The ISO received comments on the 2013-2014 Transmission Planning Process Stakeholder Meeting on November 20-21 from the following:

1. Bay Area Municipal Transmission (BAMx)
2. California Department of Water Resources State Water Project (CDWR)
3. California Public Utilities Commission (CPUC)
4. CalPeak Power, LLC (CalPeak)
5. DATPC Path 15
6. Duke-America Transmission Company and Hunt Power
7. Joint Environmental Parties
8. LS Power Development, LLC (LS Power)
9. MidAmerican Transmission (MAT) and Pinnacle West Capital Corporation (PNW)
10. NV Energy (NVE)
11. Pacific Gas & Electric (PG&E)
12. Sierra Club
13. Southern California Edison (SCE)
14. Southwest Transmission Partners
15. Transmission Agency of Northern California (TANC)
16. Valley Electric Association (VEA)

Copies of the comments submitted are located on the *2013-2014 Transmission planning process* page at: http://www.caiso.com/Documents/2013-2014%20policy-driven%20and%20economic%20assessment%7CComments%20on%20preliminary%20policy-driven%20and%20economic%20assessment,

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

No	Comment Submitted	ISO Response
1	**Bay Area Municipal Transmission group (BAMx)** **Submitted by: Robert Jenkins, Barry Flynn and Pushkar Wagle**	
1a	**Policy-Driven Transmission Project Needs & Recommendations** *Recommend CPUC LTPP Track 4 as the Proper Forum for Developing the Specifics of the Reliability Plan for LA Basin and San Diego* BAMx believes that the CPUC LTPP (R.12-03-014) Track 4 proceeding2 is the proper forum for developing the specifics of the reliability plan for LA Basin and San Diego.This is a somewhat unique opportunity to make decisions that will replace the need for generation from some OTC units and for San Onofre on a least overall cost basis. Under the Track 4 proceeding, BAMx recommends selecting a least cost plan that balances transmission solutions with local conventional generation. BAMx is concerned, however, that the CAISO's 2013-14 transmission plan as an input into the CPUC LTPP Track 4 proceeding, does not allow a full economic evaluation of the tradeoffs between transmission and generation. Based upon previous CAISO presentations, it appears that many transmission projects have been proposed for the LA Basin, but none are described in the latest CAISO studies. We do not know where these concepts for new transmission originate, but assume that at least some come from request window projects that are not available for review by stakeholders until March 2014. In determining the need for policy-driven transmission projects, the CAISO has assumed 520 MW of new generation in northwestern San Diego in the 2013/2014 33% RPS base portfolio analysis. BAMx supports this particular assumption for purposes of a base plan during this planning cycle. However, we believe that the CAISO should identify several scenarios that require a range of additional local resources for the LA basin and San Diego. For each of these resource scenarios, the scope and cost of the transmission should be identified. This would allow for more direct observation of the	These comments will be considered in the reliability analysis of the development of the transmission plan. The coordination of transmission development through the transmission planning process and resource procurement through the CPUC's LTPP process is a key focus of the ISO and the state agencies.

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	relationship between the need for new transmission and the level of local resource development. While the CAISO should develop these alternatives based upon input it has received from PTOs and others, BAMx recommends that none of these alternatives be included in the TPP for approval at this time. Rather, selection should follow the CPUC Track 4 decision concerning procurement targets for local resources. We believe the CAISO should take a reasonable set of transmission alternatives and analyze the economics of those alternatives with realistic assumptions on the cost and location of new preferred and gas fired local capacity, as suggested by the CPUC ED and CEC Staff. The CAISO should use its considerable expertise and economic assessment model to analyze the overall economics using its security-constrained production cost model developed for this planning cycle. The CAISO should report in detail on the results of this effort in the CPUC Track 4 proceeding. The CPUC, as part of its LTPP proceeding, is in the best position to select a least overall cost solution of transmission and/or local resources. Given the urgency of the need and the long lead-time to develop potential transmission additions, early development work on the transmission alternatives may need to occur prior to the decision on local generation versus transmission.	
1b	*Role of Multiple Resource Portfolios and Deliverability Assessment* BAMx supports the CAISO's analysis that makes a determination of a policy-driven transmission project not solely based upon the base case (commercial interest), but also on the remaining two alternative renewable resource portfolios (High Distributed Generation and Environmentally-Constrained). In particular, consistent with the CAISO's tariff, if a project is identified only in the base case, and not in any of the alternative resource portfolios, then that project should not be classified as a Category 1 policy-driven project.	The criteria for Category 1 projects is broader than paraphrased by BAMx, as it also includes provision for other reasons than purely the number of scenarios in which a facility is required. The ISO has not asserted that it is state policy that renewable resources be deliverable. As the ISO has indicated on previous occasions, however, the requirement for renewable resources to receive full capacity delivery status has been a consistent requirement of interconnecting generators, and a provision approved in PPAs by the CPUC. Further, consideration of the associated transmission costs provided by the ISO is one of the inputs taken into account in developing the portfolios by the CPUC for use in the ISO planning process.

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	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.3 We are all aware of the possibility of premature generation retirement due to insufficient economic support for controllable resources, as we try to determine how much of this controllable resource is needed to meet the State's system flexible resource needs. This planning process is also 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. We understand that the CAISO is not recommending any policy-driven transmission project based purely upon the deliverability assessment under the 2013-14 plan with the exception of upgrading series cap and terminal equipment at Mohave on Lugo - Mohave 500kV line. BAMx opposes approving any project based upon a deliverability analysis that is deployed only on the base resource portfolio. In assuming that all intermittent renewable projects should be "fully deliverable" under its strict criteria, the CAISO is in essence building transmission to allow renewables to provide Resource Adequacy (RA) without undertaking any cost-benefit analysis to demonstrate that this approach is economically justified.	

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	BAMx asserts that there is no state policy that renewable projects should provide Resource Adequacy irrespective of economics.5 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 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.	
1c	**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 later, 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. The CAISO's presentation of its preliminary findings on the economic assessment of five candidate projects has led to several key questions.	
1d	*Fluctuating Economic Benefits Without Adequate Documentation or Rationale* We have noticed that the estimated benefits associated with two candidate projects; the Delaney – Colorado River (DCR) 500 kV line project and the Harry Allen – Eldorado (HAE) 500 kV line project have changed significantly under multiple CAISO reportings as	For any transmission planning studies, the study results are tied to two major factors: (1) study assumptions and (2) modeling details. (1) Study assumptions From 2011 to 2012 and to 2013, study assumptions have been evolving and

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	shown in Figure 1 below. The CAISO has provided little documentation on the reasons for such major changes in the estimated benefits associated with these transmission projects. We request that the CAISO provide a synopsis of the differences including assumptions and underlying rational for each finding as well as arguments, if any, as to why the preliminary benefits calculations that were presented in the November 20th stakeholder meetings are now sufficiently reliable to support approval of transmission projects costing hundreds of millions of dollars. We question the Net Present Value (NPV) calculations of the benefits of the candidate transmission projects. For example, for the DCR project, the CAISO calculated the production benefits in years 2018 and 2023 to be $30M and $25M, respectively. Our understanding is that the CAISO interpolated these benefits for the intervening years and assumed a flat benefit of $25M in years 2024 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 $248M over 50 years. This is nearly a 1/3rd reduction in production benefit calculated by the CAISO.6 This exercise demonstrates that the CAISO's calculation of the benefits based on only two years of data is highly susceptible to how the extrapolation of these benefits are calculated. BAMx believes that it is important to recognize why the benefit has dropped from 2018 to 2023, the likely reason being the increased 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 quite concerned about the lack of scenario analysis around the 50-year projection of benefits from two data	updating. Firstly, related to the proposed DCR and HAE lines, some major transmission assumptions have been changed. The changes include but not limited to: Del Amo – Ellis loop-in, Barre – Ellis 230 kV reconfiguration, Lugo – Eldrorado series capacitors and terminal equipment upgrade, Sycamore – Penasquitos 230 kV line, West of Devers series reactors, West of Devers 230 kV reconductoring, Merchant 230 kV reconfiguration project, and Bob Tap 230 kV switchyard and Bob Tap – Eldorado 230 kV line. These downstream transmission upgrades have a positive impact on increasing the economic benefits of the studied transmission lines. Secondly, resources assumptions are also evolving. Examples of resources assumption changes include SONGS retirement and updated RPS portfolios every year by CPUC/CEC. The changes resource assumptions also led to a general tendency of increased benefits. These changes of study assumptions were documented in the ISO Transmission Plans and stakeholder meeting presentations. (2) Modeling details From 2011 to 2012 and to 2013, the production simulation model has been constantly improved. The 2011 study was based on TEPPC "2020 PC0" dataset. The 2012 and 2013 studies were based on TEPPC "2022 PC1" dataset. Also, the ISO enhancements to the TEPPC database have also made the study results to be more detailed and reliable. For example, back in 2011, the database did not have AB32 GHG model and did not have WECC-wide BAA model. In the 2012 and 2013 studies, these advanced models were developed by the ISO in order to have a more realistic representation of the power system. Other modeling details include data fixes such as incorporating updated line ratings for the Midway – Vincent 500 kV lines on Path 26. These changes of modeling details were also documented in the ISO Transmission Plans and discussed at length at the ISO stakeholder meetings. The ISO notes that we have observed predictable and reliable results with respect to the changes of study assumptions and modeling details. In the case of the

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	points. We also observe that if renewables continue to increase within the CAISO in the later years, it is likely that the benefits of the out-of-state (OOS) transmission projects like DCR and HAE will see a corresponding reduction. 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 study years to outer years.7 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. However, that 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 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 selected and supports that the benefits be truncated in future year, such as 2031	Delaney-Colorado, for example, over the past several years we have seen that the yearly economic benefits are consistently in the range of $25M to $35M, as calculated by the production simulation model. With regards to the NPV calculations of the DCR project, the ISO's studies follow the TEAM methodology by extrapolating the end-study-year benefits to the end-year of economic lifespan. In the 2004 study of DPV2 (Devers-Palo Verde #2), a 1% real escalation was used for the yearly benefit. In the current study, this was reduced to a 0% escalation rate to be more conservative. The BAMx comments refer to the decreased benefits from 2018 to 2023 and suggested that beyond 2023 the extrapolated benefit shall continue decrease by rationalizing that the decline is due to increased renewable build-out in California. The ISO does not agree that there is a firm foundation for that conclusion, especially in light of the amount of renewable generation already included in the planning studies.. Also, under FERC Order 1000, inter-regional coordination is expected to strengthen; and the role of transmission lines like DCR is not expected to diminish. Therefore, it is not appropriate to claim that the economic benefits of the DCR line will decrease in the future.

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	and beyond as suggested by SCE in the November 21st Stakeholder meeting, due to the uncertainty around future benefits.	
1e	*Sensitivity Analysis for Capacity Benefits is Needed* 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 \$281M. 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 to evaluate the capacity benefits, 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: The capital and fixed operating costs for a peaking unit must remain less in Arizona as compared with California resulting in comparatively lower capital and operating costs in Arizona which may translate into a lower capacity price. 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.	The ISO will provide detailed documentation of the capacity benefit analysis in the draft report. Rather than perform sensitivity analyses, the ISO chose the conservative end of the range for the Arizona and California resource balance years. The ISO is not aware that the TEAM methodology specifically prescribes an arbitrary splitting of benefits. As will be 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.

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	BAMx agrees that such a set of conditions is one possible future scenario. The CAISO's November 20th presentation included slides that indicated that California would be resource deficit by 2020. However, the CAISO did not provide any analysis in support of that statement. The CPUC 2012 LTPP source cited earlier suggests that the planning reserve margin is expected to be in the range of 120% during the 2020-2022 time period. An analysis based on these very different assumptions would provide significantly different results. 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 \$17 million (\$41/kW-Yr), then the assumed CAISO benefit should be half that amount or \$8.5 million.8 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 \$140M.	
1f	*The Underlying Capital Cost Elements Need to be Clearly Documented* Table 3 compares the capital cost and the total cost associated with the DCR and HAE transmission projects as reported by the CAISO over the past year. Although the capital cost associated with DCR has gone up from \$325M to \$343M, the 50% reduction in the capital cost associated with HAE from \$240M as reported in February 2013 to \$120M, in November 2013 is puzzling. Please explain the causative changes in assumptions for the HAE project. Moreover, we find the capital cost of \$3M per mile and \$1.8M per mile for the 500kV projects such as DCR and HAE to be unrealistically low. BAMx is concerned that such low capital cost estimates produce inflated benefit-cost ratios, and will ultimately cost the CAISO ratepayers much more than anticipated in the most recent CAISO	While the ISO considers that the cost estimates are reasonable for the planning studies based on relevant comparative information, we acknowledge the concern that cost overruns could later impact the overall net benefits of this economically driven project. This will have to be considered and addressed in the competitive procurement process. The ISO will review the estimated costs and benefits of the HAE project in its ongoing analysis of that project. The DCR cost estimate is based on binding cost estimates for the Hassayampa-NG #2 project. Also, will be stated in the draft report, sponsors submitting proposals for DCR in the Phase 3 competitive solicitation process will be expected to submit cost estimates consistent with the ISO estimated cost.

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	analysis. We think it is important to document the underlying capital cost breakdown and the level of contingencies assumed in the development of those capital cost estimates.	
1g	*Better to Wait to Approve DCR in Rapidly Changing Market and Regulatory Environment* 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 these projects 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, it is important to recognize the calculated transmission project benefits assume completion of other projects whose actual construction is uncertain. For example, in order to realize the 400MW of incremental RA capacity, the Category 1 upgrades9 proposed in 2013/2014 planning cycle need to be in place. An additional example is the role of the CAISO's internal transmission projects that were modeled in the CAISO's economic studies, but have yet to be approved by the regulatory authorities.	As stated in prior comments, long-term infrastructure planning is always associated with uncertainties. These uncertainties are addressed by considering a reasonable range of sensitivities and using an agreed upon methodology – the TEAM methodology – but should not be used to indefinitely delay projects that have reasonably-determined value to ratepayers. Please also note that not all economic benefits are included in the study. For example, the quantified economic benefit does not include the benefit under extreme conditions. DCR line shall have significant value in lower the risk of system collapse under multiple contingencies. The DCR line is positioned at the system's weak link, the existing Palo Verde – Colorado River 500 kV line, which is the only tie between the Palo Verde Trading Hub and the CAISO system. For another example, the flexible reserve benefit is not included either, because of difficulty of quantifying the benefits into dollars. Therefore, although the DCR has a positive net benefit, the quantified benefit is underestimated. Based on studies that have consistently demonstrated the economic benefits, it is recommended to approve the DCR project.
1h	**Recommendations for Management Approval of Reliability Projects less than $50 Million** *Projects Justified Based Upon the new NERC Planning Standards*	The Estrella Substation project need is based upon both Category B and Category C contingencies resulting in constraints on the system and load shedding. The

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	NERC recently approved new planning standards with respect to the loss of non-consequential load due to the loss of a single transmission element. This change in standards was cited in the need for at least one project recommendation (Estrella Substation). The new NERC standards, rather than prohibiting the loss of non-consequential load, provide for an open process to decide whether to continue to make use of such a solution. In light of this new NERC standard, the CAISO should initiate a process to revise its Planning Standards to explicitly address its process for making such a determination. This proposed revision and associated stakeholder review should be made prior to approving any projects due to this change in NERC standards.	reference to the NERC standards is related to changes within the NERC standards which have been approved by FERC. The ISO will be initiating the updating of the ISO Planning Standards to reflect these changes; however the ISO is required to meet the requirements of NERC standards. Planning decisions made in this cycle to address reliability requirements under the existing standards should also reasonably take into account emerging requirements through already approved changed to mandatory planning standards even if aspects of those standards are not yet in effect.
1i	*Load Interconnection Projects* The CAISO has proposed a number of projects to accommodate the interconnection of new load to the transmission grid. Frequently the costs are broken down between Interconnection Facilities and Network Upgrades. Please confirm that all work identified as Interconnection Facilities would be ineligible for inclusion in the TAC, but would either be customer Special Facilities or utility distribution upgrades. BAMx appreciates the opportunity to comment on the CAISO 2013-14 Transmission Plan. BAMx would also like to acknowledge the significant effort of the CAISO staff to develop the plan to date, 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.	The PTOs conduct the assessment of load interconnections per their tariff requirements and submit to the ISO for review their interconnection proposal for the ISO to concur that the proposed interconnection does not impact the reliability of the transmission system.

No	Comment Submitted	ISO Response
2	**California Department of Water Resources State Water Project (CDWR)** **Submitted by: John Yarbrough and Aseem Bhatia**	
2a	The California Department of Water Resources-State Water Project (CDWR-SWP) appreciates the opportunity to provide these comments following the 2013/2014 Transmission Planning Process (TPP) Stakeholder meeting held by California Independent System Operator (CAISO) on November 20 and 21, 2013. CDWR-SWP is concerned by the issue raised in comments by TANC, WAPA, and SMUD during the recent TPP stakeholder meeting. Specifically, those parties commented that the modeling parameters used in the Planning Studies may not be consistent with modeling parameters used in Operational Studies. These parties have stated that the inconsistency appears to result in the planning studies understating the impact on intertie capacity resulting from CDWR-SWP not participating in the COI-RAS. An increase to congestion on the COI, whether located inside or outside the CAISO BAA, would likely impact energy prices in the CAISO. Given the importance of imports to the state of California and the pending efforts to create an Energy Imbalance Market, any such impacts should be clearly understood. CAISO should release the modeling parameters for both studies, disclose any differences between them, and explain why the different parameters were used and whether any inconsistency impacts planning study results, or creates an increased risk of congestion on the COI. CDWR-SWP notes that it submitted its continued participation in the COI-RAS as a reliability project in this TPP process. While the proposal was not accepted by CAISO, CAISO has indicated in the response email that the CDWR-SWP proposal will be “kept in mind” during the development of the economic analysis. CDWR-SWP confirms that its proposal should be considered as a proposed economic project.	The ISO has continued to review the situation, and has not identified material economic advantages in support of further development of reinforcement (through SPS or otherwise) at this time.

No	Comment Submitted	ISO Response
3	**California Public Utilities Commission** **Submitted by: Keith White**	
3a	**1. The CAISO Should Clarify Which Transmission Projects are Considered Appropriate for Inclusion (Without Reconsideration) in the 2013-2014 Transmission Plan, and Such Projects Should be Demonstrated as Necessary Across the Range of Resource Options Being Considered for the Los Angeles Basin and San Diego Areas.** It is clear that major resource and reliability strategies for the Los Angeles Basin and San Diego areas are currently under consideration and could have substantial interaction with transmission planning matters addressed in the 2013-2014 TPP. This is acknowledged in the CAISO's presentations and discussion with stakeholders, on November 20-21, where it was stated that "reconsideration will be necessary depending on reliability mitigations that are ultimately selected" It would be helpful for stakeholders generally and for the CPUC's resource planning processes, if the CAISO could clarify which transmission projects identified in the November 20- 21 meeting or elsewhere are considered ready for inclusion (without reconsideration) in the 2013-2014 Transmission Plan. No transmission infrastructure additions should be included in the 2013-2014 Transmission Plan unless demonstrated to be needed across the range of reliability solutions under consideration for the LA Basin and San Diego areas, particularly via the CPUC's Long Term Procurement Plan (LTPP, R.12-03-014) proceeding. However, clarification of the transmission needs and other issues associated with alternative resource solutions continues to be of great interest and value.	This comment appears to pertain to the reliability analysis for the LA Basin and San Diego areas, not the policy and economic discussions that were the subject of the session. However, the ISO agrees the LA Basin and San Diego area needs are complex, and need careful consideration. Also, we agree that consideration must be made of how solutions that are being brought forward for approval in this cycle coordinate with other future solutions in future planning cycles as well as other resource processes.
3b	**2. The CAISO Should Specifically Identify the Adjustments Made to the CPUC/CEC-Provided RPS Portfolios.** CAISO staff mentioned at the November 20-21 meeting that small adjustments were made to the CPUC/CEC-provided RPS portfolios. To support coordinated planning, consistency of assumptions, and general efficiency of the CPUC's portfolio generation process going forward, the CAISO should explicitly identify these portfolio adjustments and their	The ISO did not make actual adjustments to the portfolios. We simply corrected the mapping in the calculator and the detailed resource information that was the basis for the portfolio aggregate amounts.

No	Comment Submitted	ISO Response
	rationale. For example, it appears that the TPP cases contain about 250 more MW in the Riverside East area than are identified in the original transmittal letter from the CPUC and CEC.	
3c	**3. The CAISO Should Explicitly Identify Which Benefits the High Distributed Generation (DG) Portfolio Provides Relative to the Commercial Interest Portfolio (The TPP Base Case), In Reducing the Need for Transmission Investment.** An important (certainly not the only) rationale for a high-DG RPS portfolio is to avoid the cost, delay, environmental impacts and potential controversy surrounding major transmission system additions to access concentrations of renewable resources remote from load centers. Thus, an important expected insight from studying multiple RPS portfolios in the TPP is clarification of the impact of a high DG portfolio in reducing the need for major transmission additions. However, powerflow and stability studies for the RPS portfolios appear to not show reduced transmission needs for the high DG portfolio2. While deliverability studies for the base portfolio identified beneficial transmission investments in the SCE area (on the Lugo-Mohave line) and apparently also (not as clearly defined) in SDG&E area, the high-DG and environmentally constrained portfolios were not studied for deliverability implications. The CAISO should clarify if and why the high DG portfolio is apparently found to provide no benefits in terms of reduced transmission investment needs for reliability (powerflow and stability) purposes. Furthermore, delivery network upgrades have typically been a major driver of transmission needs for renewable generation, and yet the 2013-2014 TPP has not studied deliverability for the high DG portfolio and consequently cannot shed light on how that portfolio impacts delivery network upgrades. We understand that the unresolved status of major reliability solutions for the South Coast area make it problematic to clearly identify "policy" transmission needs, or the ability of a DG-intensive strategy to reduce those needs. However, before ultimately committing to major	The ISO provides transmission data into the CPUC portfolio development process so that the likely impacts of various scenarios can be considered in the development of the process. The scenarios are used to test the needs of the system using a base case approach, and testing the needs on a least regrets basis for the various scenarios provided. The ISO's analysis therefore does not focus on testing each scenario to suggest which scenario should be selected as the base case. As noted in the comment, the ISO has not identified the need for major transmission reinforcements as policy-driven solutions beyond the reactive support needs identified.

No	Comment Submitted	ISO Response
	"policy"-related transmission investments going forward, it will be essential to have a clearer picture of how and where more emphasis on DG can help manage and limit those investments.	
3d	**4. For Economic Studies, Transmission Project Benefits and Benefit-Cost Ratios (BCR) Should be Reported Not Only for the "Economic Life" Time Horizon of 50 Years, But Also for a More Understandable Planning Horizon of 20 Years.** Transmission investments clearly have long economic lives, so that long-term benefits should be considered. However, based both on past experience and very dynamic and uncertain conditions looking forward from today, the electricity planning future is very uncertain. It would be imprudent to commit to large and potentially environmentally challenging transmission investments without first being well informed regarding the extent to which such investments are likely to pay for themselves over a reasonably foreseeable planning horizon of 20 years, as opposed to paying for themselves based on benefits projected over a much more distant and uncertain future. Therefore, while it is reasonable to compute transmission project benefits and BCR over an "economic life" planning horizon such as 50 years, it is also reasonable and in fact essential to augment this information with benefits and BCR calculated over a shorter and more foreseeable planning horizon of 20 years. Most of the discounted benefits should come from the first 20 years, and if a transmission project is not computed to "pay for itself" in 20 years, then at a minimum we need to be aware of this when weighing the project's risks and opportunities.	In evaluation of the economic benefit, yearly benefits are discounted by a social discount rate. The discount rate has a significant role of diminishing the impact of benefit in distant years. Transmission assets live a long time. The 500 kV lines with the Pacific AC Intertie have existed for about 45 years. The 230 kV lines with the Big Creek transmission system have existed for about 90 years. Those strategically-built transmission lines are still functioning reliably; and the lines have been providing great economic benefits to the ratepayers. Therefore, transmission planning shall look to the long term; and the 50 years of economic horizon is a moderate and appropriate measure that have been established in actual practices of economic studies.
3e	**5. For Economic Studies in Which Capacity Benefits Play a Substantial Role, the Basis for Capacity Benefits Should Be Adequately Explained and the Implications of Uncertainties Regarding Capacity Benefits Should be Illuminated Via Sensitivity Analysis.** Calculated capacity benefits play a very important role in making the Delaney-Colorado River (DCR) project appear to be cost-effective, accounting for 44 percent of calculated overall benefits.3 When ultimately	Please see response above to BAMx.

No	Comment Submitted	ISO Response
	computed, capacity benefits may also drive the Harry Allen-Eldorado project into "cost-effective" territory. While computed production benefits are underlain by extensive documented production simulation data input and methodology assumptions, and by augmenting base case analysis with 17 sensitivity cases for each of two time horizons,4 the almost equally important capacity benefits are computed in a much simpler manner. The capacity benefits are based mainly on estimated differential new CT costs (CA vs. AZ) for 2025 and later, plus a higher annual capacity benefit for years 2020-2024 attributed to surplus capacity assumed to be available from Arizona. Given the importance of the capacity benefit, the CAISO should more fully support and explain the way this benefit is computed, and should also provide meaningful sensitivity analysis. For example: "economic rent" for inframarginal (relative to California) capacity costs may be partly captured by AZ suppliers rather than fully by California consumers; marginal California capacity needs may be driven by local area (e.g., South Coast) needs including deliverability to that area, rather than system needs; and alternative LA Basin-San Diego reliability mitigations (e.g., transmission and resource-related measures) could impact the value and even MW magnitude of a DCR capacity benefit.	
3f	**6. For Each Reliability Project Identified for Inclusion in the Transmission Plan, the CAISO Should Explicitly Identify if Load Shedding Is Allowed as an Alternative (and if Not, Why Not) and Where Load Shedding is Allowed Should Either Identify the Amount of Avoided Load Shedding or Else Explain Why the Project Can be Identified as Needed Without Quantifying Avoided Load Shedding.** The question of when avoided load shedding and associated benefit-cost ratios (BCR) based on value of service are applicable for justifying reliability transmission upgrades has come up in the past. Also, the 2013-2014 TPP reliability studies recently identified needed reliability upgrades (Estrella	The ISO adheres to mandatory NERC planning standards and WEC planning criteria as well as the ISO planning standards, which address most of the issues set out in this comment. Further, the ISO has indicated we will conduct a process in 2014 to include in the ISO planning standards the historical consideration of large amounts of urban load shedding for category C contingencies. The ISO is also open to entertaining questions on individual studies.

No	Comment Submitted	ISO Response
	substation) due to circumstances where load shedding is apparently no longer allowable under revised NERC standards. The California ISO Planning Standards of June 23, 2011 indicate that transmission upgrades not required by "standards 1, 2 and 3 above" 5 may be justified by BCR above 1.0, as well as stating that information required for BCR calculation shall "be documented in the ISO Transmission Plan." 6 In essence, conditions where the standards provide for use of BCR to justify transmission upgrades that are not otherwise categorically required - - tend to represent multiple contingencies (N-2, TPL-003, etc.) and non-radial situations, often involving relatively large magnitudes of both load dropping and mitigation investment. These also tend to be the situations where BCR and the amount of load dropping avoided by transmission investment are not reported in TPP reliability study results. We recognize that load dropping and other consequences of contingencies in networked situations can be complex or difficult to enumerate. However, annually approved reliability upgrades on the CAISO-controlled grid run into the hundreds of millions of investment dollars or more. There should be greater clarity and consistency (across all situations, locations and service areas) (1) in reporting whether or not load dropping is allowed (and if not, why not), and (2) where load dropping is allowed, in reporting either the magnitude of avoided load dropping or the rationale for why the transmission investment is justified without quantifying avoided load dropping.	

No	Comment Submitted	ISO Response
4	**CalPeak Power LLC** **Submitted by: Clifford D. Evans, Jr.**	
4a	CalPeak urges the California ISO to consider fast tracking its request window submissions. CalPeak received notification that its submissions satisfied the request window screening criteria on the morning the November 20, 2013, while the most recent stakeholder meeting was in progress. Thus CalPeak's projects could not have been included with the other project recommendations for management approval (less than $50 million), which were briefed on November 21, 2013. CalPeak urges the ISO to include a second round of project recommendations for management approval for less than $50 million projects before or when it presents its draft 2013-14 Transmission Plan. It is appropriate to promptly recommend management approval of these projects to facilitate the negotiation and approval process. These projects are individually, and collectively, far less than $50 million, can reasonable be addressed on a standalone basis, and are "least regrets" projects which will not be impacted by the approval of the transmission plan (and reliability projects over $50 million) by the Board of Governors in March of 2014. CalPeak's proposals will quickly and effectively provide critically needed voltage support by adding the capability to operate in synchronous condensing mode to its existing interconnected generators while retaining their current capability to operate in generation mode. The capability of the existing generators to deliver real power (i.e. megawatt-hours, or MWh) will not be compromised in any way by the modifications. CalPeak believes that the cost impact to market participants will be negligible because synchronous condenser operation can be inexpensively incorporated (mainly a software update) into its existing interconnected resources. Once the upgrades to the existing generators are complete, the existing resources will effectively become highly flexible hybrid generation and transmission resources. The California ISO will be able to dispatch the facilities in whichever mode of operation it deems most appropriate for a	The ISO has not identified a need for the projects at this time and will document results of the assessment within the draft transmission plan.

No	Comment Submitted	ISO Response
	given grid condition; power generation or synchronous condensing. The California ISO will be able to call on CalPeaks's flexible hybrid resources to either generate real power (MW) or generate/absorb reactive power (megavars, or MVARs) as needed to adjust the gird's voltage and improve power factor. If the situation calls for flexible ramping to meet the morning and evening peak load conditions, the facilities can each be dispatched to deliver in excess of 50 MW of real power. Under different conditions, for example a sudden loss of a major transmission line, each of the facilities can be dispatched to deliver upwards of +60 MVAR of reactive power. Synchronous condenser capability provides a superior solution to other voltage support options available to the California ISO. For example, synchronous condensers can continuously adjust the amount of reactive power they produce while also being capable of increasing reactive current as voltage decreases. By comparison, capacitor banks cannot continuously adjust the amount of reactive power they produce and when grid voltage decreases so does their reactive power delivery. In short, CalPeak's fleet of FT8 TwinPac units: • Currently operated as generators providing real power (MW) • Could operate as synchronous condensers providing reactive power (VAR support) to stabilize the grid and help integrate renewable resources in a matter of months • Could operate as synchronous condensers without additional environmental impacts or permitting delays • Could provide vital Power Factor adjustment and system inertia • Could provide this flexibility more quickly than building new facilities to provide reactive power • Could provide this flexibility more economically than building new facilities to provide reactive power. CalPeak's hybrid generator/synchronous condenser proposals should be given fast track approval. Waiting to approve these "least regret" projects would be unfortunate. We recommend the California ISO seize this	

No	Comment Submitted	ISO Response
	opportunity and take decisive action now by recommending management approval of these proposals, resulting in these highly flexible, low-cost alternatives for both generation and voltage support being online and ready to meet the reliability needs of the grid in the early part of 2014.	

No	Comment Submitted	ISO Response
5	**DATC Path 15** **Submitted by: William A. Hazelip**	
5a	**I. Introduction** DATC Path 15 ("DATC") provides the following comments on the 2013 - 2014 Transmission Planning Process Stakeholder Meeting held on November 20th and 21st, 2013. DATC and its two parent entities, Duke Energy and American Transmission Company, have substantial experience and expertise in electric transmission from their many decades of ownership and operation of major transmission facilities in several other states. In California, DATC owns 72 percent of the transmission service rights to the Path 15 transmission project, an 84 mile, 500 kV transmission line in Central California. Path 15 is one of the 500 kV lines in CAISO's system that provides significant economic and reliability benefits statewide. The purpose of these comments is to request the CAISO's consideration of expanding the 500 kV system in a portion of Central California allowing for California to build upon the successes of the Path 15 Upgrade Project. Right now, there is a unique and fleeting opportunity for a third 500 kV line between Tracy-Tesla and Los Banos substations that would provide significant policy, economic and reliability benefits to the CAISO and to all of California and the WECC electric grid. The Western Area Power Administration ("Western") is evaluating potential transmission projects that would serve a portion of the Central Valley Project ("CVP"). On November 22, 2013, Western issued a Federal Register Notice for a 62 mile 230 kV transmission project between Western's Tracy and San Luis Substations (hereinafter "San Luis Transmission Project"). Importantly, Western indicates that they are willing to consider other transmission construction options, including 500 kV transmission line alternatives. As discussed below, the 500 kV Alternative would allow the CAISO to address a weak link in the 500 kV backbone of the CAISO grid (i.e., between Tracy-Tesla and Los Banos). If the CAISO seizes this opportunity to "right-size" the Western San Luis Project to the 500 kV Alternative now, then California will improve the transfer capability between Southern	We acknowledge that the central California 500 kV transmission lines are very important assets. Over the years, the CAISO has been monitoring and studying those backbone transmission lines. From 2007 to 2008, under a stakeholder study process known as the Central California Clean Energy Transmission Project (C3ETP), the CAISO intensively studied the 500 kV systems along Path 15. That study did not find enough economic justification for a major 500 kV upgrade in the area. However, the C3ETP study led to the Greater Fresno Area Interim Reliability Upgrade for a major upgrade of the 230 kV systems, approved in ISO 2009-2010 Transmission Plan. Further study also led to the Gates – Gregg 230 kV line, approved in the ISO 2012-2013 Transmission Plan. From 2009 to 2012, in the ISO transmission planning process, the economic planning studies investigated the congestion on the Los Banos – Westley 230 kV line. In those efforts, the ISO evaluated potential economic benefits of alternative transmission solutions (that are similar to the San Luis Project). From those studies, no adequate economic justifications were found for the proposed 230 kV solutions in the neighborhood of the Los Banos – Tesla/Tracy area. The ISO expects this will receive further consideration in the 2014-2015 planning cycle.

No	Comment Submitted	ISO Response
	California and the Bay Area. The project would yield significant reliability, economic and policy benefits both regionally and statewide at a reasonable cost. On the other hand, if the San Luis Transmission Project is built as a 230 kV project, future electric transmission projects in this corridor will be far more costly or potentially infeasible. Thus, the CAISO should take advantage of this narrow window by evaluating the ability of the 500-kV Alternative to address multiple reliability, economic and policy issues that exist within the 10-year planning period.	
5b	**II. Discussion** **A. Western Will Study a 500 kV Alternative to the 230 kV "San Luis Transmission Project".** On November 22, 2013, Western initiated an environmental review to construct a 230 or 500 kV transmission line in central California.2 The Western Project would serve the Bureau of Reclamation's primary San Luis Unit pumping facilities in the Los Banos area. At a minimum, the San Luis Transmission Project would consist of a new 230 kV transmission line (about 62 miles in length) between Western's Tracy Substation and Western's San Luis Substation, and a new 70 kV transmission line (about 5 miles in length) between the San Luis and O'Neill Substations.3 According to Western's Federal Register Notice, "Western also will consider other transmission options including: a new 500 kV transmission line about 62 miles in length operated at 230 kV between Western's Tracy and San Luis Substations [and] a new 500 kV transmission line operated at 500 kV about 62 miles in length between the Tracy Substation and PG&E's Los Banos Substation. . ." The Project will result in significant cost savings for water users and thus has significant support from the federal government. The CAISO should take advantage of this opportunity by studying the San Luis Transmission Project. It is not clear whether the 230 kV or 500 kV Alternative to the San Luis Transmission Project have already been considered by the CAISO in the development of the 2013-2014 Conceptual Statewide Transmission Plan. Thus, in addition to addressing the 500 kV Alternative in the 2013 – 2014 Draft Transmission Plan, DATC also requests that the CAISO clarify whether the 230 kV San Luis Transmission	Please see the above comment.

No	Comment Submitted	ISO Response
	Project was included in the CAISO's economic and reliability models used to produce the preliminary study plan results.	
5c	**B. The Cost Of The 500 kV Alternative To the San Luis Transmission Project Is Reasonable.** The 500 kV Alternative is a "low hanging fruit" option for California's transmission ratepayers. By supporting this Alternative now, the CAISO would avoid significant costs and siting challenges in the future when the CAISO commits to improve the transfer capability between Southern California and the Bay Area. The easements for a 500 kV project will be far easier to acquire in one attempt and during the environmental review process for a Project with federal support. Easements for the San Luis Transmission Project will likely adjoin current easements for transmission lines. Waiting to build a new 500 kV project would be far more expensive due to the need for new easements and the unique siting and permitting challenges in California. Put simply, "right-sizing" the San Luis Transmission Project today would allow for more efficient use of an already-planned right of way. "Right-sizing" this project today will also result in economies of scale. If the CAISO delays upgrading the Tracy/Tesla-Los Banos corridor, it would need to replace the towers, expand the right of way, initiate a new environmental review process and obtain new permits. In addition, upgrading the San Luis Transmission Project down the road may not have the same federal support it does now. Thus, it makes far more sense to "right-size" the Western project to 500 kV now than to try to upgrade it later or to build a new 500 kV line altogether.	Please see the above comment.
5d	**C. The 500 kV Alternative Will Yield Significant Benefits for California's Transmission Ratepayers by Addressing Multiple Issues that Exist Within the Ten Year Planning Horizon.** The 500 kV Alternative will provide substantial benefits to California's transmission ratepayers. First, the 500 kV Alternative would provide state-wide reliability benefits. The 500 kV system (which consists of only two lines between the Tracy/Tesla area and Los Banos) is a weak link in the 500 kV	Please see the above comment.

No	Comment Submitted	ISO Response
	backbone system in Northern California. All of the remaining transmission corridors in Northern California have three 500 kV lines. The relative weakness of this link has resulted in various remedial action schemes and operating procedures specifically intended to address the reliability weakness of the corridor. Upgrading the Western Project to 500 kV will enable review and likely reduction or elimination of these procedures to reflect the enhanced reliability and system transfer capability between Southern California and the Bay Area. Other WECC reliability procedures, while not specifically tied to this corridor, are also likely to benefit. For example, the N-2 conditions can currently trigger curtailments on the interregional transfers between California and the Pacific Northwest. Adding a 500 kV line on this corridor will increase the reliability of the WECC grid and reduce the potential for future curtailments. In other words, supporting the 500 kV Alternative would yield statewide reliability benefits—not just local reliability. Second, DATC is confident that the 500 kV Alternative would provide economic benefits both within the 10 year planning period and in the longer term. While we have not yet completed an economic benefits analysis for the 500 kV Alternative, given the limitations in Tracy/Tesla-Los Banos corridor, it is clear that electric customers would benefit from the 500 kV Alternative. Moreover, as noted above, "right-sizing" the San Luis Transmission Project will result in significant economies of scale, saving transmission ratepayers significant costs in the longer term as load continues to grow in both the Bay Area and Southern California. Third, the 500 kV Alternative will further California's Renewable Portfolio Standard and Greenhouse Gas policy objectives by enabling greater transmission capacity for wind and solar projects. In particular, the 500 kV Alternative will better enable the 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.	

No	Comment Submitted	ISO Response
	Finally, the San Luis Transmission Project would help levelize water rates and promote economic growth in one of the state's poorest regions. Since 1965, PG&E has provided transmission service between the Tracy Substation and the San Luis Unit of the Central Valley Project over PG&E's transmission lines, the contract expires in 2016.5 PG&E indicated that service is available from the CAISO, but that would increase costs to the water users. According to the United States Bureau of Reclamation, the San Luis Transmission Project will "avoid an estimated $8 million per year in added annual transmission service costs, which would increase water costs for California farmers and agricultural consumers."6 Thus, the San Luis Transmission Project will enable Western to provide power at a consistent rate over the life of the Project, creating additional economic benefits for Central Valley farmers and residents.	
5e	**III. Conclusion** The 500 kV Alternative to the San Luis Transmission Project is a new and fleeting opportunity. DATC as the owner of the Path 15 Upgrade, has recently engaged upon this unique opportunity for California, and we have initiated our own economic and technical studies. The corridor between the Tracy/Tesla area and Los Banos is a weak link in the 500 kV backbone of the CAISO grid, and there is an opportunity to address this issue at a reasonable cost to California's Transmission Ratepayers. As such this is an opportunity that the CAISO should evaluate. By taking advantage of an existing environmental review process and planned transmission rights of way, the CAISO will improve the transfer capability between Southern California and the Bay Area, provide for transfer capability for additional renewable energy projects and improve state-wide reliability. The CAISO should seize this fleeting opportunity to obtain the benefits from a new 500 kV project in the Central Valley by addressing those benefits in the CAISO's 2013 – 2014 Draft Transmission Plan. DATC also requests that the CAISO clarify whether the 230 kV version of the San Luis Transmission Project was contemplated in the Conceptual Transmission Plan released earlier this year. DATC appreciates the opportunity to provide these comments and looks forward to working closely with the CAISO,	Please see the above comment.

No	Comment Submitted	ISO Response
	Western, and other stakeholders on this important opportunity.	

No	Comment Submitted	ISO Response
6	**Duke-America Transmission Company and Hunt Power** **Submitted by: William A. Hazelip and Bill Bojorquez**	
6a	We appreciate the opportunity to provide comments on the preliminary economic and public policy study results. We believe CAISO is headed in the right direction by proposing to improve Path 46 and the integration of new transmission from Arizona into Southern California. While the Delaney to Colorado River project has significant benefits, the North-Gila to Imperial Valley # 2 (NGIV2) deserves more careful consideration. Given the reliability challenges in the SDG&E region due to transmission congestion, the shutdown of SONGS and the OTC retirements, DATC-Hunt believes NGIV2 provides an opportunity to not only provide societal benefits to CAISO, but an effective solution to reliability issues in SDG&E. To the extent the CAISO has determined that the NGIV2 project does not improve Path 46 or the SCIT nomogram, it may be because the proper reliability additions to the project were not proposed under the project "as proposed" in the past and the installation of dynamic or voltage stability and control devices have not been considered by CAISO or other parties. In the November 21 presentation, slide 47, CAISO states the capacity benefits of NGIV2 is determined to be zero. According to CAISO: 1. System RA benefit is zero because of downstream bottleneck, and 2. LCR benefit is zero. If the above is true and the benefits are zero there must be an outage (or set of outages) under peak load conditions that is not benefited from increased flows from the North Gila area into Imperial Valley and San Diego. If this is the case, there was no clear definition of the condition (and associated outages) reviewed by the CAISO and the results from the CAISO simulations. We request more detailed information with respect to the limiting outages and the downstream bottlenecks.	The CAISO agrees that following the proposed Delaney – Colorado River 500 kV line, the North Gila – Imperial Valley 500 kV line #2 (NGIV2) continues to have potential as an economically-driven network upgrade. Downstream limitations restrict both the production benefits and, more significantly, the potential capacity benefits of the proposed NGIV2 project. The ISO expects this area will continue to receive consideration in the 2014-2015 planning cycle.

No	Comment Submitted	ISO Response
	Further, 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 SVCs, synchronous condensers or other devices could be added near the San Diego area, the benefits of an increased flow from North Gila would include increased voltage stability for multiple contingencies, increased dynamic stability, and added Path 46 capacity in addition to the economic benefits already modeled. In fact, such solutions may actually be adopted in this year's plan and approved by the board but CAISO has stated that the economic and policy studies will not be re-run after identification of such solutions. We believe re-evaluation may be warranted given the potential impact of reliability solutions in the San Diego area to increase the benefits of the NGIV2 project.	

No	Comment Submitted	ISO Response
7	**Joint Environmental Parties** **Submitted by: Erica Brand, Kim Delfino, Helen O'Shea and Sarah Friedman**	
7a	**1. Introduction** The Nature Conservancy, Natural Resources Defense Council, Defenders of Wildlife, Sierra Club and The Wilderness Society ("Joint Environmental Parties") appreciate the opportunity to submit comments in response to the California Independent System Operator's (CAISO) 2013-2014 Transmission Planning Process (TPP) Stakeholder Meeting held on November 20-21, 2013 (the "Stakeholder Meeting"). These comments are specific to the Desert Renewable Energy Conservation Plan (DRECP) and the preliminary results of the policy-driven transmission need assessment. In addition to this letter, the Sierra Club will submit individual comments on other aspects of the Stakeholder Meeting. **2. Transmission Planning for the Desert Renewable Energy Conservation Plan** **Background** Our comments are informed by our mutual interest in improving the integration and coordination of land-use, energy generation and transmission planning. The Joint Environmental Parties believe that the DRECP could facilitate responsible and sustainable renewable energy development to meet California's renewable energy mandates and needs efficiently and effectively while simultaneously providing lasting conservation for species, natural communities and ecological processes in the California deserts. The Transmission Planning Process must address transmission upgrades and investments needed to support renewable energy development in the draft Development Focus Areas (DFAs) identified by the DRECP. While these areas are not yet final, the plan is expected to be complete in 2014 and it is important that investments to the DFAs be planned for, and executed in a timely manner after plan completion. Transmission projects currently have a long lead-time, and access to transmission with available	This input needs to be provided to, and taken into account, in the process led by the CPUC to develop the renewable portfolios used for transmission planning purposes.

No	Comment Submitted	ISO Response
	capacity within the DFAs is one of the major benefits, and a key development incentive for the DRECP. Consequently failing to plan for serving the zones could have significant impacts on the success of the entire planning effort. This is an area where enhanced coordination of CAISO with state and federal planners is needed.	
7b	**Stakeholder Meeting** At the Stakeholder Meeting it was noted by CAISO representatives that the CAISO is a participant in the Desert Renewable Energy Conservation Plan development process. It was also noted that the DRECP is utilized in the California Public Utilities Commission (CPUC) long term procurement plan proceeding where renewable generation portfolio scenarios are developed and provided to CAISO for use in the transmission planning process. The latter is consistent with the May 2010 Memorandum of Understanding between the CPUC and CAISO. The recent Stakeholder Meeting focused on the preliminary results of the 33 percent Renewable Portfolio Standard policy-driven transmission need assessment. It is not clear to our organizations how the preliminary results presented at the meeting correlate to the DRECP and if the proposed projects will provide availability/capacity to the draft DFAs. • **Recommendation:** The 2013-2014 Transmission Plan would be improved by including a section on the DRECP that clearly articulates current transmission availability in the draft Development Focus Areas of the DRECP, including which CAISO approved and proposed transmission projects correlate to these areas. It would be helpful if the target online dates for the CAISO approved and proposed transmission projects are included, so that stakeholders can understand the chronology of transmission availability/capacity within the DRECP plan area. Although the DFAs are currently in draft form, we note that there may be previously disturbed or degraded areas common to proposed DFA alternatives, and these could be used as a baseline for planning. • **Recommendation:** As stated in the November 20, 2013 comment letter submitted by The Nature Conservancy, the Natural Resources Defense Council, Sierra Club and Defenders of Wildlife, the CAISO Conceptual	The zones set out in the CPUC-led portfolios are based on input data including the DRECP input. While it may be too late in the 2013-2014 process to provide further resolution of the DFAs within the zones of the CPUC-identified zones, this can be pursued further in the 2014-2015 planning cycle..

No	Comment Submitted	ISO Response
	Statewide Plan should address how the CAISO will study and analyze the DRECP DFAs when the draft DRECP is released in 2014. The Conceptual Plan should, at a minimum, describe and outline the process and timeline for study of the DFAs and incorporation into the 2013-2014 TPP. **3. Conclusion** We appreciate the opportunity to provide comments to the 2013-2014 Transmission Planning Process Stakeholder Meeting that was held on November 20-21, 2013. We strongly support the enhanced coordination between the CAISO, CPUC and CEC related to integrated land-use, generation and transmission planning, including the DRECP. If you have any questions, our contact information is included below.	

No	Comment Submitted	ISO Response
8	**LS Power Development, LLC** **Submitted by: Sandeep Arora**	
8a	**(1) Harry Allen – Eldorado Transmission Project economic study:** LS Power is appreciative of CAISO staff's efforts in conducting the economic analysis for Harry Allen- Eldorado transmission project under the current transmission planning cycle. LS Power understands that CAISO is working on refining these study findings and preparing a draft report documenting study assumptions and findings in details. LS Power is submitting these questions/comments and requesting CAISO staff to incorporate details on study assumptions, findings etc. in the draft Transmission Plan. **(a)** CAISO's Economic Analysis from 2012/13 Transmission Planning studies identified $637mm in economic benefits for CAISO ratepayers from a new 500 kV transmission line from Harry Allen – Eldorado ("Project"). These benefits were significantly greater than the $138mm identified under the 2013/14 Transmission Plan. We would request CAISO to provide more information on why the benefits are significantly lower this year? **(b)** What is the source for $/kw-year new CT cost assumptions used for establishing Delany – Colorado River line Resource Adequacy benefits? Why is the SCE area cost assumed same for all years, $183/kw-year? What will CAISO use as cost for building similar new CT in NVE region? **(c)** Generation assumptions – For the purpose of economic studies, it appears CAISO assumed all OTC units will be retired and will be replaced by new efficient CC & CT plants. CAISO has added about 6000 MW on new generation in SCE & SDG&E area. While this is one possible scenario, but several other scenarios could potentially materialize, such as instead of replacing all existing OTC units with new units, perhaps all OTC units could be retrofitted to be compliant with new requirements. This scenario could potentially make out of state generation more economic than in state and hence more benefits from the new transmission projects that increase import capability. CAISO should consider performing a few sensitivity	(a) A number of significant changes of study assumptions and modeling details have been made between the 2012-2013 analysis and the 2013-2014 analysis. The calculated production benefit decreased in part due to the fact the Path 26 congestion became less because of updated line ratings for the Midway – Vincent 500 kV lines. The reduced production benefit was also related to an updated balancing authority area model, the new NAMGas model and reduced load (by incorporating Additional Achievable Energy Efficiency in California). (b) …The 2012 ISO Annual Report on Market Issues and Performance report and "Cost and Performance Review of Generation Technologies", WECC report dated October 9 2012 were sources of the CT cost. (c) …The CAISO replaced less than half of the retired OTC generation in the model. The preponderance of evidence suggests that very few if any of the OTC units will be retrofitted. (d) …Thank you for the comments. (e) The natural gas price assumptions are based on the NAMGas model of CEC 2013 IEPR Preliminary that was not yet published at the time of this economic planning study. The natural gas price data were communicated between CEC and the ISO in March 2013. The same set of data were used both in ISO's LTPP study (aka renewable integration study) and the transmission study.

No	Comment Submitted	ISO Response
	studies related to OTC assumptions. **(d)** Capacity benefits from Harry Allen – Eldorado line: LS Power supports CAISO staff's decision to analyze capacity benefits from this new line. As we have previously stated, new line from Harry Allen – Eldorado should not only help in improving import capability and providing access to more RA capacity, but should also provide CAISO access to more "dispatchable" resources that are required for renewable integration. Such benefits should also be analyzed and accounted for. **(e)** CAISO's presentation showed Natural gas price assumptions used for the economic study and referenced the draft CEC 2013 IEPR. Please identify more precisely which version and case of IEPR data was used, and what adjustments to the data, if any, were applied.	
8b	**(2) CAISO should perform studies in this year's planning cycle to quantify benefits of a new 500 kV path from Midpoint 500 kV station to Eldorado 500 kV station:** As LS Power has previously requested, a project proposal was submitted in CAISO's 2012/13 Transmission Planning Request Window for a new project from Midpoint substation to Eldorado substation. This project comprises of three segments: (a) A new 500 kV line from Midpoint - Robinson Summit (b) A soon to be operational new 500 kV line from Robinson Summit to Harry Allen and (c) A new 500 kV line from Harry Allen – Eldorado. This combined project offers a major parallel path to CAISO's existing WECC intertie paths such as PDCI, Path 26 & Pacific AC Intertie and CAISO's Southwest intertie interfaces. The project has huge potential in alleviating several intertie constraints that CAISO BAA currently faces. CAISO had performed a study for this path in the 2012/13 Transmission Planning cycle. We recommend CAISO to perform this assessment again as part of this planning cycle and quantify the economic other benefits that this project can offer to CAISO ratepayers, prior to finalizing this year's Transmission Plan. In addition to providing economic benefits, this new line will create a new interconnection between CAISO, Pacific Corp & NV Energy, and hence will allow increased benefits to all market participants from the new EIM market that is planned	In the ISO 2012-2013 transmission planning cycle, the economic planning study analyzed the proposed Midpoint – Robinson Summit transmission line. The ISO does not intend to repeat that study in the 2013-2014 transmission planning cycle for a number of reasons. First, the subject was studied before and no significant benefits were found for the ISO ratepayers. Second, the subject does not qualify for the top-five high-priority studies. Third, the proposed line is not in the ISO planning authority area.

No	Comment Submitted	ISO Response
	to be implemented initially between CAISO & Pacific Corp and later between CAISO & NV Energy.	

No	Comment Submitted	ISO Response
9	**MidAmerica Transmission & Pinnacle West Capital Corporation Submitted by: Darrell Gerrard and Jason Smith**	
9a	We commend the CAISO's significant steps to further the study process and approach for economic project evaluation, including deliverability and economic production cost analysis. These improvements create a robust foundation not only for projects in consideration in the current 2013/2014 cycle but future project study work as well. This work was evident in the supporting materials accompanying the project recommendations presented at the November 20-21, 2013 stakeholder meeting. In particular, we support the economic analysis specific to the Delaney to Colorado River ("DCR") 500 kV transmission line recognizing the significant benefits it provides to the CAISO customers. In particular, we believe that the CAISO's analysis of this transmission line has made substantial improvements in the following areas: 1. **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 wheel. 2. **Capacity Benefits:** The DCR evaluation also includes a conservative model of the value of capacity suitable for providing Resource Adequacy. This includes analysis supporting a 400 MW benefit to the CAISO Maximum Import Capability from the Palo Verde trading hub. 3. **Cost:** Finally, the DCR evaluation includes a detailed year-by-year revenue requirement and net present value estimate of project costs and benefits. Both benefits and costs are then discounted to the same base year for comparison. We also note that in order to achieve many of the near term benefits anticipated in the DCR project analysis, timely approval in March 2014 is paramount to allowing the project to begin its permitting and	Thank you for the comments. These will be taken into account.

No	Comment Submitted	ISO Response
	construction activities and achieve commercial operation by 2020. The DCR transmission line, if approved in March 2014, would need to undergo a competitive Phase 3 process over much of 2014, leaving only five years to permit this project through the federal National Environmental Policy Act (NEPA) process and ultimately construct the transmission line. While the in-service date proposed is achievable barring unforeseen circumstances based on analysis completed to date, it is critical that a March 2014 approval be maintained.	
9b	**Production Benefits** Modeling trading hubs, such as Palo Verde, helps capture the real value that already exists in the hub-market regulatory design by more accurately modeling the actual topology and transaction pricing of the transmission system. The DCR evaluation recognizes the unique benefits the Palo Verde trading hub facilitates by allowing direct CAISO control of scheduled generators through the trading hub to meet fluctuating load and generation needs. As the most liquid trading hub in the western interconnection, hosting thousands of megawatts of existing latent capacity and serving as the market interface across multiple balancing authorities, the CAISO's implementation of trading hub models incorporates a portion of this value in its economic evaluation.	
9c	**Capacity Benefits** We appreciate the CAISO recognizing the 400 MW resource adequacy import benefit effectuated by the DCR transmission line. 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 Category 1 system upgrades identified in the planning process provide necessary reinforcement to the southern California system and especially the San Diego system under	The 400 MW resource adequacy import benefit is impacted by a number of system issues inside the ISO footprint, and is subject to additional review.

No	Comment Submitted	ISO Response
	peak load conditions. Given the high West of River flows into the CAISO system during these conditions, we agree with the CAISO that the Category 1 transmission system upgrades identified in the draft Transmission Plan are necessary system additions to the Southern California system. DCR provides added benefits to the CAISO system by having efficient and uninterrupted access to the Palo Verde hub under N-1 system conditions and that will also benefit CAISO customers. As a result of these benefits, we agree with the CAISO that the costs of these Category 1 facilities should not burden the DCR transmission line economic analysis but viewed more as an enhancement to these elements that are already needed.	
9d	**Costs** We also support the CAISO's refined approach at assessing the economic costs to customers by forecasting detailed year-by-year revenue requirement estimates based on a conservative cost estimate as the basis for comparison to a similar stream of forecasted benefits. This process is consistent with the TEAM methodology and more accurately represents the costs of new projects, allowing better comparison to the benefits these projects bring.	Thank you for the comments.
9e	**Conclusion** We agree with the CAISO's overall assessment that the DCR transmission line is an economically beneficial project to CAISO customers under what we believe to be plausible but reasonably conservative assumptions. The results shared at the recent stakeholder meeting are consistent with our own assessment we independently developed with our economic consultant with significant experience in the California and Western Interconnection markets. While the CAISO's evaluation demonstrates the economic benefits to CAISO customers to a level where it makes sense to move forward with a recommendation to the CAISO Board of Governors to approve the DCR transmission line, we believe there are other factors that could drive even more benefits to CAISO customers that are worth mentioning. These	Thank you for the comments.

No	Comment Submitted	ISO Response
	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 clearing price for generation capacity in the CAISO, the increase in options that could be considered as a part of the San Onofre Nuclear Generating Station (SONGS) retirement mitigation plan, and the increased deliverability between the CAISO and neighboring regions which could facilitate interregional 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
10	**NV Energy** **Submitted by: Brian J. Whalen, Jr.**	
10a	NV Energy ("NVE") appreciates the opportunity to participate in the 2013-2014 Transmission Planning Process ("TPP"), and is encouraged by the information provided by the California Independent System Operator ("CAISO") in the TPP presentations on November 20th and 21st, 2013. NVE is interested in the economic planning study evaluating the benefit of a 500 kV transmission line from Eldorado to Harry Allen. To assist that work, NVE submits the following questions and comments. NVE has five specific areas for potential model improvement. 1. Are NVE's contractual rights honored across the BAA interfaces with WALC (Mead) and LADWP (Crystal/McCullough)? If the rights are not being honored, then generation from NVE's system is subject to hurdle rates for flows at those interfaces and with the CAISO and will limit economic transactions with NVE. 2. Does the transmission topology for Eldorado include the recent modification to move the El Dorado combined cycle power plant into the CAISO BAA? As part of this reconfiguration, NVE's capacity into Eldorado at 230 kV was doubled. 3. Has the Harry Allen 500kV substation been modeled as a hub? NVE recommends this configuration be evaluated for benefits as a sensitivity study for the Eldorado – Harry Allen TPP work. 4. Does the TPP database incorporate the anticipated changes in the NVE generation portfolio due to compliance with Nevada SB 123 (NVision)? NVision will remove five coal units from the NVE generation portfolio by 2019 and add 350 MW of new renewable generation in Nevada. 5. The delivered fuel prices being used by the CAISO TPP are lower for numerous facilities in California compared to the delivered fuel prices for generators in Southern Nevada. This is not consistent with historical fuel	The ISO appreciates NVE's comments and recommendations on the economic planning studies. 1. From the WALC (Mead) to LADWP (Crystal/McCullough), the contractual rights are not yet honored across the BAA interfaces because of limitations in the production simulation software. An alternative way is to use Trading Hub modeling approach. However, there is a concern that the Trading Hub modeling approach is too liberal. This modeling issue needs to be investigated further. 2. Yes, the El Dorado combined cycle plant is in the CAISO BAA in the current modeling. 3. So far, the Harry Allen 500 kV substation has not been modeled as a hub. If it is agreed that the new business rule is that the Harry Allen substation will change from status quo into a trading hub, then the database can be updated to reflect that in future studies. 4. Yes. The TPP database incorporated the anticipated resource changes pursuant to Nevada SB 123 (NVision). 5. The delivered fuel prices are based on the CEC NAMGas model. The ISO encourages stakeholders provide input to CEC NAMGas experts for possible update and improvements of the model. In summary, the ISO agrees with NVE's comments that the currently-

No	Comment Submitted	ISO Response
	prices in the Western United States. NVE recommends a review of these prices. NVE believes these modeling changes will provide a more representative evaluation of a CAISO/NVE interface at Harry Allen and capture additional benefits not in the current modeling.	calculated economic benefits are likely to be underestimated due to some modeling limitations (e.g. item #3 mentioned above).

No	Comment Submitted	ISO Response
11	**Pacific Gas & Electric** **Submitted by: Brad Wetstone**	
11a	***Reliability Projects with Costs Less Than $50 Million*** PG&E supports the CAISO's proposal for management approval of the set of reliability projects within the PG&E area with costs less than $50 million, as presented to stakeholders on November 21, 2013. ***PG&E Area Policy Driven Powerflow and Stability Study Results*** PG&E generally agrees with the CAISO's findings and conclusions as presented in slides 2-41 and offers the following specific comments: • In the North Valley Area Summer Peak Results section, on slide 27 the CAISO has proposed an SPS to curtail Colusa to mitigate the overload on the Delevan-Cortina 230 kV Line. In order to validate the reliable operation of the SPS, PG&E requests the CAISO to provide additional details of the CAISO's assessment of any interaction of the proposed SPS with existing RAS and SPS and coordination with other protection systems in the area. Additionally, since the proposed mitigation requires an existing generator to be curtailed, PG&E requests the CAISO to clarify whether it can modify an interconnection agreement with an existing generator by installing an SPS. • PG&E wishes to call attention to the comments it submitted to the CAISO on November 19, 2013 on the 2012/2013 Conceptual Statewide Transmission Plan wherein PG&E noted that the Desert Renewable Energy Conservation Plan (DRECP) has made substantial progress towards completion this year. The DRECP is a collaborative multi-agency effort and is a significant component of California's renewable energy planning efforts. PG&E reiterates in these comments its recommendation that the CAISO monitor the status of the DRECP for potential incorporation in next year's conceptual statewide plan update.	The ISO has continued the assessment of mitigation plans for the North Valley area and proposing for the Delevan-Cortina 230 kV line to be rerated as opposed to installation of an SPS. Thank you for the comments.
11b	***Policy Driven Planning Deliverability Assessment Results – PG&E Area***	Thank you for your comments.

No	Comment Submitted	ISO Response
	On slides 3-6, the CAISO identifies a number of line overloads for which no specific mitigation is proposed, rather the slides note that mitigation is "under evaluation." Based on statements made by CAISO staff during the November 20, 2013 stakeholder meeting, PG&E understands that mitigation recommendations for the overloads will be included in the Draft Transmission Plan, which will be posted in January 2014. PG&E looks forward to reviewing and assessing the proposed mitigation at that time.	
11c	***Economic Study Results*** While PG&E does not have enough information at this time to take a position on the specific projects found to be or not to be economic, PG&E applauds the CAISO for undertaking an analysis that includes an expanded set of benefits as part of the CAISO's analytic framework for evaluating proposed economic transmission projects. Beginning with the next TPP cycle, PG&E continues to encourage the CAISO to enhance the economic study methodology through stochastic modeling and evaluating a larger range of potential customer benefits as part of its analytic approach. Finally, PG&E notes that historically the CAISO market has experienced substantial congestion due to the projected thermal loading on the Table Mountain 500/230 kV transformer following a Table Mountain South Double Line Outage contingency. As part of the current TPP cycle, PG&E submitted a request to the CAISO for it to complete an Economic Planning Study to evaluate the congestion associated with this binding element. While PG&E appreciates the CAISO's review of this issue in the 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.	The ISO acknowledge PG&E's comments and recommendations on economic planning studies. PG&E suggests ISO to conduct stochastic modeling and evaluate a larger range of potential benefits. While this approach holds some appeal in theory, in practice, calculating large stochastic scenarios is not feasible due to a high computational burden of production simulation. In the alternative, the ISO uses scenario analysis methods to assess a broad range of sensitivity cases around the base case. In the ISO production simulation model, we have not been able to capture congestion on the Table Mountain 500/230 kV transformer under normal conditions, with the difference from actual experience expected to be due to limitations in modeling contingencies and associated SPS actions. The ISO is considering pursuing enhancements the software to facilitate this modeling.

No	Comment Submitted	ISO Response
12	**Sierra Club** **Submitted by: Sarah K. Friedman**	
12a	**A. There should be better alignment between the 2013/14 Transmission Planning Process (the "TPP"), reliability needs in Southern California to deal with the retirement of San Onofre Nuclear Generating Station ("San Onofre"), and the ISO's non-conventional alternatives proposal.** The ISO correctly acknowledges that there are unique challenges in this year's policy driven analysis.1 The TPP may play a role in determining whether the retirement of San Onofre could cause reliability concerns in Southern California, and whether any reliability needs could be met through transmission or non-conventional alternatives. The ISO requested in its opening testimony to Track 4 of the California Public Utilities Commission's (CPUC)'s Long Term Procurement Proceeding (Track 4) that the CPUC wait to make any procurement authorization decision until the ISO completes its transmission studies.2 The Sierra Club continues to believe it would be prudent to wait for the completion of the ISO's transmission studies to determine any need authorization in Track 4.3 However, in order for the TPP to assess how transmission and non-conventional alternatives could address reliability impacts, if any, the TPP must: (i) use accurate assumptions, (ii) not pre-suppose the outcome of Track 4, and (iii) properly align reliability determinations, transmission proposals and consideration of non-conventional alternatives.	Please see the responses below.
12b	**i. The ISO should use the 2013 IEPR Demand Projections.** Although the ISO uses the California Energy Commission (CEC) 2013 Preliminary Integrated Energy Policy Report (IEPR) numbers for natural gas and GHG prices, the demand forecast relies on the CEC 2011 IEPR (2018, 2023) with additional achievable energy efficiency to determine in-state load4.	Due to the time required to develop models based on a given forecast, the 2013 IEPR forecasts were not available in time to be incorporated into the 2013-2014 transmission planning cycle. The new forecast will be used in the 2014-2015 planning cycle.

No	Comment Submitted	ISO Response
	Per ISO staff, the differences between the 2013 and 2011 numbers is likely negligible. We believe the difference between the 2011 and 2013 numbers could range between 600-1,300 MW of demand for Southern California alone. We are concerned the ISO did not seem to compare demand numbers before determining the difference was negligible The CEC will hold a business meeting to consider adopting the final demand forecast on December 11, 2013.5This should allow time to incorporate the final number into the next iteration of the TPP. 6 Adopting the final IEPR demand number will ensure consistent and accurate assumptions across planning agencies.	
12c	**ii. Assuming local generation to meet local reliability needs could preclude the TPP from accurately assessing reliability needs and the ability of transmission and non-conventional alternatives to meet these needs.** The TPP assumes 520 MW of new generation in NW San Diego County in the system-wide basecase for the South Policy Driven Powerflow and Stability Results.7 It is difficult to see how transmission studies could properly analyze how transmission or non-conventional solutions could mitigate reliability in Southern California reliability impacts, if pre-supposing generation solutions. There is no explanation for these 520 MW. This generation number was not provided to the ISO as part of the CEC/CPUC's renewable generation portfolios under the CPUC/CAISO May 2010 Memorandum of Understanding, nor seemingly based on any authorization from the CPUC. The ISO notes " (A)nalysis assumed local resources meet local needs – and reconsideration will be necessary depending on reliability mitigations that are ultimately selected." 8 This description appears circular. It is difficult to understand how the TPP could accurately assess either reliability impacts or the ability of transmission solutions to mitigate	In summary, the need for the additional generation in NW San Diego county was determined in meeting the needs for the area in 2018, and was therefore used as an assumption in the analysis of 2023 scenarios. Further, this aligns with the ISO's expectations of the Track 4 LTPP procurement proceeding and generally aligns with the draft joint reliability plan for the LA Basin and San Diego, which reasonably led to the expectation that an array of resources would be required to address local needs.

No	Comment Submitted	ISO Response
	reliability impacts if assuming all local need will be met by local resources. We find the interplay between this assumption and the ISO's non-conventional alternatives proposal unclear. In the ISO's presentation on Consideration of Alternatives to address Local Needs in the TPP, the ISO stated they were currently applying the non-conventional alternatives methodology to the LA Basin, San Diego and the Moorpark sub-area of Big Creek/Ventura, and that in this particular TPP " a basket of both preferred resources and conventional resources (i.e., transmission and generation) will be pursued,9" with a main focus on "the local reliability needs as part of a basket of resources.10" Local preferred resources are the mitigation solutions most consistent with the ISO's 'least regrets' transmission policy. However, we are confused how potentially effective transmission solutions .will be considered in this process if it is assumed local resources will meet local needs.	
12d	**B. A 100% preferred resource solution to replacing San Onofre should be considered.** We agree with the ISO that this particular TPP presents unique challenges due to the announced retirement of San Onofre. However, we also believe that this retirement, together with the great strides the ISO has made in recent months with the non-conventional alternatives proposal, presents a great opportunity to show any reliability needs could be addressed through carbon-free resources. Given the numerous issues around the retirement of San Onofre and whether this will impact reliability in Southern California, we were surprised this was not addressed in the Conceptual Statewide Plan or the draft TPP. The TPP should study a 100% preferred resource solution to the retirement of San Onofre and include identifying as policy-driven alternatives transmission projects which would use renewables to address any reliability needs caused by the retirement of San Onofre, and analyzing how all policy-driven or economic-driven improvements could	Please refer to the above comment.

No	Comment Submitted	ISO Response
	meet any reliability concerns in Southern California. It is not clear how the various transmission proposals submitted by the IOUs and others to address reliability concerns in Southern California will be compared and evaluated against the policy-driven lines evaluated and proposed by the ISO to be presented for approval at the March Board of Governors meeting. We are concerned that in fact, the ISO has apparently already the Harry Allen-Eldorado 500 kV line as its policy driven project without analyzing how this line will address reliability concerns. Given the high direct and indirect costs of transmission, it makes sense to choose transmission investments which would serve multiple goals.	

No	Comment Submitted	ISO Response
13	**Southern California Edison** **Submitted by: Karen Shea, Megan Mao, David Franklin, Rabindra Kiran and Garry Chinn**	
13a	***Delaney Colorado River Study Project – Assumptions and Methodology:*** • **CAISO Should Describe How it Will Address Potential Upgrades on Affected Systems in the Economic Analysis.** Additional studies outside the CAISO's economic study process (e.g., through WECC or affected systems studies) may identify additional upgrades that are necessary to accommodate the Delaney-Colorado River project. SCE requests the CAISO to indicate how it will incorporate the results of such studies, as applicable, into the overall cost/benefit assessment of the Delaney-Colorado River project. • **Impacts of COD Beyond 2020 Should Be Studied.** Transmission projects take on average 7-11 years to construct. Simulations for a Commercial Operating Date (COD) beyond 2023 would be ideal. Also, use of data from the CAISO-focused 2012 LTPP is preferable to the 2012 NERC Reliability Assessment. • **Improvement to cost forecasting.** It would be more statistically accurate to draw from a larger sample size of transmission projects to determine the all-in cost of constructing the Delaney-Colorado River line.	- The ISO's analysis is based on WECC information and focused on costs and benefits from the ISO customer perspective. The ISO is not aware of any additional costs being incurred outside of those considered in this project. - The ISO employs the TEAM methodology and tariff-based planning approaches which are utilized throughout the planning process. - The basis for the costs are the most current and similarly-situated projects. Further consideration of the cost issue will be addressed in the competitive solicitation process.
13b	***Resource Portfolio Assumptions, Approval of New Equipment, and Approval of a Third Lugo AA Bank:*** • **A more robust stakeholder process is needed** to discuss the development of the RPS portfolios prior to these portfolios being used in the CAISO TPP to determine policy driven transmission. • **SCE Supports the CAISO's proposal to approve the Lugo-Mohave 500 T/L Series Capacitor** and Terminal Equipment Upgrade as policy projects in this planning cycle. SCE also recommends the CAISO review a recently submitted SSR study for possible mitigations needed in order to allow the Eldorado-Lugo and Lugo-Mohave 500 kV transmission lines to be operated at the increased compensation level.	- This input should be provided in the CPUC led process that produces the portfolios which is underway for the 2014-2015 planning cycle.

No	Comment Submitted	ISO Response
	• **Recommend the ISO Consider for Approval the Lugo No. 3 AA Bank as a Transmission Project** Given the significant interest in renewables developing in the Victor area, this must be considered for transmission planning to ensure renewable resources are deliverable.	
13c	***Other Policy Considerations Including Storage and Varying RPS Sensitivities in Economic Studies:*** • **SCE recommends that the CAISO include sensitivities reflecting State policy** on storage and various RPS levels in its Delany Colorado River economic and other economic studies.	Currently, specifics of storage assumptions are not defined. On the CPUC Staff Workshop on 2014 LTPP and TPP Assumptions (December 15, 2013), the discussions have just been started on the storage assumptions. Regarding to RPS levels, the ISO adheres to the CPUC/CEC-stipulated scenarios (base and sensitivities). The ISO's economic studies address those scenarios.
13d	**I. SCE Comments for CAISO Consideration in Finalizing its Economic Study for Delaney Colorado River Project** ***A. Potential Impacts on Affected Systems May Impact Total Costs of Delaney-Colorado River Project*** SCE recognizes that the Project Sponsor will need to obtain necessary approvals through the WECC study processes, as applicable, and, in conjunction with the CAISO, address potential affected systems impacts. However, as a result of these analyses, there may be additional upgrade costs associated with the Delaney-Colorado River project. Such impacts may result from conditions other than those studied for this economic analysis (e.g., WOR at 11,200 MW and the EOR at 9,600 MW during light load conditions). SCE requests that the CAISO indicate how it will incorporate the costs of upgrades identified outside of the CAISO's economic study into the CAISO's overall assessment of the benefits of the Delaney-Colorado River project. ***B. Resource Planning Considerations*** The CAISO's Delaney-Colorado River Transmission study assumes that the line will be	A-C – please refer to above comments. D – The ISO tariff currently provides for regional and local transmission projects. In that context, the Delaney-Colorado River project is a regional transmission project, based on the voltage level distinction set out in the ISO tariff. Further, the project is being considered for approval based on the costs being recovered through ISO ratepayers, and considering the benefits forecast to accrue to ISO ratepayers.

No	Comment Submitted	ISO Response
	operational in 2020 as a base case. Historically, transmission project takes between 7-11 years to be fully constructed and SCE believes that 2020 may be an optimistic assumption. SCE recommends that the CAISO analyze years beyond 2020 as more realistic operation dates of the line. If the CAISO analyzes operation dates of the line beyond 2020, SCE recommends that the CAISO runs simulations for additional years beyond 2023 for a more robust analysis. Additionally this transmission analysis relies on the information in the 2012 NERC Reliability Assessment to determine that California is resource deficient prior to 2020. However, results from the 2012 Long Term Procurement Plan (LTPP) show that the supply of resource in the CAISO system does not drop below a 15% margin until 2024 (http://www.cpuc.ca.gov/NR/rdonlyres/CA96D98A-F855-4C48-B6BC-298901887082/0/SummaryDataofRevisedScenariosv6.xls, "1A Early SONGS" tab). Also, recent decisions regarding local area generation and preferred resource targets have been made that will likely increase the supply of resources in the future. SCE recommends that the CAISO use the resource forecast from the 2012 LTPP and the recent generation procurement decisions as this information will change the capacity benefit that the transmission line is expected to provide. The impact of a later online date for the transmission line and a later year of when California becomes resource deficient will likely reduce the capacity benefits that this line provides. ***C. Improvement to cost forecasting*** The CAISO estimates the cost to construct the Delaney-Colorado River transmission line using the contract costs from one transmission project. SCE recommends that the CAISO also look at costs from other transmission lines that have been built or are currently being constructed to have a more complete estimate of the costs. The concern is that the costs from only one project may not fall within the average range of transmission construction costs so it would be useful to have a larger sample size. Additionally, SCE believes that the contract costs may not include the all-in costs of a line and that there may be additional costs missing from the CAISO's estimate such as environmental costs and other indirect costs. ***D. SCE requests the CAISO to indicate whether the Delaney-Colorado River project is a Regional or Inter-Regional project, including an explanation for its answer.***	

No	Comment Submitted	ISO Response
13e	**II. Resource Portfolio Assumptions, Lugo-Mohave 500 T/L Series Capacitor, and Recommend the ISO Consider the Lugo No. 3 AA Bank as a Policy Driven Project** ***A. Introduction and Overview Policy-Driving and Economic Assessment (Neil Millar)*** Page 7 Commercial Interest Portfolio For the 2013-14 TPP SCE requests the CAISO, in coordination with the CPUC/CEC, to have a more robust stakeholder process to discuss the development of the RPS portfolios prior to these portfolios being used in the CAISO TPP to determine policy driven transmission projects. SCE understands that there is an Energy Division Workshop which in collaboration with the CEC and CAISO scheduled for December 18, 2013. SCE looks forward to participating in upcoming efforts to redefine the appropriate RPS portfolios based on more accurate available data, and also provide transparency to the process. In the 2012-13 TPP SCE provided comments on the CPUC/CEC Commercial Interest Portfolio expressing concern that there may be values being understated in the various SCE zones1. For the 2013-14 TPP, similar updates may be needed. (For example, SCE offers as an example that for Riverside East, the total generation in the portfolio is indicated to be 1,209 MW. As of the date of these comments, for Riverside East, the total megawatts for executed Large Generator Interconnection Agreements (LGIA's) is 2,035 MW, and the total for executed PPA's is 1,550 MW. For the Tehachapi Area, the total generation in the portfolio is indicated to be 2,101 MW. As of the date of these comments, for Tehachapi, the total megawatts for executed Large Generator Interconnection Agreements (LGIA's) is 4,451 MW (does not include Rule 21 projects), and the total for executed PPA's is 2,492 MW). SCE would appreciate ensuring that it understands the details behind discounting the portfolios and the opportunity to work with the CPUC/CEC/ISO staffs to update these values. ***B. Policy Driven Planning Deliverability Assessment Results –SCE Area (Songzhe Zhu)*** Slide 17 Desert Area Deliverability Constraints SCE supports the CAISO on proposing the Lugo-Mohave 500 kV T/L Series Capacitor and	Please refer to the above comments.

No	Comment Submitted	ISO Response
	Terminal Equipment Upgrade as a policy-driven project for the 2013/2014 planning cycle in order to increase power transfer capability as well as integrate renewable generation in the East of Pisgah area. Since the Eldorado-Lugo 500 kV T/L Series Capacitor and Terminal Equipment Upgrade was approved as a policy driven project for the previous 2012-2013 cycle, it follows to recommend approval of the Lugo-Mohave 500 kV T/L upgrade for this planning cycle, since both lines will be operated in parallel with the increased series compensation. However, SCE has performed an SSR study to assess the impacts of the increase in series compensation and identified potential issues that will require mitigation. SCE recommends that the CAISO ensure that the mitigations are addressed in order to allow the Eldorado-Lugo and Lugo-Mohave 500 kV transmission lines to be operated at the increased compensation level.	
13f	**III. Recommend the ISO Consider for Approval the Lugo No. 3 AA Bank as a Transmission Project** While the commercial interest renewable resource portfolio shows 762 MW of generation in the Kramer area, it does not identify how much generation is assumed for the Victor, Jasper, and Pisgah areas. Based on public queue information, SCE is aware of over 1,000 MW of renewable resources pursuing developmentin the Victor, Jasper, and Pisgah areas. SCE believes the CAISO should be modeling these renewable resources in its TPP. Based on SCE's studies, the renewable generation developing in these areas drives the need for a third AA Bank at Lugo Substation.2 SCE requests the CAISO to provide the amount of Victor, Jasper, and Pisgah area generation modeled in its 2013-14 TPP studies. SCE also requests the CAISO to complete TPP studies with this area generation modeled consistent with the generation currently in the interconnection queue and provide the results to stakeholders. SCE believes these additional studies will show that a third AA bank at Lugo substation is needed and therefore should be approved by the CAISO. SCE has reviewed the CAISO's policy driven projects and understands the CAISO is following the pre-established Commercial Interest Portfolio. However, it appears that a considerable amount of Victor, Jasper, and Pisgah area projects are missing from the portfolio, which are detailed below. SCE strongly recommends that the Commercial Interest Portfolio generation assumption be updated and also incorporated in future commercial interest portfolios. Below please find a summary of commercial interest generation in the CAISO and SCE WDAT generation queues, which are publically available at:	The TPP is based on CPUC-led portfolios. If additional generation develops, additional reinforcement can be developed through the generator interconnection process.

No	Comment Submitted	ISO Response
	http://www.caiso.com/Documents/ISOGeneratorInterconnectionQueueExcel.xls and http://www.sce.com/nrc/aboutsce/regulatory/openaccess/wdat/wdat_queue.xls CAISO Kramer area: 1,430 MW CAISO Victor/Jasper/Pisgah area: 770 MW WDAT Kramer area: 207 MW WDAT Victor/Jasper/Pisgah area: 322 MW Total Queued Generation which will flow into the Lugo AA Banks: 2,729 MW	
13g	**IV. Other Policy Considerations Including Storage and Varying RPS Sensitivities in Economic Studies** • CPUC recently mandated for California utilities (IOUs) to purchase 1,325 MW of Storage capacity by 2020 (please see CPUC October 2013 Storage proceeding). There may also be an additional potential of 200 MW Storage capacity (assuming POUs at 15% of State load) to be acquired by POUs in California. In case CAISO has not accounted storage in their economic studies presented to TPP Stakeholders, does CAISO plan to re-run their production models to account for this mandated storage (1,325 MW) for California IOUs in their Benefits calculations on the Delaney - Colorado River project, as it will impact their production and capacity calculations? This mandated storage capacity amount should be accounted before the results are finalized and presented to the Board. • Also, SCE previously expressed concerned and has recommended the CAISO perform sensitivities including in 2030 to consider varying State of CA RPS policies and the impact on the interties on the benefits the CAISO is calculating.	Currently, regarding the CPUC mandates to procure 1,325 MW of storage, no specifics on the assumptions have been specified. On the CPUC Staff Workshop on 2014 LTPP and TPP Assumptions (December 15, 2013), the discussions have just been started on the storage assumptions. In a preliminary suggested assumption, the CPUC proposed to model only 700 MW of storage in year 2024 (see Slide 11 of the CPUC presentation). Out of the 700 MW, if 400 MW is assumed for southern California, the amount is insignificant to affect the assessed economic benefit of the Delaney – Colorado River 500 kV line. Moreover, storage can even increase the benefit of the Delaney – Colorado River 500 kV line because the storage will increase the usage of base-load generation. At the sending end of the proposed line, there is a large concentration of base-load type generation at the Palo Verde Trading Hub. Therefore, the storage assumptions are not expected make a material difference for the proposed Delaney – Colorado River line. The following is regarding the proposed 2030 analysis. Unlike a traditional power flow, where a partial system can be modeled, a production simulation model requires full representation of the WECC-wide system with all resource and transmission assumptions. To build a year 2030 model, most of resources assumptions are not at all available; and having only the 40% California RPS scenario is not

No	Comment Submitted	ISO Response
		sufficient. There is no sufficient information to construct a year 2030 model for production simulation and economic planning studies.

No	Comment Submitted	ISO Response
14	**Southwest Transmission Partners, LLC** **Submitted by: Mark L. Etherton**	
14a	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. A lower percentage contingency included in our Capital Cost of the Project would also produce much more positive results. Taken with other reliability and policy benefits, the Project should be considered in a more positive light. 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	The ISO appreciates the comments and suggestions. (a) The "RR-to-CC ratio" of 1.45 is an approximation for screening purposes based on prior experience of California IOUs. Based on a set of financial assumptions (see PPT "Economic Planning Studies – Part 3: Study Assumptions", Slide 4) , the ISO calculated the detailed revenue requirement for the proposed Delaney – Colorado 500 kV line. Based on the calculated revenue requirement and the ISO's other related, the "RR-to-CC ratio" was 1.44, which is very close to the 1.45 value. (b) For the proposed NGIV2 line, the capacity benefit is limited to the downstream bottleneck in the SDG&E area. Power flow studies concluded that there is zero RA capacity increase due to downstream bottlenecks. The ISO agrees with the comment that if in the future the receiving end does not have limitations, the capacity benefit will not be zero and that the proposed line will have a greater potential to be economic. (c) Please refer to ISO's comment in (b).

No	Comment Submitted	ISO Response
	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.	

No	Comment Submitted	ISO Response
15	**Transmission Agency of Northern California (TANC)** **Submitted by:**	
15a	The Transmission Agency of Northern California (TANC) appreciates this opportunity to provide further comments on the California Independent System Operator's (CAISO) 2013-14 Transmission Planning Process (TPP). Previously, on October 10, 2013 TANC submitted comments on the results of the CAISO's 2013-2014 TPP studies as originally posted on the CAISO website on August 15, 2013 and presented at the TPP Stakeholder meetings on September 25 and 26, 2013; these initial comments raised several questions/issues TANC identified related to the CAISO's planning studies. Additionally, at the TPP Stakeholder meetings held on November 20 and 21, 2013, TANC re-iterated its concerns regarding line ratings raised in our October 10, 2013 written comments, and requested clarification regarding line ratings and other items previously raised by TANC. TANC's comments have focused on the reliability assessment results for the Pacific Gas and Electric Company's (PG&E) bulk transmission system and on how issues associated with the PG&E bulk system can impact the California-Oregon Transmission Project (COTP) for which TANC is the Project Manager and largest Participant. To date, TANC has not received a response regarding any initial comments, or the issues raised at the November 20 and 21 stakeholder meetings. Therefore, we want to take this opportunity to again raise what we believe are important issues that the CAISO should address, as follows: • 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 the remedial action scheme (RAS) and identified potential mitigation solutions for each. The suggested solutions included upgrading the impacted line, limiting California-Oregon Intertie (COI) transfers, limiting generation in northern California, or modifying other existing RAS to drop generation at other locations. However, the only form of mitigation discussed in any detail	Please refer to the ISO comment matrix for the September stakeholder meeting as well as the Draft Transmission Plan for documentation with respect to the studies that were conducted as a part of the Northern California Bulk Transmission System Assessment. As indicated at the stakeholder session, the base cases have been developed with PG&E based upon the planned system for the years studied and the estimated in-service date of approved transmission projects. These base cases are posted on the ISO Market participant Portal for stakeholders to access and review.

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	during the September stakeholder's meetings was limiting COI transfers, with no detailed information presented on the other potential mitigation options. As noted previously, TANC is: − Concerned that "under playing" the available 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 − Of the opinion 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. • TANC is not clear as to whether the CDWR pump-drop remedial action was or was not modeled in the TPP studies without the CDWR generation-drop remedial action. In its September 24, 2013 email, the CAISO informed TANC that the pump-drop RAS was not modeled in the studies. However, in a response to a question from TANC at the September 25, 2013 stakeholder meeting, the CAISO indicated that the CDWR pump-drop remedial action was modeled. TANC is still awaiting clarification on this modeling question. TANC strongly believes it is critical that the studies identify how the remedial actions currently being provided by CDWR for PG&E are modeled in the TPP studies. • During recent operational studies it was noted that the base cases initially used in these studies (which were derived from Western Electricity Coordinating Council (WECC) cases) did not model the correct ratings on a number of PG&E facilities in northern California. As was noted at the November 21, 2013 Stakeholder meeting, TANC with the Western Area Power Administration (Western) and the Sacramento Municipal Utility District (SMUD), remain concerned that the data sets used by the CAISO in the TPP studies may not accurately reflect the ratings of critical lines in	

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	northern California (particularly those impacted by the Table Mountain-South outage as discussed above). If such is the case, 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. We request clarification from the CAISO regarding which data set for line ratings were utilized in the TPP studies. TANC is of the opinion that the 2013-2014 TPP reliability studies should not be deemed complete until the above items have been adequately addressed. As such, if the reliability studies are not complete, TANC questions whether the economic studies are accurate, since they were run subsequent to the reliability studies.	
15b	TANC also has comments/questions regarding the economic studies particularly related to potential congestion (or lack thereof) on the COI. The CAISO presented information on the most congested paths as part of the economic planning study process. The presentation showed 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: 11 percent 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 Balancing Authority Area (BAA) was congested 1 percent, 12 percent, and 8 percent in 2010-2012, respectively. This table indicates that Path 66 was the most congested import path in 2012 and is frequently one of the top three or four most congested paths 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 about this apparent discrepancy between planning studies and actual operations. It also seems to contradict the language of	The ISO appreciates the comments of COI congestion concerned by TANC. COI and PDCI have been among the top-five high-priority studies in the ISO economic planning studies in recent two years. Among other reasons, one reason of taking COI study as a high priority is because of the congestion listed in the Market Monitoring reports. The differences between historical experience and forecast simulated results for COI congestion are due to multiple reasons: 1. The current experience is of course based the current system (e.g. 2011-2013), while the simulation is for the future years (2018 and 2023) and includes the impact of forecast developments. With the significant renewable buildup in California, the tendency of COI congestion is expected to less than today's level. 2. Historical experience includes congestion that happens during transmission line outages. In the simulated system, transmission forced and scheduled outages are not modeled (due to the low frequency transmission outages). Therefore, actual experience generally results in somewhat more

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	the CAISO Tariff. Section *24.4.6.7, Economic Studies and Mitigation Solutions,* states that*:* The CAISO will conduct the High Priority Economic Planning Studies selected under Section 24.3.4 and any other studies that the CAISO concludes are necessary to determine whether additional transmission solutions, are necessary to address: (a) Congestion identified by the CAISO in the Congestion Data Summary published for the applicable Transmission Planning Process cycle; and the magnitude, duration, and frequency of that Congestion; *Appendix A*: *Master Definition Supplement* defines the "Congestion Data Summary**"** as "A report issued by the CAISO on the schedule set forth in the Business Practice Manual1 **that sets forth historic Congestion on the CAISO Controlled Grid.…**" TANC is concerned that the CAISO's TPP studies understate the congestion along Path 66 and fail to account for the impact the expected reduction in the transfer capability of Path 66 will have on congestion on the 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.	congestion than simulations. 3. The different dispatch mechanisms between existing market frameworks and the WECC-wide jointly dispatched simulation are to-some-extent responsible for some of the differences. The ISO database is built on top of the TEPPC database. Although the ISO added a lot of additional modeling, the simulated COI flows are not very different. Going forward, the ISO expects to continue to study COI and PDCI. The ISO will also seek to coordinate with Northwest authorities to validate and improve the modeling.

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16	**Valley Electric Association, Inc.** **Submitted by: Chris Tomchuk**	
16a	Valley Electric Association, Inc. (VEA) is pleased to submit the following comments on the CAISO Transmission Planning Process (TPP) assumptions presented on November 20-21, 2013. In particular, VEA requests that the CAISO revise its TPP renewable portfolio assumptions for the central Nevada (Nevada-C) CREZ Region to reflect the MW build out assumed in the portfolio direction provided by the CPUC in its February 7, 2013 Portfolio Transmittal Letter. IN the CPUC-provided assumptions, 316 MWs of renewables were assumed for development in the Nevada-C Region in each of the Commercial, Environmentally Constrained, and High DG cases. However, in the CAISO's Economic and Policy assumptions provided during the November 20, 2013, meeting, the CAISO indicated that only 166 MWs of renewables were being assumed for the Nevada-C Region. The CAISO's rationale provided during the meeting for only including 166 MWs of the 316 MWs offered by the CPUC was that only these 166 MWs were on the CAISO-controlled grid. However, VEA's understanding from the CAISO's TPP study plan is that a main driver for including the CREZ-area renewables is to ensure that there is sufficient deliverability across the ISO interties to deliver those renewables that the LSE's are finding viable to fulfill their California policy needs. VEA request that the CAISO revise its Nevada-C assumptions back to the CPUC-provided value of 316 MWs. If the ISO continues to believe that it is appropriate for the CAISO to include less than 316 MWs of Nevada-C renewables in its TPP. We ask that the CAISO provide a detailed explanation for the basis of the modifications to the CPUC's assumptions.	The ISO did not make actual adjustments to the portfolios. We simply corrected the mapping in the calculator and the detailed resource information that was the basis for the portfolio aggregate amounts.