft Plan. We believe a few months delay on the final decision of which transmission additions should be included in the 2013-14 Transmission Plan is justified. The CAISO's delaying of its decision on *Group I* projects as it further refines its work on the effect of preferred resources and fully accounts for the resources authorized in the ultimate decision in Track 4 process would represent the next step in State Agency co-operation on this issue.	The ISO has collaborated with the state agencies, and in particular, with the staff of the CEC and CPUC in developing the Preliminary Reliability Plan for the LA Basin and San Diego, which anticipates a significant reduction in gas-fired generation in the area over the next 10 years. Consistent with that general direction, the ISO's area analysis anticipated a level of Track 4 procurement in 2023 based on needs in 2018 in San Diego and also supported by the SCE-provided procurement scenarios for the LA Basin.
	This Draft Plan identifies a large number of potential upgrades of varying cost and efficacy. While the CAISO has done exhaustive work in identifying this menu of transmission alternatives, we are concerned that the method of selecting from the menu may not result in the most economic, least regrets transmission plan. The Draft Plan parses the upgrades into three groups based upon their	The proposed methodology for ranking projects does have some merit and may be useful in considering further development if necessary beyond the Group 1 projects in the next planning cycle. However, factors beyond exclusively the cost on a per MW basis must also be taken into account. The group 1 projects are supported by shorter

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	utilization of existing transmission lines and, for new lines, whether they are intra- or inter-area lines. Then for these three groups of upgrades, the CAISO identifies the potential benefits in reducing the residual need for local resources. Based upon this analysis, the Draft plan recommends proceeding with the *Group I* Upgrades. BAMx believes the best metric for decision-making would be a complete analysis of the economic impact of each transmission alternative. Ideally this would include the complete economic impact of trading off increased transmission to import existing generation into the LA Basin and San Diego local areas against the preferred or gas fired resources within the local areas under consideration in the Track 4 proceeding. We would encourage the CAISO to consider employing its modeling expertise to perform such economic analysis based upon a reasonable set of assumptions. We encourage the CAISO to perform this type of analysis in next year's (2014- 2015) TPP. In the further analysis for this year's plan, it would be good to include a metric that captures the relative capability for the transmission solutions to offset preferred and/or gas-fired local resources in the local areas of concern. A simplified high level, useful metric could simply be the cost of a transmission alternative divided by its kW reduction in the residual local need ($/kW). As these benefits are non-linear, the incremental benefit of each upgrade varies based upon the assumed sequence of upgrades. Therefore, several values of this metric would be appropriate with each reflecting the assumed sequence in the series of upgrades. This simplified approach should be achievable in the further analysis contemplated for this year's amended plan. Such a metric also suggests a potential sequence of priority for approval (though not necessarily a chronological sequence). The initial pass at a package of solutions could then be built up by incrementally selecting the next most efficient from this metric's perspective. Once the target transmission capacity is reached, the resulting package of upgrades can be reordered chronologically to test whether the upgrades provide adequate capacity in the intervening years until the development of the full package is forecast to be complete. If there are reliability issues in the intervening period, adjustments to the plan can be made. We believe this approach would be more likely to afford a focus on the most cost-effective transmission solutions. Based upon the rough numbers presented	lead times, higher regulatory certainty regarding the timing of their development, and the benefit of not requiring new transmission rights of way. The ISO does not consider it feasible to pursue transmission options involving significant new rights of way, when reasonable and viable options to meet the needs are available without requiring new rights of way. Procurement decisions will be made through the CPUC's long term procurement planning processes, not the ISO's TPP. Please refer to the earlier response regarding the benefits and cost effectiveness of the

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	so far, the most costly *Group I* project is probably the Mesa Loop-In. This CAISO analysis of this project based upon its assumed sequence of project approval, shows a reduction of local generation need of between 300MW to 640MW. However, the cost of up to $2,333/kW appears expensive, especially compared to the other *Group I* projects. Furthermore, based upon the CAISO presentation, the *Mesa Loop-In* cost could increase to over $3,097/kW if it is considered incremental to the *TEVS- new Case Springs 500kV* line in the *Group II*. Based upon the information presented as indicated above, BAMx believes additional analysis is called for before deciding on a group of projects to be included in a revised 2013-2014 TPP. If the CAISO decides it wants to go forward now before such further analysis, we would recommend the incremental least regrets approval be given to the Imperial Valley Flow Controller, assuming that the desired control can be accomplished by the less expensive Phase Shifting Transformer (PST). Such early approval of the clearly most cost effective solution may help with achieving CFE support for it. If such an effort is unsuccessful, a more expensive control solution, such as the back-to-back DC (B2B DC), can be further considered as a candidate transmission project in an amendment to this year's plan. As part of that additional analysis, if the PST is proposed to be replaced by the B2B DC, the CAISO needs to clearly describe why the PST is not an adequate solution. If the decision will primarily be driven by CFE requirements, it is important to know what is the driving requirement(s) and how might they impact the ability to reduce the residual resource need in the local areas. BAMx does not support approving the other *Group I* projects at this time. The additional 450 MVAR of dynamic reactive support at San Luis Rey should be deferred until the local supply/demand solutions are better understood. As the CAISO noted in the stakeholder meeting, the San Diego system is reaching a point of diminishing benefit of incremental reactive supply. Furthermore, consideration should be given to lower-cost options such as fast-switched capacitors before specifying dynamic reactive support devices. Reactive power sources traditionally have short procurement lead times. Given that the CAISO is also proposing a +300/-100 MVAr dynamic reactive power device at Suncrest 230 kV, a least regrets strategy would be to postpone this element until the possible amended plan or until the next planning cycle.	Mesa Loop-in. Reactive supply is a least cost option for mitigating voltage stability problems, and it should be installed as long as it effectively mitigates the problem. San Luis Rey synchronous condenser effectively mitigates the problem. Fast switch capacitors are less effective than synchronous condensers because they do not provide the variable control necessary to optimize the complex system configuration. Achieving maximum utilization and benefit of shunt caps in the LA Basin has proven to be problematic because of the controllability problem.

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	In Figure 1, we show how the current Track 1 and proposed Track 4 resource authorizations by the CPUC in 2012 LTPP proceeding stack up against the 4,642MW need identified for 2022/23 within the SONGS area8 identified by the CAISO. It shows a residual need of 394MW-794MW depending upon the level of Track 4 authorizations that can be met by a single *Group I* transmission project, i.e., Imperial Valley Phase Shifter, which is expected to provide local resource reduction benefit in the range of 400-840MW.9 Alternatively, the procurement authorized in the 2012 LTPP Track 1 and Track 4 could be supplemented by a) Procurement of additional preferred resources (beyond the assumptions used by the CAISO in Track 4 models) as anticipated in the Track 4 proposed decision; or b) Additional procurement authorized in future LTPP proceedings; or c) Potential delay in retirements of OTC plants to facilitate implementation of options (a) and/or (b). Given the multiple options available to meet future residual resource need in the SONGS study area, the great strides that have been made in these procurement and transmission planning cycles, and the value in allowing time for market response to these steps, we urge the CAISO to delay the approval of projects beyond the Imperial Valley phase shifter at this time. Most questionable of the *Group I* projects appears to be the SCE proposed Mesa Loop-In project. With a benefit that can drop to as little as 226 MW10 and a cost of as much as $614-700 million, this project does not fit a least regrets strategy and represents an unnecessary risk. It should be considered again in a later amendment or in next year's plan after full refinement of its expected cost and changes to its proposed configuration as identified by the CAISO.	Table 1 reflects the erroneous assumption that all resources are 100% effective in addressing the local area issues, which is not the case. There is a wide range of effectiveness factors for different locations within the targeted areas. The ISO noted in the draft transmission plan that with all of Group 1 projects, the residual need may be as high as over 800 MW.
1g	Policy-Driven Projects Deliverability Assessment and the State's System RA Needs Consistent with its past practices, the CAISO has also performed a deliverability assessment on the base case portfolio assuming all the renewable generation projects in the base case portfolio need to be delivered to the "aggregate of load" based upon a strict set of deliverability criteria. BAMx has consistently questioned the need to rely on new renewable resources to meet the State's system resource adequacy needs. As indicated by the CPUC, there is no immediate need for new system capacity.11 This planning process is also	The ISO notes that the CPUC portfolios put a heavy weighting on generation that is viable, and in particular, the "commercial interest" portfolio has been selected as the base case. Virtually all projects in the discounted core are seeking full capacity delivery status (e.g. deliverability). Based on the ISO's experience working with generation interconnection customers, full capacity delivery status has been demonstrated as a necessity in advancing generation projects. The ISO has therefore included the

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	occurring at a time that the CPUC is developing a probabilistic equivalent load carrying capability (ELCC) tool that better evaluates the incremental resource adequacy benefits of new renewables. Early indications are that there is very little resource adequacy benefit that can be attributed to the addition of new intermittent resources.12 The CAISO should coordinate the transmission planning process and deliverability assessment protocols with the development of the ELCC to account for future changes in RA counting rules by the CPUC There is no state policy that renewable projects should provide Resource Adequacy irrespective of economics.13 Rather than designating transmission projects as policy-driven solely to allow intermittent renewable projects to satisfy the State's system RA needs, the CAISO should undertake a cost-benefit analysis to show that any proposed new transmission project to assure deliverability of new resources and/or to decrease envisioned congestion is justified. The CAISO needs to determine whether the new proposed transmission is both necessary and the most economical alternative to meet the State's resource adequacy needs.	deliverability analysis in assessing the need for policy-driven upgrades since the framework for approving policy-driven upgrades was introduced. Ignoring the need for deliverability that renewable generation has so clearly required in order to develop would not enable the state's renewables portfolio standard to be met.
1h	Imperial Valley Deliverability Constraint After spending $1.9 billion on the SDG&E Sunrise Powerlink, it is disturbing to find out that there is no deliverability available in the Imperial zone. This is especially troublesome as an extreme example of adverse ratepayer impact of assuming it is a State Policy to obtain RA deliverability from intermittent resources in the renewable portfolios. The CAISO identified that adding the Imperial flow controller and restoring the Sycamore-Suncrest 230 kV line emergency ratings to the levels assumed in the previous power system studies may recover almost half (800 of 1,715) of the MW identified in the CPUC portfolios by 2018. The Delaney-Colorado River 500kV line, if approved, would increase the deliverability by another 200 MW in 2020. In any event, in concert with BAMx comments above, we believe that before the CAISO approves "a major transmission upgrade" to raise the deliverability for this area, the CAISO should explore associated cost vs. benefit of such an addition. If the portfolio for the Imperial zone remains above that which can be designated as Fully Deliverable with the approved upgrades, the CAISO should	Sunrise Powerlink was designed to reduce the local capacity needs in San Diego and the LA Basin by 1000 MW. With the retirement of SONGS and all of the OTC generation, the amount of local capacity that has retired or expected to retire is several multiples of the 1000 MW expected to be counted on from Sunrise. The Sunrise transmission line provides a great deal of benefits to the system, and has been a critical asset in managing the early retirement of the San Onofre Nuclear Generating Station. Without Sunrise, our ability to reliability operate the system today would be in doubt. It is true that Sunrise was expected to provide substantial renewable deliverability, however the transfer capability to deliver renewable on Sunrise has been utilized instead by allowing us to withstand the unexpected retirement of SONGS. In addition, additional value will be extracted from Sunrise by installing more reactive support and a flow control device on the CFE tie-line. The circumstances regarding deliverability from Imperial Valley will be revisited in the 2014-2015 transmission planning cycle.

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	only consider any additional upgrades through its annual economic planning studies to assess the cost/benefit of the line. The benefits could include any reduced congestion and availability of RA capacity of the transmission addition.	
1i	CAISO Category 1 Recommendations The CAISO identifies the Suncrest Dynamic Reactive Power Device as a policy driven project specifying, "The dynamic reactive power support is required to provide continuous or quasicontinuous reactive power response following system disturbances. It needs to be one of the following types of devices: SVC (Static VAR Compensator), STATCOM (Static Synchronous Compensator), or Synchronous Condenser."14 If other than cost, please identify how the CAISO will select between a SVC, STATCOM or Synchronous Condenser solution. Also, the CAISO should identify why fast switchable shunt capacitors are not an acceptable solution.	The key selection criteria for this project will be posted around March 3. Please see discussion above about the use of fast switched capacitors in the LA Basin and San Diego areas.
1j	Economics-Driven Transmission Project Needs & Recommendations BAMx Appreciates the CAISO's Efforts BAMx recognizes the tremendous amount of effort over past several years that has been made in improving its production cost database and analysis included in its economic assessment. The CAISO staff's efforts in modeling additions/changes to the TEPPC database as well as developing the sensitivities involving loads, hydro conditions, natural gas prices, GHG models and California RPS portfolios are commendable. As we suggest in other sections of these comments, this extensive modeling effort should be utilized to help decide what is needed in the LA basin and San Diego areas to replace OTC and SONGS generation. In our comments dated December 5, 2013, we made several arguments that question the CAISO's extrapolation of the production cost savings and the calculations of the capacity benefits associated with the candidate transmission projects. The CAISO has modified its capacity benefits assumptions and calculations; however, almost all the issues raised by BAMx have remained unaddressed. Below we have repeated some of our December 5th comments and have expanded the discussion based upon the updated analysis included in the Draft Plan.	Please refer to the ISO's responses to Stakeholder comments from the November 20-21, 2013 TPP Stakeholder Meeting posted on the ISO website under the 2013-2014 Transmission Planning Process webpage.
1k	Extrapolation of the Production Cost Benefits We question the Net Present Value (NPV) calculations of the benefits of the candidate transmission projects. For example, when looking at the Delaney – Colorado River (DCR) 500 kV line project, the CAISO calculated the production	The change in benefits from 2018 to 2013 is substantially driven by changes caused by the 33% RPS policy and the OTC policy. Both of these policies reach equilibrium by

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	benefits in years 2018 and 2023 to be $31M and $26M, respectively. Our understanding is that the CAISO interpolated these benefits for the intervening years and assumed a flat benefit of $26M in years 2026 onwards. We question the CAISO's rationale for such extrapolation of economic benefit. The CAISO has estimated the NPV of benefits over 50 years discounted at 7% to be $364M. We have verified these calculations. However, when we apply a trend on the benefits that extrapolates them beyond 2023 (which accounts for a significant drop in the benefits from 2018 to 2023), the NPV benefit is $264M over 50 years. This is nearly a 1/3rd reduction in production benefit calculated by the CAISO.15 This exercise demonstrates that the CAISO's calculation of the benefits based on only two years of data is very dependent on how the extrapolation of these benefits are calculated. BAMx believes that it is important to recognize the benefit has dropped from 2018 to 2023 and question why such a decrease would not likely continue to future years. It is likely there will be an increasing buildup of the low variable cost renewables within the CAISO BAA. We recognize the tremendous effort that goes into analyzing the results with differing assumptions on fundamental drivers such as loads, hydro conditions, renewable development, etc. However, we are concerned about the lack of scenario analysis around the 50-year projection of benefits from two data points. As indicated above, we also observe that that the buildup of renewables will continue to increase within the CAISO in the later years, forcing a reduction of the benefits of the out-of-state (OOS) transmission projects, such as *DCR* and *HAE*. The Transmission Economic Assessment Methodology (TEAM) implemented for the Palo Verde Devers #2 500kV line (PVD2) project proposed two different ways of extrapolating the two study years' benefit to outer years. A conservative assumption was that these longer-term benefits are zero. Alternatively, the other proposal was to extrapolate the average benefits for the two years used in the study to the outer years.16 In Table 1, we provide a comparison of the production benefits as calculated for PDV2 and DCR. In case of PVD2, since the analysis showed that the production cost benefit was actually increasing, extrapolating the average benefit of these two years was found to be reasonable. When PVD2 was studied in the 2002-05 timeframe, a large amount of renewable build-up within California was not anticipated. This is clearly not the case with the current transmission economic analysis for DCR, given the current rapidly changing regulatory and market environment. It is evident from the	2023 and therefore it is reasonable to assume that the benefits reach equilibrium by 2023.

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	CAISO's production cost analysis that the production cost benefit of the candidate project is primarily derived from the difference in potential economic efficiencies of gas-fired units in Arizona relative to those in California. In addition to the potential increase in price-taking renewables built within the State in the future, the production cost benefits of the projects such as DCR would tend to decrease, as more OTC units are repowered in California with more efficient gas-fired units, as well as growth in preferred resources. Therefore, due to the uncertainty around future benefits, BAMx recommends that the CAISO explicitly identify the range of uncertainty associated with the extrapolation method.	
1l	CAISO Has Not Performed Sensitivity Analysis for Capacity Benefits The CAISO's preliminary findings indicate substantial capacity benefits associated with the Delaney – Colorado River 500 kV line project. Table 2 shows how the capacity benefits that were identified in the prior assessment to be less than $10M NPV over fifty years are now projected to be as high as $150M. Since the capacity benefits for DCR are a significant portion of the overall project benefit, essentially justifying its economic viability, we believe that the CAISO should perform several sensitivity analyses for the calculation of the capacity benefits of the proposed project, similar to the work that the CAISO has done for the production benefits. Additional capacity benefits sensitivity calculations are reasonable, as such analyses will likely take relatively less effort and time—these calculations do not require deployment of the resource intensive production cost tool and analysis. We understand the CAISO has derived capacity benefits based on the assumptions that California will continue to have a resource adequacy requirement and that Arizona can be the source of contracted capacity to serve California load. Additionally, a key assumption for these savings is that the future cost of capacity in Arizona will be significantly less than the cost in California. For these assumptions to hold true in the long run, the following conditions need to persist: • A need in California for system capacity above that which exists and future by capacity built in California for local and flexibility needs. • The capital and fixed operating costs for a peaking unit must remain less in Arizona as compared with a California peaking unit or preferred resource resulting in comparatively lower capital and operating costs in Arizona which	As noted in the response to comments received following the November 20-21, 2013 TPP Stakeholder Meeting, rather than perform sensitivity analyses, the ISO chose the conservative end of the range for the Arizona and California resource balance years. Also, as described in the report, the ISO chose to not quantify the overall market price benefits of the additional supply of capacity on the overall California capacity prices. In addition, to the selection of resource balance years, by not counting this benefit the ISO has conservatively estimated the capacity benefits. The ISO notes that in contrast a significant number of sensitivities have been performed for the production cost analysis. The impact various parameters have on the production simulation results, especially when considering projects that are affecting import capabilities, are often far from intuitive due to the complexity of the production simulation analyses and the sensitivities are necessary to provide insight into the source of the savings. Regarding the justification why new resources will be built in Arizona instead of the State to satisfy the upward regulation need, the justification is based on the information provided regarding the cost of building such resources. In addition, the upward regulation deficiency is caused by the lack of available system resource capacity.

No	Comment Submitted	ISO Response
	may translate into a system capacity price difference. • There will be a greater resource surplus in Arizona than in California during the early years of the project resulting in a lower demand for capacity in Arizona as compared to California. BAMx agrees that such a set of conditions is one possible future scenario. However, the CPUC 2012 LTPP source cited earlier suggests that the system planning reserve margin is expected to be in the range of 120% during the 2020-2022 time period. The CAISO analysis assumes California will be resource deficit by 2020-22. The CAISO has included a source to indicate the California resource deficiency in 2022.17 Although this source highlights the need for greater flexible resources in the outer years, it does not identify system resource inadequacy. Furthermore, the CAISO has not provided any justification why new resources will be built in Arizona instead of within the State to satisfy the flexible upward ancillary services and load following need. We note that during the February 12th Stakeholder meeting, several stakeholders commented that there are adequate, even flexible, resources available in Southern California that can meet the future flexible and system RA needs in the future. The CAISO should explore additional alternative sensitivity scenarios and evaluate their impact on the capacity benefit associated with the candidate transmission projects. Furthermore, the CAISO's capacity benefits calculations assume that the entire capacity benefit would be attributed to CAISO ratepayers. TEAM, on the contrary, assumes that the capacity benefit is split equally between the buyers and sellers of capacity. Thus, if the estimated annual societal benefit for DCR is $9 million ($44/kW-Yr), then the assumed CAISO benefit should be half that amount or $4.5 million. In other words, the NPV of the capacity benefit to CAISO ratepayer, who will ultimately pay for the proposed DCR transmission project, should be restricted to $75M. Moreover, the capacity benefits of DCR are dominated by the values in the earlier years (in the range of $11M-$20M). In the later years, the capacity benefits are restricted to $9 million per year. This means that if DCR is delayed for some reason, then its capacity benefit over fifty years will be reduced significantly.18	Regarding the benefit splitting issue, Arizona generation is assumed to earn a full rate of return for similar investments in a competitive market.
1m	Better to Wait to Approve DCR in Rapidly Changing Market and Regulatory Environment	

No	Comment Submitted	ISO Response
	BAMx supports the CAISO's decision to postpone the HAE project until the impact of NVE joining the CAISO Energy Imbalance Market (EIM) is better understood. BAMx urges the CAISO to continue its study of the potential benefits and refine costs of projects that can import power from other States, but to make no recommendations on DCR in the current transmission planning cycle. In these comments, we have provided several reasons to delay such approval until a fuller analysis can be completed. First, the changes to the production and capacity benefits attributed to the candidate transmission projects in the latest CAISO analysis need to be clearly explained and justified. Second, a reasonable extrapolation method should be applied to the production cost benefit as calculated in the two study years (2018 and 2023) that captures varying expectations of regulatory and market conditions. Third, similar to the sensitivities analyzed for the production benefits, the capacity benefits also should be computed under several sensitivity scenarios, as they form a substantial portion of the overall project benefits, per the latest CAISO analysis. Fourth, the capital costs for the candidate transmission projects need to be understood and explained in more detail. Fifth, if there are any additional benefits attributed to DCR that are not accounted in the economic studies, they need to be clearly explained and quantified under different sensitivity scenarios.19	As explained in Chapter 5, during the selection process project sponsors are expected to provide cost estimates and describe cost controls, such as binding cost containment commitments and other measures, that will ensure that the cost of the project is aligned with its identified benefits and does not render the project uneconomic.
1n	Transmission Program Impact on HV TAC BAMx appreciates the CAISO staff and management effort in developing the TAC Model. For the last several years, BAMx has been encouraging the CAISO to address growing concerns over increasing upward pressure on transmission costs. We believe the CAISO's development of the High Voltage (HV) TAC Model is a good starting point to increase the awareness among the stakeholders and policymakers in terms of understanding how much transmission costs are increasing. These costs are no longer a small portion of consumer electricity bills. In BAMx's comments dated October 28, 2013, we had identified several areas where the CAISO TAC model needs to be improved including missing data and documentation, input assumptions, and some of the functionalities. BAMx hopes that its comments are incorporated into the next revision of the TAC model and that it is allowed to critique the latest forecast before said forecast is expected to be presented to the CAISO BoG in March.	The ISO has made a number of enhancements based on suggestions provided by BAMx and other stakeholders to improve the overall quality of the high level estimate of the high voltage transmission access charge prepared in this transmission planning cycle. The model will continue to be upgraded leading up to the development of results to be provided as information in the 2013-2014 draft transmission plan. The ISO will be posting the model in the future for further stakeholder review and comment for the next planning cycle, but it is unlikely that will take place before the March Board of Governors meeting.

No	Comment Submitted	ISO Response
	BAMx appreciates the opportunity to comment on the CAISO Draft 2013-14 Transmission Plan. BAMx would also like to acknowledge the significant effort of the CAISO staff to develop the Draft Plan, as well as the staff's willingness to work with the stakeholders in the process to more fully develop it. We hope to work with the CAISO staff to continue to improve and enhance its capabilities.	

No	Comment Submitted	ISO Response
2	California Large Energy Consumers Association Submitted by: Barbara Barkovich	
2a	The California Large Energy Consumers Association (CLECA) provides these limited comments on the ISO's draft final 2013-2014 Transmission Plan. CLECA's comments focus on the Plan's discussion of its analysis of non-conventional alternatives to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. The Plan indicates that in the future the ISO will perform a more comprehensive assessment of non-conventional alternatives, which we strongly support. However, for this Plan, the ISO looked at a subset of alternatives provided by SCE and added scenario assumptions for SDG&E. CLECA applauds SCE for the provision of alternative scenarios for non-conventional resources and the ISO for running some of these, although the criteria for the ISO's selection of the subset of alternatives chosen are unclear. However, several areas warrant clarification and greater transparency. First, how did the ISO identify the "performance attributes needed from these alternatives" (p. 27) and, second, what were these performance attributes? Third, how did the ISO select "the input data that aligned with the ISO's view of the necessary performance attributes" (Ibid. and also p. 99.) Fourth, how was this selection process performed? Finally, how did this affect the ISO's choice of three of the SCE scenarios for analysis? Since the ISO has indicated that it will pursue more of this type of analysis in the 2014-2015 Transmission Planning Process, these are important considerations for a transparent process. Reviewing the scenarios studies by the ISO as presented in page 100 of the Plan, it appears that they did not include demand response (DR) in Orange County or North LA. However, several pages in the related February 12 presentation (pp. 17-22) do include some DR and some scenarios appear to include incremental DR. Thus, the Plan is unclear as to how DR was modeled and what performance attributes it was given. There should be much more clarity about the modeling of DR for the 2014-2015 TPP. In addition, there should be a coordinated effort among the ISO, CPUC, and CEC to assure that any load forecast used for the relevant study period includes projected load shape changes; such changes are anticipated to occur as a result of the	As explained in the February 12 stakeholder meeting, the ISO selected three SCE alternatives as sample alternatives that would best represent the range of performance of all of the alternatives SCE provided. By studying the SCE alternatives, the ISO determined the ability of those alternatives with their particular characteristics to meet the identified reliability needs. The relative benefit of the different characteristics was measured by their relative performance. More details behind the SCE alternatives are on the ISO market participant portal. The selection process consisted of studying the alternatives provided and measuring their performance. Table 2.6-4 on page 100 shows 900 MW of 4 hour DR in the SCE area which is concentrated in the Orange County and North LA area. The ISO will continue to coordinate with the CPUC and CEC on refining our load forecast study assumptions to include the latest information on load shapes. This information is refined in the IEPR process, so please participate in that process as well.

No	Comment Submitted	ISO Response
	transition of all non-residential IOU customers to time-of-use rates with dynamic pricing options. In addition, starting in 2018, there may be a transition to default time-of-use rates for the residential class. A sensitivity analysis as to the possible impact of the residential rate design change could be very useful, since residential and commercial load are the most temperature sensitive.	

No	Comment Submitted	ISO Response
3	California Public Utilities Commission Submitted by: Keith White and William Dietrich	
3a	***1.*** *The Final Plan Should Include Tables (and Text) Clarifying the Resource Composition of the Conventional versus Nonconventional Resources Study Cases for the L.A. Basin and San Diego Area, as Well as the Incremental Versus Combined Impacts of the Different Group I Transmission Additions.* CPUC Staff requests clarification of the table entitled, "Conventional Local Resource Needs (2018 & 2023) and Additional Dynamic Reactive Support (for comparison purposes)"[1] on page 18 of CAISO's February 12 slide presentation on "Southern California Reliability Assessment." Is it true that the inclusion in the reliability studies of: (a) LTPP Track 1-based authorized MW, plus (b) LTPP Track 4 scoping memo-based assumed MW, plus (c) generic 298 MW (later approved as the Pio Pico PPA) and the Escondido repower conventional resource additions (about 308 MW combined), resulted in no modeled reliability violations, at least at the bulk system level, even without adding the "Group 1" bulk system transmission additions characterized in Table B3-1? *If this is not the correct interpretation*, then there should be clarification in the final Plan. In any event, the final Transmission Plan table analogous to Draft Plan Table B3-2 should distinguish which MW of conventional resources assumed to be added in each area represent Track 1-based versus Track 4 scoping memo-based, versus other conventional resources, and should also show what nonconventional resources (e.g., DR) are also included in each area, and what is their basis (Track 1, Track 4 scoping memo, other). Additionally, recognition of the relevant demand-side management contributions to load reduction should be highlighted. These should include, but are not limited to, energy efficiency, self-generation, and energy storage connected at the distribution level. Regarding the "local resources reduction benefits" of the three Group I transmission (mitigation) measures (i.e., Imperial Valley Flow Control, Mesa Loop In, and additional dynamic reactive support) recommended for approval (discussed on pages 94-97 of the Draft Transmission Plan and shown in Appendix B, Table B3-1), it should be clarified (in the table), that these benefits represent local resource	The additional required new capacity values in the aforementioned table on slide #18 of the ISO's February 12th presentation on the Southern California (Bulk Transmission) Reliability Assessment (LA Basin and San Diego area) was meant as a summary of the estimated need of additional new local resources for the LA Basin and San Diego before inclusion of Track 1 (other than 10 MW incremental capacity for Escondido peaking generation) and proposed Track 4 local capacity authorizations. The reasons that the ISO considered those capacity values as additional new local capacity requirements rather treating some of them as existing new resources are the following: • At the time of the ISO's commencement of the 2013-2014 related Southern California bulk transmission studies, the only certainty, in terms of resource location, was the 10 MW incremental capacity authorized by the CPUC for the Escondido peaker repowering. Pio Pico was not yet authorized as approved local resources for SDG&E. In addition, even though Track 1 local resources were authorized for SCE's LA Basin area, specific project authorizations with their locations are still not yet known as of this writing. Given the uncertainty in the locations of the resources yet to be authorized and approved with specific Power Purchase and Tolling Agreements, the ISO identified those as potential new resource needs. • The resource need evaluations were performed first as an option in which transmission additions were to be compared for estimating the benefits of local capacity reductions brought on by potential transmission options. The "Summary of Costs and Benefits of Group I Transmission Upgrades" summary table on slide #13 of the same presentation should be used in comparison with the identified 4,882 MW total new resource needs on slide #18. In other words, the benefits brought on by the proposed transmission options from Group I were in the range of 800 – 1680 MW (i.e., reducing the total new local resource needs by 800 – 1680 MW). • A new assessment, other than the assessment performed for LTPP Track

[1] This table appears to be identical to Draft Plan Appendix B, Table B3-2, "Summary of Local Conventional Resource Need Assessment", PDF p. 92. Note: CPUC Staff does not believe its comments reveal confidential information in Appendices B or D, but merely cite to them regarding non-sensitive information. If, due to these references, CAISO believes CPUC Staff's comments should only be posted on CAISO's secure web portal with the other confidential material associated with the Draft Plan, rather than on CAISO's public web site, that is fine.

No	Comment Submitted	ISO Response
	reductions from the resource levels shown in Table B3-2, if that is true. Furthermore, regarding the MW of local resource reduction benefits shown in Table B3-1, the CAISO should clarify: a) The basis for the ranges in benefits (e.g., -800 to -1680 MW reduction benefit for the three transmission measures combined). For example, what variations in assumed resource locations give rise to the low versus high resource reduction benefits, and what are the benefits for a phase shifter versus back-to-back DC flow controller in the Imperial Valley? b) If and how the local resource reduction benefits are additive (without apparent interaction) over the three different Group I transmission solutions, as implied by Table B3-1, and if the three solutions do in fact <u>interact</u> (are not additive), then what are the incremental local resources reduction benefits for applying the three solutions in different sequences (e.g., how much incremental benefit is provided by the Mesa Loop-In when applied first, versus when applied after the Imperial Valley Flow Controller)? Also, there should be a table explicitly showing how the seven, different nonconventional resources scenarios compare to the basic conventional resource additions needed to avoid violations as summarized in Table B3-2, and against which the benefits of transmission additions (reducing resource need) were tested. Specifically, which conventional resource additions depicted in Table B3-2 were removed from, and which were retained in, the nonconventional resource scenarios depicted in Table B3-4? (The nonconventional resource scenarios include some gas resource additions, and apparently give 3,150 MW of total resource additions for western L.A. Basin and San Diego.)	4 Studies, was performed for year 2023. The reason for this assessment is because of load growth associated with 2023 vs. 2022 (of LTPP Track 4) and some differences in the system-connected DGs for the San Diego area due to updated 33% RPS portfolio for the 2013/2014 TPP. When adding the total authorizations from the CPUC LTPP Track 1, and the potential authorizations from the CPUC LTPP Track 4 (based on Proposed Decisions), and the low end of the transmission benefits, there is still a residual need of about 600 MW for the LA Basin / San Diego combined study area. This is a gross approximation at this time due to uncertainty to where the remaining resources authorized for Track 1, and potential resources from Track 4, would be developed and implemented. In response to questions regarding Table B3-1, the ISO also noted that similar responses were provided at the stakeholder meeting on Feb. 12th, 2014: • No variations in resource locations were assumed for the studies used to determine the benefits of the transmission options from Group I. The most effective locations in the Southwest LA Basin and San Diego area proxy resources were assumed for the studies based on suggestions from the CPUC Energy Division staff (to assume the most effective locations for the studies to arrive at the minimum amount of local capacity need). • The benefits of the back-to-back DC flow controller vs. the phase shifting transformer option were provided on page 102 of the Draft ISO 2013/2014 Transmission Plan. • The transmission options were added to the study case based on the timeframe for the need and the most likely in-service dates based on the project proponent's inputs considering environmental permitting feasibility. For the case of the Mesa loop-in, the ISO evaluated it as a stand-alone project without the flow controller device and the benefits were determined to be lower (i.e., about 300 MW) compared to when it's being included in conjunction with the flow controller device. In other words, the Mesa loop-in project provides more benefits (i.e., up to its maximum benefits) if it were coupled with the flow controller option. In regards to the Table B3-4 (non-conventional transmission alternative

No	Comment Submitted	ISO Response
		evaluations), the resource assumptions were based on SCE's submitted scenario analysis and were meant to be used as an illustration of how the non-conventional alternative analyses would be performed. The resource assumptions used for these analyses were different from ISO's assumptions of proxy resources, which were assumed at the more effective locations, for transmission benefit evaluation. SCE subsequently informed the ISO that the resource assumptions would be subject to change depending on the results of its Request for Offer (RFO) for resources to meet the CPUC Track 1 and Track 4 authorizations.
3b	***2.*** *CPUC Staff Appreciates the CAISO's Initial Analysis of Nonconventional Local Capacity Alternatives and Requests Clarification of the Study Methodology for Intermittent and Energy-Limited Resources, as Well as Proactive Disclosure and Discussion with Stakeholders regarding How this Process Will Proceed (including Information Needs) for the Next TPP Cycle.* CPUC Staff appreciate the first-time inclusion in the Transmission Planning Process of an assessment of the ability of nonconventional resources to help meet local capacity needs. In the final 2013-2014 Plan, the CAISO should clarify the rationale for selecting the particular hours of a 1-in-10 peak day for which nonconventional alternatives were tested. More generally, CAISO should clarify the study methodology and rationale for assessing the contributions of intermittent and energy-limited resources, i.e., PV, DR and storage. (For example: if 4-hour DR or storage is considered, is it necessary to study the "fifth" hour? Why is PV availability set to zero for 6 p.m.?) The 2014-2015 TPP will be the first opportunity to integrate the nonconventional local resources assessment into a full planning cycle. The CAISO should continue to conduct helpful informational studies of this type regardless of what specific nonconventional resources proposals are submitted in 2014. It is essential to communicate and discuss with stakeholders proactively (early enough in the cycle): a) The anticipated methodology for analyzing nonconventional local resource alternatives including energy-limited and intermittent resources, reflecting lessons learned from the 2013-2014 TPP cycle; and b) Types and granularity of information required (identifying highest priorities) for analyzing nonconventional local resource alternatives in the new TPP cycle, again reflecting lessons learned from the 2013-2014 TPP cycle.	The ISO selected the two hours that were expected to result in the most stress on the transmission system. The purpose of the study was to determine if the resource characteristics were adequate. The point in time when an energy-limited resource runs out of energy is an obvious point in time that should be studied. The solar PV curves that were utilized showed zero output at 6 PM. However, we will fine tune our data and analysis in the next iteration of studies.
3c	***3.*** *CPUC Staff Appreciates CAISO's Analysis of Preferred Resources Scenarios, and Encourages CAISO to Study Additional Scenarios*	

No	Comment Submitted	ISO Response
	regarding Demand Response and Other Preferred Resources. CPUC staff appreciates that the CAISO selected and studied three of the seven preferred resources scenarios provided by Southern California Edison. We note, however, that only one of the three scenarios selected included demand response (DR) resources, which consisted of 900 MWs of 4-hour DR products. The CAISO did suggest in its paper, "Consideration of alternative to transmission or conventional generation to address local needs in the transmission planning process," dated September 4, 2013, that 2-hour DR products may have a reliability benefit. Thus, while the CPUC appreciates the inclusion of the aforementioned scenario, we encourage the CAISO to also study scenarios with a mix of 4-hour and 2-hour DR products in future studies. Also, no scenario showing a mix of DR and other resources was studied (such as Scenarios 2 or 6). We understand that CAISO intends to study additional scenarios with DR during the next TPP cycle. We look forward to ongoing interaction with the CAISO regarding development, study, and use of such scenarios.	These comments should be provided into the 2014-2015 planning process.
3d	***4.*** *The Rationale for Finding any Reliability Project Needed Should be Specifically Identified, Using a Consistent Framework for Characterizing Rationale Across All Projects and Addressing the Role of Reliability Standards and Criteria, as Well as the Role of Avoided Load Shedding.* Reliability-driven transmission has accounted for a large share of overall costs associated with transmission infrastructure approvals and additions, amounting to several billions of dollars of approved transmission additions over recent years. This year's plan is no exception. Yet, the specific rationale for finding that a particular reliability upgrade warrants approval is often not reported in a consistent manner across all approved projects, and is sometimes unclear to stakeholders interested in the annual Transmission Plan. Ideally for the 2013-2014 Transmission Plan, but certainly going forward, the Plan should identify for each approved reliability upgrade, in a manner consistent across all such upgrades, whether and how: a) The upgrade is required because no load shedding is allowed under the contingency in question, citing the relevant reliability standard; b) The upgrade is required because the load shedding that would be avoided i. is explicitly calculated to have greater expected economic cost than the upgrade, when using appropriate levelization or discounting out X years into the future, or ii. is judged on a qualitative basis to have greater expected cost than the upgrade, with a *clear explanation of the rationale for this qualitative*	The ISO has provided detailed discussions of the need for the various reliability projects in Appendix B, which is available on the ISO participant portal.

No	Comment Submitted	ISO Response
	conclusion; c) The upgrade is required without needing to explicitly consider the expected load shedding avoided, with a clear explanation of why this is so. This would give stakeholders a clearer understanding of how the reliability standards are being applied, and how studies are being conducted and interpreted, across the different circumstances being examined.	
3e	***5.*** *Calculation of Capacity Value in the Studies of Economic Transmission Projects Is Insufficiently Rationalized and Insufficiently Robust to Uncertainties, and This Should Be Addressed Going Forward (Not Left as a Possible Compensation for 'Unquantified' Benefits).* It appears that the 2013-2014 Transmission Plan will recommend one or two economically driven transmission projects for approval: the Delaney-Colorado River project and perhaps the Harry Allen-Eldorado project. The potential value of these projects perhaps extending beyond energy market benefits is plausible. (The Delaney-Colorado River project essentially represents the Arizona portion of a transmission project that was previously approved and partially built in California, i.e., DPV-2.) The sensitivity analysis of the energy (locational price/marginal cost-based) benefits of these projects is informative and well appreciated. However, the energy benefits appear insufficient to justify the projects on a benefit-cost basis, without adding the calculated capacity benefits. The capacity benefits are thus an important part of the analysis and project justification, where at least the Delaney-Colorado River project appears destined for approval. Yet, the capacity benefit calculations in their present form are unconvincing for several reasons. a. The rational for projecting a California capacity deficit that can be met equally well by Arizona or California resources is not well developed. Will there be a generic capacity deficit, as apparently assumed, or will such a benefit be much lower or even nonexistent once RPS, local capacity, and flexible capacity needs (the latter two, at least, not yet clearly known) have been met? b. If Arizona capacity is at least partly able to meet California capacity needs, and if it enjoys a cost advantage, why should that economic surplus flow entirely to California loads, without any of it flowing to Arizona suppliers? c. In fact, there a variety of factors and uncertainties affecting the possible capacity benefits for the Delaney-Colorado River and Harry Allen-Eldorado projects, as the above discussion indicates. Just as was done for energy benefit uncertainties, capacity benefit uncertainties should be subjected to sensitivity analysis.	The analysis has identified a modest amount (200 MW to 300 MW) of capacity deficit that could be met generation in Arizona as a result of building this transmission line rated at more than 2000 MVA. Arizona generation is assumed to earn a full rate of return for similar investments in a competitive market. As discussed in the ISO's responses to Stakeholder comments from the November 20-21, 2013 TPP Stakeholder Meeting posted on the ISO website under the 2013-2014 Transmission Planning Process webpage, economic planning models require sensitivity studies because they are more difficult to estimate the results of those models. Capacity models are much simpler and easier to predict the results of

No	Comment Submitted	ISO Response
	In conclusion, these two "economic" projects have plausible value, and they may have benefits not addressed via analyses summarized in the draft Plan. However, the important capacity value analyses that *were* presented are not convincing. Perhaps the capacity value simplifications offset omission of additional sources of potential value that were not quantified, but we cannot know this. CPUC Staff requests that as the planning process proceeds with these or other potentially economic projects, the valuation of non-energy benefits will become more fully rationalized and more robust.	sensitivities. The ISO chose conservative assumptions in its capacity model to avoid the complexity of including additional sensitivity parameters in the presentation of the results.

No	Comment Submitted	ISO Response
4	CalPeak Power, LLC Submitted by: Clifford D. Evans, Jr.	
4a	As the CAISO has recognized, there is ample justification for adding reactive power support to meet reactive margin requirements and to partially replace the inertia and dynamic reactive capability of retiring the San Onofre Nuclear Generating Station ("SONGS") and once-through-cooling ("OTC") generation. Adding reactive power support also furthers the renewable integration objectives of the State of California and the CAISO by providing dynamic reactive capabilities that wind and photovoltaic solar generation cannot provide while at the same time reducing the risk of voltage collapse during high import conditions. Since the CAISO has recognized a need for adding reactive power, during the transmission planning process request window CalPeak submitted requests to study a change in the way the CalPeak units are used. The CalPeak units all utilize Pratt & Whitney, Model FT8 (DLN), Twin-Pac industrial gas turbine packages which enable the plants to operate not only as generators, but also as synchronous condensers to provide voltage support, and, with minimal capital investment, the ability to toggle between being generators and synchronous condensers. Currently, the ability of these units to provide voltage support (outside of what is provided when operating as a generator) is not being utilized. CalPeak believes enabling the units to run as either generators or synchronous condensers is a fast, low-cost way to provide additional voltage support with no environmental impact. Since the units are already constructed and permitted, the solution is available almost immediately and without construction and permitting risks. The recommended solution provided by the CAISO will not be available for years and still needs to cross the hurdles related to developing the sites/projects (acquiring site, permitting, construction, etc.). To support its request, CalPeak submitted information regarding the existing units, power flow study results prepared by its consultant, Navigant, and our proposal for providing this product. The power flow studies showed that each of the CalPeak units can provide significant voltage support, particularly in SDG&E's service territory where, with the shutdown of SONGS, the need for voltage support is most acute. Unfortunately, it appears from the Draft Transmission Plan that the CAISO did not properly evaluate CalPeak's proposal to provide synchronous condenser capability. • In Draft Transmission Plan, Appendix B, "Reliability Assessment Study	The ISO identified the need for reactive power that would be in addition to existing real and reactive power that is currently available. Calpeak's proposal would not provide any additional benefits beyond what their existing resources already provide, that would meet the needs identified by the ISO, as the resources provide more support operating as generators than switching into synchronous condenser modes of operation. CalPeak refers to a discussion with ISO staff - during our meeting with Calpeak, Calpeak stated that they understood and agree with the ISOs statement above. However, they asked the ISO to investigate the economic benefits of converting their existing generation to be able to operate at times as synchronous condensers, which the ISO agrees may hold economic (rather than reliability) benefits. The ISO agreed to investigate the economic benefits and regulatory challenges of the Calpeak proposal. The CalPeak comments appear to be confused between reliability benefits versus economic benefits, and also confuse the conversion of the Huntington Beach units 3 & 4 to synchronous condensers (rather than being retired altogether) with providing generators the flexibility to operate at times as synchronous condensers. But to be clear, there are no reliability benefits associated with the Calpeak proposal. As noted above, the ISO is aware that there may an economic and environmental benefit in certain areas to certain generators being capable of switching from generator modes of operation into synchronous condenser modes of operation, when a lower level of support would suffice and the gas fired generation is not needed. The current framework of market and regulated transmission service does not provide for the compensation of operating costs for a generator temporarily operating as a synchronous condenser, and the ISO intends to review this in 2015.

No	Comment Submitted	ISO Response
	Results," there is no mention whatsoever of the proposal for the CalPeak Enterprise unit although it is in Escondido which is in the vicinity of SONGS and electrically within the area where the CAISO has indicated that new synchronous condensers are needed for voltage support. • Information in Draft Transmission Plan, Appendix E, "2013 Request Window Submittals," contains some statements that are incorrect. o The reference to the proposal for CalPeak Border erroneously suggests that the proposal to use the synchronous condenser capability would cost $10 million and that the proposals for the other units would cost $3 million. Appendix E, Table E-1 at items 8-11. The cost figures are for the project proposals at their 230-kV interconnection cost rather than their 69-kV/115-kV cost. The cost of the 69-kV solution is significantly less -- estimated to be between $300,000 and $500,000. o The references to the proposals for the CalPeak Panoche and CalPeak Vaca-Dixon erroneously state that the units are in SDG&E's service territory. See Appendix E, Table E-1 at items 10-11. They are in PG&E's service territory. Given the absence of any discussion in the Draft Transmission Plan of Escondido, representatives of CalPeak met with representatives of the CAISO to determine the extent of the CAISO's efforts to evaluate the CalPeak proposals. The CAISO stated in the meeting they believe the CalPeak units are more valuable as generators (in part because the CAISO assumed it has no way to compensate units as synchronous condensers if they are also generators[2]). As a result, the CAISO simply did not analyze the system benefits the CalPeak units could offer if modified to operate as synchronous condensers when not called upon for generation. CalPeak understands our proposal may require an RMR contract until a better way to procure MVARS, as has been instructed by FERC, is developed by the regulatory agencies in California. However, our proposal could be much less	

[2] CalPeak understands that its proposal may require a non-conforming reliability must-run agreement such as the agreement CAISO currently uses to compensate AES Huntington Beach, LLC for operating two synchronous condensers to produce reactive power to provide voltage support in the Los Angeles Basin and the San Diego/Imperial Valley local capacity areas. *See AES Huntington Beach, LLC*, FERC Docket No. ER13-351-000, 142 FERC ¶ 61,017 (2013). CalPeak understands that there is likely a better way to procure reactive power and has actively supported the development of competitive voltage procurement within the California market, as has been suggested by FERC. Unfortunately, however, development of competitive voltage procurement within the California market has not been made a priority.

No	Comment Submitted	ISO Response
	expensive, available quicker, and with fewer environmental impacts than what is currently in the Draft Transmission Plan. *Simply put, if existing generators can provide synchronous condensing when not generating, the need for additional MWs can be reduced. In addition, based on our understanding that some existing generators are currently dispatched in order to provide MVARs, making use of units like CalPeak avoids what is currently a very expensive and environmentally harmful way to address the situation.* Although the CAISO did not model the CalPeak proposals, it did find a need for synchronous condensers to provide voltage support. In particular, the Draft Transmission Plan indicates that the CAISO has identified the need for an additional 450 - 700 MVAR of dynamic reactive support at future SONGS Mesa Substation or electrically equivalent location in the vicinity. Draft TP at 103. To address this need the ISO recommends installing two synchronous condensers at the San Luis Rey substation totaling 450 MVAR and notes there is a potential need for 250 MVAR of additional dynamic reactive support at SONGS Mesa or an electrically equivalent location which will be reviewed in future planning cycles. *Id*. The cost of the synchronous condensers at the San Luis Rey substation is estimated to be $80 million and they would not be in service until June of 2018. Draft TP at 284. The synchronous condensers would be constructed by SDG&E rather than being subject to competitive solicitation process. Draft TP at 288. The CAISO's determination to not study the CalPeak proposal, while finding a need for synchronous condensers, is not in ratepayer interests. CalPeak believes that the possible use of existing units to provide voltage support should be studied before ratepayers are asked to pay the bill for synchronous condensers that may be larger than necessary and will not be available for many years. Making the changes needed to enable the CalPeak units to run as both generators and synchronous condensers is desirable because: • Making changes to the existing units is much less expensive than building new synchronous condensers. • Voltage support can be available almost immediately from the units, rather than waiting many years for new synchronous condenser units to be built (and taking the risk that the new units can't be permitted/constructed as proposed). • There is no environmental impact associated with the enabling the units to run as synchronous condensers.	

No	Comment Submitted	ISO Response
	Allowing the peakers to earn some additional income for providing voltage support also helps to address the so-called "missing money problem" which is being experienced by many owners of units that do not have power purchase agreements. Earning extra income for providing voltage support helps ensure that the peakers meet the revenue requirements necessary to stay in operation and, thus, to be available to provide power or voltage support to the grid. Even if the CAISO is not able to evaluate the CalPeak proposals and thus make them part of the Final Transmission Plan, CalPeak believes that the CPUC may well be interested in further evaluation of the proposal. CalPeak has intervened in the CPUC Long-Term Procurement Proceeding to raise the need to consider procurement of voltage support. Thus, CalPeak requests that the CAISO modify the Draft Transmission Plan to make it accurate and complete with respect to what it did and did not do when it reviewed the CalPeak proposal. Making these changes will make it clear that the CAISO has not "rejected" the proposal - it simply did not evaluate it – as using the units as both generators and synchronous condensers.	

No	Comment Submitted	ISO Response
5	Clean Coalition, Natural Resources Defense Council and Environmental Defense Fund Submitted by: Stephanie Wang, Lauren Navarro and Carl Zichella	
5a	II. Reflect Methodology From Non-Conventional Alternatives Straw Proposal We recommend refining the next Local Preferred Resources Assessment for the LA Basin and San Diego to better reflect the methodology set forth in the Straw Proposal. We urge the ISO provide stakeholders with the "preliminary catalogue" of local preferred resources, which is the first step in the Straw Proposal. This catalogue of resources should include the essential performance characteristics of each resource, listed in the Straw Proposal as response time, availability, and duration.3 The Draft 2013-2014 Transmission Plan included scenario data tables, such as the one below, which only addressed one of the three performance characteristics (duration). Stakeholders should have an opportunity to comment on the preliminary catalogue of local preferred resources. This is an essential step for ensuring that the modeled scenarios include an optimal mix of resources, that the performance characteristics of such resources are realistically described in light of cost and availability considerations. For example, while the ISO prefers demand response products that can respond in "sufficiently less time than 30 minutes from the CAISO dispatch,"5 it may be more cost effective from ratepayer perspective to address local reliability needs with a combination of demand response products with different performance characteristics. Similarly, stakeholders should have opportunities to participate in the annual updating of the catalogue of local preferred resources to include new technologies and products.6 For example, future catalogues of local preferred resources should include advanced inverters paired with solar and storage facilities for providing reactive power and voltage support.7	As noted in the draft transmission plan and in previous stakeholder sessions, the general methodology developed by the ISO to consider more generic circumstances needed to be adapted to the unique situation in the LA Basin and San Diego areas, where the aggregate need is expected to require a range of resources and the focus was on how those resources would interact. This is a markedly different circumstance than screening for areas where preferred resources may hold promise for deferring development altogether – clearly preferred resources are expected to play a material role in the LA Basin and San Diego area. We encourage your comments on how the analysis can be improved in the next planning cycle.
5b	III. Rely on Local Preferred Resources The Joint Parties recommend that the ISO model scenarios that rely 100% on local preferred resources and transmission solutions, except to the extent that the California Public Utilities Commission (CPUC) Long Term Procurement Plan rulemaking requires minimum levels of gas-fired generation. We recommend the following specific refinements to the Local Preferred Resource scenarios to	As the Track 4 process is proceeding ahead of the finalization of the 2013-2014 transmission plan, our objective was to align the plan with reasonable expectations in the process. Further, the ISO determined that based on meeting 2018 needs, some level of gas-fired resource would be required. The ISO's plan leaves residual need for further analysis and consideration of preferred resources in the next planning cycle - we expect to

No	Comment Submitted	ISO Response
	reflect the CPUC's recent proposed decision in Track 4 of the Long Term Procurement Plan, provided that such requirements are affirmed in the final decision.8 First, the ISO should adjust all local preferred resource scenarios to reflect the minimum amount of additional gas-fired generation (1300 MW rather than 1400 MW) required by the CPUC's proposed decision. The proposed decision concluded that no additional gas-fired generation is required in the LA Basin and San Diego area beyond the 1000-1500 MW of gas-fired generation authorized for the Southern California Edison territory and the 300 MW Pio Pico gas-fired plant authorized for San Diego Gas & Electric territory.9 Developing scenarios with the minimum amount of required gas-fired generation is consistent with the stated intent of the Straw Proposal to identify the volume of local preferred resources that, combined with transmission solutions, will reduce the need for conventional generation to fill the gap. Second, if the CPUC affirms its initial finding that the Mesa Loop-In solution for reducing local capacity requirements is too uncertain to be counted, the ISO should separately model sufficient additional local preferred resources to replace this transmission solution.11 We support the ISO's approach of identifying transmission solutions to avoid investment in additional gas-fired generation. However, we are concerned that if the ISO does not timely show how the potential gap can be met with local preferred resources, such a gap would be met with gas-fired resources by default.	study a variety of scenarios as described in the 2014-2015 study plan with better information about the results of the Track 1 and Track 4 decisions and will consider your comments. Regarding the Mesa loop-in project, the ISO understand the proposed decision to mean that the issue was expected to be addressed in the ISO's 2013-2014 transmission plan and the ISO agrees that this is where the Mesa Loop-in project needs to be considered.
5c	IV. Optimize Portfolio of Local Preferred Resources The Joint Parties recommend that the ISO make the following refinements to the local preferred resources scenarios to optimize the portfolio of resources to meet local reliability needs. We recommend that the ISO develop new scenarios that include demand response, distributed renewable generation, *and* energy storage. As shown in Table 1 above, each of the seven proposed scenarios contain *either* 900 MW of demand response *or* 900 MW of distributed renewable generation and energy storage. However, the CPUC proposed decision requires that the resource mix include at least 50 MW of energy storage. 12 Further, local preferred resources have complementary performance characteristics. For example, the draft transmission plan notes that Scenario 4	The ISO looks forward to your participation in the 2014-2015 transmission planning process, and expect to study refined scenarios in that cycle. As noted earlier, the ISO focus was to test the effectiveness of various resources, and expects the analysis to be fine-tuned as some level of procurement is achieved and there is better clarity upon which to build scenarios. Regarding some of the other concerns expressed, it is important to note that the ISO's recommended actions in this transmission plan would not completely address the residual need. We expect the analysis to be useful in the development and consideration of various preferred resource options, and that this will continue to be fine-tuned as resource procurement develops.

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	"appears to be infeasible due to higher net peak load resulting for the San Diego and LA Basin study area and some conventional resources partly located in less optimal area of the northwest LA Basin."13 Net peak load concerns can be addressed with "load modifier" demand response products, such as time of use rates, which reshape or reduce load.14 The potential for Smartmeters to enable ratepayers to better manage their electricity use remains largely untapped, as do associated rate and enabling technology innovation. We also recommend that the ISO develop response time requirements for demand response that reflect actual needs for first and second contingencies, consistent with response time requirements for other types of resources that meet local capacity requirements. This will increase the volume of demand response available to meet local reliability needs. Demand response products that can response faster than minimum requirements should receive a premium.16 In addition, we urge the ISO to work with the California Energy Commission to develop a scenario that accounts for the potential impact on load curves of a future requirement of residential default time of use after 2018, as well as current load reshaped prompted by mandatory time-variant rates imposed in all non-residential classes. New, time-variant tariffs could significantly reshape load, reducing the need for peaking and ramping resources. Similarly, as the electric vehicle population continues to grow, it will provide a means to soak up bountiful clean electricity generated mid-day and provide ramping and peaking resources during the later-afternoon and early evening. We also recommend that the ISO modify the quantity of local preferred resources in each scenario as needed to meet local reliability needs. The initial seven scenarios rigidly adhere to an artificial requirement that the total capacity of local preferred resources must add up to 900 MW, and this resulted in findings that certain portfolios that relied upon resources with shorter durations could not meet reliability needs. Considering portfolios with a greater total capacity of local preferred resources is important since such portfolios may be less expensive for ratepayers than portfolios with a lower total capacity that only includes the most expensive types of resources. As shown in Table 2 above, this is permitted by the proposed Long Term Procurement Plan decision.	

No	Comment Submitted	ISO Response
	The Joint Parties look forward to continued collaboration with the CAISO, and we appreciate the opportunity to offer comments on the Draft 2013-2014 Transmission Plan.	

No	Comment Submitted	ISO Response
6	Duke America Transmission Company Submitted by: Christopher T. Ellison with Ellison, Schneider & Harris	
6a	I. Prudent Transmission Planning Should Be Flexible To Accommodate an Uncertain Future. Like the CAISO, DATC's parent entities, Duke Energy and American Transmission Company, are entities responsible to millions of ratepayers for reliable and cost-efficient electric power services. As such, DATC appreciates the difficulty and competing priorities involved in planning and maintaining a high-voltage transmission grid, which supports the economy and public welfare of a large portion of the United States. The most important lesson DATC has learned in this business is the importance of flexibility and the ability to respond to change. An essential element of any critical infrastructure planning process should be the recognition that the future is uncertain. This is especially true when applied to electricity - a commodity essential to the public welfare that must be delivered in real time. The price of failure to hedge for uncertainty is particularly great in the context of transmission planning. This is due to two fundamental facts regarding transmission. The first fact is that major transmission additions take many years to plan and permit. This is especially true in California. Thus, needed but unplanned for transmission cannot be built quickly as circumstances change. The failure to plan for needed transmission cannot be remedied cheaply or easily, if it can be remedied at all. The opposite is not the case. Transmission that is planned, but later determined not to be needed, can be quickly suspended prior to ultimate construction. As the vast majority of transmission costs are in the physical construction of facilities, a decision to cancel planned transmission is not expensive. Stated simply, transmission planning risks are asymmetric: a transmission plan is much more flexible downward than upward. These indisputable facts translate into two specific policies for the TPP: (1) multiple scenarios should be considered to determine a set of transmission projects, and (2) the CAISO should investigate and institute processes and procedures to create multiple options that can prepare for an uncertain future. To expand on the first point, the CAISO currently only evaluates a future that is determined by stakeholders in an open process to be the most likely to occur. While DATC agrees that this has historically been the preferred	The ISO notes that transmission costs form part of the input into the generation planning process conducted by the CPUC which produces the renewables portfolios relied upon for policy-driven transmission planning in meeting renewables portfolio standards requirements. As we approach 2020 and more of the generation has been firmed up through procurement processes, successive years' portfolios have demonstrated less variability in the expected sources. That being said, flexibility is an important consideration in planning decisions.

No	Comment Submitted	ISO Response
	approach, the future energy system Californians face today is much different and much more uncertain than in the past. Therefore, it makes sense to evaluate multiple potential future scenarios and determine a set of high value transmission projects that meet the need over a range of potential outcomes. These policies are also supported by another basic fact: transmission costs—even assuming construction—are a small percentage of the customer's overall bill, typically less than 10 percent.1 By far the major driver of the customer's total bill is generation. As Zephyr and Pathfinder have repeatedly noted in comments filed at the CAISO and at the CPUC, minimizing transmission costs does not result in lower overall costs, as generation costs far outweigh the costs of building transmission. But transmission, while relatively inexpensive to construct, can have a major impact on generation costs. A transmission plan that guesses wrong on generation can force reliance on generation that is costly, environmentally harmful, unreliable, and lead to stranded costs. Thus, the price of planning for, or even building, too much transmission is relatively small, while the price of having too little can be very large. A myopic planning focus on reducing transmission costs can easily prove "penny-wise and pound foolish." In sum, California should plan for transmission that accommodates a reasonable range of possible generation futures, rather than a singular focus on a plan that minimizes transmission costs. As shown next, the proposed TPP does just the opposite.	
6b	II. The CAISO TPP Puts California Ratepayers at Risk by Planning for the Minimum Transmission Necessary to Meet a Too Narrow Range of Scenarios and Policy Objectives. Section 24.4.6.6 of the CAISO Tariff establishes the procedures for identifying and evaluating policy-driven transmission solutions that are needed to meet state, municipal, county or federal policy requirements or directives as specified in the CAISO's Study Plan.2 In Section 3.1 of the Study Plan, the CAISO identified "the state's mandate for 33% renewable energy by 2020" as the "overarching public policy objective" in the current planning cycle.3 This high-level public policy objective has been further broken down into two sub-	Over the last several years the ISO has analyzed a wide range of portfolios and OTC retirement and replacement assumptions. Only recently has that range converged to a more certain - and more manageable - outlook. However, there are still major uncertainties that need to be addresses such as the mix and location of preferred resources and conventional generation.

No	Comment Submitted	ISO Response
	objectives: First, to support the delivery of 33% renewable energy over the course of all hours of the year, and second, to support Resource Adequacy (RA) deliverability status for the renewable resources outside the CAISO balancing authority area that are needed to achieve the 33% RPS goal. Either of these sub-objectives could lead to the identification and approval of policy-driven transmission elements in the CAISO's 2013-2014 comprehensive transmission plan.4 These two sub-objectives are described and detailed in Sections 3.1.1 and 3.1.2 of the 2013-14 Study Plan. The criteria identified in Section 24.4.6.6 of the Tariff are also relevant to the CAISO's determination of need and designation as Category 1 or 2 for policy-driven transmission upgrades and additions. These criteria include planning level costs, environmental evaluation, resource integration requirements and needs, and the resource planning priorities of the CPUC and other regulators.5 The process briefly summarized above is data-driven and analytical, but also allows the CAISO to exercise discretion in order to align its prioritization of policy-driven transmission projects with the resource planning processes of regulatory agencies, and to use its judgment and experience in making decisions about public policy-driven project priorities.6 This flexibility and discretion is important, because for the reasons discussed above, efficient and effective transmission planning requires both pragmatic consideration of a spectrum of planning assumptions *and* the ability to balance long and short term options and priorities. As the Draft Plan acknowledges, "[t]he primary policy directive for the last three years' planning cycles and the current cycle is California's RPS that calls for 33 percent of the electric retail sales in the state in 2020 to be provided from eligible renewable resources."7 DATC believes there are multiple policy objectives that the CAISO must take into account during its planning process. The CAISO assessment for the 2013-2014 TPP did not identify any "new major transmission projects needed to support achievement of California's 33%	

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	RPS…"8 In part, the negligible amount of policy-driven projects were the result of the narrow range of renewable portfolios used in the 2013-2014 TPP (see discussion of broadening the portfolios in the next section). The limited number of policy-driven projects was also a result of the CAISO's focus on a single policy issue: the 33% RPS. This narrow focus causes, and is exacerbated by, the reliance upon a narrow range of generation scenarios. Pursuant to a May 2010 Memorandum of Understanding ("MOU"), the CAISO relies upon input from the CPUC and the CEC to develop the renewable resource portfolios that the CAISO uses in the TPP. There continues to be a great deal of uncertainty about which areas of the grid will actually realize most of this new resource development."9 In order to address this uncertainty, the CAISO applies what it refers to as a "least regrets" principle, in order to balance the need to develop needed transmission in time to meet public policy requirements, while at the same time avoiding "the risk of building transmission in areas that do not realize enough new generation to justify the cost of such transmission."10 Despite the Draft Plan's concession that "there continues to be a great deal of uncertainty about which areas of the grid will actually realize most of this new resource development," the number of alternate portfolios have been reduced in this TPP, and there is less variability between those scenarios.11 For this TPP, the CPUC and the CEC recommended the use of only three scenarios: a "commercial interest" scenario, a "environmental" scenario, and a "high-distributed generation" portfolio.12 The CAISO used only these limited scenarios to determine policy-driven need. Use of only a few scenarios, with little variability, results in the development of a less flexible transmission plan that runs the risk of failing to provide transmission access to least cost generation assets.	
6c	III.The CAISO Should Take Five Steps to Develop a More Prudent and Flexible Plan. *A. The CAISO TPP Should Expand the Policy Objectives to Include California's Greenhouse Gas Goals.* The 2013-2014 TPP ignores what is likely to be one of the key policy drivers for transmission development: California's greenhouse gas reduction goals.18 Assembly Bill 32, the California Global Warming Solutions Act of 2006 declared	The ISO closely coordinates with the CPUC long-term procurement process – the ISO encourages your input into that process.

No	Comment Submitted	ISO Response
	that global warming posed a serious threat to the economic well-being, public health, natural resources, and environment of California. It set an initial target of reducing California's GHG emissions to 1990 levels by 2020. It further tasked the California Air Resources Board ("CARB") with "monitoring and regulating sources of emissions of greenhouse gases that cause global warming in order to reduce emissions of greenhouse gases."19 Pursuant to Executive Order S-3-05, California has a GHG goal of 80% below 1990 levels by 2050, and CARB is currently developing a broad framework for measures to meet this goal.20 CARB calls for significant energy-related emission reductions, coupled with electrification of the transportation sector. Moreover, a recent study by Lawrence Berkeley National Laboratory (and supported by CARB's Research Division) showed that in order to reach California's 2050 GHG goal, the state would need to achieve greater than 40% renewable generation by 2020, or 51% by 2030.21 Rather than a singular focus on California's 33% RPS, the CAISO should consider the policy-driven impacts of the much higher levels of renewable generation required to achieve California's GHG goals. A recent E3 report, "Investigating a Higher Renewable Portfolio Standard in California," ("E3 Report") highlights the problems with focusing on individual costs of each resource, rather than looking at the portfolio as a whole.22 Those impacts will be mitigated by considering a more diverse set of renewable portfolios than the ones used by the CAISO in the Draft Plan. Those portfolios must include out-of-state wind, including resources such as Pathfinder's Wyoming projects, to ensure renewable integration at least cost. As Order 1000 emphasizes, "evaluating proposed alternative solutions at the regional level may resolve the region's needs more efficiently or cost effectively."23 Ignoring California's GHG goals and the benefits that can be provided by out-of-state resources in reaching California's GHG goals will not only inhibit the State's ability to reach those goals, it will significantly increase the ultimate costs to ratepayers of complying with those policies.	
6d	*B. The CAISO Must Consider a Broader Range of Renewable and Low Carbon Portfolios.* The limitations of the narrow set of portfolios provided by the CPUC are illustrated by two reports that highlight the need to account for a broader range of portfolios. First, the E3 Report cited above, notes that one of the largest integration challenges would be over generation, consistent with concerns that	The ISO transmission plan is coordinated with the ISO's over generation and integration study work. Please see responses above regarding a broader range of scenarios.

No	Comment Submitted	ISO Response
	that the CAISO has raised through its ubiquitous "duck curve." The study explored various methods of addressing that projected over generation, including studying the effects of various RPS resource portfolios. The study considered four RPS portfolios under a 50% RPS: portfolios emphasizing large solar, small solar, rooftop solar, and a diverse resource portfolio. Integration costs were lowest under the diverse resource portfolio (including 4,985 GWh of out-of-state wind), even though the transmission costs associated with that portfolio were higher than for the other three portfolios.24 The study emphasizes the need for enhanced regional coordination to allow for access to out-of-state renewable resources that can reduce integration costs and provide lower rate impacts than overreliance on in-state solar resources. Second, the University of Wyoming's Wind Research Center released a report in January 2013, entitled "Diversity Enhancement of Wyoming/California Wind Energy Projects." That study found that combining Wyoming and California wind resources reduced the variability of power production from one-third to one-half when two California wind projects were combined with two Wyoming projects.25 Both reports provide strong support for the view that the CAISO needs to consider a broader range of renewable portfolios, especially portfolios that include a diverse mix of resources, such as Wyoming wind supplied by the Zephyr Project. Failure to do so will only increase integration costs and ratepayer impacts. Though the CPUC and CEC, pursuant to the May 2010 MOU, assist the CAISO by preparing renewable generation portfolios in the LTPP, the CAISO is not obligated to rely solely on those portfolios in the TPP. Indeed, as Zephyr and Pathfinder have noted in the past, FERC Order No. 890 requires the CAISO to provide its own transparent stakeholder process that ensures that the appropriate study assumptions and scenarios are used in the TPP.	
6e	*C. The CAISO Should Adopt Policies That Support Contingency Transmission Planning.* The CAISO should have the ability to allow an entity to permit high value transmission projects and recover the costs of doing so through transmission rates. In fact, this is exactly what occurred in the past under the vertically integrated model. A utility would determine that value exists in having multiple alternatives available in the future by permitting routes that were determined to be of high value. The cost of this was then passed	This concept has been explored in the past, and most recently in the development of the revised transmission planning process that was approved by FERC in 2010. While the concept holds interest, solutions to key implementation issues have not been found in the past. In particular, procuring a right of way for a facility without knowing the complete engineering details (or even the ultimate owner of the facility) due to uncertainty of future requirements can be particularly challenging. Also, it is not

No	Comment Submitted	ISO Response
	through rates. One specific example of how valuable these options can be is the Path 15 Upgrade, which relied on a route that had been permitted by Western in the 1980's and allowed for the project to be operational within three years of conception at a significantly reduced cost.	clear how this would align with the ISO's competitive solicitation process or the fact that a particular utility may already own rights-of-way for the route.
6f	*D. The TPP Should Address the Benefits of Projects Such as the Zephyr Project.* The Zephyr Project is an HVDC transmission line which will run from southeast Wyoming and interconnect to the CAISO balancing authority area at the Eldorado substation. It will deliver wind generation being developed in southeast Wyoming by Pathfinder Renewable Wind Energy, LLC to communities in the Southwestern United States. In the previous and current 2013-2014 TPP cycle, the CAISO declined to study the Zephyr Project.26 DATC understands that the CAISO will not recommend for approval transmission needed to support generation that the CPUC currently assumes will not be built. However, failure to complete at least some planning for such potential future scenarios will result in an incomplete plan and could be very costly to California ratepayers. In light of this history, DATC continues to have serious concerns about the development of the RPS portfolios at the CPUC and the CAISO's determination to rely exclusively on those portfolios in developing its transmission plans, including the Draft 2013-2014 Plan (See Discussion Section I(c) above). The RPS portfolios increasingly rely on significant solar generation, including distributed solar, to meet California's current 33% RPS. The E3 Report illustrates that there is a significant risk that overreliance on solar resources will exacerbate renewable integration costs and potentially lead to significant over generation.27 This is the same concern the CAISO has understandably emphasized for years through its publication of its "duck curve."28 As noted above, the CAISO needs to consider, either on its own or in conjunction with the CPUC's development of the RPS portfolios, a wider range of potential resources to meet California's RPS, including out of state wind that can ameliorate costs of renewable integration. In addition, as discussed above, the CAISO should consider higher levels of renewable penetration that will be necessary to the meet the State's greenhouse gas objectives. The Zephyr Project would satisfy both of these needs.	These concerns should be communicated during the annual development of the portfolios. The ISO has performed analysis in the past that remains relevant today, to inform policy and resource planning processes, and has not been made aware of circumstances necessitating refreshing that study work.
6g	*E. The 2013-2014 Draft Plan Should Include Expansion of the San Luis*	

No	Comment Submitted	ISO Response
	Transmission Project. DATC Path 15 provided comments on December 5, 2013 urging the CAISO to take advantage of the opportunity to support a 500 kV Alternative to Western's proposed 230 kV transmission line between Western's Tracy and San Luis Substations. The comments described the Western project, and noted that Western had initiated environmental review of both the 230 kV San Luis Transmission Project and a 500 kV alternative that would allow CAISO to address a weak link in the 500 kV backbone of the CAISO grid between Tracy-Tesla and Los Banos ("San Luis 500 kV Alternative"). The comments below provide a more detailed discussion of why the San Luis 500 kV Alternative can and should be designated a public policy-driven transmission solution. Specifically, CAISO should approve the additional capacity (approximately 1000 MW of transfer capability between Los Banos and Tracy) created by the San Luis 500 kV Alternative. *i. The San Luis 500 kV Alternative Qualifies as a Policy-Driven Transmission Solution.* The San Luis 500 kV Alternative is consistent with the CAISO's 2013-14 public policy objectives and provides significant public policy benefits under the criteria set forth in CAISO Tariff Section 2.4.6.6. The project offers an "efficient and cost effective" approach to supporting delivery of 33% (or more) renewable energy over all hours of the year. As established in the 2013-2014 Study Plan, a proposed transmission solution's ability to support the delivery of 33% renewable energy over the course of all hours of the year could lead to the project's designation as a policy-driven transmission element in the CAISO's 2013-2014 comprehensive Transmission Plan. The San Luis 500 kV Alternative clearly qualifies as a policy-driven transmission solution under this requirement. It will improve the transfer capability between Southern California and the Bay Area, and enable delivery of wind energy from the Tehachapi region and solar energy from projects in the San Joaquin Valley to serve load in the Bay Area. While the Study Plan specifically identifies meeting the state's 33% RPS over all hours of the year as the CAISO's primary public policy objective, it is important to recognize that the San Luis Transmission Project can help achieve other Public Policy goals, such as the AB 32 goals and the higher levels of renewable penetration that will be necessary to meet the state's	The ISO undertook in the 2012-2013 Transmission Planning Process assessment of the Central California area which identified the need for 230 kV transmission developments in the Fresno area. In addition congestion analysis was conducted as a part of the economic analysis indicating no significant congestion anticipated on Path 15. Within the 2013-2014 Draft Transmission Plan there was also no significant congestion identified on Path 15. The assessments take into consideration the CPUC's 33 per cent RPS portfolios which are submitted to the ISO for use in the TPP. The ISO will continue to assess the reliability, policy and economic needs associated with Path 15 in future planning cycles. As a part of the development of the 2014-2015 TPP Study Plan economic study requests can be submitted as a part of the stakeholder comments on the Study Plan.

No	Comment Submitted	ISO Response
	2050 GHG goal (see Discussion above under Section I(B)). This broader view of the state's policy needs should be taken into consideration in developing the 2013-2104 Transmission Plan (and subsequent transmission planning processes) and is specifically relevant when considering the benefits of including the San Luis 500 kV Alternative as a policy-driven project.	
6h	*ii. The San Luis 500 kV Alternative Is Efficiency and Cost Effectiveness Compared to Alternatives Constitute a Compelling Public Policy Consideration.* The process established in CAISO Tariff section 2.4.6.6 expressly requires consideration of both a policy-driven project's inherent efficiency and effectiveness and its cost as compared to "other transmission solutions".29 The consideration of efficiency and cost overwhelmingly favor identifying the San Luis 500 kV Alternative as a policy-driven transmission solution in the 2013- 2014 Transmission Plan. As described in previous DATC Path 15 comments, the opportunity to "right size" the San Luis Transmission Project to 500 kV now provides a unique one-time opportunity to avoid significant foreseeable costs in the future, and to develop transmission capacity in the Tracy/Tesla – Los Banos corridor more effectively and efficiently than would otherwise be the case. Even leaving other benefits aside, the efficiency and cost effectiveness considerations alone strongly support identifying the San Luis 500 kV Alternative as a policy-driven transmission solution. Siting and permitting new and upgraded transmission is complex, time-consuming and costly. Thus, any efficiencies, cost savings and avoided environmental impacts that can be achieved by sizing transmission to meet foreseeable future system requirements is a clear benefit to California ratepayers. This is reflected in both federal and California state policies mandating the efficient use and planning of transmission in existing transmission Rights of Way ("ROW"). For example, The Bureau of Land Management's Corridor Policy states that "in order to minimize adverse environmental impacts and proliferation of separate ROWs, the utilization of rights-of-way in common (corridors) shall be required to the extent practical . . ."30 Similarly, in adopting Senate Bill 1059, the California legislature found that "to promote the efficient use of	Please refer to the response to 6g).

No	Comment Submitted	ISO Response
	the existing transmission system, the state should …: (1) *encourage the use of existing rights of way*, the expansion of existing rights of way, and the creation of new rights of way in that order [and] (2) promote the efficient use of new rights-of-way when needed, to improve system efficiency and the environmental performance of the transmission system."31 Further, California Public Utilities Code Section 399.26(b)(1) requires the CAISO to "work cooperatively to integrate and interconnect eligible renewable energy resources to the transmission grid *by the most efficient means possible with the goal of minimizing the impact and cost of new transmission needed* to meet both reliability needs and the renewables portfolio standard procurement requirements." (emphasis added) Federal, state, and local policies dictating the efficient and effective use of rights of way necessitate that the CAISO consider and evaluate and the San Luis 500 kV Alternative. By authorizing the San Luis 500 kV Alternative now, the CAISO will avoid the more inefficient and costly alternative of building iterative upgrades over time to improve the transfer capability between Southern California and the Bay Area. Easements for a 500 kV project will be far easier to acquire in one attempt and in the context of a project that has strong federal support. Construction of a 500 kV project in existing rights-of-way will minimize environmental and land use issues. "Right-sizing" the project will avoid all of the predictable (and unpredictable) impacts and costs of upgrades and replacement of transmission facilities in the near future. From an efficiency standpoint, the 500 kV Alternative is justifiable under the CAISO's mandates and consistent with state and federal policies favoring optimal use of existing ROW, along with long-term planning to avoid unnecessary cost and environmental impacts. Plainly, the CAISO should look at efficiency and cost in the context of long-term planning and with a realistic assessment of the alternatives. This project offers an unusual opportunity to avoid inefficiencies and future costs by providing transmission capacity that clearly is consistent with the future needs of the system.	
6i	*iii. The San Luis 500 kV Alternative Will Contribute to Meeting Resource Integration Needs and Priorities.* The state's ambitious RPS goals and the expansion of renewable resource development both within and outside of California require consideration of current and future resource integration requirements. This is reflected in CAISO	Please refer to the response to 6g).

No	Comment Submitted	ISO Response
	Tariff §2.4.6.6(g) and (h), which require the CAISO to consider "resource integration requirements and the costs associated with these requirements in particular resource areas designated pursuant to policy initiatives" and "the potential for a particular transmission solution to provide access to resources needed for integration…." The San Luis 500 kV Alternative will help the state meet forecast resource integration challenges by improving backbone 500 kV facilities used for conventional as well as renewable resources. This function will be particularly beneficial over the longer term as intermittent generation increases and integration needs become a system priority between the load centers in Southern and Northern California.	
6j	*iv. The San Luis 500 kV Alternative Offers a Unique Opportunity to Avoid Future Environmental Impacts* CAISO Tariff section 2.4.6.6(e) authorizes the CAISO to consider, in deciding whether a transmission solution offers public policy benefits: …the environmental evaluation, using best available public data, of the zones that the transmission is interconnecting as well as analysis of the environmental impacts of the transmission solutions themselves; The potential environmental benefits of the 500 kV Alternative as compared with forgoing the opportunity are significant. Construction of a "right-sized" 500 kV line on existing ROW will avoid the impacts created by first building a 230 kV line and later upgrading or replacing it. *v. The San Luis 500 kV Alternative Compliments the Results and Identified Priorities of the California Public Utilities Commission's and California Local Regulatory Authorities' Resource Planning Processes.* CAISO Tariff section 2.4.6.6(b) requires consideration of "the results and identified priorities of the California Public Utilities Commission's or California Local Regulatory Authorities' resource planning processes" in considering the need for and categorization of policy-driven transmission solutions. As discussed above, the CPUC and Local Regulatory Authorities have adopted resource planning priorities focused on meeting targets of 33 percent or more renewable generation by 2020. The CPUC has also committed to goals related to GHG reduction and to the Loading Order prioritization of preferred resources, including renewable resources, over	Please refer to the response to 6g).

No	Comment Submitted	ISO Response
	fossil-fuel resources. In doing so, the CPUC has emphasized that LTPP plans should focus on exceeding rather than simply meeting public policy targets: *[W]e will require that subsequent LTPP filings for our regulated utilities not only conform to the energy and environmental policies in place, but aim for even higher levels of performance. We expect the utilities to show a commitment to not only meet the targets set by the Legislature and this Commission but to try on their own integrate research and technology to strive to improve the environment, without compromising reliability or our obligation to ratepayers.32* Thus, while the Study Plan focuses on the 33 percent statutory RPS target, the CPUC's long-term procurement planning process is broader and more ambitious in its scope and mandate. In considering policy-driven transmission solutions, the CAISO may take these broader goals into consideration, along with the resource planning priorities of the Local Regulatory Authorities that regulate public-owned utilities in California.	
6k	*vi. The San Luis 500 kV Alternative Provides Insurance Value Against High Costs Imposed on Customers During Challenging Market Conditions.* In addition to the policy considerations cited above, the San Luis 500 kV Alternative provides significant economic benefits that deserve careful consideration. First and foremost, increased transfer capability provided by the San Luis 500 kV Alternative will help to mitigate the cost impact of a low hydro year by allowing for more generators in southern California to serve load in northern California. Additionally, providing another facility will mitigate the cost of generation and transmission outages, which can be significant. For all of the above reasons, the San Luis 500 kV alternative meets the CAISO's tariff requirements and should be included in the Plan as a policy-driven project.	Please refer to the response to 6g).
6l	CONCLUSION DATC submits these comments in order to help the CAISO focus its planning efforts on high value opportunities in the TPP. In general, the CAISO should account for the fact that the actual mix of future generation scenarios is uncertain and the economic and environmental cost of planning for too much transmission is far less than the cost of planning for not enough transmission. Prudent transmission planning should err on the side of flexibility and include hedges against generation and load uncertainty rather than creating risks for the State's economy and environment by minimizing the planned-for transmission. The Draft 2013-2014 TPP does not account for these planning principles and as a result, it	The ISO appreciates the concern, and will continue to study reasonable ranges of scenarios in future cycles. Your input into the coordinated processes, and in particular the development of generation portfolios, is encouraged.

No	Comment Submitted	ISO Response
	puts California ratepayers at risk by planning for the minimum transmission necessary to meet a too narrow range of scenarios and policy objectives. In order to incorporate these planning principles into the TPP, the CAISO should recognize a broader set of public policy goals and address a broader set of generation scenarios. The CAISO should also address the need for both the Zephyr Project and the 500 kV Alternative to the San Luis Transmission Project. DATC appreciates the opportunity to participate in the transmission planning process and provide these comments.	

No	Comment Submitted	ISO Response
7	Duke-American Transmission Company and Hunt Power Submitted by: William A. Hazelip and Bill Bojorquez	
7a	DATC and Hunt commend the CAISO for their evaluation of transmission projects that have the potential to lower costs for CAISO customers, including NGIV2. We appreciate the opportunity to provide comments on the CAISO's draft transmission plan for the 2013/2014 transmission planning process. We believe improvements to Path 46 and the integration of new transmission from Arizona into Southern California are critically needed. We appreciate all of the work CAISO has done to study projects that have the potential to increase the economic efficiency of the transmission system and improve reliability. The Delaney to Colorado River project is one such project that has been shown to provide significant benefits. In addition, the draft CAISO plan notes the results of the economic studies that show the significant economic benefits of NGIV2. We agree that the economic benefits are significant and that the project deserves continued careful consideration in the next planning cycle. Given the reliability challenges in the San Diego Gas & Electric region due to transmission constraints, the shutdown of SONGS and the Once Through Cooling retirements, DATC and Hunt believe NGIV2 would not only provide societal benefits to CAISO, but is also an effective solution to reliability issues in SDG&E. Further, we believe that the CAISO should specifically study the potential for NGIV2 to create Resource Adequacy and Local Capacity Resource benefits when combined with the Group 1 projects recommended for approval in the draft plan. In addition to the Group 1 projects, we recommend that the CAISO evaluate the potential capacity benefits of NGIV2 in combination with potential Group 2 and Group 3 projects. We understand that downstream bottlenecks limit the value of the NGIV2 project, however, we believe that the downstream bottlenecks could be reduced or eliminated by means of additional transmission additions that can be combined with the NGIV2 project. To the extent not considered as part of the Group 1, Group 2, or Group 3 projects discussed above, SVCs, synchronous condensers or other devices could be added near the San Diego area. In addition to the benefits of increased flows from North Gila and economic benefits already demonstrated, other reliability advantages from such devices would include increased voltage stability for multiple contingencies, increased dynamic stability, and added Path 46 capacity.	The ISO expects that this path will be brought forward for consideration in an economic study in the 2014-2015 transmission planning process and we look forward to your participation in the 2014-2015 transmission planning process.

No	Comment Submitted	ISO Response
8	Duke Energy Submitted by: Seth D. Hilton and Stoel Rives	
8a	II. The CAISO Must Improve Its Processes for Evaluating Energy Storage Duke appreciates the efforts of the CAISO to provide a process that would increase opportunities for non-conventional or preferred resources, including energy storage resources, to meet local area needs in lieu of new transmission and conventional generation. Duke participated in the stakeholder process, which began with the September 4, 2013 white paper entitled "Consideration of alternatives to transmission or conventional generation to address local needs in the Transmission Planning Process" ("White Paper"), and participated in the September 18, 2013 stakeholder teleconference. One of the advantages of energy storage is its ability to perform multiple functions. This very advantage, however, can make it difficult to carve out a place for energy storage in the traditional regulatory structure. As the Federal Energy Regulatory Commission ("FERC") has noted, "storage devices do not fit neatly into a traditional category of assets, be it transmission, generation, or distribution, given their ability to perform multiple functions." (*Western Grid Development, LLC*, 130 FERC ¶ 61,056, at ¶ 47 (2010).) Storage can be either a transmission facility or a non-transmission alternative, functioning similar to both generation and load. Under the CAISO tariff, energy storage can be treated as either. (*See* October 11, 2012 FERC Order 1000 Compliance Filing, Docket No. ER13-103-000, at 81.) However, choosing one or the other can curtail the uses to which the storage device can be put. (*See Western Grid Development, LLC*, 130 FERC ¶61,056 at ¶¶ 49-51.) One of the challenges in fully utilizing energy storage will be to develop a regulatory structure, and more particularly, a transmission planning process("TPP"), that will allow the CAISO, and participating transmission owners, to both recognize and utilize the benefits that energy storage can provide. Pursuant to the CAISO's TPP, energy storage projects have been submitted in the Phase II request window for consideration as transmission solutions in both the 2010 and 2011 TPP. (October 11, 2012 FERC 1000 Compliance Filing, Docket No. ER12-103-000 at 81 n.210.) However, none were approved. In 2010, Western Grid Development, LLC submitted a total of eight projects. All eight were eventually rejected. Seven were rejected as unnecessary in the 2010	The ISO agrees that storage can either be considered a transmission asset or a market resource, and expects that the market resource alternative enables the broadest possible value proposition through the full range of services they can provide. As set out by FERC, however, storage that has developed as a transmission asset is limited in the other market services it can provide, which necessitates a narrow view of the benefits when these products are compared as ratepayer funded transmission assets to other alternatives. Given our past experience in assessing proposals, we are more optimistic that storage can play a much larger role and be more successful as a market resource (that includes being able to provide resource adequacy service.) We are looking to take additional measures to increase the success of storage, and will provide additional clarification in the final draft transmission plan. Notwithstanding the ISO's keen interest in seeing storage develop together with

No	Comment Submitted	ISO Response
	Transmission Plan. Evaluation of the eighth, Auburn 60 kV Energy Storage Project, was deferred until 2011, and then was rejected in the 2011/2012 Transmission Plan. Last year, the CAISO begin developing a process to consider non-conventional alternatives that could be selected as the preferred solution in the CAISO's TPP. These alternatives were to be considered as non-transmission solutions that could defer or eliminate the need for conventional generation or new transmission. As part of that process, the CAISO published the White Paper on September 4, 2013, and used a modified version of the process outlined in the White Paper in this TPP. As explained in the Draft Plan, the CAISO evaluated a number of scenarios using non-conventional alternatives, including energy storage with durations of four hours and two hours, and determined that 580 MW of storage with a duration of four hours, along with other resources, "appear[ed] to be feasible in mitigating the most critical contingency." (Draft Plan at 100.) A number of local transmission reinforcements were deferred in the San Diego area as a result of this analysis. (Draft Plan at 8.) However, as discussed further below, the CAISO intends to take only a "wait and see" approach to see whether such storage resources develop, and may in the end pursue the transmission solution if the alternative resources fail to materialize. While Duke appreciates the efforts that the CAISO has made to consider energy storage as potential transmission and non-transmission solutions, much more needs to be done to ensure that energy storage becomes a viable alternative to more conventional solutions. Taking full advantage of these potential resources requires careful coordination between the CAISO and stakeholders, and between various regulatory agencies that are involved. It also requires a transparent process that allows stakeholders, especially energy storage developers with intimate knowledge of the capabilities of various storage technologies, to work with the CAISO to ensure that energy storage has an opportunity to participate in the TPP, to be appropriately evaluated, and to eventually be constructed and utilized in lieu of conventional alternatives. In the 2013-2014 TPP, the CAISO did not provide the White Paper until it was well within Phase 2 of the process, and shortly before the Phase 2 request window closed. As noted in the White Paper, the CAISO's new approach to non-conventional resources was designed to avoid case-by-case evaluation of	preferred resources, storage must provide the necessary characteristics to be an effective alternative on a locational basis, just like other non-conventional resources,. The ISO has studied a number of proposals in this transmission planning cycle and previous cycles where the proposed characteristics did not meet the local area needs. These were normally due to the storage device not being able to sustain the necessary output level for a sufficient period of time, although some proposals have been limited by insufficient local capacity to recharge the storage. However, the ISO was able to confirm that at least one pumped storage proposal would meet the needs of conventional resources in this cycle. (For clarification, the comment refers to the deferral of a number of transmission projects in the San Diego area due to anticipated benefits – those deferrals were due to energy efficiency, demand response, and distributed generation programs, not storage, as discussed in more detail in Appendix B of the draft transmission plan on page B-130.) We do not understand the reference to a "wait and see" approach. The ISO is anticipating storage to be considered in the various CPUC processes that enable access to the broadest range of value, coordinates with the state agencies including the CPUC in planning assumptions, and also actively participates in CPUC proceedings in providing assessments of the needs resources are called upon to meet. The purpose of proposing to develop generic resources was to help verify the validity of potential resources that could be considered in various combinations to meeting local area specific needs. It is not a certainty that all generic resources would in fact be

No	Comment Submitted	ISO Response
	specific proposals, and instead identify needed performance characteristics in advance to allow suppliers of non-conventional resources to assess whether their resources could provide the needed performance. (White Paper at 8.) The first step of that process, as proposed in the White Paper, was to develop a generic resource catalog that would allow CAISO to test what mix of generic resources might provide the performance characteristics needed for a particular local area. (White Paper at 10.) However, for the 2013-2014 TPP, the generic resource catalog was developed without any input from stakeholders. Though the White Paper suggested that the generic resource catalog would be updated in Phase 1 of any given TPP cycle to reflect new information or new resource types that might become available (White Paper at 10), such a process was not provided in this 2013-2014 TPP. It is essential that the CAISO create a stakeholder process that allows stakeholders to fully vet thegeneric resource catalog to ensure that it fully captures the appropriate performance characteristics. That process should allow stakeholders and the CAISO to jointly develop a final generic resource catalog that would be included in the final Study Plan.	useful in assisting in any given area's specific local needs – in fact we would only expect certain resources to be useful in certain circumstances, but the identification of generic resources in advance would streamline the screening process. However, the local requirements needed to be considered – it appears from the comments that Duke Energy's interpretation was that a resource that met one of the generic category's characteristics would be attributed a value whether it was helpful in meeting a particular local area need or not.
	The White Paper also contemplates that, "[o]nce a preliminary catalog of generic resources is developed, the second component of this methodology is to carry out a process of selecting, refining, and validating a potential mix of resources that could best provide the performance characteristics needed for a particular local area." (White Paper at 10.) The White Paper contemplates that this step would be carried out during Phase 2. The White Paper also contemplates that stakeholders would have input in the selection of the potential resource mix, prior to the CAISO's analysis to validate that selected mix of resources would meet identified reliability needs. In the 2013-2014 TPP, no such opportunity was provided to stakeholders, and the CAISO only evaluated a set of scenarios provided by Southern California Edison. While Duke understands that the timeline associated with implementing the new procedure may have inhibited the CAISO's ability to allow such input, it is important that such opportunities be provided in future TPPs.	These comments should be submitted into the 2014-2015 study plan consultation process.
	In both instances, creating opportunities for dialogue between stakeholders, especially resource developers, and the CAISO is critical to the success of any process to allow consideration of non-conventional solutions. Resource developers need opportunities to convey the capabilities of their resources to the	

No	Comment Submitted	ISO Response
	CAISO, while the CAISO needs to convey sufficient information regarding reliability needs that developers can create the solutions for those needs. The same holds true for energy storage utilized as a transmission solutions. CAISO should also consider whether the current TPP process allows energy storage proposed as transmission assets to fully compete with more traditional transmission assets, and whether further refinements to the TPP would be appropriate to allow energy storage to be a viable alternative to traditional transmission assets.	
	Finally, the White Paper, although it creates a process for the participation of non-conventional resources, contemplates that such resources would only be considered "in situations where the timeline for an identified need allows time for monitoring the development of non-conventional alternatives *before* a conventional solution would be required to be approved." (White Paper at 3 (emphasis added).) As explained in the White Paper, the CAISO would monitor the development of the non-conventional solution to determine whether it would be in place by the time needed, and if the CAISO determined the non-conventional resource is not developing in a timely manner, it would reinstate the conventional (i.e., transmission or generation) solution. Furthermore, the CAISO would not play a part in the development of the non-conventional solution. "To the extent an identified non-transmission solution constitutes the most prudent and cost-effective solution for meeting a need, the CAISO will simply decline to approve a transmission solution. The CAISO does not approve specific non-transmission solutions, nor does it have the tariff authority to do so." (October 11, 2012 FERC Order 1000 Compliance Filing, Docket No. 13-103-000 at 81-82.)	The ISO has focused its current efforts on the specific circumstances of the LA Basin and San Diego areas as the biggest opportunity for preferred resources and storage to make a material contribution to local area needs. Due to the unique circumstances in those areas, and the active participation of utilities in seeking to acquire preferred resources and storage, the ISO's approach has been modified from the original broadly-targeted white paper approach to focusing on the specific needs of the area.
	The timeline contemplated the CAISO is problematic. Transmission solutions take considerable time to permit and construct, far longer than many types of energy storage. Requiring the development of energy storage before a transmission solution would be required to be approved means that energy storage solutions would have to be developed well before they are actually required to meet reliability needs. While Duke understands that the CAISO does not have the tariff authority to approve specific non-transmission solutions, the CAISO should work in conjunction with the California Public Utilities Commission ("CPUC") to create a process whereby any non-conventional solution could be pursued through the long-term procurement proceeding ("LTPP") or other CPUC	We do not understand the comment. The CPUC's processes do allow for the approval of non-conventional resources. However, in the event these resources are not procured, or are not producing the anticipated benefits, alternatives would have to be pursued to ensure reliability is maintained. The ISO is committed to working with the state agencies so that progress is made in tracking development of preferred resources and storage, and that the necessary comfort with forecasts of future preferred resource development is reached.

No	Comment Submitted	ISO Response
	procurement mechanisms. By coordinating with the CPUC to create a process whereby non-conventional solutions can be selected and developed, the CAISO and the CPUC will increase the likelihood that such solutions are actually implemented. Duke appreciates the efforts of the CAISO and the CPUC to coordinate the LTPP and the TPP. However, such coordination should be expanded to consider specifically how non-conventional solutions selected by the CAISO can be further pursued through the LTPP. III. Conclusion While Duke appreciates the efforts that the CAISO has made thus far to appropriately consider and evaluate energy storage, there is significant work remains to be done to ensure that energy storage becomes a viable part of the solution, along with traditional generation and transmission. Duke urges the CAISO to consider the above recommendations as it finalizes the 2013-2014 draft Transmission Plan, and begins the 2014-2015 TPP.	

No	Comment Submitted	ISO Response
9	EnerNOC, Inc. Submitted by: Melanie Gillette	
9a	EnerNOC appreciates the opportunity to provide these comments on the February 3, 2014 *Draft 2013-2014 Transmission Plan* (Transmission Plan). We commend the California Independent System Operator (CAISO) for proposing a methodology to support California's policy emphasis on the use of preferred resources—specifically demand response and energy efficiency, which are at the top of the state's loading order. EnerNOC supports CAISO's consideration of how such resources can provide "non-conventional" solutions to meet local area needs that would otherwise require new transmission or conventional generation is commendable.[3] It is critical to incorporate these preferred resources into the planning assumptions to meet local reliability needs in order to appropriately represent the current and future potential of these resources. EnerNOC understands that the methodology applied in the 2013-2014 transmission planning cycle is a new approach due to unique circumstances in the LA Basin and San Diego and that a more generic application of this methodology will be applied in future transmission planning process cycles. We will be participating in the 2014-2015 Transmission Planning process just getting underway to support the inclusion of demand side resources in the assumptions and scenarios. EnerNOC's overarching concern is that the planning assumptions and scenarios being used by the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and CAISO do not adequately represent the demand potential. For example, they fail to incorporate any growth over current levels of demand response; do not include modifications to the load forecast to reflect increasing customer exposure to time-variant rates; do not include any demand response resources for local reliability purposes; and fail to define the attributes that would allow preferred resources to be included for local reliability going forward. In Track 1 (Local Reliability) Decision of the 2012 Long Term Procurement Proceeding (LTPP), the CPUC provided explicit direction to Southern California	We look forward to your participation in the future transmission planning cycle as well as the state agency processes that the transmission planning cycle coordinates with and relies upon for input assumptions. Comments on demand-side impacts, in particular, should be expressed to the CEC who develops the load forecasting information relied upon by the ISO and other state agencies. Supply side comments are best provided to the CPUC and ISO. The ISO expects that the analysis of preferred resources in the 2014-2015 planning cycle will continue to evolve and improve based on feedback and the results of the 2013-2014 analysis. Referring to the earlier response to the comments of the California Large Energy Consumers Association, the ISO notes that up to 900 MW of 4 hour demand response was studied in the SCE area which is concentrated in the Orange County and North LA area.

[3] *Consideration of alternative to transmission or conventional generation to address local needs in the transmission planning process,"* September 4, 2013, p.3.

No	Comment Submitted	ISO Response
	Edison Company (SCE) regarding the amount and type of procurement they were authorized to pursue, with as much as 800 MW of the maximum 1,800 MW procurement authorization to come from preferred resources.[4] This direction on preferred resource procurement has been confirmed in the CPUC's new Demand Response Rulemaking, with the stated goal to "increase the penetration of demand response programs,"[5] as well as the CEC's 2013 Integrated Energy Policy Report (IEPR), which recommends "taking full advantage of the contribution of low-carbon renewable generation."[6] All of this was captured in the Preliminary Reliability Plan for LA Basin and San Diego, prepared by Staff of the CPUC, CEC, and CAISO on August 30, 2013, in relation to the permanent retirement of the San Onofre Nuclear Generating Station (SONGS), which identifies its first key action to be development of 3,250 MW of preferred resources to meet 50 percent of the identified resource needs resulting from the SONGS closure.[7] Demand response is one of the preferred resources being promoted in the state's policy context; however, it is being virtually ignored for planning purposes. This apparent lack of coordination among the agencies and their staffs conducting the studies is leading to an untenable situation. Parties, including EnerNOC, have to devote significant time and resources to continually advocate for the inclusion of preferred resources into planning scenarios, when they should be included automatically, consistent with state policy. We include this background to support our position that the scenario analysis must accurately reflect the demand potential. EnerNOC strongly encourages the use of scenario analysis for supply-side and for non-dispatchable demand response in the load forecast. It is unreasonable to continue to rely on a forecast that assumes *no* growth in supply-side demand response over the planning period. It is also unreasonable to fail to consider demand resources for local capacity. Several supply-side demand response resources, including	

[4] D.13-02-015 , at pp. 10-11.
[5] R.13.09-011, Order Instituting Rulemaking (September 25, 2013), at p. 15.
[6] CEC 2013 IEPR, at p. 40
[7] Preliminary Reliability Plan, at p. 2.

No	Comment Submitted	ISO Response
	Aggregator-Managed Contracts, the Capacity Bidding Program, the Demand Bidding Program, and the Base Interruptible Program, are dispatchable by either local capacity area or sub-load aggregation point. However, this capability does not appear to be captured in the Transmission Plan's scenarios. Of the 2000 MW of demand response in California, a modest 200 MW is assumed to be in the LA Basin.[8] However, CAISO does not include any demand response for local reliability. It is unclear what rationale CAISO is using for excluding demand response from the local reliability scenarios in the Transmission Plan. However, there is reference in the "Demand Response" section of the Plan to a requirement that demand response resources must be fast response curtailment (20 minutes) in addition to meeting the resource adequacy requirement for four hour duration.[9] Presumably this requirement is related to CAISO's need to stabilize the system within 30 minutes after a contingency event. CAISO interprets that requirement to suggest that demand response resources would need to be dispatched in advance of that 30 minute timeframe. To our knowledge this is not a requirement in other markets, however. The reality is that with 30 minute notification of an event, customers do start to drop load, so there is some amount of load drop that would definitely occur within the 20 minute window. However, resources that come on line within the 20-30 minute window still have some value for restoring the system, especially considering that most generation in a local capacity area cannot respond to a 30 minute dispatch signal and yet still counts toward meeting local reliability. The value for the 30 minute demand response is certainly not zero! The Transmission Plan also includes several scenario data tables, but it is unclear what the performance characteristics are for each of the resources. While the September 4 white paper describing the proposed new methodology for including preferred resources listed a number of characteristics, such as response time, availability and duration,[10] the Transmission Plan only appears	For clarity, mandatory planning and operating standards call in certain circumstances for the system to be repositioned after a contingency to be properly positioned for the next contingency within 30 minutes from the initial contingency. As time is also required for dispatch instructions, the entire 30 minutes is not available for solely the load response. Where those circumstances apply, compliance is not optional or discretionary, and resources responding after the total 30 minute elapsed time do not help in meeting these mandatory standards. Other stakeholders have also suggested that this is inconsistent with the treatment of conventional dispatchable generation, which cannot be started and reach the required output level within 30 minutes. The fundamental difference is that non-use limited resources can be dispatched at the necessary levels (or within the range that they can respond to within 30 minutes) prior to the first contingency occurring. Demand response programs that could be called upon with this higher frequency (every time the local area load reaches into the range that action would be required following a first contingency whether the contingency occurs or not) could also meet that need. The ISO will look forward to input in the next planning cycles as to the possibility of demand response programs that can offer this more frequent dispatch service.

[8] 2012-2013 LTPP Track 1 Decision.
[9] Draft 2013-2014 Transmission Plan, at p. 92.
[10] *Consideration of alternative to transmission or conventional generation to address local needs in the transmission planning process,"* September 4, 2013, pp. 8-10.

No	Comment Submitted	ISO Response
	to include duration in the LA Basin Preferred Resource Scenario Data.[11] EnerNOC recommends that the catalog of local preferred resources, which is the first step in the September 4 proposal, includes the essential performance characteristics of each resource. It would be helpful to have a better understanding of how this September 4 proposal fits into the next iteration of transmission plans, as it has not been explored through the working group process or the CPUC process, to EnerNOC's knowledge. Therefore, this proposal that is the foundation for the 2013-2014 studies plans, has not been adopted and is conceptual at this point. EnerNOC appreciates the opportunity to provide these comments and respectfully requests CAISO's consideration.	

[11] Draft 2013-2014 Transmission Plan, Table 2.6-4: Summary of Non-Conventional Alternative Assessment

No	Comment Submitted	ISO Response
10	LS Power Development, LLC Submitted by: Sandeep Arora and Lawrence Willick	
10a	CAISO's economic study CAISO's economic study for the HAE project, done as part of 2013/14 Transmission Plan, shows significant economic benefits from building a new 500 kV transmission line from Harry Allen to Eldorado substations. At $240 mm, the economic benefits of this project far outweigh the capital cost (and annual revenue requirement). CAISO's study shows that HAE project provides reduction in LMPs for all CAISO Load Serving Entities. This reduction in LMPs provides economic savings to all CAISO ratepayers. CAISO Management however mentioned the need to complete additional economic studies to factor in the proposed implementation of CAISO/NVE Energy Imbalance Market (EIM), but only for the HAE project. While LS Power understands the need to analyze impacts of CAISO-NVE EIM market, but does not understand why this analysis is only required for the HAE project. As CAISO is well aware, the East of River and West of River paths inextricably tie the Arizona, Nevada and California markets together in the South West US. If EIM is implemented between any two of the three markets, it could have an impact on value of new transmission being built between any two of the three markets. Any such impact should be analyzed on a more global basis rather than being performed more locally for a single project. LS Power had expected that CAISO would start this additional economic analysis shortly after the announcement of NVE's interest in joining the EIM in Nov 2013, and that this would be completed prior to CAISO releasing the draft 2013/14 Transmission Plan. Nevertheless, we urge CAISO to complete this analysis as soon as possible.	Previous ISO analysis has indicated that the two projects (Harry Allen-Eldorado and Delaney-Colorado River) provided benefits that were not competing, and therefore the ISO has been able to move forward addressing each project independently. The inclusion of NVE in the Energy Imbalance Market is clearly material to the Harry Allen-Eldorado project and as there could be improvements or reductions to the benefits through NVE joining the EIM, it is only reasonable to reassess those benefits before a recommendation can be finalized. There is a reasonable possibility that some of the benefits the Harry Allen-Eldorado line identified in the ISO's current studies can be achieved through NVE joining the Energy Imbalance Market. Therefore, it is necessary to restudy the Harry Allen-Eldorado line in light of NVE's intended participation in EIM. Given the structure and timing of the tariff-established planning process and timing of consultation windows within the process, it was not feasible to undertake major modeling changes in the final stages of the study process. The ISO intends to conduct this analysis as part of this 2013-2014 transmission planning cycle and may bring forward a recommendation to the Board later this year. If necessary, the ISO will carry the analysis forward into the 2014-2015 planning cycle.
10b	Additional HAE project benefits exist: some not quantified, others under-estimated CAISO staff performed an economic study and quantified the production cost savings and capacity benefits from HAE project. Several additional benefits from the project exist, which have not been quantified. We urge CAISO Management to take these into consideration prior to concluding on this project. • Reliability benefits from HAE line not quantified:	The Harry Allen-Eldorado line is being considered firstly as a potential economically driven project, and other benefits will factor into the overall decision. The issues raised will be reviewed in the updated studies, and we look forward to your comments in the next level of analysis. These do not obviate the need for addressing the material change in circumstance necessitating updating our studies, however.

No	Comment Submitted	ISO Response
	Per CAISO's 2013/14 Draft Transmission Plan, HAE project relieves several overloads caused by the contingencies in Southern California, such as the loss of Imperial Valley – ECO - Miguel & Suncrest – Sycamore lines. CAISO states that "…*The WECC path rating for WOR has been established as 11,200 MW under certain operating conditions. However, under summer peak operating conditions the transfer capability of this path is limited to a level that is below the WECC path rating due to contingency overloads on the Suncrest-Sycamore 230 kV lines and the Imperial Valley – ECO-Miguel 500 kV lines. These overloads are caused by imports from Arizona, Nevada, and IID and existing and new generation dispatch in southwestern California. Adding the Harry Allen – Eldorado 500 kV line to the system incrementally relieves these overloads and creates approximately 150 MW of incremental import capability…"* While the economic benefit of additional 150 MW of import capability has been quantified, the incremental "reliability" benefit that HAE project brings is not quantified. There are potentially several other critical contingencies (especially ones leading to loss of major 500 kV import lines into CAISO BAA) that HAE project helps relieve either thermal overloads or voltage instability, but these benefits are not captured. A new major 500 kV transmission line connecting CAISO BAA to NVE BAA significantly improves overall system reliability, as studied by LS Power. Such new line should also help prevent regional blackout such as the one that took place in Southern California & Arizona in Sep 2011, "2011 Southwest blackout". This blackout was reported to have left over 2.7 million customers in dark for up to 12 hours in California & Arizona, and has been estimated to have costed between $97 & $118 million in economic losses. Over the 50-year lifespan for HAE line, if it can help prevent just one similar blackout, that will more than pay for the capital investment made on building this line now. • Flexible reserves/capacity benefits not quantified: CAISO has been stating for a long time that it needs Flexible Capacity/Ramping Capability to manage the intermittency being introduced into the CAISO grid from 33% RPS implementation. While it is generally acknowledged that a new import transmission line such as the HAE line will help provide more flexible capacity to CAISO in the forward markets and Flexible ramping capability in Real-Time markets, the benefits of unlocking access to this new capability have not been quantified. • Increase in import capability is underestimated:	

No	Comment Submitted	ISO Response
	CAISO has estimated that import capability increases by 150 MW from building HAE line. LS Power understands that this calculated increase is a very conservative estimate. The increase as calculated by CAISO is for a "summer peak 1-in-10 load" condition. CAISO grid is only expected to experience a 1-in-10 type condition for 1 day (for a few hours) in 10 years. For times other than this, more can be imported into CAISO BAA. CAISO has not accounted for any of these additional benefits. • Reduction in market power is not quantified: New HAE line helps reduce market power in Southern California. Market power has typically existed in Southern California portion of the CAISO grid and this is expected to increase in the future given that SONGS has been shutdown and thousands of MWs of Once Through Cooling (OTC) generators in Southern California are at the risk of shutting down in next few years. The new HAE line brings another source of power to serve Southern California load, hence effectively helping to reduce market power. This benefit has not been quantified. • Additional modelling enhancements should further increase benefits: LS Power understands that some additional modelling enhancements can be made in NV Energy area that will help account for more potential benefits from this line. One such modelling enhancement would be modelling Harry Allen as a trading hub (as recommended by NV Energy) rather than a regular bus. This should reduce the hurdle rate between CAISO & NV Energy potentially allowing for additional cheaper energy/capacity from NV Energy to access CAISO markets, thereby increasing the economic benefits of HAE line. • Loss reduction benefits have either not been quantified or are under-estimated: CAISO estimates a $1.0 mm per year loss benefit from a 110 mile long DCR line, but estimates no loss benefits from a much shorter 60 mile long HAE line. It is not clear whether no loss benefits mean CAISO's analysis on this is incomplete or that there are no benefits. HAE line (being a shorter line) should have at least the same loss reduction if not more than the DCR line, so one would expect the loss savings from the HAE project to be at least the same as the DCR project. CAISO should reevaluate this benefit for HAE line or explain why there is a disparity in results for the two projects.	

No	Comment Submitted	ISO Response
	• Sensitivity studies with low discount rate and lower Sycamore-Suncrest line rating have not been completed: CAISO performed these studies for the DCR project but not for the HAE project. CAISO estimated a 150 MW Import capability increase from the HAE project. It appears that this was calculated by using the higher rating for the Sycamore-Suncrest line. If the rating is lower (which is a possibility), the HAE project should improve the import capability more than 150 MW (similar sensitivity for the DCR project show 200 MW import capability increase by using higher rating and 300 MW by using lower rating). This additional analysis should be completed and these additional benefits quantified.	
10c	Conclusion LS Power requests that CAISO perform the remaining studies for the HAE project related to NVE's participation in the EIM on a priority basis prior to the March 2014 board meeting and request board approval of HAE project at that time, or complete such analysis with a recommendation to the board at the April 2014 board meeting. LS Power also requests that CAISO take into consideration the additional benefits of the HAE project stated above to the extent necessary to satisfy the economic criterion for approval.	As indicated at the ISO stakeholder meeting on February 27, 2014 on the 2014-2015 Transmission Planning Process Study Plan, the ISO will continue to undertake the study work on the Harry Allen-Eldorado 500 kV line economic analysis subsequent to approval of the 2013-2014 Transmission Plan by the ISO Board; however depending upon the timing of this analysis and its ultimate completion, it may be moved into the 2014-2015 Transmission Planning Process.

No	Comment Submitted	ISO Response
11	Imperial Irrigation District Submitted by: Tony Braun	
11a	The Imperial Irrigation District (IID) has appreciated the constructive and collaborative working relationship enjoyed between the California Independent System Operator Corporation (CAISO) and the IID that has led to, in a few short years and among other things, increased information exchange between our respective Balancing Authority Areas (BAA), a new Adjacent Balancing Authority Operating Agreement, selection of IID as a Project Sponsor for a policy-driven project to interconnect renewable resources in the Imperial Valley, dynamic transfer arrangements, qualification of the IID as its own Scheduling Coordinator and reformation of the methodology to calculate the Maximum Import Capability for Resource Adequacy counting purposes, specifically at Interties between the IID and the CAISO BAAs. It is on this latter issue that IID makes comment and seeks clarification as it relates to discussion in the 2013-14 Transmission Plan (TPP). Together, IID and the CAISO identified potential issues with the way the MIC was calculated between the IID BAA to the CAISO BAA. Through reformation of the Reliability BPM, and associated work with the California Public Utilities Commission (Commission) that culminated in the Assigned Commissioner Ruling (ACR) of Commissioner Ferron (July 7, 2011), the MIC from the IID BAA to the CAISO is targeted to be 1400 MW by 2020 consistent with resource development projections and assumptions of successful completion of certain transmission projects. The ACR specifically stated that it would be unreasonable to assume less than the 1400 MW of MIC in procurement calculations for CPUC jurisdictional Load Serving Entities. This MIC trajectory was confirmed in the latest advisory MIC calculations dated July, 2013, and referenced in the 2013-2014 Transmission Plan. All along, the IID has recognized that the 1400 MW MIC was contingent upon certain assumptions including the successful reconductoring of the West of Devers corridor, and subject to anticipatory concerns regarding West of River flows. The approved 2012-2013 TPP describes these issues, and the 2013-2014 TPP reiterates these interdependences. At page 139 of the Draft 2013-2014 TPP, it also introduces the issue of the early retirement of the San Onofre Nuclear Generating Station (SONGS). It is IID's understanding that the	The ISO is reviewing the feedback from IID and other stakeholders, and will revisit and clarify the situation in the revised draft transmission plan to the extent it can.

No	Comment Submitted	ISO Response
	introduction of early SONGS retirement, and the fact that the deliverability studies occur relatively late in the TPP cycle, lead to the conclusion that the CAISO believes that this issue requires further study in the 2014-2015 TPP cycle. Just yesterday, the ACR of Commissioner Picker requires study of an additional transmission interconnection from the Imperial Valley under an additional scenario transmitted for purposes of the 2014-21-015 TPP. Clearly, this issue is evolving. Nevertheless, how this issue is characterized is important to the commercial viability of the resources in the Imperial Valley that seek Purchase Power Agreements and may be in negotiations currently. Fundamentally, IID believes the CAISO is committed to honoring the MIC values through the TPP. While the SONGs closure is a major development, several projects that affect the future targeted MIC values for the IID/CAISO branch group are already being considered and proposed for approval. Therefore, no modifications to MIC values from IID to the CAISO have been finalized, and the advisory MIC values published in July 2013 are still valid. This should be more clearly stated in the final 2013-2014 TPP provided to the CAISO Board for possible approval in March. IID therefore requests that Table 3.2-3 included in previous transmission plan reports be inserted into the 2013-2014 transmission plan report and further makes the following proposed language changes to the Draft 2013-2014: the deliverability of future renewable generation from the Imperial Valley area ~~has been~~ may be significantly reduced primarily due to changes in flow patterns resulting from the retirement of the San Onofre Nuclear Generating Station. Despite the impacts being heavily offset by other reinforcements proposed in this transmission plan, only 1000 MW of the 1715 MW of Imperial zone renewable generation portfolio amounts can be made deliverable without additional actions. Given this significant change in circumstance, the ISO will conduct further study in the 2014-2015 transmission planning cycle to develop the	

No	Comment Submitted	ISO Response
	most effective solution to this issue to maintain previously established target MIC values. (Draft TPP at 2) However, the deliverability of future renewable generation from the Imperial Valley area ~~has been~~ may be significantly reduced primarily due to changes in flow patterns resulting from the retirement of the San Onofre Nuclear Generating Station. Despite the impacts being heavily offset by other reinforcements proposed in this transmission plan, only 1000 MW of the 1715 MW of Imperial zone renewable generation portfolio amounts can be made deliverable without additional actions. The change will also impact the ability to maintain deliverability of import capability from the Imperial Irrigation District at the intended level of 1400 MW. Given this significant change in circumstance, the ISO will conduct further study in the 2014-2015 transmission planning cycle to develop the most effective solution to this issue to maintain previously established target MIC values. (Draft TPP at 9) Moving forward, IID looks forward to working with the CAISO to harmonize MIC calculations with deliverability analysis not only at all Interties, but also in relevant portions of the CAISO BAA. Considerable renewable development is occurring at IID's BAA boundaries, directly connected to the CAISO BAA, but electrically similar to resources connecting to the IID. It would appear that these resources face similar deliverability questions, and resolution of this issue should treat this issue in a comprehensive and consistent manner.	

No	Comment Submitted	ISO Response
12	MidAmerica Transmission and Pinnacle West Capital Corporation Submitted by: Darrell Gerrard and Jason Smith	
12a	Capacity Benefits We support and agree with the CAISO recognizing the incremental RA import capacity calculated by PSLF power flow of 400 MW effectuated by the DCR transmission line presented in the November 20-21, 2013 stakeholder meeting. These capacity benefits indicated an overall Benefit to Cost Ratio of 1.3x. We understand the assigned 400 MW capacity benefit is derived using power flow analysis conducted with peak loads and peak transfers into the southern California system consistent with CAISO business practice. Based upon power flow analysis, we believe that the resource adequacy benefits at times exceed 400 MW under many different sets of plausible system loading conditions. The recent Draft 2013/2014 Transmission Plan included scenarios with 200 MW and 300 MW import capacity attributed to DCR, although we believe the capacity benefits for the project in many hours of the year can be even higher than the 400 MW presented in November 2013. In addition, the draft plan only includes the direct benefits of purchasing lower cost capacity in Arizona, and does not separately account for the indirect benefits of the DCR project creating additional lower-priced capacity in California due to increased competition between generators for service customer load in the marketplace. Combining the reduced scenarios on import capacity along with the exclusion of indirect benefits could lead to a conservative capacity valuation for the DCR project. The Benefit to Cost Ratios (B/C) for the project with the lower capacity benefits indicated values greater than 1.0 (1.04 B/C and 1.18 B/C for the 200 MW and 300 MW capacity scenarios respectively) in the stakeholder presentation. These scenarios further indicate the robustness and economic viability of the DCR project.	These comments have been considered in the development of the revised draft transmission plan. As described in response to earlier comments, the ISO chose conservative assumptions in the capacity analysis.
12b	Production Benefits The DCR evaluation now fully recognizes the established regulatory framework at the Palo Verde trading hub which allows CAISO market participants to access and utilize transmission through this hub without being assessed a transmission wheeling charge. This unique regulatory structure also allows for CAISO control on interconnected generation to the Palo Verde hub.	
12c	Customer Cost The DCR evaluation is also based on a detailed year-by-year revenue requirement and net present value comparison of project costs and benefits in	

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	2020. This approach allows the CAISO to compare the true net present value cost to customers as well as indicates the unique timeline of benefits the DCR project brings.	
12d	Policy Benefits CAISO has also indicated in the policy driven system assessment at the stakeholder presentation that the DCR project increases the deliverability of Imperial Valley area renewables into LA/San Diego areas from 700 MW or 800 MW (depending on restoration of emergency rating for Sycamore – Suncrest 230 kV) to approximately 1,000 MW (evaluated on a system after the installation of a flow control device at Imperial Valley). While policy attributes do not appear to be needed in light of the compelling economic support for the project, this represents additional support above and beyond the base scenarios evaluated.	
12e	Reliability Benefits CAISO has also shown a clear reliability benefit of the DCR project by partially mitigating the common corridor outage of the Lugo – Mohave and Lugo – Eldorado 500 kV lines.	
12f	Conclusion We agree with the CAISO's overall approach to the economic assessment of the DCR transmission line. This is an economically beneficial project to CAISO customers even under what we understand to be plausible but conservative assumptions. The results shared at the stakeholder meeting are consistent with our own parallel assessment which we independently developed with our economic consultant with significant experience in the California and Western Interconnection markets. The one exception to this is that we believe a 400 MW transfer capacity assumption is appropriate and could yet be even greater during many hours under reasonable system conditions. While the CAISO's evaluation demonstrates the DCR transmission line will provide economic benefits to CAISO customers considering a conservative capacity benefit, we believe there are other less quantitative factors that could drive even more benefits to CAISO customers that are worth considering. These benefits include the ability to access flexible thermal capacity to follow generation and load fluctuations, the ability to capture indirect capacity benefits created by lowering the proxy market clearing price for generation capacity in the CAISO, the increase in options that could be considered as a part of once-through cooling and the San Onofre Nuclear Generating Station retirement mitigation plans, and the increased deliverability between the CAISO and	

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	neighboring regions which could facilitate further inter-regional market development. In summary, we commend the CAISO for its thoughtful analysis of this transmission line. We concur with the CAISO that the DCR transmission line is an economically justified investment for CAISO customers, and we support the CAISO moving forward with its plan to seek Board approval to competitively bid the project.	

No	Comment Submitted	ISO Response
123	Office of Ratepayer Advocates Submitted by: Charles Mee, Zita Kline and Traci Bone	
13b	<u>ORA's Recommendation on Southern California Local Area Reliability Assessment (Los Angeles Basin and San Diego)</u> 1. When planning transmission in the SONGS area, the CAISO should leverage its existing local resources to provide the needed reactive power rather than relying on new transmission projects. For example, the CAISO should consider using existing generators to provide voltage support rather than building new transmission infrastructure. The CAISO is currently using the Huntington Beach generators to provide voltage support in the SONGS area. Therefore, the CAISO should be receptive to having other generators in that area to provide the same support. In addition, CAISO should also consider the use of preferred resources to meet the required load in the area. 2. The CPUC's Track 4 Proposed Decision (PD), issued on February 11, 2014, should be incorporated into the Draft Plan to address issues presented by the SONGS' retirement. Therefore, a final decision on LA Basin/San Diego area should be deferred in order for the CAISO and stakeholders to consider the CPUC's procurement mandate. Without considering the CPUC's Track 4 proposed decision, the CAISO's Group I transmission proposals are premature. It is worthy to note that the Track 4 PD makes certain assumptions not modeled in the current CAISO studies such as extending the reliance on the San Diego Special Protection Scheme (SPS) and creating mid-level Energy Efficiency in San Diego Gas and Electric (SDG&E) area. Also, the CAISO already decided to defer its recommendation on some transmission projects to a later date with the possibility that CAISO management may come to the CAISO Board of Governors after March 2014 and propose these transmission additions as amendments to the 2013-2014 Transmission Plan.	The ISO maximizes the use of reactive power from existing generation that they are required to provide as described in the ISO Tariff. The Huntington Beach units 3 and 4 were converted to synchronous condensers as the units were otherwise being returned to retirement and were not going to be operational as generators under any circumstances. While a synchronous condenser is not as effective as an equivalent amount of synchronous generation – which also provides reactive power - operation as synchronous condensers provided much needed reactive support. The ISO also considers the use of large quantities of preferred resources as described in the draft 2013-2014 Transmission Plan and in the 2014-2015 study plan. The ISO incorporated the assumptions and analysis from the Track 4 proceeding in its 2013-2014 Transmission Plan. The draft Track 4 decision is aligned with what the ISO recommended and anticipated as the outcome. Therefore the ISO recommendations are compatible with the draft Track 4 decision.
13c	<u>ORA Recommendations on Policy Driven Projects</u> 1) The Draft Plan mistakenly requires full deliverability for renewable resources. However, full deliverability for renewable resources is not supported by state policy. The goal for renewable transmission	As noted in our response to BAMx above, the ISO notes that the CPUC portfolios put a heavy weighting on generation that is viable, and in particular, the "commercial interest" portfolio has been selected as the base case. Virtually all projects in the

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	projects should be to ensure that 33% of the California's energy consumption is supplied from renewable resources.[12] Transmission projects to deliver renewable resources should only be developed if needed to relieve congestion or for economic reasons. 2. The CAISO may have understated the deliverability of renewables to the Los Angeles area by assuming high capacity factors for renewable resources. Based on previous CAISO transmission planning studies, 1,715 MW of renewable generation could be accommodated in the Imperial zone. However, due to the decommissioning of SONGS, the Draft Plan reports that none of the 1,715 MW renewables in the Imperial zone can be delivered. As a result, the Draft Plan proposes construction of several new transmission projects to ensure that 1,715 MW of renewables will be fully deliverable to load centers during peak hours. The SONGS retirement may create reliability problems, but not necessarily create deliverability problems for the Imperial zone. Existing generation within the combined Southern California area should be able to support the Imperial zone deliverability to some degree. 3. The Draft Plan also mistakenly requires full deliverability for resource adequacy (RA) resources. With more and more generation resources being interconnected to the grid, RA resources and/or their full deliverability may not be needed. Similar to the test for renewable resources, transmission projects for RA capacity should only be included if needed for congestion relief or for economic reasons.	discounted core are seeking full capacity delivery status (e.g. deliverability). Based on the ISO's experience working with generation interconnection customers, full capacity delivery status has been demonstrated as a necessity in advancing generation projects. The ISO has therefore included the deliverability analysis in assessing the need for policy-driven upgrades since the framework for approving policy-driven upgrades was introduced. Ignoring the need for deliverability that renewable generation has so clearly required in order to develop would not enable the state's renewables portfolio standard to be met.
13d	ORA Recommendations on Economically Driven Projects 1. The CAISO's current benefit-cost methodology fails to account for all the resources within the Energy Imbalance Market (EIM) footprint. According to the CAISO itself, the integrated ramping capacity needs for an EIM footprint will be less than the sum of the ramping capacity needs of individual Balancing Authority Areas (BAAs) within the EIM	The ISO agrees that the Energy Imbalance Market needs to be modeled where appropriate; the analysis in the 2013-2014 transmission plan includes PacifiCorp in the EIM, and the studies will be modified to include NVE before a recommendation can be made on the Harry Allen-Eldorado project. For clarity, however, the EIM does not provide different levels of import and export capability, but provides benefits in

[12] California Air Resources Board, Climate Change Scoping Plan: A Framework for Change (Dec. 2008) p. 45, ("Based on Governor Schwarzenegger's call for a statewide 33 percent RPS, the Plan anticipates that California will have 33 percent of its electricity provided by renewable resources by 2020, and includes the reduction of greenhouse gas emissions based on this level.")

No	Comment Submitted	ISO Response
	footprint. Also, since BAAs within the EIM footprint will be able to help each other, each BAA can procure less ramping capacity while still meeting grid reliability requirements. Therefore, the CAISO should fully incorporate EIM implementation in its economic analyses.	streamlining dispatch to fully utilize transfer capabilities.
	2. The CAISO should work cooperatively with existing generators to meet the grid's flexible capacity needs. At the February 12, 2014 stakeholder meeting, stakeholders expressed concern that generators which were still in the process of obtaining a rating were not included in the CAISO's planning assumptions. Without correctly assuming flexible ramping capacity within the CAISO BAA, the economic analyses could overstate the external needs for the flexible ramping capacity. The CAISO should actively seek to utilize existing resources prior to assuming additional resources are required.	The full impact of flexible generation needs for renewable integration are not yet developed and incorporated into the ISO's analysis of benefits of economically driven projects.
	3. The CAISO needs to justify the assumed capacity prices and make projections for future capacity costs consistent with current capacity costs. Capacity prices published by the CPUC's ED show that the median cost of capacity is approximately $26 per kW/yr.[13] Therefore, it seems unreasonable to assume that capacity cost of new entry in California will jump eight fold to $208 in 2023.[14] Based on the above, the Draft Plan's assumed price difference may not be supported and could be overstated, resulting in an overstated benefit/cost ratio for the project. 4. The CAISO has not provided any adequate justification/analysis explaining why California would be resource deficit by 2020. The only source cited by the CAISO is the need for flexible resources in the future.[15] The CAISO should defer to the California Public Utilities Commission (CPUC) when modeling capacity needs. The CPUC determines capacity needs in the Long Term Procurement Plan (LTPP) (R.12-03-014) and Resource Adequacy (R.11-10-023)	Please see the ISO references and calculations in the draft 2013-2014 Transmission Plan showing the revenue requirement for a new combustion turbine after subtracting revenues that it would obtain from the energy market. One of those references http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf in Figure 1.25 shows the gap between levelized fixed cost for a new generation project and its expected revenues. The draft 2013-2014 Transmission Plan essentially shows this same calculation but it is for a new Aero CT instead of a Frame CT. The Aero CT has more flexible capabilities for renewable integration. This gap is assumed to be met in the form of a capacity cost to ensure that the new CT is viable. The benefits have been apportioned based on the characteristics of the particular upgrade, and from the perspective of the party bearing the costs of the development.

[13] CPUC Energy Division, 2011 Resource Adequacy Report (Feb. 5, 2013), p. 22.
[14] Draft Plan at 257.
[15] *See* Draft Plan.

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	proceeding. Currently, the CPUC determined that there is an excess of capacity in the system.[16] 5. The CAISO fails to explain why building resources in Arizona is the best way to meet the California's flexible capacity need. The CAISO should explore additional alternative sensitivity scenarios for changing capacity costs and evaluate their impact on the capacity benefit of the transmission solutions. 6. The CAISO's modified capacity benefits calculations assume that the entire capacity benefit is attributed to CAISO ratepayers. However, the CAISO's previously established Transmission Economic Assessment Methodology (TEAM) assumed that the capacity benefit is split equally between the buyers and sellers of capacity. Thus, under the TEAM, the estimated annual societal benefit for DCR line would have been $4.5 million, but the current approach the CAISO assumes a ratepayer benefit of $9 million. The CAISO should justify the new approach or adjust the ratepayer benefit according to the established TEAM.	Please see the ISO references in the draft 2013-2014 Transmission Plan showing shortages in upward ancillary services and load following capability. These shortages occur when all capacity is fully utilized and upward ancillary services and load following capability requirements are violated to avoid shedding load. Adding more capacity to serve load is needed to restore the ability to meet upward ancillary services and load following requirements to meet NERC operating standards. Accessing lower cost resources in Arizona is a viable way to meet a portion of California's flexible capacity need. The ISO considers the assumptions to generally be conservative. Please refer to the earlier response to the CPUC Staff, item 3(e). The ISO assumes that the generation would earn a full rate of return, and this is a reasonable assumption for a competitive market.
13e	ORA's Recommendations on the Competitive Solicitation Process 1) The CAISO, CPUC, CEC and ORA should work collaboratively with stakeholders to develop the project sponsor solicitation criteria. 2) For policy driven and reliability projects, where no cost benefit analysis is conducted, the CAISO should include a mandatory cost-cap or revenue requirement cap on projects at the time of project approval as a condition of project sponsor approval. Without a cost-cap, sponsors are motivated to low-ball cost estimates to obtain approval and then increase their construction costs later. Additionally, a mandatory cost-	The selection criteria were developed through a consultative process and ultimately approved by FERC as part of the ISO tariff. One of the ISO's project sponsor selection criteria pertains to cost containment. The imposition of mandatory cost caps in all cases is not necessarily a viable remedy as it would necessitate a "risk premium" being built into revenue requirements that are unlikely to be considered in general a reasonable outcome. The ISO's tariff addresses this "low-balling" issue by not considering specific project sponsor cost estimate claims that are not reflected in a binding cost cap. The applicable criterion also asks project

[16] 2012 LTPP, See Appendix B. Data shown is the Base Scenario from D. 12-12-010, Appendix C, and page C-1. Also, see the presentation by Edward Randolph, Director Energy Division, CPUC at CPUC-CAISO Long-Term RA Summit, February 26, 2013.

No	Comment Submitted	ISO Response
	cap should be set prior to approval of economic projects since the viability of the project depends on the transmission cost being lower than the benefit. Potential project sponsors should be required to assume the risk of cost overruns unless they present a compelling justification for the cost increase. Furthermore, the CAISO should defend the approved cost cap in front of FERC during transmission owner tariff proceedings.	sponsors to demonstrate effective cost management processes and cost containment measures, which the ISO considers in selecting the approved project sponsor.

No	Comment Submitted	ISO Response
14	Pacific Gas & Electric Submitted by: Mark Higgins	
14a	<u>San Francisco Peninsula Reliability Concerns</u> PG&E appreciates the CAISO's continued efforts to assess the reliability needs of the San Francisco Peninsula. PG&E is providing separate comments on the San Francisco Peninsula Reliability Concerns that will be posted to the Market Participant Portal. <u>PG&E Local Areas Assessment</u> PG&E's comments below are organized to reflect the organization of the transmission plan for the convenience of the CAISO and other stakeholders; however, the order of comments is not necessarily reflective of their order of importance. <u>2.5.8.3: Assessment and Recommendations</u> <u>Estrella Substation Project</u> The Estrella Substation Project scope description calls for looping the 230 kV bus off the Templeton-Gates 230 kV line. PG&E urges the CAISO to modify the project scope to require looping of the Morro Bay-Gates No. 2 230 kV line instead. Modifying the scope as recommended will enable balanced power flows on the parallel Morro Bay-Gates No. 2, Templeton-Gates, and Morro Bay-Templeton 230 kV lines improving transfer of power from Morro Bay to Gates Substations and will better utilize existing transmission capacity. Additionally, looping the new substation onto the Morro Bay-Gates No. 2 230 kV line will improve reliability during 230 kV line clearances. The CAISO proposed arrangement would connect both Estrella and Templeton in series and would put both substations at risk for a single line (L-1) outage during a line clearance which is highly undesirable from a reliability perspective. This comment applies to all instances where the Estrella Substation	The responses to the San Francisco Peninsula Extreme Event Assessment comments are provided within a separate comment matrix which is posted on the ISO Market Participant Portal. The ISO identified the Estrella Substation Project along with the details of the looping in of the new Estrella Substation into the Templeton-Gates 230 kV line as being recommended for approval at the November 20-21 stakeholder meeting. This project is less than $50 million dollars and as such following no comments or concerns raised at the December 18-19 ISO Board meeting, ISO management approved the project. The ISO has reviewed the proposed change to loop the new Estrella Substation into the Morro Bay-Gates No. 2 230 kV line rather than into the identified Templeton-Gates 230 kV line. Looping the line into Morro Bay-Gates No. 2 230 kV line does not change the need for the project, the identified estimated costs or negatively impact the system performance and may provide additional future benefits as identified. Accordingly, the ISO has requested ISO management to approve the change of the 230 kV line looping to supply the new Estrella Substation and it is reflected in the Final Draft of the 2013-2014 Transmission Plan.

No	Comment Submitted	ISO Response
	Project scope is mentioned in the Draft Transmission Plan and its appendices.	
14b	<u>Local Preferred Resources Assessment (Non-Conventional Transmission Alternative Assessment)</u> PG&E supports the CAISO's movement to more fully consider the ability of demand-side resources to mitigate identified deficiencies in local areas and strongly encourages the inclusion of preferred resources that offer a cost-effective and reliable alternative to conventional transmission. PG&E has been forthcoming in the planning process and provided extensive locational data to aid the CAISO in its planning process, and we strongly encourage the CAISO to consider that information in their unified planning assumptions. The CAISO should update its white paper clarifying the process and criteria for non-conventional resources to meet transmission needs based on lessons learned from the 2013-2014 pilot. Since stakeholders provided comments on the CAISO's White Paper on Non-Conventional Alternatives (http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf) issued on September 4, 2013, the CAISO has not provided further information or instructions to the stakeholders on key implementation issues beyond that provided in the 2014-2015 TPP draft study plan. In the context of the State's Loading Order, the CAISO should adopt preferred resources if they can provide comparable reliability to the conventional approach in a more cost-effective manner consistent with PUC code section 454.5(C) which states that: *The electrical corporation shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible.* (http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=451-467)	The ISO appreciates the comment and will be continuing and expanding the assessment of preferred resources in the 2014-2015 Transmission Planning process as indicated in the ISO's draft 2014-2015 TPP Study Plan.
14c	<u>Economic Planning Study</u> During the 2013 request window, PG&E submitted a request to the CAISO to undertake an Economic Planning Study to evaluate the	The economic assessment identified areas of congestion on the system. The assessment did not identify congestion related to the Table Mountain 500/230 kV Transformer to be considered as one of the five high priority studies. The ISO will

No	Comment Submitted	ISO Response
	congestion associated with the Table Mountain 500/230 kV Transformer. While PG&E appreciates the CAISO's review of this issue in the bulk system reliability assessment, PG&E encourages the CAISO to continue to evaluate transmission upgrades that will provide economic benefits by relieving Table Mountain congestion and avoiding Real-Time Congestion Imbalance Offset Charges. PG&E also encourages the CAISO to further consider the installation of the second Table Mountain 500/230 kV transformer, as proposed by PG&E, as part of the long term solution to this issue. Similarly, PG&E appreciates the CAISO's recognition of the Table Mountain – Tesla Transmission project submitted by PG&E into the request window. This project was submitted as a conceptual plan that requires further evaluation. PG&E supports the CAISO's position on the need to continue to work with PG&E on any upgrades required in the future in order to preserve COI's existing import capability and to avoid curtailment on existing resources as well as avoid potential impact of any new resources that may be connected to the transmission system north of the Tesla substation.	continue to monitor in the reliability and economic assessments of future planning studies. The ISO will continue to assess in future transmission planning cycles the COI transmission system within the Bulk System reliability assessments and economic assessments.
14d	<u>Transmission Project List</u> <u>7.3: Competitive Solicitation for New Transmission Elements</u> <u>Wheeler Ridge Junction Project</u> The Draft Transmission Plan incorrectly defines the Wheeler Ridge Junction station scope as including a 230/70 kV component. The Wheeler Ridge Junction Station project substation scope should be for a 230/115 kV substation. This comment applies to all instances where the Wheeler Ridge Junction Station project scope is mentioned in the Draft Transmission Plan and its appendices.	The ISO appreciates the comment and has made the change identified to the Wheeler Ridge Junction Project in the Final Draft of the 2013-2014 Transmission Plan.
14e	<u>Description and Functional Specifications for Transmission Elements Eligible for Competitive Solicitation</u>	The ISO has updated the information for the Functional Specification for transmission elements eligible for competitive solicitation in Appendix F of the Final Draft of the 2013-2014 Transmission Plan.

No	Comment Submitted	ISO Response
	The functional specifications for the Estrella and Wheeler Ridge Junction substation projects in Appendix F of the Draft Transmission Plan are lacking detailed data required. PG&E will be providing the CAISO with separate set of specific comments on the functional specifications for these two projects which will align the specifications with current PG&E design criteria and standards for new substation equipment.	

No	Comment Submitted	ISO Response
15	San Diego Gas & Electric Submitted by: Fidel Castro	
15a	1) In the past, ISO typically limited its reliability study only to the compliance of NERC, WECC, and CAISO reliability criteria, and approved projects only to the extent of mitigating Category B violations if there is no generation re-dispatch available. In the 2013/2014 planning cycle, ISO staff looked beyond the minimum reliability criteria requirement and took into account: i) the possibility of loss of critical / major loads and the corresponding value of service; ii) the cost and operational constraints associated with re-dispatch of generation; iii) the possibility that a single major improvement may mitigate the need for multiple small or incremental upgrades, avoid the risk of making multiple upgrades to the same facilities, and result in a net savings to ratepayers. The kind long-term, big picture vision in transmission planning arena is much needed in the environment of post-SONGS and looming OTC retirement, and SDG&E applauds CAISO's timely move in the right direction.	Thank you for the comments.
15b	2) SDG&E's reliability study demonstrated that post-SONGS and OTC retirement, the San Diego in-basin generation need is 1470MW (**without** the long term transmission solution); or 620MW (**with** the long term transmission solution). Recent CPUC LTPP track 4 Proposed Decision allows SDG&E to procure up to 500MW of new conventional generation, which is below the bare minimum even assuming the long term transmission solution in service by year 2023. ISO deferred the approval on the long term transmission solution to a future planning cycle. Given the long lead time for permitting and constructing any major transmission projects, SDG&E urges ISO investigate the long term transmission solution with a sense of urgency and expedite the approval process.	This investigation is already underway in the 2014-2015 transmission planning cycle.
15c	3) ISO draft transmission plan prescribes a June 2018 in-service date for San Luis Rey Synchronous Condensers. This is based on the assumption that other reactive support projects within this area will be installed by 2015/2016 time frame. In light of the potential delay of the SONGS Mesa reactive support project due to land issues outside of SDG&E's control, SDG&E recommends ISO advancing the in-service date of San Luis Rey Synchronous Condensers to June 2016 to ensure the reliability criteria compliance.	The ISO agrees with SDG&E's recommendation to advance the date of San Luis Rey synchronous condenser project to June 2016 to meet potential dynamic reactive support need for the LA Basin / San Diego area.
15d	4) With regards to the Suncrest reactive support project:	

No	Comment Submitted	ISO Response
	a. ISO draft transmission plan main report recommends for approval of Suncrest 300 Mvar SVC. However, Appendix F "Description and Functional Specifications for Transmission Facilities Eligible for Competitive Solicitation" indicates the technology type "can be one of the following types of devices: SVC (Static VAR Compensator), STATCOM (Static Synchronous Compensator), or Synchronous Condenser". To avoid confusion, SDG&E suggests ISO revise the main report and refer to this project in a more generic term as "300MVAR of dynamic reactive support at Suncrest 230kV bus". b. ISO draft transmission plan identifies this project as one of the five facilities that are eligible for competitive solicitation. SDG&E would argue this is a substation voltage control equipment for that would most logically be installed within the existing substation fence line, therefore should not be a candidate for competitive solicitation. Putting a straightforward substation voltage equipment project through the competitive solicitation process, is <u>not</u> in the spirit of FERC Orders 890 and 1000 which encourage the competitive bidding of transmission projects to reduce the transmission congestion, and will only prolong the process and incur un-necessary cost to the rate payers.	We will incorporate this edit in the revised draft transmission plan. The ISO agrees that the equipment may ultimately be located most efficiently inside the existing substation fence line. However, we are not aware at this time of a requirement that the equipment must be located inside the existing substation, and this is similar to a generator interconnection. Therefore, the ISO considers it necessary to follow the competitive solicitation process.
15e	5) ISO draft transmission plan main report recommends for approval the reliability project Miguel 500 kV Voltage Support: Install up to 375 MVAR of reactive support (i.e., shunt capacitors) at Miguel substation. Preliminary investigation by SDG&E's staff indicates the installation of 375 MVAR shunt capacitors while retaining the existing 500kV reactors at Miguel will require extensive site preparation (grading and fence modification) and therefore become costly. SDG&E proposes to install a synchronous condenser of similar size instead, which will provide continuous dynamic reactive support, enable the removal of the existing 500kV reactors and can be installed within the existing fence line (minimal civil construction due to smaller footprint). The overall cost for either option will be nearly the same.	Based on this input, we will revise the report to allow alternative reactive support technologies and open this project to the competitive solicitation process.
15f	6) ISO draft transmission plan identifies Imperial Valley generation Deliverability Constraint due to the reduction in emergency rating for the Suncrest-Sycamore-230 kV lines (TL23054 and TL23055). The initial as-build line ratings issued for these two lines were calculated by Sunrise	The ISO appreciates this update, and will adjust the discussion of the deliverability issues affecting the Imperial Valley accordingly.

No	Comment Submitted	ISO Response
	consultants and included specific assumptions, which accounted for the different environmental conditions of the regions the lines traversed. SDG&E has since reevaluated these assumptions and has determined that they remain applicable to the 500kV line segments, but they are not applicable to the 230kV line segments of the Sunrise Powerlink lines. Recalculating the overhead line ratings using TE-0144 assumptions yields the emergency ratings are being raised, from 1089MVA up to 1183MVA.	
15g	7) On the last paragraph of page 196 of the 2013-2014 ISO Transmission Plan, the Imperial Valley Deliverability Constraint section states "With SONGS retired and the new Suncrest-Sycamore 230 kV emergency line ratings no renewable generation can be accommodated in the Imperial zone until considering the reliability mitigations being proposed in this transmission plan" can the CAISO clarify in this section of the report that the deliverability analysis is relevant only to the year 2023. The way the deliverability section is written, it is easy to reach the apparently erroneous conclusion that all deliverability out of the Imperial Valley was lost upon the retirement of SONGS.	The existing generation did not lose its deliverability and the ISO will clarify this issue in the revised draft transmission plan.
15h	8) Will the CAISO be willing to perform an extra interim deliverability analysis for five years out for the future Transmission Plans Reports? This would be helpful in showing how quickly deliverability out of the Imperial Valley is eroding.	Indicative information will be available through the operational studies prepared as part of GIDAP in December 2014, as the ISO queue volumes studied in that work are larger than the target import capability from IID. The results will be provided in the Phase II studies posted on the ISO Market Participant Portal.

No	Comment Submitted	ISO Response
16	Sempra US Gas and Power Submitted by: Shawn Bailey	
16a	The CAISO has continually assessed the economics of upgrading the Palo Verde to California path (Path 49) over at least the last three transmission planning cycles. In the 2011-2012 CAISO Transmission Plan, the CAISO found the upgrade of the Colorado to Valley segment of the path to be needed for renewable procurement policy reasons. However, in assessing the economic benefits of the Delaney-Colorado River upgrade, the final remaining segment of the path, the CAISO found the upgrade the Delaney-Colorado River segment was uneconomic based on costs totaling \$319mm and benefits totaling \$237mm[17]. It should be noted that Arizona Public Service and Electric Transmission America filed comments on February 28, 2012 estimating the cost of the upgrade to be \$256mm using the CAISO methodology. In the 2012-2013 CAISO Transmission Plan, the CAISO estimated the total cost of the upgrade to be \$471mm, but due to modeling concerns indicated that the benefits of the project required further study and consideration for approval at a future CAISO board meeting[18]. Now in the 2013-2014 CAISO Draft Transmission Plan, the CAISO staff have again assessed the Delaney-Colorado River upgrade, and found the upgrade to be economic based on an estimated total cost of \$498mm, and benefit to cost ratios of between 1.04 and 1.53[19]. Despite an over 50% increase in the estimated cost from the 2011/2012 plan, the CAISO staff finds the upgrade to be economic, and is recommending Delaney-Colorado River for approval by the CAISO board. The economic, reliability and renewable integration benefits of the upgrade combine to make the Delaney-Colorado River a compelling upgrade for California. This conclusion is underscored with the recent retirement of roughly 2,200MW of baseload generating capacity in southern California associated with the San Onofre Nuclear Generating Station, an event which had not occurred at the time of the 2012/2013 plan. The Delaney-Colorado River upgrade provides for an increase in expected flow on the corridor by 30%, and	The ISO made conservative assumptions in the capacity analysis, to ensure that we not overestimating the benefits. Also, if further upgrades provide sufficient economic benefit, they can be reviewed and advanced in future planning processes.

[17] CAISO 2011/2012 Transmission Plan dated March 23, 2012, page 407.
[18] CAISO 2012/2013 Transmission Plan dated March 20, 2013, pages 8 and 356.
[19] CAISO Draft 2013/2014 Transmission Plan dated February 2, 2014, page 261

No	Comment Submitted	ISO Response
	an approximately 1200MW increase in non-simultaneous import capability into California from the largest concentration of modern flexible and efficient combined cycle generation in the West; resources that are critical to integrating intermittent renewable generation required to meet California's 33% renewable portfolio standard. Delaney-Colorado River also increases system reliability by providing an additional line for flow in the event of an N-1 contingency of either the existing Palo Verde-Devers #1 500kV line or the Hassayampa-Hoodoo Wash 500kV line, and thereby reduces overloads on the northern East-of-River path into the SCE and LADWP areas (i.e. El Dorado-Lugo 500kV, Mohave-Lugo 500kV, Lugo-Victorville 500kV). The upgrade also enhances San Diego local area reliability by reducing overloads due to loss of the Southwest Power Link (i.e. IV to Miguel 500kV segments). In addition, the upgrade contributes to California's renewable policy goals, by increasing renewable deliverability from the Imperial Valley area. Given the overall benefits of the upgrade to the California system and San Diego local area reliability, access to flexible generation capacity in Arizona, enhanced access for renewable development in the Imperial Valley, and reduced east to west congestion, now is the time for California to support the upgrade of this final segment of Path 49. However, despite this conclusion, Sempra USGP remains concerned that the import capacity assigned to the project in the economic analysis is underestimated. The CAISO staff indicated in the February 12 stakeholder meeting that downstream constraints in the San Diego system could limit the import capacity of the upgrade to only 200 to 300MW. Sempra USGP suggests that the CAISO reevaluate the nature of the downstream constraints, and determine whether downstream upgrades to meet local San Diego reliability needs should be included in the base case of the economic analysis. Sempra USGP appreciates the CAISO staff's effort to assess the benefits of Delaney-Colorado River, and supports the staff's recommendation to the board for approval.	

No	Comment Submitted	ISO Response
17	Sierra Club and California Environmental Justice Alliance Submitted by: Matthew Vespa and Shana Lazerow	
17a	Sierra Club and California Environmental Justice Alliance ("CEJA") submit the following comments on the Draft 2013-2014 ISO Transmission Plan ("TPP"). Sierra Club and CEJA's comments are limited to the TPP's assessment of local capacity areas impacted by the retirement of the San Onofre Nuclear Generating Station ("San Onofre"). We urge CAISO to model a low carbon scenario that uses a mix of preferred resources, in potential combination with Group 1 transmission upgrades, to meet local capacity needs in the LA Basin and the San Diego local capacity area. The retirement of San Onfore presents the State with a crucial opportunity to ensure that the State meets its energy and environmental laws, goals and policies. California must significantly reduce its greenhouse gas emissions from existing levels to meet the emission reduction targets set forth under AB 32 and Executive Order S-3-05. Because San Onofre generated carbon-free energy, replacing San Onofre with fossil fuel generation will both undermine achievement of California's GHG goals and exacerbate harmful pollution in an area that already suffers from unhealthy air quality. Indeed, in CAISO's analysis of Southern California Edison's local capacity needs for Track 1 of the California Public Utilities Commission's (CPUC's) Long Term Procurement Proceeding (LTPP), it forecasted that 4.25 million tons of CO2 emissions would be added per year in the SCE area as a result of the added conventional generation it was recommending.1 The long-term nature of conventional power plants means that approval of new fossil fuel generation will likely affect GHG emissions for at least 40 years into the future. These impacts cannot be viewed in a vacuum; they should be compared and added to the total of all current and future direct emissions. Recent values from a natural gas plant demonstrate that new conventional generation will emit significant amounts of GHGs and other pollutants including nitrous oxide and PM 2.5.2 Since many current and proposed natural gas power plants are located near disadvantaged communities, this also raises environmental justice issues. In contrast, preferred resources generally emit little to no GHGs or other pollutants.3 In the Proposed Decision for LTPP Track 4, the CPUC determined that "all incremental procurement as a result of this decision may be from preferred	The ISO appreciates the comments and encourages these comments to be entered into the 2014-2015 planning cycle. We note that the long term (2023) scenarios studied in this cycle were based on reasonable Track 1 and Track 4 expectations, which were reinforced by emerging needs and realistic expectations about means to address those needs. Beyond the generation assumed in those scenarios, the ISO anticipates addressing remaining needs with preferred resources or transmission mitigations. The transmission mitigations and forecast resource additions leave potential for additional preferred resource development and/or other reductions in load forecast. The ISO also expects to be able to further refine its analysis in subsequent planning cycles. We have provided additional clarification about the need for resources to be repositioned within 30 minutes from the occurrence of a critical contingency in response to comments from EnerNOC, Inc. above.

No	Comment Submitted	ISO Response
	resources."4 Consistent with this decision, the CAISO should model in the TPP a low carbon scenario that meets all local capacity need in the LA Basin and San Diego Local Capacity Area with preferred resources and an alternative scenario that meets local capacity need with a combination of preferred resources and transmission upgrades. In particular, Sierra Club and CEJA support development of the Mesa Loop-In. This upgrade would provide significant reliability benefit to the LA Basin and facilitate repowering of wind resources in the Tehachapi, thereby avoiding greenfield development of other potential projects. In addition, the Imperial Valley Flow Controller (for emergency flow control to prevent overloading on CFE line and voltage collapse under Category C.3 contingency) provides significant local resource reduction benefits, particularly when coupled with the Mesa Loop-In. Although the ISO did evaluate a number of preferred resource scenarios, none of these scenarios are either directed at meeting all LCR need or evaluated a combination of preferred resources. For example, Scenario 1 models 4 hour DR, while Scenarios 3 and 4 evaluate a combination of solar PV and energy storage.5 A new scenario should be developed that leverages the complementary benefits of the suite of available preferred resources. Low carbon solutions to meet local capacity needs are technically and economically available today. The real challenge is leadership. A CAISO scenario would help with that challenge by providing a path forward. Finally, Sierra Club and CEJA request that CAISO provide clear guidance on the use of demand response resources to meet local capacity needs that is consistent with standards for conventional generation. CAISO has recently asserted it prefers demand response products that can respond in "sufficiently less time than 30 minutes from the CAISO dispatch."6 Yet "sufficiently less time" is not a clear standard from which to contract with DR customers. In addition, the ability to respond in significantly less than 30 minutes is not applied to conventional resources in determining their local capacity contributions. Indeed, the start time of combined cycle gas plants is significantly higher than 30 minutes. Demand response is already meeting local capacity needs in practice and has significantly greater potential to do so provided CAISO provides clear and non-discriminatory standards for DR resources. To the extent there is a desire to procure DR resources that respond more quickly than conventional generation, these resources should	

No	Comment Submitted	ISO Response
	receive a premium for that service.	

No	Comment Submitted	ISO Response
18	Southern California Edison Submitted by: Dana Cabbell, Garry Chinn, Kevin Richardson, Megan Mao and Karen Shea	
18a	*I.* ***SCE Supports the CAISO's Southern California Reliability Assessment*** Southern California Edison Company (SCE) appreciates the California Independent System Operator's (CAISO's) extensive study effort and thorough analysis in its 2013/14 Draft Transmission Plan, and supports the CAISO's conclusions on recommending three projects in Southern California Reliability (SCR): 1.) Dynamic Reactive Support at San Luis Rey, 2.) a Flow control device at Imperial Valley, and 3.) the Mesa Loop-in Project.[20] SCE also supports that CAISO's overall structure for its SCR study efforts by organizing it in three study groups: Group I: Transmission upgrades optimizing use of existing transmission lines; Group II: Transmission lines strengthen LA/San Diego connection – optimizing use of corridors into the combined area; and Group III: New transmission into the greater LA Basin/San Diego area. Regarding the Mesa Loop-in Project, SCE's own analysis has confirmed the benefits of adding this project to address SCR.[21] SCE has performed preliminary work on the Mesa Loop-in Project and as soon as the Mesa Loop-in Project is approved by the CAISO Board as part of the CAISO 2013-2014 Transmission Plan SCE will move forward expeditiously to complete final design and engineering, and initiate efforts to obtain regulatory approvals.	
18b	*II.* ***Delaney-Colorado River 500 kV Line*** SCE is appreciative of the CAISO for this stakeholder process, as well as the 2012-2013 Transmission Planning Process, and its restudy effort for the	

[20] Capitalized terms used but not defined have the meaning ascribed to them in the CAISO tariff.
[21] Mesa Loop-In reduces the need for LCR resources in the LA Basin by between 734 MW and 1,196 MW, depending on assumptions regarding load shedding in the SDG&E area. See SCE testimony in the CPUC's Long-Term Procurement Plan proceeding, R.12-03-014, Exhibit SCE-1, page 32, Table III-5 (comparing scenarios 1 v. 2 and 1S v. 2S).

No	Comment Submitted	ISO Response
	Delaney-Colorado River 500 kV line, which it has concluded is an economic transmission project.	
	SCE would appreciate clarification from the CAISO on the following issue: • Will the Project Sponsor need to obtain a WECC Path Rating Study and would the CAISO undertake a Study of the Affected Systems with respect to the project?	Yes, the project sponsor will need to follow the WECC Path Rating Process to address any concerns raised regarding the potential for the project to adversely affect WECC paths. This process could also serve as a forum for potentially affected systems to raise their concerns.
	As stated in Appendix F of the Draft Transmission Plan, once the Delaney-Colorado River 500 kV line is approved, the CAISO will request cost estimates from SCE for the facilities needed for the substation connecting to the new Delaney-Colorado River 500 kV line. SCE has the following questions for which it seeks clarification: •How will the substation cost be incorporated into the bid process?	Estimated substation costs will be not be part of the bid process, and bids will be expected to align with an estimated cost that does not include substation costs.
	•How will the CAISO report back on any changes on the cost management aspect (e.g. any additional facilities identified by additional studies)?	The project sponsor selection process information provided will provide clarity on this information. The ISO expects that the successful project sponsor must provide assurances in some form that costs will not escalate such that the project is not economic.
	•Please confirm that the point of ownership change will occur at the last structure (e.g. a tower) located outside of the Colorado River Substation. Please also confirm that the facilities interconnecting the Delaney-Colorado River 500 kV line project to existing substations will be owned and operated by the PTOs that currently own those substations. Will there agreements required between the Project Sponsor and APS/SCE? If so, what agreements are envisioned?	The interconnection agreements between the project sponsor and the substation owners will delineate the point of ownership changes.
	•Does CAISO expect that the Delaney-Colorado River 500 kV line substation costs will be recovered through the TAC by the Project Sponsor after it reimburses the PTO(s) for the substation work necessitated by the project?	The SCE substation costs will be recovered by SCE through TAC. The APS substation costs will be recovered by the project sponsor through TAC.
	Finally, the Delaney-Colorado River 500 kV line, as well as other projects subject to competitive solicitation, further demonstrates the need for the CAISO to consider increasing the priority of the Transmission Interconnection Stakeholder Initiative, and initiating a stakeholder process in 2014. In its 2013 Stakeholder Initiatives Catalog, the CAISO has indicated that it would address this issue in 2014 only if time permits. Given the expected increase in competition due to FERC Order 1000, the need is great for a smooth and clear	We will reevaluate the priority for this initiative.

No	Comment Submitted	ISO Response
	process administering the transition from using the Transmission Owner Tariff (TO Tariff) to using the CAISO tariff. It is critical that transmission interconnection studies be considered comprehensively as part of the CAISO system so that all reliability impacts and associated solutions to address those impacts are identified.	
18c	*III.* ***<u>Approved Project Sponsors for Composite Parts of a Substation</u>*** *a. Having Multiple Project Sponsors for Composite Parts of a Substation Could Lead to Reliability Issues* Section 7.3 of the Draft Transmission Plan identifies Wheeler Ridge Junction 230/115 kV Substation and Estrella 230/70 kV Substation as reliability-driven transmission solutions eligible for competitive solicitation. SCE has some concerns about there being potentially two owners of facilities comprising one substation. Specifically, the Wheeler Ridge Junction Substation and the Estrella Substation both contain Regional and Local Transmission Facilities, as defined in Appendix A of the CAISO tariff that could be owned and operated by more than a single entity. In the case of the Wheeler Ridge Junction Substation, the 230 kV buswork and termination equipment, and the 230/115 kV transformers are eligible for competitive solicitation (these are new Regional Transmission Facilities), while the 115 kV buswork and termination equipment, and the reconfiguration of existing facilities will not be eligible (as these are existing and Local Transmission Facilities). The PTO in whose service territory the facilities are entirely located has the responsibility to construct, own, finance, and maintain Local Transmission Facilities and upgrades or additions to existing facilities, as per Section 24.4.10 of the CAISO tariff. If the PTO in whose service territory the substation is entirely located, in this case Pacific Gas & Electric Company (PG&E), is NOT the competitively-selected Approved Project Sponsor for the Regional Transmission Facilities, *then there could be two owners of different facilities within one substation.* In much the same way, the Estrella Substation project scope consists of Local and Regional Transmission Facilities; the Regional Transmission Facilities will	The concerns here are similar to the concerns expressed by SDG&E (above) regarding reactive control devices. The ISO recognizes that having separate owners of the 230 kV facilities potentially could result in increased design, construction and operating complexity. If this hurdle materializes, it will need to be offset by other advantages in order for a non-incumbent proposal to succeed. For clarity, the ISO would anticipate that if the approved project sponsor is not the incumbent owner of the 230 kV transmission lines and the lower voltage buswork, the the 230 kV substation and buswork and transformers would be enclosed in separate fenced facilities, similar to the design of the larger industrial substations where the secondary buswork may be owned by a third party. The increased complexity and effectiveness of proposed mitigations are issues that will be taken into consideration in the Phase 3 selection process. However, we are not aware of a reason why the design itself is wholly infeasible and therefore find it necessary to conduct a competitive solicitation pursuant to the ISO tariff. In particular, tariff section 24.4.10 provides that transmission solutions associated with both regional and local facilities, and for which the ISO determines it is not reasonable to divide construction responsibilities, will be subject to the competitive solicitation process.

No	Comment Submitted	ISO Response
	be up for competitive solicitation while the Local Transmission Facilities will be the responsibility of the PTO in whose service territory the substation is located, also PG&E, according to Appendix F of the Draft Transmission Plan.[22] It is also true in the case of the Estrella Substation project that if the PTO in whose service territory the project is located is not the Approved Project Sponsor as a result of the competitive solicitation process, then there could be more than one owner of different facilities located within a single substation.[23] Having more than one owner of substation facilities creates a concern of joint jurisdiction and control from a reliability perspective. Regional Facilities that are included in the competitive solicitation process should stop at the substation fence such that a substation only has one owner and operator. The Local PTO should own all the facilities within its substation, including the Regional Transmission Facilities of the Approved Project Sponsor. The Approved Project Sponsor would pay the Local PTO for the costs incurred within the substation to interconnect the Approved Sponsor's Project, and as with the Project line costs, it would recover those costs in its own Transmission Revenue Requirement. The possibility having two owners within the same substation creates a NERC compliance concern with the determination of which entity is responsible for the maintenance and operations of the shared facilities. It should be made clear in either the Interconnection Agreement or the Reliability Standards Agreement that there is a clear delineation of ownership and NERC compliance responsibility. Parties involved with owning and operating composite parts of a substation should not be held responsible for the NERC compliance of third party assets unless specifically addressed in an agreement. *b. Clarification is needed on Assignment of Ownership of Composite Part of Estrella Substation* The proposed Estrella 230/70kV Substation includes a 45MVA distribution transformer connected to the 230kV bus. Neither the Draft Transmission Plan	

[22] CAISO Draft 2013-2014 Transmission Plan, Appendix F, Section F4.1, Page 11, Paragraph 6
[23] CAISO Draft 2013-2014 Transmission Plan, Appendix F, Section F3.1, Page 7, Paragraph 4

No	Comment Submitted	ISO Response
	itself nor Appendix F explains who would be responsible for construction and ownership of this distribution transformer. One would assume a new distribution transformer would be considered a Local Transmission Facility not eligible for competitive solicitation. As explained above, this could complicate operations if the Approved Project Sponsor and the PTO in whose service territory the substation is entirely located, PG&E, are not the same entity.	
18d	IV. <u>*SCE Supports the CAISO Advancing Non-Transmission Alternatives and Preferred Resources*</u> SCE very much appreciates the steps the CAISO has taken to study Preferred Resources and Energy Storage characteristics in meeting Local Capacity Requirements (LCR) needs in addition to transmission and conventional generation options. These types of studies are good initial steps in taking a holistic view of all resource types and available options in meeting LCR needs. SCE recognizes that this is an evolving process and looks forward to continuing to work with the CAISO, and encourages the CAISO to continue to focus in this area. SCE looks forward to obtaining a set of necessary attributes and characteristics for Preferred Resources and Energy Storage that LSE's may use in meeting their LCR needs.	The ISO appreciates the comment and will be continuing and expanding the assessment of preferred resources in the 2014-2015 Transmission Planning process as indicated in the ISO's draft 2014-2015 TPP Study Plan.
18e	<u>*Technical Comments*</u> *I.* <u>*Coolwater-Lugo Transmission Project*</u> a. On page 215 of the Draft Transmission Plan, the Coolwater-Lugo 230 kV line is listed in Table 5.5-6 entitled "Assumed network upgrades added to the database model." SCE believes that this is an error, and that the Coolwater-Lugo line ought to be placed in Table 5.5-4, "GIP-related network upgrades added to the database model" instead. The reason for this is that the West of Devers 230 kV Reconductoring Project is also a Generator Interconnection Procedure (GIP)-related network upgrade, and is located in Table 5.5-4. The West of Devers and the Coolwater-Lugo Projects are listed together on page 10 in Table 2, "Elements of the 2013-2014 ISO Transmission Plan Supporting Renewable Energy Goals." These two projects should not be separated and treated differently from one another in another part of the document.	We will make the suggested edits to the tables and footnotes in the final draft transmission plan.

No	Comment Submitted	ISO Response
	b. Footnote 29, on page 215, states, "In the 'Assumed network upgrades' table, the listed network upgrades are needed to establish a feasible database to meet reliability standards and policy needs. These assumptions are for database modeling purposes and do not imply that the network upgrades will be approved and constructed." This footnote only applies to the Inyo 115 kV phase shifter, and should be removed from the Coolwater-Lugo upgrade. Because of the signed Generator Interconnection Agreement (GIA) between Abengoa and the CAISO, the phrase "do not imply that the network upgrades will be approved and constructed" does not apply to the Coolwater-Lugo upgrade. This footnote should instead be attached to the Inyo phase shifter because this upgrade will likely be required and included in a future GIA for WDAT 315, a transition cluster project. c. Footnote 30, on page 215, states "Either the Coolwater – Lugo 230 kV line or equivalent transmission upgrade are needed to deliver the renewables in the Coolwater-Kramer area. Another alternative is the proposed AV Clearview Transmission. As a placeholder, the Coolwater – Lugo 230 kV line is used in the database modeling." This language should be removed. No other GIP-related upgrade, other network upgrade, or assumed network upgrade has a footnote listing its system alternatives, so the Coolwater-Lugo Project ought not to be singled out in this way. Moreover, the characterization that the AV Clearview proposal is an "alternative" is not accurate and conflicts with CAISO's previous conclusion that the AV Clearview proposal "is not on its own an equivalent substitute for the Coolwater-Lugo 230 kV line in the context of the ISO Generation Interconnection study process."[24] Lastly, the Coolwater-Lugo Project is subject to a fully executed LGIA which calls for full 250 MW deliverability by 2018[25] and this deliverability date will not	

[24] CAISO, AV Clearview Phase I Transmission Project - New Alternative Evaluation, at pg 4 (August 2, 2013).
[25] SCE, Large Generation Interconnection Agreement, filed November 30, 2010, FERC Docket No. ER11-2204-000, at pg 128.

No	Comment Submitted	ISO Response
	be met with the AV Clearview proposal. Unlike the Coolwater-Lugo Project which is a CAISO approved project[26] with a FERC approved LGIA[27] and is currently undergoing environmental review with the California Public Utilities Commission (CPUC)[28] and the U.S. Bureau of Land Management, the AV Clearview proposal is not a CAISO approved project[29], does not have a LGIA, nor has any CEQA or NEPA environmental review begun on the proposal.[30] In fact, very little work has been done on the AV Clearview proposal according to AV Clearview's sponsor Critical Path Transmission which has gone on record stating that only a desktop routing and a siting study has been completed[31], no CEQA or NEPA application has been filed[32], additional work will only begin once AV Clearview is CAISO approved project[33], AV Clearview is not eligible for ratepayer cost recovery[34], and AV Clearview cannot be evaluated by CAISO while the Coolwater-Lugo Project remains a CAISO approved project[35]. Therefore, given also that SCE's CPCN Application for the Coolwater-Lugo Project is currently under review by the CPUC, it is unreasonable and inappropriate to include any reference to the AV Clearview proposal in the Draft Plan as an alternative to the Coolwater-Lugo Project.	
18f	*II.* *<u>North of Lugo Area</u>*	a. We will make the suggested edits to the tables and footnotes in the final draft transmission plan.

[26] CASIO, 2012-2013 Transmission Plan (March 20, 2013).
[27] FERC, Order Conditionally Accepting Non-Conforming Large Generator Interconnection Agreement, Docket No. ER11-2204-000 eff. January 30, 2011.
[28] SCE, Certificate of Public Convenience and Necessity (CPCN) Application filed August 28, 2013, CPUC Docket No. A.13-08-023.
[29] CASIO, 2012-2013 Transmission Plan (March 20, 2013).
[30] In the Matter of the Application of Southern California Edison Company (U338) for a Certificate of Public Convenience and Necessity for the Coolwater-Lugo Transmission Project, CPUC Docket No. A.13-08-23, Pre-hearing Conference (December 17, 2013), Critical Path representative Kevin Davis stated "No CEQA or NEPA application or notice of intent or preparation is currently on file with the Kern County Planning and Community Development Department", transcript at 56, lines 6-10.
[31] *Id*. Kevin Davis, "To date, we've performed a desktop routing and siting study complete with a proposed study area." Transcript at 54, lines 10-14.
[32] *Id*, Kevin Davis, transcript at 56, lines 6-10.
[33] *Id*. Kevin Davis, "But once the concept is an approved project, the appropriate notice will be submitted for review and approval by Kern County." transcript at 57, lines 16-19.
[34] *Id*. Kevin Davis, "And as such, we have not yet been studied for inclusion in the ISO's transmission plan. Without inclusion in that transmission plan, we are not eligible for ratepayer cost recovery." transcript at 561, lines 8-12.
[35] *Id*. Kevin Davis, "We have been informed by the ISO that they cannot under their current tariff, or the tariff at the point at which this comparison was initiated, evaluate this project unless there is demonstrated need. And the demonstrated need will not exist unless Coolwater-Lugo is removed from the base case. Coolwater-Lugo will not be removed from the base case unless it is determined that it will not be built, and will not be determined that it will not be built unless it fails to meet a CPCN." transcript at 61, lines 16-28, and "It is not eligible for inclusion in the transmission plan unless or until Coolwater-Lugo is removed, or other transmission planning factors change substantially." transcript at 62, lines 13-17.

No	Comment Submitted	ISO Response
	a. The Eldorado-Baker-Cool Water-Dunn Siding-Mountain Pass 115 kV line, as mentioned on page 110, should be called the Ivanpah-Baker-Coolwater-Dunn Siding-Mountain Pass 115 kV line because of Ivanpah Substation's interconnection into that line, and because of SCE's Standard Operating Bulletin 123. b. The total generation in Table 2.7-5 on page 111 is listed as 2,698 MW, while the generation table on page A-16 of Appendix A lists the total generation as 2,559 MW. The two values should match. On page 112, it is stated that "An interim SPS will open the two 115 kV lines between Victor and Lugo if the voltage fails to recover for 2 seconds." However, there is no 115 kV at Lugo Substation, and thus no 115 kV line between Victor and Lugo. The CAISO should clarify whether this statement is referring to the Lugo-Victor No. 1 & No. 2 220 kV lines or the 115 kV lines between Kramer and Victor.	b. The 2,698 MW number was provided by SCE and the Appendix A number comes from base cases which were also provided by SCE. The ISO will revisit this issue with SCE to resolve the inconsistency. The ISO will correct the text on page 112 in the final draft transmission plan.
18g	*III.* *<u>East of Lugo</u>* On page 113, the bullet point saying "115 kV transmission line from Cool Water to Eldorado" should instead say "115 kV transmission line between Cool Water and Ivanpah," as EITP looped Ivanpah there and rebuilt the last 35 miles of that 115 kV line back to Eldorado as 220 kV.	We will edit the line name in the final draft transmission plan.
18h	*IV.* *<u>Path 42's path SOL in Table 2.3-5 May Need Clarification</u>* On page 42, Table 2.3-5 shows Path 42's path SOL as 800 MW. Based on SCE studies, the existing path rating is actually 600 MW, with a plan to go up to 1,500 MW. Until the rating reaches 1,500 MW, there would be an interim rating as generation is added. SCE's suggestion is to add a footnote to Table 2.3-5 stating that the current SOL is 600 MW and the SOL is expected to be 1,500 MW beginning in 2015.	We will make the suggested edit in the final draft transmission plan.
18i	*V.* *<u>Wheeler Ridge Junction Substation Definition needs to be Updated</u>* In several places in the Draft Transmission Plan and the Appendices thereto, the Wheeler Ridge Junction Substation is referred to as a 230/115 kV	The ISO appreciates the comment and has made the change identified to the Wheeler Ridge Junction Project in the Final Draft of the 2013-2014 Transmission Plan.

No	Comment Submitted	ISO Response
	substation as well as a 230/70 kV substation. Wheeler Ridge Junction Substation is a 230/115 kV substation, so references to it being a 230/70 kV substation should be corrected in the next version of the 2013-2014 Transmission Plan.	

No	Comment Submitted	ISO Response
19	Southwest Transmission Partners, LLC Submitted by: Mark L. Etherton	
19a	Our specific comments are related to the economic analysis that was conducted for the NGIV2 Project. We are encouraged that the latest analysis includes a reduction in congestion and ultimate benefit to consumers of $279M, very close to the latest cost estimates provided to the CAISO of $295M. We have a few comments related to the: a) Calculation related to the Total Cost – the calculation of the Total Revenue Requirement over the life of the project is calculated as the Capital Cost x 1.45. It is our estimation that the factor is much less and closer to 1.1 over the life of the Project. This lower percentage contingency included in the Capital Cost of the Project would produce much more positive results. b) Consideration of System Resource Adequacy (RA) - the analysis concludes that no capacity benefit is attributed to the Project due to the "downstream bottleneck" (assumed to be in the SDGE area). We believe that the Economic Analysis should include some capacity benefit, primarily based on the G-1/N-1 involving the outage of the existing North Gila – Imperial Valley 500kV line. SDGE had also provided comments to the potential benefit to the System RA by reducing the Local RA for the SDGE area earlier this year in response to the previous (2012-13) Economic Analysis. If some capacity benefit were included in the calculation, the BCR would prove to be greater than shown in the current economic analysis. c) Reliability Benefit – the reliability benefit of the NGIV2 Project should also be included in the analysis, primarily for: i. Increase in the capacity of both the Path 46 (West of River) and Path 49 (East of River) paths under various conditions. The increase in capacity on the Path 46 is at least 1600MW and Path 49 at least an incremental 600MW (on top of the rating for the proposed HANG2 project). ii. The CAISO Reliability Assessment included several CAISO system overloads for the N-1 of the existing North Gila – Imperial Valley 500kV line, as well as for the loss of Path 42. With the NGIV2 Project (including the interconnection to the IID Highline 230kV substation), the requirement for many of the upgrades noted in the Reliability Assessment can be eliminated or deferred.	a. The comment refers to a lower percentage contingency. For clarification, the total cost referred to - in the ratio of the total cost to the capital cost – is the present value of the annualized revenue requirement determined for the given capital cost. The annualized revenue requirement is determined by considering the annual depreciation expense, tax expense, interest expense, return and incremental operating costs, over the life of the project and then calculating the present value of that annual stream of numbers. While the ISO has reviewed the parameters used to derive the 1.45 ratio used for screening purposes, we are open to reviewing your results. b. The G-1/N-1 is addressed by renewable generation production in the Imperial Zone which is assumed to be developed regardless of the NG-IV 500 kV line being built. The cost of the capacity from the renewable generation is assumed to be comparable to the cost of capacity from Arizona. Therefore there would be no capacity cost benefit for the G-1/N-1. c. (i.) Based on ISO studies of Path 46 transfer capability during summer peak conditions, the NG-IV project would not mitigate the identified constraints. (ii) The ISO is not sure which identified overloads this comment is referring to, so we are unable to provide a response.

No	Comment Submitted	ISO Response

No	Comment Submitted	ISO Response
20	Transmission Agency of Northern California Submitted by: Rin Helzerman	
20a	Over-Reliance by the CAISO on Reductions in COI OTC to Mitigate Overloads The TPP studies noted a number of issues due to an outage of the Table Mountain-Tesla and Table Mountain-Vaca Dixon (the "Table Mountain-South") 500-kV lines if the California Department of Water Resources (CDWR) generation at Hyatt and Thermalito is not tripped via RAS, and identified potential mitigation solutions for each. The solutions suggested by the CAISO included upgrading the impacted line(s), limiting COI transfers, limiting generation in northern California, or modifying other existing RAS to drop generation at other locations. However, with one exception, the only form of mitigation discussed in any detail in the draft Transmission Plan was limiting COI transfers. As noted previously, TANC is: • Concerned that not assessing all of the available mitigation options might lead stakeholders to believe that the only option is to limit COI imports and lead the CAISO to a sub-optimal result; and • Convinced that all of the impacts of limiting COI imports have not been adequately studied and is concerned about CAISO statements that limiting COI import capability (by reducing the existing nomograms) does not impact the reliability of the system. With respect to the above, it is noted that operating studies done for 2013 and 2014 have indicated that curtailing generation interconnected to the impacted PG&E 115-kV system south of Table Mountain would be considerably more effective in mitigating overloads on these facilities than would curtailing COI transfers.	The reliability assessment did not identify a reliability need or an economic need to due to congestion to mitigate the impacts identified with the COI transfer limits identified in Appendix B of the Draft Transmission Plan.
20b	System Modeling Inaccuracies in the CAISO Base Cases During recent operational studies for the summer of 2013 and the spring of 2014, the involved parties (the CAISO and members of the Operating Studies Subcommittee) determined that the base cases initially used in these studies (derived from WECC cases) did not model the correct ratings on a number of PG&E facilities in northern California. The issue as to how these facilities were modeled in the TPP cases was raised by TANC (as well as by the Western Area Power Administration (Western) and the Sacramento Municipal Utility District (SMUD)) at the November 21, 2013 stakeholder's meeting and	The ISO has responded to stakeholder comments from the September and November stakeholder meetings. The base case concern referenced in the comments is related to potential discrepancies in operational study cases not the TPP base cases. At the November stakeholder meeting, TANC and SMUD indicated potential concerns related to the TPP without any specific details of the concerns provided at the meeting or in the stakeholder comments submitted by stakeholders as a part of the ISO TPP which are posted on the ISO website under the 2013-2014 Transmission Planning Process webpage. As indicated TANC submitted to the ISO on February 5th, 2014, outside the TPP

No	Comment Submitted	ISO Response
	in TANC's written comments submitted on October 10, 2013 and December 11, 2013. To date, these comments have not been addressed by the CAISO. As TANC never received a response to the above comments, TANC initiated discussions with PG&E in December 2013 as to the correct modeling of the PG&E 115-kV lines located south of Table Mountain in the 2015, 2018, and 2023 time frames. PG&E did provide such information and TANC compared it to the modeling of these facilities in the TPP cases posted by the CAISO. The results of this comparison (shared with the CAISO on February 5, 2014) indicated that: • The 2015 TPP case modeled incorrect ratings on four of the pertinent facilities; • The 2018 TPP case modeled incorrect ratings on three of the pertinent facilities and incorrect ratings and impedances on nine of the pertinent facilities1; and • The 2023 TPP case modeled incorrect ratings on three of the pertinent facilities. The above information indicates that had the modeling for the PG&E facilities used in the TPP cases corresponded to the information provided by PG&E, the results of studies done by the CAISO for all three study years would have been different than those presented in the draft Transmission Plan. As a result of the above modeling inaccuracies, TANC remains concerned that the potential impacts on COI transfer capability or the need for reinforcements to the transmission grid could well be greater than those identified during the TPP studies. On February 5, 2014, TANC forwarded to the CAISO a document that discussed the modeling inaccuracies discussed above. On February 21, 2014, TANC received a response from the CAISO which notes that "…we have ensured that the issues identified do not affect long term results." Later in the CAISO's response, it is acknowledged that there were inaccuracies in the 2018 data due to changes in forecast in-service dates for certain transmission projects and it is implied that the CAISO does not view any issues in 2018 as "long term" in nature. While it may be argued that 2018 is not "long-term," TANC is of the opinion that the modeling inaccuracies noted in 2018 need to be addressed and that there remain issues that need to be	stakeholder process, concerns with respect to discrepancies within the TPP base cases and base cases that TANC received from PG&E in January of 2014. The ISO responded to TANC's specific concerns on February 21. 2014. The bulk of the differences relate to a 1 year delay of a capital project by PG&E. As part of the ISO's annual Transmission Planning Process, the base cases are developed based upon the Unified Planning Assumptions and Study Plan, developed through the stakeholder process which includes the current schedule for approved transmission projects. After the base cases were prepared and the ISO's reliability assessment was performed, the in-service date for the identified South of Palermo project changed from 2018 which has been reflected in the Draft Transmission Plan to 2019. The change in one year results in a difference between the ISO's 2018 cases and information TANC has received more recently from PG&E but does not impact the long-term assessment for 2023. The remainder of changes identified by TANC related to discrepancies in the 2023 case is on radial lines, either gen tie or radial lines serving load. We appreciate the identification of those issues and will follow up with PG&E – however, the ratings of these lines have no impact on the COI studies as they do not carry flows parallel to the higher voltage system

No	Comment Submitted	ISO Response
	addressed in northern California as soon as possible, and that cannot wait until the 2014-2015 TPP studies are completed. With respect to the South of Palermo Transmission Reinforcement Project, TANC notes that in Appendix B to the draft Transmission Plan it states that this Project was expected to be in-service by 2018 and was modeled in the 2018 Heavy Summer Peak case. However, Table 7.1-2 in the Transmission Plan states that the South of Palermo Transmission Reinforcement Project will not be in service until May 2019.	
20c	Discussion of Study Results Appendix B to the draft Transmission Plan contains nomograms for 2015 and 2018 (Figures B1.2-4 and B1.2-5) that depict the COI flow limits for different levels of northern California hydro generation and for various scenarios with and without the DWR RAS (refer to the nomograms on Page 4). Appendix B also contains two tables (Tables B1.2-1 and B1.2-2) that summarize the information on the nomograms as well as provide information as to the limiting facility for the pertinent operating point. As noted above, both the 2015 and 2018 TPP bases case used in developing these nomograms contained modeling inaccuracies. The decreases in the COI flow limit at the 80 percent hydro level for the 2015 and 2018 cases, as depicted in the above mentioned nomograms, are summarized in Table 1. Preliminary studies by TANC that utilized the posted TPP cases (in which the CDWR generation was at 710 MW in 2015 and at 806 MW in 2018, Colusa generation was at 690 MW in both cases, and Hatchet Ridge generation was at 103 MW in both cases), indicate that the above reductions in the COI flow limit would likely be much larger if the modeling deficiencies in the 2015 and 2018 TPP cases were corrected. Specifically, these studies indicate that: 5 • The reductions to the COI flow limit in 2015 would be 1,500-1,600 MW higher than the values noted above; and • The reductions to the COI flow limit in 2018 would be 1,200-1,300 MW higher than the values noted above. As discussed above, TANC is of the opinion that there are issues that need to be addressed in northern California as soon as possible, and that cannot wait to be resolved until the studies associated with the 2014-2015 TPP effort are	The reliability assessment did not identify a reliability need or an economic need to due to congestion to mitigate the impacts identified with the COI transfer limits identified in Appendix B of the Draft Transmission Plan. In addition, the historical northern California hydro output maximum has been at or below the 80 per cent.

No	Comment Submitted	ISO Response
	completed. TANC is willing to work with the CAISO and the other impacted parties (PG&E, SMUD, Western, and PacifiCorp) on resolving these issues.	
20d	Economic Analyses As noted in the previous comments submitted by TANC, the lack of congestion on Path 66 shown in the economic studies is a considerable departure from historical congestion on that Path. TANC references the CAISO's own market reports for the high level of historic congestion along the COI and the high costs that have been associated with that congestion. The draft report shows just three hours of congestion on the COI for 2018 and no congestion for 2023. The 2018-2023 congestion assumptions represent a significant departure from recent reports from the CAISO. In fact the *2012 Annual Report on Market Issues & Performance* published by the CAISO Department of Market Monitoring (April 2013 Table 7.1 [p. 151]) shows considerable congestion over the prior three years: 11percent of the hours in 2010 and 2011, and 42 percent of the hours in 2012 for the Pacific AC Intertie (PACI) were congested, and the COTP rights within the CAISO BAA was congested 1 percent, 12 percent, and 8 percent in 2010-2012, respectively. This table indicates that Path 66 was the most congested path in the state every year. It is consistently the most costly in terms of congestion charges. The *Market Monitoring Report*, Table 7.1, showed that congestion on the PACI cost between $20 million and $84 million from 2010 to 2012. TANC is concerned that the CAISO's TPP studies understates the congestion along Path 66 and fails to account for the impact the expected reduction in the transfer capability of Path 66 will have on congestion on COI (see comments above regarding DWR RAS). Congestion on Path 66 is very costly to California. By assuming in the 2013-14 economic studies that there is virtually no congestion along the COI, the CAISO fails to fully account for recent experience, the CAISO's own tariff, and the financial impact of congestion from PG&E's loss of the CDWR remedial action.	The ISO congestion analysis for 2018 and 2023 takes into consideration the planned upgrades to the transmission system, forecast loads and generation additions and retirements which will impact future operation of the system as reflected in the production simulation models.
20e	Transmission Access Charge Forecast TANC appreciates the addition of a Transmission Access Charge (TAC) forecast indicating the impact of recommended and approved projects from this cycle. TANC encourages the CAISO to continue the development and improvement of this model. TANC recommends the CAISO re-visit its $250 million dollar floor on transmission development in the outer years and possibly rely on a value more representative of recent history.	The ISO acknowledges that the estimate of the floor is an approximation, and is open to considering input on the rationale for a different value. We look forward to your input in future planning cycles.

No	Comment Submitted	ISO Response
21	The Nevada Hydro Company Submitted by: David Kates	
21a	1. Summary of Comments While ISO recommends a number of what are called "Group I" projects to fill the reliability need in Southern California, the ISO admits that these projects are not able to bring the system into reliability compliance in the next five to seven years.1 Nor are they particularly timely or inexpensive. Two of the three recommendations are estimated by ISO to enter service in 2018 and the third in 2020. The ISO has estimated the total cost for these projects at between $870 million to $1.08 billion. Further, its proposals for the "Group II" and Group III" projects, with the exception of Nevada Hydro's TE/VS Interconnect, are vague and couched in terms of long-term fruition. The problem is that the area needs solutions to its reliability problems now, and denials, no matter how fervent or well-articulated, is not a good engineering or good politics. In its review of the Draft Plan, it is clear that the ISO has before it the facts as to the dire state of affairs in Southern California and particularly in San Diego. Nevada Hydro was flabbergasted at the scope of issues Appendix C identified in San Diego area. Because it is the responsibility of the ISO to address overall system reliability in Southern California, Nevada Hydro sees also that the ISO has no solution to remedy this multi–utility problem, and that it, and the area utilities, will continue to remain out of compliance with NERC and FERC mandates. Perhaps the ISO will now seriously consider Nevada Hydro's TE/VS Interconnect as the near term solution it is. Nevada Hydro therefore requests: 1. As described in Section 2 below, that the TE/VS Interconnect has been incorrectly categorized as a Group 2 project should be transferred into Group 2. As described in Section 3 below, the Draft Plan's failure to treat LEAPS as a preferred resource contradicts the assumptions set forth in the Draft Plan and fails to follow the milestone schedule in the project's interconnection agreements carefully negotiated among all of the parties, including the ISO. The ISO cannot agree with this timeline through the interconnection process and then delay the project through this TPP. Additional comments are provided in Section 4 relating to study assumptions, other issues in the Draft Plan, and to issues in the Appendices.	Please refer to the detailed responses below.
21b	2. Group 1 reliability projects for Southern California are	

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<tr><td></td><td>miscategorized and do not solve the near term reliability issue

Nevada Hydro has concerns about the Group 1 classification of reliability projects in Southern California. These concerns include Nevada Hydro's belief that the projects identified are misclassified and do not solve the reliability problem facing the region. As described below, Nevada Hydro believes that the TE/VS Interconnect rightfully should be a Class 1 project and if properly designated, the Group 1 projects would then solve the regional reliability problem as soon as 2016 or 2017 (well ahead of the other proposals), while substantially reducing the overall cost per MW of the proposed Group 1 solutions.

2.1 Categories for Southern California reliability assessment and approval are artificial and not based upon relevant criteria

Nevada Hydro sympathizes with ISO staff regarding the difficulty it faced in determining how to analyze the range of proposals it received. As presented, the ISO classified these submissions as being part of one of three "Groups", and evaluated four Group 1 projects, while 3 projects and variations were evaluated under Group 2. Further, the ISO is recommending the Group 1 projects to its Board "at this time".

Nevada Hydro notes that the cost of each of these Group 1 projects ranges up to "$700 million", although the basis for and the reliability and completeness of these estimates is not at all clear. In addition, the projects are described as being "in service" between mid-2018 and December 31, 2020.

The ISO justifies its groupings of projects a number of ways:
• First, on page 102, the Draft Plan claims that these Group 1 projects somehow "optimize the use of the existing transmission lines in the San Diego and LA Basin study area." The Draft Plan fails to provide any support for this claim, nor why such "optimization" is important, and important enough to commit perhaps $1 billion of ratepayer funds for this "optimization".
• The Draft Plan also notes that with regard to the Group 2 projects, that "[S]iting is expected to be challenging for all these alternatives" and that these Group 2 projects "represent higher cost, new transmission right of way, lengthier development timelines, and higher regulatory uncertainty that [sic] the Group I projects." Nevada Hydro addresses why these</td><td>As set out in page 94 of the draft 2013-2014 Transmission Plan, the group 1 projects were defined as those projects that do not require new transmission lines that require new right of way. The TE/VS proposal does not meet this category. This grouping was developed for discussion and study purposes.

The Mesa loop-in and flow control projects and cost estimates were submitted into the ISO request window, and meet several identified reliability needs as documented in the draft Transmission Plan. Please refer to the response to comment 1a from BAMx above, which also reiterates the reasons the group 1 projects are being recommended for approval at this time.

The Mesa loop-in, flow control, and reactive support projects balance and boost the flows on the existing transmission lines so that that increased asset utilization is achieved. Without these upgrades, the existing transmission line flows are unbalanced and voltages are depressed so that the local generation capacity needs are much higher due to the need to mitigate line overloads and voltage instability problems.</td></tr>
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No	Comment Submitted	ISO Response
	statements are incorrect when applied to the TE/VS Interconnect in Section 2.4. • The Draft Plan notes further on page 101, that "The recommended strategy also provides the least risk of the need for delay in compliance with OTC generation requirements." While Nevada Hydro was not aware that the ISO has such influence over the water regulator, Nevada Hydro describes in Section 2.4 why its TE/VS Interconnect can be on–line as soon as 2016 or 2017, in time to address the OTC mandate without further disruption to the reliability of the Southern California grid. • Finally, the Draft Plan claims on page 101, that "it is not necessary or reasonable to seek approval" of LEAPS (as a "more expensive alternative") and the TE/VS Interconnect (as a Group 2 project) apparently because Nevada Hydro has developed timelines to meet the upcoming crisis that "are extremely aggressive and potentially unlikely to be met given the need for reliability and the higher than usual degree of uncertainty with many of the inputs into this analysis." If Nevada Hydro understands this logic, perhaps if it had not developed its aggressive timelines to meet the need it sees, then the ISO would have considered the projects now? Nevada Hydro developed its timeline in conjunction with the ISO and the area utilities, and reduced this timelines to firm milestones in its recently signed interconnection agreements with the ISO and area utilities. The ISO cannot at the same time agree with this timeline through the interconnection process and use it as reason to delay the project in this TPP. To Nevada Hydro, the Group 1 projects appear to be short-term solutions to a problem better solved by taking a holistic perspective to address the full scope of problems facing the region, rather than individual localized fixes. Moreover, this must be done now. Given the dire state of affairs, Nevada Hydro contends that more relevant parameters for placing candidate projects into Group 1 should relate to the maturity, effectiveness and economics of the project itself. For example: • The project's actual routing and permit status; • The reliability of and level of detail of engineering and cost estimates; • The work remaining to be completed before construction can actually	

No	Comment Submitted	ISO Response
	commence; • The range of reliability issues the project can solve; and, • The cost of the proposal related to the level of benefits it provides.	
21c	2.2 The identified Group 1 projects do not meet the ISO's own requirements for inclusion Whether the identified projects were included in Group 1 because they "optimized use of existing transmission lines, because of "lower cost", shorter development schedules, or less perceived risk by the ISO, the Group 1 projects seem incorrectly classified. For example: • Flow control at the Imperial Valley substation requires "coordination with CFE", further analysis as to the type, configuration and cost of equipment and one or more competitive solicitations. While the ISO provided no indication of the status of environmental work, engineering seems far from complete and Nevada Hydro sees no evidence of any shorter or less risky development to arrive at a hoped for June 2018 in service date. • San Luis Rey MVAR appears to be justified only "when coupled with other projects." • Nevada Hydro wonders how the roughly $600–700 million (presumably 2014 dollars) Mesa Loop–in project meets these standards when the ISO itself believes it cannot be in service until the end of 2020, more than 6.5 years into the future.	The ISO grouped projects for analysis into groups of similar function and characteristics. The group 1 projects are projects that do not require new transmission lines that require new rights of way. A number of group 1 projects are recommended for approval, but not all of them at this time. TE/VS does not meet the characteristics of group 1 projects, as new transmission line right of way is required. The ISO considers it is not viable to pursue permitting a new transmission line on a new right of way when viable options exist that do not require new transmission line rights of way.
21d	2.3 The projects identified in Group 1, even if implemented, do not solve the reliability problem facing Southern California As the ISO clearly states on page 104, the Group 1 projects *do not address all of the requirement identified for the San Diego and LA Basin area; they result in a residual need of up to 900 MW overall for those areas, assuming conservative estimates for their overall effectiveness and based on the resource assumptions discussed earlier.* Nevada Hydro has also concluded that with the Group 1 projects fully implemented, the Southern California reliability problem still exists. While the Mesa Loop in project contributes to solving the reliability problem in the SCE system, it fails to protect the SCE's southern flank. It and the other Group 1 projects do not address the problem south of Serrano and in San Diego, particularly in the event of a system collapse (either as a G–1/N–1 or N–1–1 contingency realized). While Nevada Hydro does not minimize the importance	The group 1 projects recommended for approval along with procurement of conventional and preferred resources with adequate characteristics are expected to meet the bulk of the residual reliability needs in the 10 year planning horizon. The ISO's analysis indicates that there may be residual need depending on the precise locations of preferred resources in the area, and other factors, and the ISO will update the residual need in the 2014-2015 planning cycle.

No	Comment Submitted	ISO Response
	of addressing SCE's individual reliability concerns, it is the responsibility of the ISO to address overall system reliability in Southern California, particularly when an outage in the San Diego system so clearly affects SCE. For example, Nevada Hydro has modeled the classic N–1–1 contingency of the loss of the IV-Miguel and Sunrise lines and has found that the identified Group 1 projects do not prevent system collapse. Figure 1 – N–1–1 SONGS Areas shows that even with roughly 500 Mvars included at SONGS, the 230 kV system is only running at 130.2 kV under the N–1–1 contingency; a collapse situation. Further, under the same assumptions, Figure 2 – N–1–1 Serrano Area and Figure 3 – N–1–1 Imperial Valley Area show a system collapse south of Serrano.	
21e	2.4 The TE/VS Interconnect should properly be classified as a Group 1 project As described above, Nevada Hydro has concluded that the projects included in Group 1 do not meet the ISO's own criteria. Nevada Hydro therefore urges the ISO to properly consider the TE/VS Interconnect as a Group 1 project, now. Not only is it much farther advanced then all Group 1 projects in terms of routing, permitting, engineering and cost, but it will also solve the reliability problem in Southern California economically, timely and substantially reduce the overall societal cost per MW of the Group 1 projects. 2.4.1 Permitting and Approval status As Nevada Hydro pointed out in its Request Window filing: • The TE/VS Interconnect has routing that has been fully vetted with the US Forest Service. As you know, 30 of the approximately 32-mile length of the line traverses the Cleveland National Forest. This vetting process involved detailed evaluation of the proposed location of each of the 170 transmission towers to be located on Forest land, as well as substation and work locations within the Forest. Project and Forest staff met and discussed each proposed location to assess existing site conditions, proposed site access methods, tower erection as well as site maintenance and rehabilitation. A sample page from the completed Forest Workbook appears as Figure 4 – Sample Page from Forest Workbook. • The TE/VS Interconnect has most of its engineering work completed. This includes the project plan, profile, and line sag assessment prepared by SAE Towers; detailed substation design and engineering prepared by Siemens AG and cost estimate prepared by Siemens AG and Barnard	As noted above, Group 1 projects are those projects which do not require new transmission lines. The ISO intends to study the Group 2 and 3 solutions in the 2014-2015 planning cycle and will consider the planning and environmental work conducted by Nevada Hydro at that time. However, transmission solutions of the advocated by Nevada Hydro, involving new transmission lines, will be subject to the competitive solicitation process. The design and route development already accomplished by a particular project sponsor will be considered as part of that process.

No	Comment Submitted	ISO Response
	Construction Inc. A sample page of SAE's analysis appears as Figure 5 – Sample Tower Analysis Page. Nevada Hydro has provided engineering drawings and its detailed cost estimate as part of its the Request Window filing. • The TE/VS Interconnect has rate incentives granted by the FERC after Nevada Hydro demonstrated with independent evidence that the project provides benefits to ratepayers. FERC's Order is in docket ER06–278, and was included in the Request Window filing. This Order from the FERC will allow Nevada Hydro to move rapidly from permitting to construction. • The TE/VS Interconnect has a final environmental impact statement ("FEIS") that has been issued by FERC addressing both the TE/VS Interconnect and the sister LEAPS project describing the project FERC could approve and the mitigations it and the Forest Service would impose on the approved project. The FEIS is now in the process of being updated. • The California Public Utilities Commission ("PUC") has completed an extensive analysis of the TE/VS Interconnect under the California Environmental Quality Act ("CEQA") in connection with its analysis of the Sunrise Powerlink project proposed by SDG&E.5 That analysis included a review of the TE/VS Interconnect as a CEQA alternative to Sunrise. The TE/VS Interconnect was identified as the environmentally superior transmission project in that proceeding. • Nevada Hydro is preparing to refile its own application to the PUC for approval of the TE/VS Interconnect shortly. With its routing vetted with the landowner, and with much of the environmental work and engineering complete, Nevada Hydro is confident that its present estimate of $750 will not vary substantially. This cost includes all costs; including detailed interconnection upgrade costs from SCE and SDG&E, mitigation costs, and all financing costs. Nevada Hydro does not believe the other Group 1 projects have anything close to the level of detail Nevada Hydro has, most of which has been provided to ISO staff. Nevada Hydro is also confident that at this cost, the system benefits will far outweigh the project's cost, thereby meeting the test to receive approval from the PUC. As a result, Nevada Hydro can have the TE/VS Interconnect project operating well ahead of other proposed Group 1 projects identified in the Draft Plan.	

No	Comment Submitted	ISO Response
	With some cooperation from permit authorities, Nevada Hydro's real time estimate for commercial operation is late 2016 or early 2017, placing it at the leading end of the other projects identified in Group 1.	
21f	2.4.2 The TE/VS Interconnect will solve the reliability crisis in Southern California As Nevada Hydro noted in Section 2.3, the identified Group 1 projects fail to solve the reliability issue in Southern California. However, when the TE/VS Interconnect is added to Group 1, the system becomes stable. Powerflow diagrams showing the effect of incorporating the TE/VS Interconnect into the Southern California system are provided in the following self-explanatory figures: Figure 6 – N–1–1 with TE/VS Interconnect, SONGS Area Figure 7 – N–1–1 with TE/VS Interconnect, IV Area Figure 8 – N–1–1 with TE/VS Interconnect, Serrano Area	The ISO plans to review the need for Group II and III projects in the 2014-2015 transmission planning cycle.
21g	2.4.3 The TE/VS Interconnect will reduce the cost per MW of approved Group 1 Projects Nevada Hydro's extremely detailed cost estimate combined with the ISO's own estimate that the TE/VS Interconnect will be able to import at least 1,500 MW (Nevada Hydro believes the figure is 1,800 MW), will allow the TE/VS Interconnect to reduce the cost per MW of approved Group 1 projects from more than $925,000 to less than $675,000–more than a 30% reduction. These calculations are shown below. Nevada Hydro notes that of the projects presently identified in Group 1, all have a higher cost per MW than does the TE/VS Interconnect, even though the TE/VS Interconnect has a detailed, inclusive and nearly firm cost.	The ISO plans to review the need for Group II and III projects in the 2014-2015 transmission planning cycle.
21h	3. LEAPS should have been included as a Preferred Resource in the LA Basin and was not In Section 1.8 of the Draft Plan, the ISO discusses its analysis of how "non–conventional", "non– transmission" or "preferred resources" "can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure." The Draft Plan notes on page 26 that *The general application for this methodology is in grid area situations where a non-conventional alternative, such as demand response or some mix of preferred resources could be selected as the preferred solution in the ISO's transmission plan rather than the conventional transmission or generation solution. This would be possible in situations where the timeline for an*	The ISO acknowledges that LEAPS could meet the resource needs in the LA Basin and Sand Diego areas. Our understanding is that large pumped hydro does not qualify as a preferred resource, but that does not mean that it cannot be utilized as a resource for this area. The ISO will provide additional clarification in Chapter 2 of the final draft transmission plan regarding the analysis of the proposed pumped storage facility. Please refer to footnote 8, page 26 of the draft 2013-2014 Transmission Plan for the ISO's interpretation of the term "preferred resource".

No	Comment Submitted	ISO Response
	identified need allows time for monitoring the development of non-conventional alternatives before a conventional solution would be required to be approved. The Draft Plan describes, on page 8, "non–conventional resources" as including, for example demand response and storage. The Draft Plan never exactly describes what the term "non–transmission resources" means, although it is mentioned throughout the document. With regard to "preferred resources", perhaps ISO staff is not clear on its own definition. If we heard correctly during his Workshop comments, Mr. Stark advised that Nevada Hydro's LEAPS facility is not a "preferred resource." Clearly, he is incorrect, as section 1.8 of the Draft Plan, describes "preferred resources" as including energy storage." Further, and as noted in the CPUC's recent Track 4 Long Term Procurement Decision, *Each utility should solicit all resources as required by this decision, and may propose for approval any set of resources which can meet the LCR need in its portion of the SONGS service area consistent with the authorized resource ranges herein. Within the categories that include preferred resources, bulk energy storage and large pumped hydro facilities should not be excluded.7* LEAPS is clearly an "energy storage" facility located in the load pocket. Whether the ISO is considering "non–conventional", "non–transmission" or, "preferred resources", it should have analyzed Nevada Hydro's LEAPS pumped storage project in this Section, and clearly, it did not. This is particularly troubling to Nevada Hydro when the ISO states on page 27 that: *The ISO applied in the current planning cycle a variation of this new approach in principle to several specific local areas in Southern California: the LA Basin and San Diego areas. Because of the magnitude of the projected reliability needs in these areas incremental transmission options were also studied to complement non-conventional alternatives (i.e., preferred resources) to reduce the need for conventional generation to fill the gap. Thus, unlike the generic application of the methodology in future transmission planning process cycles where preferred resources are considered as an alternative to transmission, the main focus of this effort with respect to the LA Basin and San Diego areas was to evaluate non-conventional alternatives and identify performance attributes needed from these alternatives that could effectively address the local reliability needs in these two priority areas as part of a basket of resources.*	

No	Comment Submitted	ISO Response
	Further errors relative to LEAPS as are found in the following assertions, from page 27: *In the course of reviewing energy storage projects — both battery and pumped hydro — proposed in this planning cycle as mitigations to reliability needs, the ISO developed a further appreciation for considerations that will need to be refined in future planning cycles. These projects were proposed as rate-based transmission assets, as opposed to market assets providing local resource capacity to utilities, and as such, are precluded from other market participation. While we could not recommend approval of these projects in this cycle for other reasons, we believe energy storage projects have significant potential for addressing renewable integration needs and plan to evaluate this potential in future cycles as well as potential barriers to achieving this potential. [Emphasis added.]* First, Nevada Hydro requests that the ISO specify what "considerations" it will need to "refine" in future planning cycles and why these considerations could not have been applied to LEAPS now. Further, Nevada Hydro did not propose that LEAPS be included in any "rate base" as claimed. Third, the ISO must clearly specify the reasons why it could not "recommend approval of these projects in this cycle". Also on page 27, the ISO notes that: *As the ISO's work in this area evolved in determining the necessary attributes, it received several sets of preferred resource development scenario input data from Southern California Edison for the LA Basin.* In Footnote 9, the ISO noted that, "No other stakeholders provided preferred resource scenario input data for consideration by the ISO." Nevada Hydro was not aware that the ISO had requested such scenarios, but was aware that the ISO was to "evaluate non-conventional alternatives and identify performance attributes needed from these alternatives that could effectively address the local reliability needs in these two priority areas as part of a basket of resources". In its Request Window filing, Nevada Hydro provided detailed operational attributes of LEAPS for use by the ISO for this process. As these operating attributes of LEAPS we apparently ignored for those provided by SCE, Nevada Hydro requests that the operating scenarios for LEAPS be added to the analysis described in this section of the final report.	
21i	4. Other Comments 4.1 Nevada Hydro agrees that the ISO is facing "unique challenges" In the Forward to the Draft Plan, the ISO admits to a particularly "unique	

No	Comment Submitted	ISO Response
	challenge" it is facing: *Transmission solutions that are pushing the boundaries of optimizing existing assets and require extensive implementation coordination with neighboring systems.* Nevada Hydro agrees wholeheartedly. It has reviewed the WECC summary of the SCE system in the 2023 heavy summer load flow case, shown in Figure 9 – WECC System Summary for SCE. This analysis more than supports the ISO's concern. As shown by WECC, the system load for the SCE system is modeled with a leading power factor, with 2182.1 Mvar in excess of a net balance of reactive power consumption versus reactive power provision at the load points. This is a highly unusual condition for heavy load times, and is unique in WECC for all its systems in the case. Nevada Hydro also notes the following: • Regarding the transmission line losses and charging for 500 kV lines and 230 kV lines, the reactive power losses for the two voltages are approximately 15 times the real power losses. Nevada Hydro also notes that the line charging for the 500 kV lines versus the line losses is approximately the inverse of the situation for the 230 kV lines. • Regarding the difference between the real power and reactive power losses and line charging for the 115 kV and 66 kV lines, with little charging to offset the reactive losses, the reactive power losses, at about 3,500 Mvar, is a significant drag on system voltage. • The total of all line charging is approximately half of the losses, and over a third of that charging comes from the 500 kV. • Under critical contingency situations, reactive power losses increase. This is a major problem when the loss of elements of the backbone transmission is lost and flows are increased on the 230 kV system. This data confirms the sense reflected in the Draft Plan that the present system has been pushed to its reliability limits. It also shows that the future for transmission in Southern California will require the move to a 500 kV base more extensive than is presently in place. This is especially important as the amount of generation in the coastal regions of Southern California declines because of regulator pressures and aging, balanced by new generation sources requiring large land areas not available near the coast. Nevada Hydro recent Whitepaper titled, "Future Transmission Needs in Southern California" is attached to provide additional reference material.	

No	Comment Submitted	ISO Response
21j	4.2 Generator Interconnection and Deliverability Allocation Procedures The Draft Plan describes the procedures it intends to use to assess interconnection and deliverability commencing on page 20. However, these procedures fail to take account the present status of the LEAPS project, specifically, its queue position, its completed interconnection agreements and the timing of milestones agreed therein and the fact that deliverability studies are long complete. The new procedures described in Section 1.3 at page 20 introduces *a new planning objective into the transmission planning process: to provide deliverability status for new generating resources in a total amount and geographic distribution corresponding to the base case resource portfolio the ISO uses in the transmission planning process for purposes of identifying public policy-driven transmission solutions. In this way, the transmission planning process identifies any policy-driven upgrades needed to provide deliverability status to a generation portfolio that is consistent both in total volume and geographic distribution with how the state expects its LSEs to procure resources to meet their 33 percent RPS requirements.* In Nevada Hydro's view, this new procedure is fundamentally unfair to those projects, like LEAPS, that have already been through the interconnection approval process and that provide resources that will allow LSEs to meet their RPS requirements today. LEAPS, like other higher queued projects, has deliverability, is absorbing all upgrade costs and has executed interconnect agreements with definitive timetables.	Section 1.3 (Generator Interconnection and Deliverability Allocation Procedures) summarizes for the benefit of stakeholders the generation interconnection processes that are already approved by FERC after completing a full stakeholder process. These processes do not impact the deliverability status of projects like LEAPS that have already completed the interconnection study process.
21k	4.3 Renewable Integration On page 25–26, the ISO notes that it is now planning to address flexible resources in the 2014–2015 transmission plan where it will also look at overgeneration. While the Draft Plan notes that "[R]renewable integration operational studies have focused in particular on the need for flexible resource capabilities", the ISO continues to largely push aside the LEAPS facility, which will be the most flexible of resources to be located in the Southern California load pocket with the ability to address the loss of SONGS, now. Because it is the responsibility of the ISO to manage the state's grid, Nevada Hydro urges the ISO to address flexible resources as a high priority item. Particularly as resources like LEAPS can serve multiple needs in the reliability impaired Southern California grid, it must be assessed holistically, including the full range of benefits advanced pumped hydro projects can contribute to grid stability and operation. Nevada Hydro would be	As indicated in the 2014-2015 Transmission Planning Process draft Study Plan the ISO will be undertaking an assessment of the potential risk of over-generation within the 2014-2015 planning process.

<table>
<tr><th>No</th><th>Comment Submitted</th><th>ISO Response</th></tr>
<tr><td></td><td>pleased to work closely with ISO staff on this endeavor.</td><td></td></tr>
<tr><td>21l</td><td>4.4 Study Assumptions
Nevada Hydro is concerned that some of the study assumptions do not reflect the real world limitations of the present system. An example of this missed limitation may be found in Table 2.3-5. Here, the ISO has included the ratings of WECC Paths 43 and 44 at their levels before the retirement of SONGS. While Nevada Hydro believes these limits no longer apply, this is an example of the complexity of planning in this area, with the prospect of missed understandings of limits, which could lead to the kind of disaster noted in the "FERC/NERC Staff Report on the September 8, 2011 Blackout". As the ISO is well aware, the staff of these national regulatory bodies conducted an intensive review of the operating and planning practices of the responsible bodies in Southern California and WECC. The report draws parallels between the August 2003 blackout in the northeastern U.S. and this event. The report states,
"Similarly, this inquiry's report found that several entities' operational and long-term studies did not adequately ensure the reliable operation of their systems. Specifically, both reports described relevant planning studies that: (1) did not adequately identify and study critical external facilities; (2) did not adequately analyze potential contingency scenarios; and (3) were based on inaccurate models and invalid system operating limits (SOLs)."</td><td>The ISO and PTOs are continuing to review the need for these path ratings. Full contingency analysis was performed in the ISO studies and all NERC planning standards were met.</td></tr>
<tr><td>21m</td><td>4.5 Comments on Appendix A
Nevada Hydro understands that Appendix A is primarily set out to define the generation to be modeled in the various analyses to be conducted as part of the Draft Plan. While the tables for existing generation are clear, there seems to be confusion about whether the Maximum Capacity values listed are gross values (before station service use is deducted) or net values. For example, the "Maximum Capacity" listed for Alamitos is shown as 2,010 MW. This appears to be a gross generation value, since the Pmax shown in load flow cases reflects 1,950 MW for this station. On the other hand, the values shown for SDG&E stations, listed by unit rather than plant total, appear to be net values. The generation shown for Palomar and Otay Mesa are shown as a block.
In addition:
The Ocotillo Express wind farm probably should be considered to be outside the San Diego load pocket since it is outside of the load pocket for the most critical contingency facing SDG&E. This appears to be the</td><td>The "Maximum Capacity" listed for Alamitos is based on the CPUC Net Qualifying Capacity (NQC). The "Maximum Capacity" values shown for SDG&E's Palomar and Otay Mesa energy centers are based on the CPUC NQC that are modeled by unit in power flow cases and listed by plant total in Appendix A.
The Ocotillo Express wind farm was considered to be outside the SDG&E load pocket as it is outside of the load pocket for the most critical L-1-1 outage of</td></tr>
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<tr><td></td><td>principle applied in not listing the generation located near Imperial Valley, and should be carried through for Ocotillo Express.
• While Breggo Solar has many projects in the San Diego load area, it is distributed generation and should be included as part of that classification, not as a central station.
• The planned new generation includes the Carlsbad Project. It is listed for service in 2016. Nevada Hydro understands that permitting and contracting for the plant is not yet final. Further, if the facility continues as a combined cycle project, construction is generally around thirty months. Unless the facility is to be built with a simpler configuration, it appears that even under the best of circumstances, Carlsbad will miss service in the 2016 summer peak period. As noted, Carlsbad does not yet have a tolling agreement in place. This has been an issue for some time, and it is overly optimistic to assume this issue away now.
• While the Pio Pico Project may not take as long to build as Carlsbad, nevertheless it still has not cleared all pre-construction hurdles. It would be inappropriate to include the project before 2017 without special awareness that all pre-construction hurdles have been cleared.
Finally, there appears to be a category of generation missing from this appendix: The generating units that will be retired for lack of mitigation in compliance with the “Once-Through-Cooling” order. It would be appropriate to add a table showing these units, their required mitigation deadline, and if mitigation is not forthcoming, whether and how much prospective replacement generation is planned and when will it be available for service. Nevada Hydro understands that this is a particularly knotty problem, especially in such complex sites as Huntington Beach.</td><td>East County-Miguel and Occotillo-Suncrest 500 kV lines.
• Breggo Solar was deemed as a utility scale solar generation located in the SDG&E load pocket, and was modeled based on its NQC determined by CEC.
• Carlsbad Project was treated as a proxy of resource available in the SDGE area after Encina plant is retired and was modeled in the 2018 and 2023 cases
• Pio Pico Plant was also considered as a proxy of resource available in the SDGE area after the Encina retirement and was modeled in the 2018 and 2023 cases

Modeling of the once-through cooled generating units followed the State Water Resources Control Board (SWRCB)’s Policy on OTC plants. More detail information on generation project assumption can be found in Section 4.1.9 of the 2013-2014 Study Plan.</td></tr>
<tr><td>21n</td><td>4.6 Comments on Appendix B
Nevada Hydro reviewed Table B3-2 and observed two optimistic and one very surprising assumption in the notes for the table. In terms of rose-colored glasses, Nevada Hydro believes that it is extremely optimistic to assume that Long Beach and the Etiwanda are not being retired. Nevada Hydro believes that it would be a better planning practice to assume that these units are to be retired. This more conservative assumption would help avoid surprising and troublesome outcomes that the ISO would face if it assumed these older and less efficient units were available but turned out to be unavailable.
Nevada Hydro was also surprised to see that the ISO is assuming that the Encina Station will meet OTC compliance by 2018. We imagine that the City</td><td>Long Beach and Etiwanda have not announced a retirement date, so they are reflected in the base cases. However, in the LA Basin and San Diego study area analysis the ISO assumed these units would be retired, as was assumed in the LTPP Track 4 studies. The ISO identified a reliability need for resources in Northwest San Diego in 2018 and in our policy and economic studies we assumed that this need would be met.

As stated above, the ISO will be building upon our analysis in the next planning cycle.</td></tr>
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No	Comment Submitted	ISO Response
	of Carlsbad would be surprised as well. As the ISO provided no support for this surprising statement, it is difficult to believe, particularly as its retirement is being coordinated with development of the Carlsbad Project. Further on Table B3–2, Nevada Hydro suggests that "Conventional Resource Need", may need to be revised if it is deemed prudent to reconsider the status of any of the Long Beach, Etiwanda and Encina units. Omitted from the discussion surrounding Table B3-4 is any indication of what year is being considered. Nonetheless, Nevada Hydro can only conclude from the information presented that the system is in dire trouble for any of the combinations of equipment additions and non-conventional transmission assessments. Of the fourteen possible combinations, only five do not lead to system collapse. And of those five, there is no indication of whether there is compliance with transmission element loading limits. It is likely that if the more conservative assumption on the Long Beach, Etiwanda and Encina units were considered, that none of the options in Table B3-4 would result in anything but a system blackout under the critical contingency.	
21o	4.7 Comments on Appendix C Nevada Hydro has reviewed Appendix C and saw that the impacts of contingencies in SCE and SDG&E systems show that the San Diego system has many and major problems. While SCE has a few thermal overload issues under Category B and a dozen under Category C, SDG&E has dozens of problems, a listing covering 40 pages. These range from some Category A to Category C, including the loss of the two 500 kV lines into the San Diego load area from Imperial Valley. The types of trouble include thermal overloads, voltage deviations, high or low voltage and "voltage instability" (meaning voltage collapse/blackout). It should be obvious that SDG&E and the ISO have a considerable amount of work to bring this system into reliability compliance. Further, the Appendix acknowledges that some of the problems, which are major, cannot be corrected by the SONGS retirement mitigation strategy through the Group I projects. Without the completion of at least a portion of the Nevada Hydro's TE/VS Interconnect, no correction of the reliability shortfall will be possible before 2020 and perhaps later still. It is apparent to Nevada Hydro that the path set out in this Draft Plan will leave San Diego's system integrity in jeopardy until sometime in the next decade. While we understand it may be difficult to hear, the ISO's only choice	As stated above, the ISO will be building upon our analysis in the next planning cycle.

No	Comment Submitted	ISO Response
	may be to move the TE/VS Interconnect to its Group I project list and to pursue its completion with all due haste. While it would be advantageous to have both the Case Springs to Talega 500 kV path and the Case Springs to Rainbow/Escondido path in service, it is possible to gain the needed reliability improvement in a stepwise fashion. This would consist of completing the Case Springs-Rainbow/Escondido portion as soon as possible, probably 2016. Initial testing of system performance with just this leg in place for 2016 heavy summer conditions showed that a system collapse would be avoided for the two major contingencies (L-1-1 or G-1/L-1). Of course having both branches, Case Springs to Talega included, would allow the system to weather the potential contingencies handily. Even if there is some delay (perhaps due to transformer delivery schedules) and the completion of the Talega leg were delayed until 2017, that would still provide an adequate reliability result and still ahead of the partial solutions in the present Group 1 configuration. Nevada Hydro suggests that while the construction work to complete TE/VS in its extended form is in progress, it would be prudent to conduct the development work on the Suncrest to Escondido/Rainbow and on converting the Serrano-SONGS 230 kV line to a Serrano-Talega 500 kV line. Completion of this or a similar project would then provide the transmission capability to handle the impacts of the once-through-cooling retirements. Nevada Hydro notes that the change in reactive power consumption when moving from a normal condition to the N-1-1 worse case situation is about 4,000 MVar. The Group I reactive supply projects are an important part of the reliability problem's solution, but cannot achieve such a result themselves.	
21p	5. Conclusion The ISO has all the facts it needs scattered throughout the Draft Plan. Clearly, the San Diego area particularly is in dire trouble. Clearly too, the situation needs to be address now, to avoid additional fines being levied after the next crisis occurs. The ISO has the tools it needs to solve the problem quickly in the TE/VS Interconnect and, as described herein needs to: • Move the TE/VS Interconnect into Group 1. • Assess LEAPS is a preferred in basin resource in this planning cycle. Nevada Hydro and its development team is standing by to help in any way it can to alleviate the pending crisis. We hope that the ISO will allow us to help.	As stated above, the ISO will be building upon our analysis in the next planning cycle. We will continue to consider the need for solutions like TE/VS.

No	Comment Submitted	ISO Response
22	The Voter Solar Initiative Submitted by: Jim Baak	
22a	I) Modify the Assumption Used in the Preferred Resources Scenarios In its assessment of local Preferred Resources (Non-Conventional Transmission Alternatives Assessment) for the area around the shuttered San Onofre Nuclear Generating Station (SONGS), the CAISO chose to evaluate a number of scenarios that include distributed generation, demand response and energy storage. However, the CAISO (basing its scenarios on ones developed by SCE) did not evaluate combinations including distributed generation (DG), demand response (DR) ***and*** energy storage. We believe this is the most probable scenario and one that would provide additional benefits not identified in the scenarios studied. We strongly recommend CAISO include a scenario to evaluate this additional combination of Preferred Resources.	We will continue our analysis in the next planning cycle and we look forward to your participation.
22b	II) Include Vehicle-Grid Integration Capabilities as a Preferred Resources Option Vote Solar has provided comments and/or testimony in various California Public Utilities Commission (CPUC) proceedings, including the Long Term Planning and Procurement (LTPP), Resource Adequacy (RA) and Alternative Fuel Vehicle (AFV) proceedings, recommending that VGI capabilities be evaluated alongside other Preferred Resources as a viable resource option for replacing SONGS. VGI is a valuable tool for dealing with ramping events, potential daytime over-generation, and evening peaks that could be associated with future high penetration of solar PV. The Governor's Zero Emission Vehicle (ZEV) Action Plan calls for 1.5 million ZEVs on the roads in California by 2025. The CPUC's AFV proceeding has already begun the process of identifying regulations and programs to support achievement of this goal. Consistent with the CAISO's own VGI Roadmap, we recommend CAISO include an estimate of the potential benefits of VGI in its evaluation of Preferred Resources options.	The implications of addressing variability needs have not yet been fully addressed nor mechanisms to address those needs and cost the potential mitigations. At this time, our transmission planning process would not provide an effective means to properly assess the potential benefits of this resource. We will be looking to enhance our analysis in future cycles, and will consider your input on those issues.

No	Comment Submitted	ISO Response
22c	III) Approve the Mesa Loop-In Upgrades As we stated in our testimony and comments in LTPP Track 4, Vote Solar supports the development of the Mesa Loop-In project as a means for improving reliability and expanding options for meeting LA-Basin and San Diego area needs. We are pleased to see that the Draft Transmission Plan supports this project and encourage the CAISO to model additional renewable and Preferred Resources as part of any evaluation of the benefits of the Mesa Loop-In. In its Proposed Decision for LTPP Track 4, the CPUC indicated a strong desire to replace SONGS with Preferred Resources, suggesting SCE and SDG&E could meet the entire Track 4 procurement authorizations with Preferred Resources alone. The retirement of SONGS requires non-carbon emitting resources in order to meet the energy needs of the LA Basin and San Diego areas while protecting air quality and helping the State meet its aggressive GHG reduction goals.	
22d	IV) Approve Upgrades to the Lugo-Mojave Line As detailed in the Draft Transmission Plan, renewable generators in the Desert Area may cause overloads on neighboring transmission systems. This limits the deliverability of renewable generation over a wide area in Southern California. Vote Solar therefore supports the proposed upgrades to the series capacitors and terminal equipment at the Mojave substation along with the suggested operational changes to the Lugo-Mojave transmission line to relieve this constraint. As discussed below, adopting these measures could provide relief to the serious deliverability constraints in the Imperial Valley area. Vote Solar encourages approval of the identified upgrades to this line.	.
22e	V) Take Immediate Measures to Relieve Deliverability Constraints at Imperial Valley The CAISO analysis indicates the closure of SONGS has changed flow patterns in Southern California that now preclude deliverability of any new renewable generation in the Imperial Valley area, potentially affecting up to 1,725 MW of new renewable generation. While CAISO's initial analysis indicates the possible need a for major new transmission line and equipment upgrades, the Draft Plan identifies some near-term options to allow for around 1,000 MW of renewables to be delivered from this area.	.

No	Comment Submitted	ISO Response
	We support these measures, including upgrading emergency line ratings on the Suncrest-Sycamore 230 kV line, adding flow control devices and approving the Delaney-Colorado River 500 kV transmission project. We also encourage CAISO to study cost-effective upgrades or additions to restore full deliverability from the Imperial Valley zone as expeditiously as possible.	
22f	VI) <u>VI) Recommend Approval of the Harry Allen–El Dorado 500 kV Line</u> CAISO's analysis of the Harry Allen–El Dorado 500 kV transmission line yields the highest benefit-cost ratio of any project studied (1.38). Yet the CAISO is recommending further study before recommending this project for approval. CAISO states that this is based on the uncertainty over potential impacts of NV Energy's announced desire to join the Energy Imbalance Market (EIM). While we appreciate the CAISO's careful evaluation of costly and complex transmission projects, we believe the potential negative economic impacts to this project from NV Energy joining the CAISO are minor compared with the significant additional benefits. We are also concerned about the inconsistency in how this project was evaluated compared to the Delaney - Colorado River 500 kV project. While NV Energy has indicated an interest in joining the CAISO, they have not yet signed an agreement to do so. Similarly, Arizona Public Service (APS) and representatives from the Arizona Corporation Commission (ACC) have actively participated in the EIM stakeholder process, yet CAISO is not recommending additional study before recommending approval the Delaney–Colorado River to assess the potential economic impacts of APS joining the EIM. This is despite the fact that the Delaney–Colorado River project has a lower benefit-cost ratio relative to the Harry Allen-El Dorado project . We are unconvinced by the argument for delaying approval of the line pending additional study. Given the deliverability constraints in Imperial Valley and the need to access additional renewable resources, we see significant value in the Harry Allen-El Dorado line. Indeed, CAISO's analysis shows that building the Harry Allen–El Dorado line improves the benefit-cost ratio of the Delaney–Colorado River line. We therefore recommend CAISO recommend approval of the Harry Allen–El Dorado line.	As indicated at the ISO stakeholder meeting on February 27, 2014 on the 2014-2015 Transmission Planning Process Study Plan, the ISO will continue to the study work on the Harry Allen-Eldorado 500 kV line economic analysis as part of the 2013-2014 process subsequent to approval of the 2013-2014 Transmission Plan by the ISO Board; however depending upon the timing of this analysis and its ultimate conclusion, it may be moved into the 2014-2015 transmission planning, process.
22g	VII) <u>VII) Support Approval of the Delaney – Colorado River Line for</u>	

No	Comment Submitted	ISO Response
	Renewable Deliverability Despite the concerns expressed above regarding the lack of evaluation of the potential economic impacts of APS joining the EIM, we encourage approval of the Delaney-Colorado River 500 kV transmission project. However, we disagree with CAISO's presumption that the project's value is its ability to deliver natural gas to Southern California. Rather, we see great value in this project for its ability to facilitate solar (particularly Concentrating Solar Power with thermal energy storage) and renewable energy deliveries to help California meet its GHG reduction goals. Arizona has very high quality solar resources and due to the state's less stringent siting and permitting requirements, generation and transmission projects can be brought online more quickly. And as CAISO states in the Draft Plan, the project will support delivery of up to 1,000 MW of renewable energy from the constrained Imperial Valley zone. These factors, combined with improved reliability, make this project very attractive and we encourage CAISO's approval of this project.	

No	Comment Submitted	ISO Response
23	Trans Bay Cable LLC Submitted by: Sean O'Reilly, Chetty Mamandur and Les Guliasi	
23a	1. Trans Bay is Concerned that the CAISO's Process in Developing the Transmission Plan is not Open and Transparent, as Required Under the Federal Energy Regulatory Commission's ("FERC") Order No. 1000. Over the past several years, the CAISO has worked to improve its TPP to provide a more open and transparent process that allows input from all stakeholders and the opportunity for a broader range of companies to construct transmission.[36] Those efforts continued with the issuance of FERC Order No. 1000, which, among other things, requires that the CAISO conduct an open and transparent TPP. In its filings implementing Order No. 1000, the CAISO stated on numerous occasions that its process is intended to be "fully transparent."[37] With the implementation of competitive solicitations for certain transmission projects, objectivity and transparency in selecting what projects will be included in the Transmission Plans are even more important than ever. In practice, however, the CAISO has failed to reach the ideal of an open and transparent process. The result of the CAISO's failure to conduct a truly objective TPP has been an erosion of confidence in the results of the TPP. Additionally, Trans Bay is concerned that the CAISO's over-reliance on the studies and input from the investor-owned utilities ("IOUs") may be influencing the results of the Transmission Plan, resulting in suboptimal solutions, and limiting the number of facilities that (1) will be available for competition; and/or (2) will not be "slam dunks" for the incumbent utilities in any competitive solicitation process. If the IOUs' preferred projects are consistently chosen over other proposed solutions, without adequate explanation and input from other stakeholders, the process is clearly tainted and lacking objectivity. The clear axiom here is that 'the process drives the results.' Thus, if the process is not truly open to all in a meaningful way, the results of the TPP will not effectuate the purpose of FERC Order No. 1000. More importantly, a flawed process increases the likelihood that the best, most cost-effective project may, to the	

[36] *See, e.g., California Indep. Sys. Oper. Corp.,* 133 FERC 61,224 (2010) (order accepting the CAISO's Regional Transmission Planning Process Tariff filing).

[37] *See, e.g., California Indep. Sys. Oper. Corp., et al.,* 143 FERC P 61,057, at PP 143, 169.

No	Comment Submitted	ISO Response
	detriment of ratepayers, not even be included in the CAISO's Transmission Plans.	
	For example, in prior comments Trans Bay consistently stated that the CAISO should include it and other stakeholders located in the San Francisco Peninsula region, in the analysis and decision making process concerning mitigation solutions for the area. However, the CAISO has not once convened a meeting among the parties in the region to have a detailed technical discussion regarding the proposed alternatives. Rather, it appears that the CAISO relies heavily on the input of only one party – Pacific Gas and Electric Company ("PG&E") – to determine the best technical solution. Although it is appropriate and necessary to include input from the load serving entity in the region, there is no reason that other parties should not be provided the opportunity to participate in meetings between the CAISO and PG&E to offer additional input. This is of particular importance when the load serving entity is also a transmission owner that routinely competes in competitive solicitation for chosen transmission solutions. Trans Bay is a Participating Transmission Owner ("PTO"), and owns one of the major transmission lines serving the Bay Area, and yet the CAISO has not invited Trans Bay to be part of any of the technical planning discussions, despite several requests by Trans Bay to be included. Trans Bay also understands that key stakeholders, such as the City of San Francisco ("San Francisco" or "City"), also have not been included in technical discussions concerning the best solution for the San Francisco Peninsula region. CAISO's current "process" is in sharp contrast to the process used in 2005 to select the Trans Bay Cable Project as the best solution when numerous alternatives were being considered. That process was far more inclusive and allowed all parties to have meaningful input on the best solution for the region. The current process only allows parties to submit comments and ask questions in large stakeholder meetings covering the transmission plan for the entire CAISO territory, with follow up written comments. These comments are largely ignored or brushed aside by the CAISO, and Trans Bay has seen little meaningful change in the CAISO's decisions based on comments from stakeholders. As a result, it does not appear that comments, whether written or verbal, have any impact on the CAISO's actual decision making process.	The ISO is following its FERC-approved transmission planning process, which FERC found to be just and reasonable and not unduly discriminatory or preferential. The ISO has provided for an open and transparent access and stakeholder consultation opportunities as set out in that process. In particular, TBC and all stakeholders have the opportunities to submit needed reliability projects, participate in stakeholder meetings and submit comments during the process, all for the purpose of identifying the more efficient or cost effective solution. In Phase 2 of the process, the ISO determines the more efficient or cost-effective solution. The ISO relies on its own electric system studies, and also turns to the owners of transmission equipment for the circumstances affecting their equipment. Also, it is the ISO that determines what projects are needed, not the PTOs. The ISO evaluates all feasible alternatives --- both transmission and non-transmission -- including reliability solutions submitted by PTOs, solutions submitted by stakeholders, solutions identified by the ISO, and solutions suggested in comments. The ISO is responsible for complying with NERC standards and is subject to penalties if it fails to comply. Under these circumstances, there is no basis to suggest that the ISO intentionally chooses sub-optimal solutions to address reliability needs. In its comments, TBC does not identify a single, specific instance where the ISO failed to adopt the more efficient or cost-effective solution. The ISO has been coordinating its planning studies with PG&E in its capacity as the NERC-registered Transmission Planner, as well as the Distribution Provider and Load Serving Entity in the area. Further, the ISO will be reaching out to TransBay Cable as a Transmission Owner for additional information on its facilities in that capacity.

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	If the CAISO is not going to be truly independent – i.e., perform its own studies and not relying on the IOUs – then it should allow all stakeholders in the applicable region to participate in the process that it utilizes in actually determining which facilities it will choose. Other stakeholders should not be limited to simply proposing projects and then commenting "after the fact" when the CAISO has already chosen the preferred project, which in many cases is the project proposed by the incumbent utility. If this "process" continues to function in the status quo, parties will continue to question the results, which will effectively undermine the CAISO's credibility.	
23b	a. The LA Basin/San Diego/Southern California Solutions Require Additional Study. With the retirement of the San Onofre Nuclear Generation Station (SONGS) and proliferating renewable development in the Imperial Valley, the system needs a balanced set of solutions, including new conventional generation, flexible generation with fast ramping and fast startup characteristics, new transmission, and reactive support. In the Draft Plan, the CAISO recommends installing an enormous amount of reactive support, and heavily relying on imports into the area to meet demand and ensure reliability. The recommended measures could lead to potential system vulnerabilities, such as transient stability or import capability issues in Southern California. Trans Bay recommends that the CAISO perform studies on an expedited basis to develop new generation and transmission solutions as soon as possible in order to alleviate any reliability risks. Trans Bay has submitted off-shore HVDC VSC solutions in the LA Basin/San Diego areas and an inland HVDC VSC overhead transmission line in the Imperial Valley area and requests that the CAISO further consider and evaluate all alternatives as soon as possible to avoid any potential system issues in the area, such as transient stability and system separation into multiple islands.	As stated above and in the report, the ISO is evaluating the need for additional transmission solutions in the LA Basin and San Diego study area in the next planning cycle.
23c	2. Conclusion and Recommendation The inconsistencies highlighted above underscore the dire need for an independent third party consultant to, with the active participation of all the affected stakeholders, evaluate all feasible alternatives to address reliability for the San Francisco Peninsula. In addition to the CAISO, other stakeholders would include PG&E, the load serving entity with the responsibility for system restoration; Trans Bay, a PTO with an important supply asset in the region and whose facilities would be affected by any chosen alternative; the City and	The ISO will continue to engage the PTOs, Transmission Planning entities and Load Supply Entities within the San Francisco Peninsula area as appropriate with respect to impacts to each of PTOs facilities, individual planning assessments and loads supplied in the area as a part of the identified continued future assessment. The ISO has engaged stakeholders throughout the 2012-2013 and 2013-2014 Transmission Planning process thru specific stakeholder meetings on the extreme event assessment as well as within regular TPP stakeholder meetings. The ISO will continue to engage stakeholders as it continues the assessment within the 2014-2015 Transmission Planning Process.

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	County of San Francisco, in particular, the San Francisco Public Utilities Commission; and the CPUC. Trans Bay requests that the CAISO include this recommendation in its final San Francisco Peninsula Assessment Report and in the Final 2013-2014 Transmission Plan. While Trans Bay appreciates the opportunity to submit these comments, Trans Bay urges the CAISO to provide meaningful responses to the concerns raised, rather than to just provide cursory responses that do not address the fundamental concerns expressed about the process and the results. Trans Bay also urges the CAISO to implement a more open, inclusive, and participatory process throughout the analysis phase of the transmission plan and to identify the best solutions, rather than simply have input from stakeholders at the project proposal phase and then again after decisions are already made. This is particularly important if the CAISO is going to continue to rely on the study results and input of the load-serving entities and IOUs, who are also parties to the competitive solicitation process. Allowing those parties to participate, without also providing an opportunity for other interested stakeholders to provide technical analysis, where appropriate, is discriminatory on its face and will lead to results that repeatedly benefit the incumbent utility – the exact opposite result mandated by FERC in Order No. 1000.	

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24	City of Victorville Submitted by: Douglas B. Robertson	
24a	The CAISO is nearing the end of its 2013-2014 Transmission Planning Process (TPP) and recently released its 2013-2014 Draft Transmission Plan. The Draft Transmission Plan includes recommendations on various transmission projects based upon reliability, economic or policy-driven criteria. One of the proposed transmission upgrades evaluated by the CAISO is Southern California Edison's (SCE Mesa Loop-in project. The CAISO's Draft Transmission Plan recommends approval of the Mesa Loop-in project as a reliability project. Victorville supports approval of the Mesa Loop-in project as part of the CAISO's final 2013-2014 Transmission Plan. As described by SCE, the Mesa 500 kV Loop-in project would expand SCE's existing Mesa 230/66/16 kV Substation to include 500 kV service. This allows SCE to bring a new 500 kV electric service into its metropolitan load center. The project includes three 500/230 kV and three 230/66 kV transformer banks providing significant capacity to deliver power from the 500 kV transformer system to load in the LA Metro area. The Vincent-Mira Loma 500 kV, Laguna Bell-Rio Hondo 230 kV and Goodrich-Laguna Bell 230 kV lines will be looped into the expanded substation. According to SCE, the Mesa Loop-in project was proposed, along with an additional 500 MW local resource capacity in the Western LA area, to: • Address the loading concerns identified in the CAISO's reliability assessment results; • Alleviate the increased overall loading on transmission facilities in the LA Metro are resulting from the retirement of the San Onofre Nuclear Generation Station (SONGS) and once-through cooling (OTC) generation as well as long term load growth in the LA metropolitan and San Diego areas; and • Reduce the amount of local capacity needed to replace retired generation. The Mesa Loop-in project will provide significant capacity to deliver power form the 500 kV transmission system to load in the LA Basin. In Track 4 of the California Public Utilities Commission's (CPUC) Long-Term Procurement Plan (LTPP) proceeding (R.12-03-014), SCE noted that the Mesa Loop-in project will also reduce the amount of new generation required in the LA Basin by Approximately 1,200 MWs (2,802 MW minus 1,606MW). This is so because the	

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	Mesa Loop-in project, as stated by SCE, will allow greater flexibility for other generation locations to meet local reliability needs. Specifically, the Mesa Loop-in project will allow out-of-LA Basin generation resources, like the proposed VV2 Project, to meet local reliability needs and provide other benefits to the LA Basin. As noted by SCE, such additional benefits would include a reduction in the amount of gas-fired generation "that would be sited in areas most affected by stringent air emission requirements, including those associated with fine particulate matter of less than 10 microns diameter (PM-10)…[while also] creat[ing] additional pathways for electricity to be imported to loads in the LA Basin, making the transmission grid more robust in its ability to meet future uncertainties. Victorville urges the CAISO to approve the Mesa Loop-in project as part of its 2013-2014 Transmission Plan. This important transmission project will reduce the amount of LA Basin generation by nearly 1,200 MW and provide SCE with additional flexibility in choosing generation to assist in meeting local reliability needs. For the reasons set forth above, Victorville respectfully request that the CAISO approve the Mesa Loop-in project as part of its final 2013-2014 Transmission Plan.	