The ISO received comments on the topics discussed at the November 16, 2016 stakeholder meeting from the following:

1. Bay Area Municipal Transmission Group (BAMx)
2. Citizens Energy Corporation
3. California Public Utilities Commission (CPUC) Staff
4. Eagle Crest Energy (ECE)
5. Large-scale Solar Association (LSA)
6. LS Power
7. Next Era Energy Transmission West, LLC (NEET West)
8. Office of Ratepayer Advocate (ORA)
9. Pacific Gas & Electric (PGaE)
10. San Diego Gas & Electric (SDGaE)
11. Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities)
12. Smart Wires
13. Transmission Agency of Northern California (TANC)
14. The Utility Reform Network (TURN)

Copies of the comments submitted are located on the 2016-2017 Transmission Planning Process Page at:

http://www.caiso.com/planning/Pages/TransmissionPlanning/2016-2017TransmissionPlanningProcess.aspx

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

| No | Comment Submitted | CAISO Response |
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| 1 | Bay Area Municipal Transmission Group (BAMx)<br>Submitted by: | |
| 1a | <u>General Process Concern</u><br>The efforts in this transmission cycle have been focused on many special studies. This is understandable, as the most recent load forecasts show a decline in future requirements that reduce the need to expand the transmission system for reliability. Many of the analyses presented are interim products requiring additional work before findings and recommendations are available. BAMx understands the timeline to include final recommendations in late January, discussion in February, and comments due also in February.<br><br>We are concerned that this late release of the CAISO staff's findings and recommendations significantly diminishes the ability of stakeholders to influence the TP presented to the CAISO Board. With a stakeholder meeting in mid-February and stakeholder comments due at the end of February, there is very little time for the CAISO staff to address stakeholder comments, much less to potentially augment any studies, before posting the draft TP for Board consideration in mid-March. Postponing the disclosure of the CAISO's findings until the draft TP is a process that is appropriate to use only rarely for narrow circumstances. As a general practice, stakeholders should have had the opportunity to review and comment on proposed transmission projects prior to the issuance of the draft TP.<br><br>For the current TP, BAMx recommends that the process be more transparent. For all cases where the draft TP may include the recommendation of either including or cancelling (or deciding not to cancel) TP capital projects in the TP, the CAISO should hold a December web-conference to review such findings and answer questions by the stakeholder group. This would allow stakeholders to have a meaningful opportunity to provide comments that can be fully considered in the final draft TP that will later be considered by the CAISO Board. | While the findings presented on several issues were preliminary, the ISO encourages comments on those specifics rather than waiting until a draft plan is available - especially for the consideration of new projects addressing needs identified in the August postings and discussed with stakeholders in September.  The ISO considers the draft plan to be a meaningful stakeholder feedback opportunity and looks forward to the comments received following its posting and presentation at the stakeholder session in February.<br><br>Unfortunately, recommendations in the transmission plan regarding canceling projects cannot be finalized until late in the year, as the consideration of those projects also requires coordination with the generation interconnection processes. As the number of previously approved projects is further reduced, through completion or cancellation, the ISO expects this to be less of an issue in the future. |

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<tr><td>1b</td><td><u>Economic Planning-TEAM Overview and Review of Updated Documentation</u><br>The Update of TEAM Documentation is Long Overdue<br>BAMx recognizes the tremendous amount of effort over that past several years toward improving the production cost database and analysis used in the TEAM 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.<br><br>BAMx also appreciates the CAISO presentation providing an overview of the elements that will be included in the upcoming updated TEAM documentation. This is long overdue. The CAISO proposes to remove obsolete contents of the original TEAM, and clarify and update components to reflect current practices and circumstances. BAMx encourages the CAISO to consider the stakeholder input in determining the criteria that make certain elements of TEAM obsolete.</td><td>The comment has been noted.</td></tr>
<tr><td>1c</td><td>Need for a Separate Stakeholder Process<br>Over the last several Transmission Planning Process (TPP) cycles, BAMx has indicated several concerns with applying the decade old TEAM methodology and has urged the CAISO to review and revise TEAM via a separate comprehensive stakeholder initiative. These concerns include the following:<br>- The scope is too narrow: As the CAISO has made it amply clear during the November 16th stakeholder meeting, current CAISO's efforts are limited to a TEAM documentation update only. No methodology review is being contemplated.<br>- Several key elements of the original TEAM that developed in 2004-05 timeframe merit review: For example, the capacity benefits methodology that was determined under TEAM is outdated due to significantly changed circumstances, since the TEAM approach was originally developed more than a decade ago. 2 These changed circumstances include increased renewable generation, relative adequacy of system capacity and need for greater flexible capacity in California. Moreover, for the last two major transmission projects approved by the CAISO as economic-driven, the capacity benefits constituted a significant portion of the overall benefit, essentially</td><td>The ISO may consider a broader scope at some point in the future. However, we consider it necessary to update the documentation to reflect current practices and interpretations, and remove obsolete detail from existing documentation, as process improvement for the current planning processes as well as to set a more meaningful foundation for any future discussions.</td></tr>
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| | justifying the transmission projects' economic viability. This increased role for capacity value in overall project benefits demands that several sensitivity analyses be performed, similar to the work that the CAISO has done for the production benefits. Additional capacity benefits sensitivity calculations are not burdensome, as such analyses will likely take relatively less effort and time than production costs. These calculations do not require deployment of the resource intensive production cost tool and analysis. The capacity benefits assumed in the TEAM methodology are based upon a projection of the need for capacity at the ends of a new line and the cost to build new capacity when there is a need. The CAISO is not the primary regulatory agency that makes decisions as to when and what generation capacity needs to be built. Therefore, the CAISO should defer to the CPUC for the IOU's and to the LRA's within California for the other LSE's to determine the capacity value. If regional expansion occurs, this determination should be by some body that represents the LSE's from the included states in the expanded regional footprint.<br>- Different analyses to assess project benefits and analyses for cost allocation: The TEAM approach to date is done to determine whether the overall benefits of any given transmission facility under consideration exceeds its cost. However, in the Regional Transmission Access Charge (TAC) Options stakeholder initiative, TEAM is proposed to have an additional role as the key cost allocation tool. In other words, TEAM would be used to determine sub-regional shares of economic benefits associated with regional transmission projects.<br>- Lack of stakeholder review: The stakeholders need to have an opportunity to provide input into the determination of both the quantifiable and non-quantifiable benefit categories utilized under TEAM. Furthermore, the stakeholders participating in the Regionalization initiatives are unfamiliar with TEAM and have never had an opportunity to influence TEAM's development.<br><br>For the above-mentioned reasons, BAMx urges the CAISO to begin a separate comprehensive stakeholder process to review TEAM. | |

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| 1d | BAMx Recommendations on TEAM Documentation and Review<br>In the table below, we provide some suggestions on the TEAM documentation update for the CAISO's consideration. BAMx recognizes that some suggestions below constitute a TEAM methodology update must be explored as part of a separate stakeholder process.<br><br>*Note to facilitate the recommendations in the table within the BAMx comment submission, each of the TEAM Element and BAMx Recommendation are included below in individual cells of the comment matrix (Comments 1e – 1j)* | BAMx is correct that much of the input below does not represent comments on documentation but rather questioning the methodology as it exists today.<br><br>We will respond to those comments where we can clarify a misunderstanding, but suggestions of materially changing the existing methodology will have to rest with case by case application until and if a broader review is initiated. |
| 1e | *Use of Social Discount Rate to calculate the net present value (NPV) of the benefit of transmission expansion*<br>Using a social discount rate can create a discrepancy between the revenue requirements funded at the borrowing entity's cost of capital, and the benefits, which are valued at a different discount rate. Historically, the CAISO has used 5% and 7% real discount rates as two alternatives.3 The CAISO needs to justify to stakeholders the use of social discount rates or sensitivity thereof. | This appears to be a misunderstanding. The discount rate is used to assess the perceived present values of a benefit stream over a number of years and a corresponding cost stream of annualized revenue requirement and other potential costs, from a rate-paying customer perspective. As the same social discount rate is applied to the cost stream as the annualized revenue stream, there is no discrepancy. While a utility's financing costs may be relevant in translating a capital expenditure into an annualized revenue stream, the annual cost (once determined) is the quantity for which the present value to the ratepayer is being assessed. |
| 1f | *NPV Calculations*<br>The CAISO typically calculates the production benefits in two distinct (5 and 10) years. The CAISO then typically interpolates these benefits for the intervening years and assumes a flat benefit of certain amount in the outer years. BAMx has repeatedly questioned the CAISO's rationale for such extrapolation of economic benefit, and has demonstrated that different methods of extrapolation of the benefits yield vastly different results, and in turn, benefit to cost ratios.4 The CAISO needs to justify to stakeholders its current practice in performing the extrapolation of the benefits in the outer years of the study period and include sensitivities to alternate forecast methods. | The standardized approach is considered a reasonable starting point. If there are specifics that BAMx believes warrant further consideration, those need to be raised on a case by case basis. |
| 1g | *Sensitivity cases performed to test the robustness of the economic assessment results* | The sensitivity cases were discussed in the presentation in the Stakeholder meeting in Nov. 16. The same discussion will be included in the updated documentation. BAMx provided a similar comment |

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| | There is a need to clearly document the CAISO's current practice of running sensitivity cases by varying the most critical assumptions for the project under evaluation such as, loads, hydro conditions, natural gas prices, etc. The CAISO needs to add specifics on some relevant additional sensitivities involving varying levels of In-State and Out-of-State renewable development to meet the RPS goals and GHG emissions (CO2 tax) scenarios, etc. As mentioned above, there is a need to perform several sensitivity analyses to evaluate the capacity benefits, similar to the work that the CAISO has done for the production benefits. | regarding the need to provide sensitivity study results for capacity benefit calculations of a specific project evaluated in the past. Sensitivity studies are explicitly performed for the production cost model simulations because the results are not always linear and predictable. However, the capacity benefit calculations in that study were linear and predictable, so providing sensitivity calculations was unnecessary, and stakeholders can perform these calculations themselves. |
| 1h | *Quantification of Benefits Under Multiple Categories*<br>The CAISO has identified transmission loss saving benefit as a separate benefit category. However, the past CAISO studies have not separately quantified such a benefit. As explained in the November 16th stakeholder meeting, the CAISO's production cost model internally calculates energy savings associated with transmission losses embedded in the production cost simulation results. Per the CAISO, the peak savings benefit associated with the transmission losses can be translated to capacity benefit. If that is indeed the case, such benefit should be itemized separately from the remaining system capacity benefit. | Concerns with the application of the methodology and the itemization of the benefits should be raised on a case by case basis. |
| 1i | *Other Benefits*<br>During the November 16th meeting, the CAISO identified several other benefits beyond the production cost and capacity benefits such as, Public Policy benefits, renewable integration benefits and avoided cost of other projects, etc. In the TEAM documentation, the CAISO should clearly identify which of these benefits are quantifiable and which are not. For instance, if any economic project improves reliability by increasing options for recovering from supply disruptions and transmission outages, then the CAISO needs to determine a method to quantify those benefits. If there is no specific guide to quantify such benefits, they cannot be used to tip the scale in favor of justifying the transmission project if the economic benefits benefit-to-cost ratio is very close to 1.0. | Regarding a pre-determination of the ability to quantify other benefits, these need to be considered on a case by case basis.<br><br>Regarding the consideration of (objectively determined) qualitative benefits, the ISO agrees that they are challenging to portray, but does not agree that they have no place in decision-making. |
| 1j | *Benefit-to-Cost Ratio*<br>Given future uncertainties, BAMx recommends the CAISO discuss with stakeholders why it uses the lower bound of the benefit-cost ratio ("BCR") allowed by FERC. Retaining an unduly low threshold for economic projects may result in the approval of potentially costly new projects and the accompanying long term financing costs without any assurances that the projected savings will | Risk considerations need to be weighed on a case by case basis. |

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| | be achieved. Not only could benefits calculations shift in subsequent years, but any cost overruns will reduce the BCR. It is important to recognize that costs are real and benefits are speculative. | |
| 1k | <u>Policy Driven Planning Deliverability Assessment</u><br>BAMx supports the CAISO's direction to recommend no transmission improvements increasing the deliverability from the Imperial Valley, given the modest shortfall in deliverability from this area | The comment has been noted. |
| 1l | <u>Economic Planning-Preliminary Results of Congestion and Economic Assessments</u><br>While detailed production cost simulations and economic analyses have not yet been performed, if the CAISO decides to perform an economic assessment for either the Bob SS (VEA)-Mead S 230 kV line or Path 45, more information should be provided concerning the historic congestion on these paths. If the CAISO expects an increase in future congestion, rationales for such increases should be thoroughly explained. | The comment has been noted. |
| 1m | <u>50% RPS Special Study Update</u><br>BAMx supports the CAISO's efforts to increase the information available concerning the potential for utilizing Out-of-state (OOS) resources in meeting California's 50% RPS requirement as well as the ability to export excess in-state resources. The information presented in the bar charts on slide 59 of the CAISO presentation show significant potential for in-state resource curtailment due to an assumed 2,000 MW export limit. Such findings support the need to expend additional effort to understand the impediments to exports of California surpluses as well as a coordinated effort among state agencies to determine whether incentives within California are properly aligned.<br><br>For example, during times of surplus are California consumers given price signals similar to those given to external entities, allowing California consumers an opportunity to utilize and fully benefit from the renewable resources for which they are paying? If California consumers were to see zero or negative prices during surplus periods, would the need for higher exports or potential renewable generation curtailment still exist?<br><br>BAMx also notes that the preliminary curtailment results shown during the November 16th meeting are higher than the comparable results shared in the 2015-16 TPP. For instance, the latest In-state EO portfolio showed 11,890 | The comment has been noted.<br><br>The higher numbers compared to last year are due to enhanced ISO export limit modeling. |

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| | GWh (or 13.62% of total renewable potential) of curtailment under a 2,000 MW of net export limit, whereas the same portfolio and export limit combination found to have only 8,439 MW (or 9.65% of total renewable potential) in the 2015-16 transmission plan.5 If the renewable portfolios have remained largely unchanged since the last year, it would be helpful to understand the drivers behind these apparent differences in the curtailed renewable energy levels. | |
| | BAMx supports the study of Energy Only (EO) for both In-State and OOS resources, as this allows for informed choices. Through the TAC Options stakeholder process, BAMx also supports the allocation of transmission costs associated with implementing the Load Serving Entities' (LSE) plans to the Local Regulatory Authorities (LRA). This linkage is critical for ensuring that cost allocation is consistent with cost causation. Cost allocation by the CAISO should be more discerning with respect to cost causation, particularly in the case of policy-driven projects needed to implement the resource plans approved by LRAs. | The TAC Options discussion is not part of the transmission planning process. |
| | Regarding the CAISO's "first attempt to incorporate Effective Load Carrying Capacity (ELCC) data into deliverability assessment," this proposal would calculate the expected renewable generation within a three-hour window around the shifted system peak due to behind-the-meter generation. We understand the CAISO would then apply its current exceedance-based deliverability methodology to the resultant expected renewable generation during this three-hour window. As an initial matter, while the proposal is a step toward reflecting the impact of the time shift in the system peak load in the deliverability determination, it does not itself incorporate any probabilistic reliability modeling inherent in an ELCC calculation. As such, the documentation must carefully and properly ensure that the description of the CAISO studies make clear that deliverability methodology itself is not ELCC based. | The comment has been noted. |
| | The transition to ELCC resource counting reflects the shortcomings of the existing exceedance methodology for RA counting as the renewable penetration increases.6 Therefore, BAMx is concerned that the CAISO proposes to maintain the exceedance methodology contained in its general deliverability methodology even while transitioning the resource counting used | As noted in the comment, the ISO's analysis was a first step in considering how these issues may be examined. However, as no firm proposal regarding implementation of ELCC methodologies is in place, |

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<tr><td></td><td>as an input to the CAISO studies. CAISO needs to address why, in order to comply with this state mandate, the deliverability methodology is not also being transitioned away from an exceedance-based calculation.</td><td>the ISO has not proposed any revisiting of the deliverability methodology.</td></tr>
<tr><td>1n</td><td><u>2016-2017 TPP Gas-Electric Coordination Study</u><br>BAMx offers no comment at this time.</td><td></td></tr>
<tr><td>1o</td><td><u>Review of Previously Approved Transmission Projects</u><br>BAMx strongly supports the CAISO’s efforts to review previously approved projects in light of the significant changes in the planning environment, especially in the load forecasts due to both increasing energy efficiency and BTM generation. The fifteen (15) lower voltage projects for which it has been identified that any mitigation is no longer needed represents a reduction in capital expenditures of $176 million to $335 million without a significant adverse impact on reliability. The potential deferral or cancelation of the Gates-Gregg 230 kV project represents a net reduction of additional $150 million, representing a total reduction potentially approaching almost half a billion dollars.<br><br>BAMx supports the CAISO’s analytic method used to evaluate the Gates-Gregg 230 kV project whereby initial assumptions favorable to the transmission project were tested to assess project viability. As the project is not justified even under such assumptions, there is a high level of confidence that the CAISO’s previous approval of the project should be rescinded.[7] If the CAISO chooses to defer rather than cancel the project, BAMx requests that:<br><br>• Controls be implemented to minimize costs to the project to no more than those required for an orderly suspension of work.<br>• A future review date be established whereby a final decision to either proceed or cancel the project will be made so that the project expenditures to date will not continue to accumulate Allowance for Funds Used During Construction (AFUDC).<br><br>BAMx also requests that the TPP documentation include more information of the review process to date. The documentation should include a list of all transmission projects currently in the CAISO’s approved transmission plan that were originally justified in whole or in part based upon the reliability of service to</td><td>The comment has been noted. Please refer to the draft Transmission Plan posted on January 31, 2017.</td></tr>
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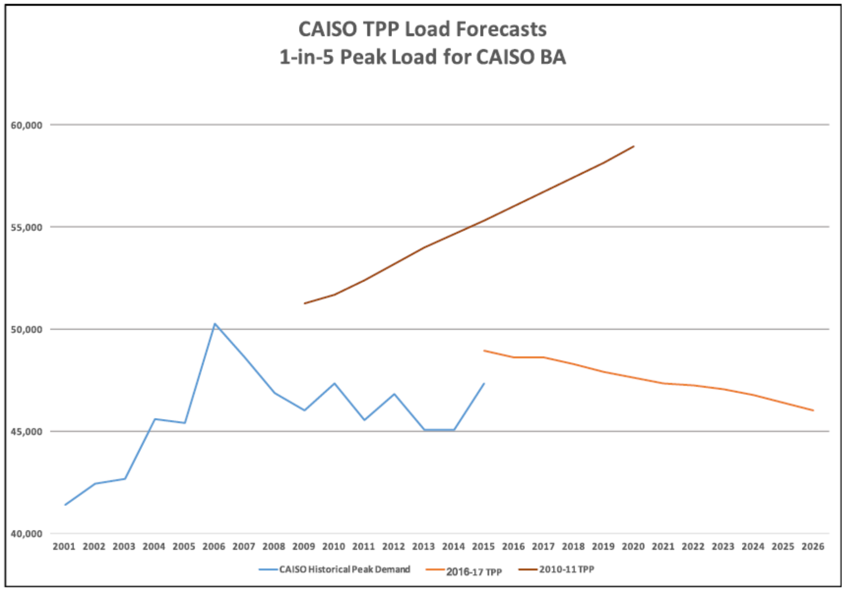
| | load. Given the forecasted long-term reduction of load at the system level, for each project not cancelled, a description should be provided as to why the existing system is inadequate to serve the load. Additionally, the CAISO's focus under this review should not be limited to transmission projects approved before 2010-11 transmission plan. Such a review and the list described above must properly include all load growth related approved projects. As can be seen from the graph below, there has been a substantial change in the CEC load growth forecast for the CAISO Balancing Area between the 2010-11 and the 2016-17 transmission planning cycles. Even the latest lower load forecast does not include expected reductions due to the impacts of increased energy efficiency under SB 350. Therefore, there is ample reason to expect that transmission projects approved within the last six years may also no be longer needed.<br>The list of projects being reassessed appears to be confined to projects in the PG&E service territory with no explanation for that restriction. BAMx encourages a broader assessment encompassing all previously approved projects be undertaken with no area or approval date restrictions.<br> | |

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| 2 | Citizens Energy Corporation<br>Submitted by: Donald R. Allen | |
| 2a | Citizens submits that, in the circumstances presented here, deferral is clearly the better of these choices, for the four reasons explained below. Cancellation of the project at this juncture would be imprudent and counterproductive, given the forecasting uncertainties affecting the need assessment for the Gates-Gregg project. | The comment has been noted. |
| 2b | 1 The technical justifications for considering cancellation are speculative and premature<br><br>Given the factors that drive the revised need assessment, deferral is clearly the correct solution. The three main drivers of the revised need assessment for the Gates-Gregg project are (1) a new load forecast, (2) the estimated Additional Achievable Energy Efficiency ("AAEE") and (3) a forecast of behind-the-meter solar photovoltaic installations. These three factors have one important thing in common - they represent the cumulative effect of individual choices by tens of thousands of retail electric customers over an extended period of time. Especially to the extent these factors are focused specifically on developments in one local community, namely, the Greater Fresno Area, they are inherently susceptible to forecast uncertainties.<br><br>For example, Slide 115 predicts that an estimated 60 megawatts of installed solar rooftop PV generation in 2016 will grow exponentially to 600 megawatts of rooftop generation in 10 years. The rate of assumed growth in PV installations would be more than 25 percent every year. By any measure, this is an extremely ambitious rate of growth. Even the slightest inaccuracy in the base year figure or in the growth rate will be amplified into a major error by year 10.<br><br>Retail-driven factors like behind-the-meter PV installations, especially those in a particular local community, are inherently volatile and not the most reliable barometer for the purpose of transmission system planning. Because the growth of rooftop solar installations by retail customers is a major driver of the revised need assessment for Gates-Gregg, it makes common sense to defer the project and then evaluate the need again after more data is available. | The ISO recognizes the uncertainties associated with the factors influencing the need for the project, and is recommending that the project be reviewed next year and that no application for permit be filed until the review has been completed. |

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| 2c | 2. The implications of premature cancellation are irreversible and potentially wasteful, especially considering the relatively minimal cost of deferring the project and reassessing need later<br><br>Cancellation of the Gates-Gregg project at this juncture would be economically unsound and could well result in waste of ratepayer dollars. To date the sponsors have invested approximately $15 million in this project. The costs of abandoned plant have largely been dealt with by FERC in the parties' various incentive orders and will be triggered, due and payable upon cancellation. The actions would be irreversible and cancellation will result in the loss of any value associated with the investment to date.<br><br>On the other hand, the cost of deferring the project pending further study should be minimal – not much more than the carrying cost on the funds already expended. Thus, at very low cost to ratepayers, the CAISO has the opportunity keep this project alive until forecast uncertainties decrease and a more fully considered need assessment can be completed.<br><br>In short, the best use of ratepayer dollars at this juncture is a small investment to keep the current Gates Gregg option open. | |
| 2d | 3. Cancellation of Gates-Gregg would undermine public confidence in the CAISO's new competitive bidding process<br>Gates Gregg was one of CAISO's first competitively bid projects. In the revised Need Assessment, at Slide 123, Staff has identified several factors creating "uncertainty" that "could impact need." These include solar photovoltaic installations, load growth, and the prospect of more frequent over-supply situations. Staff correctly observes that its need assessment would be impacted by changes in any of these factors.<br>Citizens respectfully submits that, in the face of this type of forecast uncertainty, abrupt cancellation of a previously selected project, especially after a successful competitive bidding process, would send the wrong signal to the market. Given the identified uncertainties, the CAISO should take extra care to act deliberately to ensure that Gates-Gregg is not prematurely cancelled.<br>Cancellation of a previously selected and competitively bid project, in the face of acknowledged planning uncertainties, would undermine the confidence that | |

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| | the CAISO needs future competitive bidders to place in its competitive bid process. | |
| 2e | 4. It would be particularly unwise to cancel the Gates-Gregg project at this time, given the role of Gates-Gregg in integrating the Helms Pumped Storage Project, and the prospect of an expanded need for facilities like Helms in an enlarged, multi State ISO<br><br>In evaluating the need for the Gates-Gregg project, there is another key strategic issue that needs to be considered – namely, the looming prospect of a major redesign of the CAISO's entire transmission planning paradigm.<br>What will be the size of the CAISO footprint going forward? For whom and for what loads will the CAISO be planning its transmission system? Will it be only for current CAISO stakeholders in California and Nevada? Or might it be for stakeholders of a significantly larger Western ISO in Oregon, Idaho, Utah and beyond, in addition to California and Nevada?<br><br>In the near future, the CAISO may recognize that it will require in the future substantially more or different tools in its transmission planning tool box than it has now. This is especially likely when it comes to transmission so closely linked with a large and unique storage resource such as the Helms Pumped Storage facility. Storage itself could become significantly more important as greater reliance on renewable generation comes into its own.<br><br>This factor alone augers for deferring further consideration of the Gates-Gregg project. It would challenge common sense to irrevocably discard the opportunity of capturing the enhanced transmission access to the unique Helms storage facility, which the Gates-Gregg project affords. We may be on the cusp of a fundamental change in the CAISO's entire transmission planning paradigm, and the dawning of an era when renewable generating resources may increase to levels greater than 50%. The Gates Gregg project, which offers the potential to better integrate the Helms facility on the transmission grid, warrants especially careful consideration in the face of these major developments. In short, deferral is the obvious "no regrets" option. | |

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| 3 | California Public Utilities Commission (CPUC) Staff<br>Submitted by: Keith White and Justin Hagler | |
| 3a | 1. Updated Documentation of the TEAM Framework Should Clarify Reasonable (Not Prescriptive) Expectations for Application and Applicability to Planning Issues and Decisions Beyond What Was Envisioned Under the Original TEAM Concept.<br><br>We are moving into an era of large, complex and interacting resource and demand-side1 electric system changes extending from increased possibilities for distributed resources on one hand and western regional integration on the other. While the TEAM framework has been applied for recent studies,2 the above developments suggest that the future could entail TEAM being applied to a more diverse range of situations. For example, proposed Transmission Access Charges ("TAC Options") for allocating certain high voltage transmission costs within a potential regional ISO rely partly on the TEAM framework, and so might evaluation of "interregional" transmission project proposals under western transmission providers' new planning provisions pursuant to FERC Order 1000.<br><br>Therefore, it is both appropriate and necessary that the TEAM framework documentation be updated in a clear manner that addresses planning needs and supports productive discussion regarding those needs. There has been substantial evolution in planning circumstances and decisions since the TEAM framework was first developed,[3] as well as evolution of modeling tools and accumulation of practical experience in applying the TEAM framework. These developments plus anticipated challenges going forward should be reflected in updated and expanded documentation of the TEAM framework.<br><br>We agree with statements at the November 16 meeting that the actual detailed application of the framework should be on a case-specific basis, not constrained within an overly prescriptive or narrow methodology. However, the updated framework documentation should provide insight into the application of TEAM over a range of situations and benefits likely to be encountered going forward, including new analytic tools and methods that may be applied. It is also | As noted in response to earlier comments, the ISO's current effort is to update the documentation associated with current practices and clear away obsolete detail. This will provide greater clarity for stakeholders seeking to consider both current applications as well as other potential applications of the TEAM methodology. |

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<tr><td></td><td>essential that the CAISO establish reasonable bounds and expectations regarding what assessments may and may not fall within the scope of TEAM.<br><br>CPUC Staff recommendations regarding the CAISO's development of updated TEAM documentation cover the following areas:<br>a. Original five TEAM principles,<br>b. Kinds of situations and decisions for which the TEAM framework may be applied and applicable, and<br>c. Types of benefits quantified.</td><td></td></tr>
<tr><td>3b</td><td>a. CPUC Staff support updating of the original TEAM principles taking into account a potentially expanded range of applications as well as new modeling tools.<br>The original five TEAM principles include the following.<br>i. Consideration (or at least potential consideration) of multiple benefit perspectives including consumers/ratepayers, generators, transmission owners, and society at large - - potentially over multiple geographical/electric system aggregations<br>ii. Full network representation (modeling), acknowledging that contract path approaches may be acceptable in some circumstances if adequately justified<br>iii. Market-based pricing<br>iv. Accounting for strategic behavior by generators<br>iv. Modeling of uncertainty.<br><br>The CAISO's November 16 presentation indicates that the manner and extent to which the above principles are anticipated to be applied will be updated, and provides some helpful examples. CPUC Staff understand the TEAM framework to encompass development and utilization of production cost modeling studies, but potentially also to include use of additional analytic tools to cover the range of benefits being included in the framework. CPUC Staff recommendations for the CAISO's update of the TEAM framework include the following:<br><br>i. Benefit perspective The November 16 presentation indicates that applications of the TEAM framework to date have emphasized the</td><td>The ISO notes the comments. For clarity, however, the intent is to document the methodology for how it is being used today – and how it may continue to be used into the future. Any process to revisit alternative approaches given how the TEAM methodology may be used in the future, and how refinements may be needed to properly address the specifics of those other uses, will need to be part of a future effort.<br><br>For the given use in assessing regional (ISO) transmission alternatives, we consider the current application appropriate.</td></tr>
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| | CAISO ratepayer (CAISO footprint consumers) benefit perspective, whereas the original TEAM documentation anticipated a variety of perspectives including a WECC-wide perspective. Going forward the TEAM framework may be applied to transmission decisions affecting non-CAISO and non-California entities and stakeholders, both within and external to the transmission analysis/decision process. The updated documentation should illuminate (not narrowly prescribe) TEAM application in such expanded circumstances. The documentation should also clarify and update the extent and limitations of the "societal" perspective; the distinction between merchant versus LSE-owned/contracted generators; situations where there is reduced dependence on energy market revenues; situations where there is a mixture of organized market and bilateral trading practices; and situations where ability to identify resources as contracted to specific loads or load areas is significantly limited. | |
| | ii. *Full network representation (modeling)* The updated documentation should clarify (not prescribe) where less than full network modeling may be acceptable or appropriate such as if needed to make sensitivity or stochastic studies computationally manageable. | This appears to require a case-by-case determination at this time – we don't believe there is sufficient history to have a comprehensive listing of where this might be the case. |
| | iii. *Market-based pricing* The updated documentation should clarify the meaning of "market-based pricing" when some modeled areas do not have organized markets (with LMP), and/or when there are large amounts of must-take, must-run, and/or potentially curtailed generation - - both with and without known contractual relationships between generators and loads. | Market price in the original documentation was specifically used for strategic bidding associated with market power. In the current practice, the study relies on the full network model for WECC and assumes economic dispatch for the entire system based on the variable cost of generators. |
| | iv. *Accounting for strategic behavior by generators* CPUC staff understand the CAISO's November 16 presentation as indicating that strategic behavior will not be modeled at least within the CAISO footprint. We request confirmation of this approach as well as clarification whether it would extend beyond the CAISO footprint. | As indicated in the previous item by CPUC staff, other areas within WECC do not have organized markets. The ISO believes it is appropriate to use cost-based economic dispatch in the production cost simulation for these areas as well. |

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| | v. *Modeling of uncertainty* The original TEAM design contemplated examination of uncertainty with or without explicit probability weighting and the November 16 presentation illustrates some typically considered uncertainties but also mentions "other sensitivities." Based on current planning challenges as well as recent studies (e.g., SB 350 studies), future planning challenges are likely to involve additional important uncertainties posing additional modeling challenges. This likelihood should be accounted for and clarified in the updated documentation of the TEAM framework (not fully prescribed). Examples include alternatives/sensitivities regarding resource additions and retirements (explicit portfolios and also more general resource uncertainties); hurdles or other inter-BA trading restrictions; carbon penalties/policies; RPS counting/credit practices; and other uncertainties that may be important going forward. Furthermore, the possibility of using "stochastic" models in the TEAM framework as indicated in the November 16 presentation should be more fully explained, especially regarding what variables could be treated stochastically and whether/how this may require acceptable sacrifices in detail elsewhere, such as using less than full network representation or modeling less than 8760 hours per year. | As various methods to deal with these issues are identified, we believe it would be appropriate to augment the documentation at that time.) |
| 3c | *b. Updated documentation should clarify and illustrate the range of anticipated TEAM applicability to planning issues and decisions, especially if extending beyond the initial TEAM concept and application.*<br><br>The updated TEAM framework documentation should provide meaningful insight (not prescribing full methodology) regarding extent and limits of TEAM applicability to types of situations and decisions anticipated going forward. Some example situations include:<br><br>i. Transmission benefiting or located within multiple areas (e.g., states or service territories) within a regional ISO such as envisioned under "TAC Options," and separately, "interregional" transmission located | As various methods to deal with these issues are identified, we believe it would be appropriate to augment the documentation at that time. |

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| | within or benefitting *multiple planning regions* including the CAISO plus one or more other regions.<br>ii. Single or multiple competing transmission options accessing renewable or preferred resources in-state; or out-of-state within a regional ISO; or outside of CA and CAISO - - as envisioned on page 27 of the November 16 presentation. The CAISO should clarify when such situations, studies and decisions are within versus beyond the scope of TEAM.<br>iii. Transmission providing renewables integration benefits such as access to ancillary services or shared ramping capability, or increased ability to export overgeneration.<br>iv. Transmission providing system and/or local capacity benefits, when accounting for overall system + local + flexible capacity needs.<br>iv. Other examples which CAISO believes to represent important foreseeable TEAM applications and/or which illustrate the expanded applicability of the TEAM framework beyond the original TEAM concept. | |
| 3d | *c. The updated documentation should clarify application of the TEAM framework to calculate an expanded (relative to the initial TEAM concept) range of benefit categories, particularly benefit categories important for emerging planning challenges.* | The comment has been noted. |
| | This includes but is not limited to the following kinds of benefits. | |
| | i. *Public policy-related benefits such as involving acquisition or integration of renewable or zero-carbon resources.* Essentially this amounts to identifying and quantifying particular types of benefits under scenarios described under subtopic b. above. Key questions include: what benefits of this type can and should be incorporated into the TEAM framework, and at what point (and to what degree) do the needed benefit assessments and decisions have to be made outside of the TEAM framework? | While second order effects may fall under the TEAM framework, consideration of policy direction has been consistently addressed – under the structured transmission planning process – ahead of economic driven transmission analysis relying on the TEAM methodology. |
| | ii. *System and (separately) local capacity benefits*. The original TEAM concept and documentation acknowledge only briefly the possibility of integrating capacity benefits into the overall TEAM framework for quantifying benefits. However, capacity benefits | The comment has been noted. |

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| | played an important role in two recent major transmission project approvals.4 The updated documentation should clarify and establish reasonable bounds or rules of applicability for addressing capacity benefits within the TEAM framework. This should address quantification of both capacity costs (e.g., supply curves) and capacity need over time, and should also explicitly address both differences and interactions between analyses of system and local capacity. Resource deliverability and capacity benefits potentially address the same ultimate benefit. For purposes of TEAM applications, the distinction and interaction between these two benefit concepts should be clarified.<br><br>Additionally, as noted in the November 16 presentation, the general practice has been that capacity and deliverability issues are ultimately addressed via power flow studies. The updated TEAM documentation should clarify the circumstances under which TEAM's production simulation studies must be, or do not need to be supplemented with power flow studies. Where a combined production simulation - power flow modeling approach would be used, how this would be done should be clarified (not prescribed). | |
| | *iii. More generally, the original TEAM concept focused on energy market-related benefits based on loads, generator dispatch, transmission flows and locational marginal prices in production simulations, whereas emerging planning challenges appear to place increased emphasis on non-energy needs and services, must-run/must-commit and intermittent generation, and integration/overgeneration issues.*<br><br>The updated TEAM documentation should describe how the kinds or magnitudes of benefits needing to be calculated have changed and likely expanded under the above "emerging" circumstances. This should address if and where such evolving needs go beyond what can be addressed via the TEAM framework. | The ISO expects that these other kinds of benefits will be identified on a case by case basis as future circumstances are considered, and the documentation can be updated to incorporate those issues at that time. |

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| 3e | 2. For the Gas-Electric Coordination Study (Aliso Canyon Storage Outage) the CAISO is Requested to Clarify Aspects of (a) How the Study Methodology from the April 2016 Aliso Canyon Risk Assessment Technical Report for Summer of 2016 was Extended to the Study for 2026, (b) How the "No BTM PV" Sensitivity Assessment was Constructed and (c) How These Kinds of Studies will be Applied for "Medium- and Long-Term Local Capacity Requirement Assessments"[6] | |
| | CPUC Staff understands that broadly speaking the April 2016 Aliso Canyon Risk Assessment Technical Report projected gas supply shortfall over an 8-hour electric system peak scenario during a high stress summer day, relative to gas supply needed to fuel the minimum required local CAISO area (the SoCalGas-dependent portion) plus local LADWP area thermal generation under the most critical electric system contingency. This projected gas supply shortfall was then converted to electric supply shortfall assuming 103 MWh/MMcf. Regarding the long term extension of the above study to year 2026 as presented on November 16, we understand that besides the appropriate long-term load forecast, it was assumed that planned transmission and resources infrastructure comes on line to help manage a potential gas (and thus local generation) shortfall.<br><br>Regarding how the assessment for summer of 2016 was extended to 2026, CPUC Staff request that the CAISO clarify the following.<br>i. Is there a basis for assuming that the minimum required local LADWP area generation over an 8-hour peak stress period remains unchanged from 2016 to 2026 even as the minimum required local CAISO area thermal generation (under the most critical electric system contingency) declines significantly presumably due to planned infrastructure additions? Should the LADWP assumptions be updated?<br>ii. The 103 MWh/MMcf gas-to-generation conversion used for the summer 2016 assessment, equivalent to roughly 9900 Btu/kWh, was carried forward unchanged for the 2026 assessment. Should a significantly different heat rate be assumed for local gas-fired generation ten years from now? | Please refer to the draft Transmission Plan posted on January 31, 2017. The methodology has been explained in more detail in chapter 6, and the local capacity requirements assessments – which do not include Aliso Canyon sensitivity analysis – are discussed in chapter 5. |

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| | For constructing the no BTM PV sensitivity cases depicted on pages 79 and 80 of the November 16 presentation, the "Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation for the most critical transmission constraint" was increased by 875 MW and 483 MW under the two different critical electric system contingencies that were examined - - relative to the base case (with BTM PV) summarized on page 76. The CAISO is requested to clarify the following aspects of the methodology for constructing the no BTM PV cases, which could be relevant for future studies. | |
| | i. On Page 74 of the November 16 TPP presentation the CAISO states that the CEC 2026 forecast of SCE Peak Load Impact from distributed behind-the-meter photovoltaic generation (BTM PV) is 1,739 MW, and a table on page 75 indicates that "Total LA Basin peak load (1-in-10) without peak shifting is 18,580 MW. On Page 78, the total LA Basin load without BTM PV, for 6 PM, is shown as 19,775 MW. When compared to the previous figure this represents a peak increase of 1195 MW, or approximately 68% of the 1,739 MW peak load reduction impact of BTM PV, forecasted by the CEC. The CAISO should explain the methodology used to adjust LA Basin peak load under the peak shifting (no BTM PV) case. | Based on the BTM PV peak impact modeled at individual load buses in the power flow study case, which was provided by SCE, the amount of peak load impact due to BTM PV in the LA Basin (for 2026 timeframe) is 1,195 MW. This is compared to the total of 1,739 MW of BTM PV peak impact for the entire SCE service area. The ratio of these two values provide a factor of 68.7% of peak load impact due to BTM PV in the LA Basin versus the entire SCE service area. In summary the ratio of 69% of the BTM PV impact for the LA Basin versus for the entire SCE service area is based on the amount of BTM PV peak impact (in MW) modeled by the Participating Transmission Owners - in this case, it is SCE that provided this granularity for the power flow model). |
| | What portion of CEC-forecasted BTM PV in the SCE area was assumed to be located in the LA Basin?<br><br>ii. For the Gas-Electric coordination study the load-increasing impact of removing BTM PV would have been spread over 8 hours, since the gas shortage effects were assumed to be spread (to accumulate) over the peak 8 hours. Thus, it appears that what matters is the impact of "no BTM PV" over 8 hours, not just during the peak hour. Some of these high stress summer day hours would presumably have significant sunlight and BTM PV generation, even when accounting for peak shifting leaving no (or low) BTM PV output in the later stress hours. | The potential for gas curtailment is at higher risk during peak load conditions, which can occur anytime between 13:00 – 21:00 hours. Since it is infeasible to pinpoint exactly which specific time during this 8-hour window that a gas curtailment would occur, the ISO evaluated for the potential of gas burn shortage per hour for the potential most critical load conditions, which could be anytime at 18:00 hours or 19:00 hours in the future ten-year horizon. Row 13 of the tables on slides 79 – 80 includes the "conversion of gas burn short per hour (MW)". |
| | For the base case gas shortfall assessment (summarized on page 76) and for the corresponding no BTM PV assessment (summarized on pages 79 and 80) - - which 8 hours of the day were included in the gas | In April 2016, the Reliability Task Force, consisting of the CEC, CPUC, ISO, and LADWP with participation from SoCal Gas Company completed the Aliso Canyon Risk Assessment Technical Report, |

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| | supply shortfall assessment, and what were the assumed in-basin load and BTM PV output for each of those hours?<br>To further clarify the extension of the gas electric coordination studies to the 2026 long-term horizon, the CAISO should explain if and how assumed Diablo Canyon Power Plant (DCPP) retirement impacted study results, relative to having DCPP on line in the near-term studies. On Page 75 of the November 16 presentation, Path 26 flow is listed as 3,316 MW for the base case (with BTM PV), also noting that DCPP retirement affects Path 26 maximum flow. For the peak shifted/no BTM PV sensitivity case, Path 26 flow is stated as 3,823 MW on page 78. The CAISO should explicitly quantify how the DCPP retirement effect on Path 26 flow was incorporated into these assumptions and how it impacts results (local gas supply and thermal generation shortfall) for the 2026 base case summarized on page 76 and for the peak load shift/no BTM PV cases summarized on pages 79 and 80.<br><br>Finally, page 83 states the intent to conduct N-1-1 electric system contingency studies, beyond the N-1 studies already presented, apparently to inform “medium- and long-term local capacity requirement assessments.” The CAISO should explain and justify studying such apparently extreme co-occurring contingencies (two gas storage outages + one gas pipeline outage + N-1 or N-1-1 electric system contingencies). The CAISO should also explain why studying 8-hour coincidence of the above events is reasonable, and whether this is intended to inform, or to require, infrastructure investments. Additionally, the CAISO should explain how gas electric coordination studies examining 8-hours of co-occurring high loads plus co-occurring gas and electric system outages are or could be made compatible with and useful for local capacity requirements studies that have generally relied on snapshot peak load (not 8-hour) scenarios. | http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf<br><br>quantifying the potential impacts to electric generation under various gas curtailment scenarios with the Aliso Canyon gas storage outage constraint for the summer 2016 time frame. The ISO relied on this work in the selection of contingencies and scenarios to be studied.<br><br>For the 2026 summer peak study that the ISO evaluated, for the peak shift without BTM PV distributed generation, this represents a potential loss of about 1,195 MW of internal resources within the LA Basin. This scenario would require extraordinary efforts to replace this loss of resources in the LA Basin by dispatching resources from the Northwest through COI (California Oregon Intertie) as there is not sufficient resource within PG&E without DCPP replacement to flow through COI without causing flow to exceed COI limit and then through Path 26 (PG&E-SCE) to SCE service area. In addition, resources from the Southwest are also dispatched to SCE. The reason that both the Northwest and Southwest resources are needed under this condition is because the Southwest resources are also maximized for use to serve high summer loads in other areas in the Southwest area and not just southern California. The increase in Path 26 flow for the peak shift condition is due to extraordinary dispatch to get resources from the Northwest via COI to PG&E and then to SCE (via Path 26) without exceeding COI rating.<br><br>The potential consideration of evaluating a full planning criteria, which includes overlapping outage such as N-1-1, could be justified if the Aliso Canyon gas storage outage moves from operational concern to permanent outage or removal of the gas field from service. This extreme scenario could potentially be part of the scope of the study to be evaluated under the CPUC Order Instituting Investigation to determine the feasibility of minimizing or eliminating the use of |

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| | | Southern California Gas Company's Aliso Canyon Natural Gas Storage Facility while still maintaining energy and electric reliability for the Los Angeles region. |
| 3f | 3. Several Studies Described on November 16 Identify Where Transmission Investments May be Valuable Under Resource Futures that are Currently Only Speculative, and CPUC Staff Support the CAISO's Approach of Not Considering Such Investments for Detailed Study or Approval Until the Underlying Long-Term Resource Priorities are Clarified.<br><br>The CAISO's studies of policy driven (for RPS resource deliverability) and economically driven (for congestion reduction) transmission discussed on November 16 identified the potential value of additional transmission capacity from the Imperial Valley into the CAISO area. It was noted that such transmission investment might be justified under a much increased need to import renewable energy (or capacity) from this area, beyond what is currently planned. Separately, enhancement of Helms pumping opportunities to help manage renewables-driven system overgeneration was apparently found to provide insufficient justification for the previously approved Gates-Gregg 230 kV transmission project, given currently projected levels of overgeneration. This project was also found not to be justified for reliability reasons, under updated load forecasts.<br><br>It is prudent to monitor situations such as those described above without pursuing the related transmission expansion possibilities, unless justified by longer term resource priorities established in the CPUC's Integrated Resource Plan (IRP) process. | The comment has been noted. |

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| 4 | Eagle Crest Energy (ECE)<br>Submitted by: Susan Schneider (Consultant to ECE on this matter) | |
| 4a | Eagle Crest Energy ("ECE") appreciates this opportunity to submit comments on the presentations and discussions at the CAISO's November 16th Transmission Planning Process "(TPP") meeting. Eagle Crest supports the CAISO's objectives in evaluating the benefits of Large Scale Storage and its potential to address over-generation and curtailment issues as the state approaches its 50% renewable energy mandate and carbon goals.<br><br>To that end, Eagle Crest supports the inclusion of additional California pumped storage projects in the study framework to broaden the scope of the analysis. However, we respectfully request consideration of building on the existing 500MW pumped storage work by studying projects larger than 1000MW – specifically, the 1,300 MW Eagle Mountain Project capacity. Alternatively, to the extent the CAISO expects smaller project benefits to be scalable for larger projects, the CAISO should explicitly so state.<br><br><u>Background</u><br>ECE is developing the 1,300 MW Eagle Mountain Pumped Storage Project (Eagle Mountain or the Project) in Riverside County, California. The Project has been awarded an operating license by the Federal Energy Regulatory Commission (FERC).<br><br>The Project is located at the inactive Eagle Mountain Iron Ore mine and makes use of two former mine pits as the upper and lower reservoirs. The Project will be a closed loop pumped hydro project, i.e., will not be located on a perennial river or have a surface water connection to other bodies of water.<br><br>The closed-loop process at this brownfield industrial site will allow the Project to provide, with minimal environmental impacts: (1) 22,000 MWh of multi-hour energy storage capacity (e.g., storing off-peak energy for use in on-peak periods, and/or to ameliorate over-generation conditions); (2) fast Regulation service; (3) ramping/load-following services; and (4) relief of import congestion from the southwest. It thus should help the CAISO meet the significant future | The ISO considers that the two data points of 500 MW and 1000 MW will provide sufficient information to extrapolate other project sizes. These comments will be taken into consideration. |

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| | renewables-integration challenges California confronts as it approaches (and perhaps exceeds) the 50% RPS.<br><br>The CAISO granted ECE's request for an Eagle Mountain Project Economic Planning Study in this year's Transmission Planning Process (TPP). ECE understands that the Eagle Mountain Economic Planning Study results will be included in the CAISO's 2016-2017 Transmission Plan. | |
| 4b | Eagle Crest comments on the November 16th presentation<br>Eagle Crest understands from the November 16th meeting discussion that the CAISO will be combining Economic Planning studies with a broader Large-Scale Storage Special Study ("Combined Study"). The Combined Study will include two other pumped storage projects – the Lake Elsinore Advanced Pumped Storage (LEAPS) and the San Vicente Pumped Storage Project, which are both about 500 MW.<br><br>ECE understands that the Combined Study will: (1) Apply TEAM and other locational tools to perform project/location-specific analyses for each project – basically, a modified form of the Economic Planning Study analysis performed for transmission projects; and (2) update the prior analysis of a 500 MW generic pumped-storage project that will focus on system-level benefits (e.g., reduced renewables curtailments during over-generation conditions). Together, these two elements are intended to provide an overall picture of the potential benefits to the CAISO system of large pumped-storage projects.<br><br>Eagle Crest agrees and supports including additional projects in the Combined Study with the expectation it will increase the robustness of the study and provide a better analytical framework for policy-makers. Eagle Crest shares the CAISO's interest in ensuring a solid analytical framework by which to understand the benefits of large scale storage in meeting the state's renewable requirements and carbon objectives. | |
| 4c | The Combined Study Should Build on the Prior Pumped Storage Studies by analyzing the benefits of a larger project<br>ECE believes that the CAISO should increase the size of the generic project in the system-level analysis to 1,300 MW (or add a 1,300 MW project analysis to the 500 MW analysis). Because both the project specific locational analysis and the system level analysis would both study 500 MW project sizes, the results | |

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| | would provide a comprehensive benefits picture for the smaller 500 MW projects, but it is not clear that the same will be true for the much larger Eagle Mountain Project unless the system-level benefits would be scalable (in which case the CAISO should state its belief that this is so).<br><br>There are other reasons for studying a larger project. Much of the system-level benefits work was already performed for the Bulk Energy Storage Resources Study in the 2015-2016 Transmission Plan, so another study of the same project size seems unlikely to yield additional insights. In addition, the prior 500MW pumped storage studies indicated that the benefits may be limited by the project size, and it would be helpful to see the additional benefits achievable with a larger project. | |
| 4d | Conclusion<br>ECE supports the CAISO's current approach generally – broadening the Eagle Mountain Economic Planning Study to include additional projects, and performing both local and system-wide benefits assessments. Thus, the CAISO should modify its current study plan to analyze a 1,300 MW project in the system-level study, instead of or in addition to a 500 MW project. If the CAISO cannot complete a 1,300 MW Large Storage special study by February or March, ECE requests a CAISO commitment to supplement the study for a larger facility shortly thereafter. | Any decisions regarding further analysis will depend on the results of the initial analysis and considerations of other issues requiring consideration in the 2017-2018 planning cycle. |

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| 5 | Large-scale Solar Association (LSA)<br>Submitted by: Susan Schneider | |
| 5a | 50% RPS Special Study – use of study findings to expedite transmission development<br>LSA is concerned generally that, long after the California legislature adopted the 50% Renewables Portfolio Standard (RPS) by 2030, the CAISO is still using the 33% RPS for its main studies. Based on the discussion at the Meeting, it seems possible that this situation may persist until the 2019-2020 TPP.<br>If that happens, new transmission to meet the higher RPS would not be approved by the CAISO until well into 2020 or even 2021 (especially with a possible competitive solicitation process). These projects would be unlikely to be on-line until the mid- or late 2020s, when the state is supposed to be close to meeting its 50% RPS obligation.<br><br>LSA understands the need for additional work to craft 50% RPS portfolios for use in the main TPP studies. However, the 50% RPS Study in the last planning cycle clearly identified some areas where transmission congestion and renewables curtailment could be a strong concern.<br><br>The TPP Study Plan for this cycle, which states (on p.50) that one objective of this study would be to "anticipate potential transmission needs to meet the 50% renewable energy goal." This objective is stated in relation to comparing transmission needed for Energy-Only vs. Full Capacity status for the generation procured above 33% RPS to meet the 50% RPS target. However, given the long lead-time for development of new transmission, it would be prudent for the CAISO to use the Energy-Only scenarios in this study to make at least a preliminary evaluation of any new transmission that might be needed to address these problems.<br><br>The CAISO should consider asking the PTOs to begin at least some low-cost, preliminary development work on upgrades that look to be highly likely to be needed under these scenarios, even though definitive recommendations and approvals may not be issued until later planning cycles. That would reduce the lead time needed to move these projects forward once the 50% RPS portfolios are finalized and the need for the transmission can be confirmed. | The comment has been noted – however, the portfolios being studied were provided on the specific basis of being for informational purposes only. Further, the suggested approach assumes that future transmission projects – if found to be needed to address energy only scenarios – would in fact ultimately be assigned to the PTOs. |

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| 5b | 50% RPS Special Study<br>The CAISO stated that the results and details for the Special Studies may not be included in the January draft transmission plan. The CAISO may issue preliminary results at the February stakeholder meeting, but final details and final results may not be available to stakeholders until the Draft Final Proposal (which goes to the Board) is issued in March.<br><br>The TPP is designed as a transparent process that allows stakeholders to offer input to the CAISO, with time for the CAISO to consider that input and use it as appropriate. A three-minute Public Comment statement to the Board in March is not a meaningful substitute for that part of the process.<br><br>Instead, the CAISO should consider characterizing the Special Study results in the Transmission Plan, allow one additional round of stakeholder comments, and issue supplements or updates after March if there are any changes. This is similar to the Bulk Storage Study update the CAISO recently issued for the last planning cycle. | The special studies are informational only, and being conducted in parallel with the tariff-based transmission planning process to benefit from the efficiencies of conducting the studies in parallel with the tariff-dictated analysis. The studies are specifically not for approval purposes, and the results and comments on the work will be considered in future study plan efforts. |
| 5c | Gates-Greg 230 kV Transmission Project<br>The CAISO stated at the Meeting that it is considering cancelling or deferring this project. This recommendation was made in light of: (1) Reduced reliability needs in the Fresno area based on recent load forecasts and other data; and (2) renewables-integration benefits that are less than the project costs.<br><br>LSA is concerned about the potential reduced availability of Helms, a valuable renewables-integration resource, based on what appear to be some fairly aggressive demand and behind-the-meter solar estimates. LSA strongly prefers deferring the project for a year or two instead of cancelling it altogether, to see if the current findings hold up over time. | The comment has been noted. As noted above, the ISO recognizes the uncertainties associated with the factors influencing the need for the project, and is recommending that the project be reviewed next year and no application for permit be filed until the review has been completed. |

<table>
<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td>6</td><td>LS Power<br>Submitted by: Sandeep Arora</td><td></td></tr>
<tr><td>6a</td><td>LS Power appreciates the opportunity to provide comments on the CAISO 2016/17 Transmission Planning Study. Following comments are related to the Economic Studies Section of the presentation. These comments are based on modelling work that LS Power has conducted using the latest WECC TEPPC 2026 model, Version 1.5. In addition to these comments, LS Power requests CAISO staff to release the Economic Study model as soon as it gets finalized, so the stakeholders have an opportunity to review assumptions prior to the release of Draft Transmission Plan in January 2017.</td><td></td></tr>
<tr><td>6b</td><td>(1) COI path baseline flows are low:<br>The baseline COI flows in the 2026 TEPPC common case model are low in the North to South direction, as compared to historical flow patterns. While LS Power understands that these flows are for a future year, our review of the TEPPC model shows that the following areas should be investigated and modelling changes made, as appropriate, to correct the baseline flows before any congestion analysis is done:<br><br>(a) Load assumptions:<br>The overall peak load modelled for California is low. This includes CAISO IOUs as well as Non-CAISO entities including LADWP, BANC and IID. CAISO load in the 2026 model is 7% below the load in the 2025 CAISO TP case. Within CAISO, the PG&E load is 14% below the load in the 2025 case, and the SCE load is 2.4% below the 2025 case. Outside of CAISO, LADWP, BANC, and IID loads are also lower as compared to the 2025 case. See Table 1 below.<br><br>Table 1: Comparison of loads modelled in WECC TEPPC 2026 case vs CAISO 2025 case<br><table><tr><th>Total Load (GWh)</th><th>Type</th><th>ISO-2025</th><th>TEPPC 2026 v1.5</th><th>Changes</th></tr><tr><td>CA_CISO</td><td>Region</td><td>238,546</td><td>221,069</td><td>-7%</td></tr><tr><td>CA_LDWP</td><td>Region</td><td>31,341</td><td>28,304</td><td>-10%</td></tr><tr><td>CA_BANC</td><td>Region</td><td>19,728</td><td>17,388</td><td>-12%</td></tr><tr><td>CA_IID</td><td>Region</td><td>4,687</td><td>4,528</td><td>-3%</td></tr></table></td><td>(a) California load was updated based on CEC load forecast.<br>(b) Thermalito hydro units in the TEPPC PCM were updated in the ISO's PCM<br>(c) (i) The hurdle rates in the TEPPC PCM were agreed by all related entities during the TEPPC PCM development. Also, given the fact that large part of Northwest resources is hydro, which is energy limited, changing hurdle rates will not impact the total available energy of the NW hydro resources in the model<br>(ii) To model firm transmission rights on a specific path has to also consider the impact of transmission rights on other paths in the system. This requires coordination in the interregional planning process and the support of production cost simulation software</td></tr>
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| | Lower loads in California will lead to lower imports for California, which will mask any intertie congestion issues. We understand that CAISO performs modelling enhancements to the TEPPC caseand believe these adjustments will likely include adjustment of loads to the CAISO Region, but adjustment to other Non CAISO Utilities in California is equally important and should be addressed.<br><br>(b) Generation assumptions:<br>A few units within the Northern California Hydro Generation group have duplicate models, which mean the dispatch level for this generation is higher than it should be. As an example, Thermalito_2A, Thermalito_3A, Thermalito_4A units are in the model in addition to Thermalito_2, Thermalito_3, and Thermalito_4. Higher dispatch of Northern California Hydro artificially reduces COI North to South flows. Dispatch assumptions for Northern California Hydro generation should be carefully reviewed.<br><br>(c) Hurdle & Wheeling rates:<br>The use of hurdle rates in the WECC TEPPC 2026 model should be carefully reviewed. Hurdle rates have a huge impact on how much energy can flow between two Balancing Authorities, therefore inaccurate assumption of hurdle rates can have major impacts on path flows. Our review of the Hurdle rates used in the WECC TEPPC 2026 model shows that the following areas should be investigated:<br>(i) Hurdle rates for energy imports into California from Pacific Northwest need to be reviewed. The model does appear to apply a $15/MWhr hurdle rate for all energy transfers flowing into California from Pacific Northwest. Our understanding is that this is equivalent to the CO2 emission adder charge, for AB32. Since most of the energy that gets imported into California from Pacific Northwest is “hydro”, the use of this charge should not apply to hydro imports into California.<br>(ii) Wheeling rates on firm transmission capacity should not be used. As discussed at the TEPPC 2026 modelling meeting held last year1, wheeling rates should be only be used to cover non-firm transactions. In the TEPPC database, wheeling rates are applied as flat rates on all transfers resulting in double dipping. Firm | |

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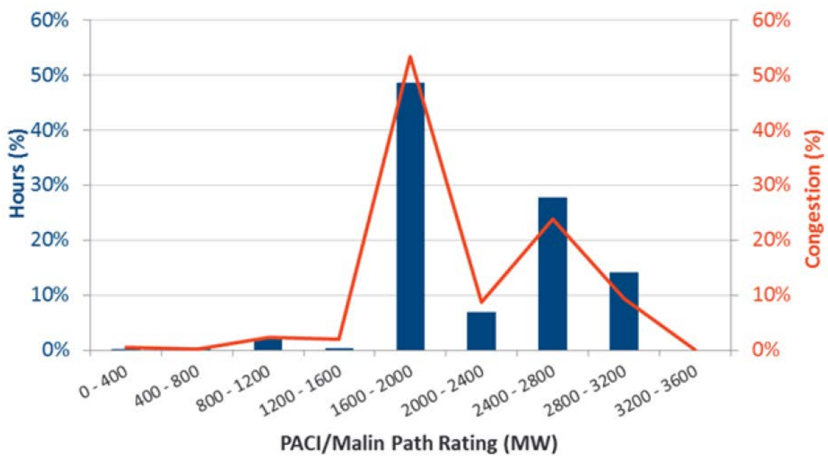
| | transactions are associated with rights that have sunk costs and should not be charged wheeling rates. Most WECC paths, including COI/PACI/COTP are fully committed, which means there is very little if any non-firm transmission transaction. Applying wheeling rates artificially reduces the flow on transmission paths and masks congestion issues, as may be the case with no congestion on COI path for CAISO's previous year TPP studies. | |
| 6c | (2) COI vs PACI/COTP modelling:<br>In the last few transmission cycles CAISO has been studying COI congestion by modeling the three 500 kV lines that comprise the COI path with a Total Transfer Capacity (TTC) of 4800 MW (and de-rated as driven by operating nomogram). Two of these 500 kV lines are owned by CAISO IOUs and operated by CAISO. This path is known as the Pacific AC Intertie (PACI), with a TTC of approximately 3200 MW. The third line, also known as the COTP line, is owned by members of Transmission Authority of Northern California (TANC) and operated by Balancing Authority of Northern California (BANC). This line has a TTC of approximately 1600 MW. A significant portion of this TTC is reserved for native use by TANC members and the rest becomes available for use by third parties and TANC members for market transactions with other entities, including CAISO. The way production cost simulations are run do not accurately capture these details. In the TEPPC case there is no hurdle rate for energy to flow out of Malin HUB to CAISO or BANC system. For energy to flow from BANC to CAISO there is a $2.53/MWhr hurdle rate. What this means is that in the production cost simulation a portion of the energy flowing to CAISO from Malin and Captain Jack actually flows through the COTP into CAISO. In reality the portion of energy that is reserved for TANC use should not be available to flow into CAISO through COTP. This reality should be modelled in the production cost simulation runs, perhaps by adjusting hurdle rates, as appropriate to mimic this. Further the PACI and COTP paths should be separately enforced in the production cost simulation runs. The congestion that occurs appears to be mainly associated with scheduling limits and perhaps this could be simulated in the production cost runs by use of phase shifter to limit the flows on the COTP line. If modelled correctly, congestion on the PACI interface will likely match with historical PACI congestion that has been noted by CAISO's DMM for the last several years. | Regarding the comment on modeling PACI and COTP separately with adding a phase shifter to the model, the ISO does not agree this approach since it changes the system topology. Also, the hurdle rate model between BANC and the ISO already captured the hurdle between PACI and COTP, while still allowed energy transfer to use the whole system capacity based on economic dispatch. The ISO used the same hurdle rates between BANC and ISO in the TEPPC PCM. If all related parties agree upon a new hurdle then ISO is willing to adopt it.<br><br>As LS Power's comment indicated, most historical COI congestion is associated with the scheduling limit. The ISO noticed that there is a gap between the scheduling limit and the physical limit, which is used in transmission planning. . Further investigation of this gap is needed to have a better understanding of its implication to the economic transmission planning |

<table>
<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td>6d</td><td>(3) COI de-rates:<br>The COI path very frequently gets de-rated due to maintenance work. It is our understanding that a relay maintenance and replacement program has been underway for a number of years. This causes Transmission Owners to schedule outages of the transmission segments on the COI path and transmission segments adjacent to the COI path boundary. Every time a transmission segment is taken out of service, it causes de-rates on the COI path. COI de-rates lead to congestion in CAISO’s Day Ahead and Real Time markets. We understand that CAISO is currently investigating this and intends to model these de-rates in economic studies. In support of our recommendation, we present the following data from CAISO OASIS for 2015. The chart below shows that the PACI path, which has a full rating of 3200 MW, was limited to between 1600 and 2000 MW for almost 50% of the time during 2015. Also shown on this chart is the congestion on this path. Most of the congestion, as expected, occurs when the Path gets de-rated.<br><br><br>**Fig 1: PACI congestion and ATC limits**</td><td>The ISO worked with COI facility owners to collect repeating outages on COI including relay outages, and the associated derates on COI. The annual outages were modeled in the ISO PCM as a baseline assumption and the outages that may happen every two years and beyond were modeled in sensitivity studies. The results can be found in the draft transmission plan posted on January 31, 2017.</td></tr>
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| No | Comment Submitted | CAISO Response |
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| 7 | Next Era Energy Transmission West, LLC (NEET West)<br>Submitted by: **Edina Bajrektarević** | |
| 7a | During the 2015-2016 and 2016-2017 TPP planning cycles, CAISO performed a special study to provide "information only" results that will support a state 50% renewable energy goal. Furthermore, NEET West recognizes the 33% renewable portfolio used in CAISO's 2016-2017 TPP studies is approximately the same as that used for the 2015-2016 TPP studies. Given the modest shortfall in deliverability and the objective of reviewing reinforcement requirements when 50% policy renewable generation portfolios are available, NEET West understands that CAISO will not recommend any mitigation for policy purposes but this may be revisited in economic project evaluations. In order to address several contingency violations that were observed in several different transmission planning studies (including reliability as well), we observed the continued reliance on operating procedures, inclusive of the Special Protection Systems (SPS) and re-dispatch of resources to relieve transmission constraints and congestion. NEET West views these tools as near term only, and we recommend CAISO to take into account the complexity of operating procedures including SPS and any impact these schemes might have on the short-term and long-term operational and planning flexibility while comprehensively recommending system mitigations. A careful analysis should be undertaken to properly weight benefits and cost of SPS and re-dispatch of resources versus conventional transmissions solutions that might offer significant advantages to maximize not only the reliability of the grid but also provide the reliable deliverability of resources and robust operation of the transmission grid. This consideration will become even more important to support 50% RPS integration. | The comments have been noted. However, the ISO cannot agree generically that SPS and operating procedures are limited to short term mitigations. Many SPS have provided long term benefits to avoid unnecessary transmission expense. Specific concerns should be raised on a case by case basis. |

| No | Comment Submitted | CAISO Response |
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| 8 | Office of Ratepayer Advocates (ORA)<br>Submitted by: Joseph Abhulimen | |
| 8a | ORA appreciates the opportunity to submit comments and recommendations on the California Independent System Operator's (CAISO) November 16, 2016 Economic Planning TEAM [Transmission Economic Assessment Methodology] Overview and Review of Updated Documentation (Presentation). The current TEAM is the appropriate methodology to use to determine whether or not a transmission project should proceed, as it assesses the project's benefits and costs to ratepayers. The CAISO also should include in the TEAM analysis the benefits of new transmission projects that might accrue to a sub-region. The economic activity associated with new transmission projects is not incidental; it directly benefits related local businesses and contributes to the economy of a sub-region. Accurately attributing these benefits is critical to compliance with Federal Energy Regulatory Commission Order No. 1000, which requires that project cost allocations be commensurate with benefits. For this reason, ORA continues to support estimating the sub-regional benefits from new transmission projects such as job and tax base increases among the benefits assessed for project cost allocations. | The comment has been noted. It should be noted that in the context of the ISO's current footprint and its FERC Order 1000 interregional coordination process (in which the ISO footprint is a single region, and the ISO is not considering using TEAM to redefine cost responsibility for high voltage transmission among different parties within the ISO footprint, and does not consider relying on non-electric industry benefits such as perceived social benefits is a viable way to revisit current cost allocation. |
| 8b | Going forward the CAISO should include estimates of job and tax base increases as variables in the TEAM analysis to account for all economic benefits resulting from new economic transmission projects.1 After a project is completed, these job and tax base estimates can be confirmed, and the project benefits can be recalculated for cost allocation purposes. ORA also recommends that the TEAM include additional sensitivity analyses such as: (1) meeting the California Renewable Portfolio System target through in-state or out-of-state renewables; (2) transmission line and system capacity; and (3) greenhouse gas compliance costs. | TEAM is a framework for transmission economic planning study. Estimating potential job and tax base increases is beyond the scope of transmission planning and TEAM, and raises questions about where the boundary can or should be drawn in considering social costs and benefits.<br><br>The other comments have been noted. |

| No | Comment Submitted | CAISO Response |
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| 9 | Pacific Gas & Electric (PG&E)<br>Submitted by: Matt Lecar | |
| 9a | First, as a general comment, PG&E is concerned by the delayed pace of providing preliminary results from the six special studies in the 2016-17 TPP. Only two of the six, the 50% RPS and gas-electric reliability studies, presented preliminary results in time for the November meeting (and only partial results in the case of the 50% RPS, at that). The remaining four studies will not therefore provide stakeholders any opportunity to review results prior to the issuance of the draft plan in January or the February stakeholder meeting (or possibly even the draft final plan in March).<br><br>It is unhelpful to the stakeholder community when so little information is provided. PG&E hopes that the CAISO will consider both paring back to a more manageable study plan and dedicating the necessary staff resources to conduct the TPP studies in a timely fashion for the 2017-18 cycle. | As noted earlier, the special studies have been conducted on an information only basis. The ISO agrees that the scope has grown on a number of studies responding to stakeholder input, and has clearly communicated the expectation that would affect the timing of the results. Further, no special studies have been committed to for the 2017-2018 planning cycle. |
| 9b | <u>Comments on Economic Planning-TEAM Overview and Review of Updated Documentation</u><br>PG&E appreciates the CAISO's efforts to inform the stakeholders on the documentation update of TEAM. In the updated documentation, PG&E recommends that the CAISO:<br>1) Describe the scope, methodology, inputs, outputs, and any limitations;<br>2) Include examples of how TEAM is applied; and<br>3) Include a section (e.g. Frequently Asked Questions) with answers to the following questions, with examples wherever applicable. | The comment has been noted |
| 9c | <u>Questions on TEAM Methodology (page numbers refer to the slides presented at the November stakeholder meeting)</u><br>Page 15<br>• At the stakeholder meeting, the CAISO stated that the benefits are calculated for two years (5-year and 10-year). Please explain how benefits and costs are extrapolated for other years. What is the length of the analysis to support the NPV calculation? Does the CAISO make any adjustments to the benefits calculations if the benefits streams are expected to change over the life of the project?<br>• Please confirm, as stated in the workshop, that the social discount rate used is 7% real. | Regarding the benefit calculation for other years, please refer to 2016-2017 draft transmission plan Chapter 4 Section 4.5.6.2. Adjustment beyond the standard approach described in the draft transmission plan report would be case by case determination.<br><br>The social discount rate is "real". Please refer the draft transmission plan for further information. |

| No | Comment Submitted | CAISO Response |
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| 9d | Page 16<br>• Please confirm that the Grid View model is the production cost simulation tool used in TEAM.<br>• Does the CAISO analysis begin with the TEPPC 2026 Common Case? If so, what modifications, if any, are made to:<br>o Assumption inputs (e.g., gas prices, GHG prices, CA RPS portfolio, loads, BTM resources, unit retirements, level of exports out of California, etc.)?<br>o Network topology (additions or removal of transmission lines, etc.)? | GridView is the production cost simulation tool currently used in ISO's economic planning study for production cost simulation.<br><br>Regarding the ISO's production model development, modification, and assumptions, please refer to the 2016-2017 transmission plan study plan and the draft transmission plan. |
| 9e | Page 17<br>• Does the CAISO currently perform a stochastic analysis? If so, how? If not, does the CAISO expect to perform one in future and how? | Stochastic analysis does not have a very unequivocal definition. In fact, the ISO's planning process has considered the stochastics of many variables, including load forecast and generator forced outage rates. If the comment specifically meant Monte Carlo simulation, then for now only the generator forced outage rate was dealt with in such way as a built-in function in the production cost simulation tool. The Monte Carlo simulation can be augmented to other stochastic variables in the future. |
| 9d | Page 23<br>• Based on the workshop discussions, please confirm the components of generator costs used in derivation of generator profit are variable production costs only. Do these include: fuel, CO2, variable O&M, and startup costs?<br>• How is ancillary service value determined? | The costs include fuel, emission, variable O&M, and startup costs. Ancillary services are co-optimized with energy. |
| 9e | Page 24<br>• What are "'Owned facilities' operated to ISO ratepayer advantage"? Please explain how resources are identified (e.g. ownership, tolling agreements, RA commitments). For the 2016-17 TPP Case, what percentage of CAISO units are included vs. excluded?<br>• Which imports are identified as CAISO Owned Facilities and therefore used in benefits calculation? For example, are Paloverde, out of state renewables, Hoover, etc. included as Owned Facilities?<br>• The CAISO stated that Wind and Solar under contract are included in the analysis. Should other renewable technologies under contract be assumed as Owned Facilities? | The definition of "owned facilities" remains the same as in the presentation in the Nov. 16 stakeholder meeting. The ISO's production cost simulation model defines ownership for facilities following the same definition.<br><br>ISO utilities own part of Palo Verde and Hoover. Wind and solar that are included in the portfolios are modeled as "owned facilities".<br><br>Renewables other than wind and solar under contract to an ISO utility are not modeled as "owned facilities". There is not enough public information to show which other resources are under contract and what the contract terms are. |

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<tr><td>9f</td><td>Page 25<ul><li>What proxy capacity value is used when LCR need is deferred? If the LCR is deferred by, for example, 5 years, are the benefits limited by 5 years?</li><li>What LCR studies are currently relied upon in TEAM for reduction in local capacity requirement? How is the time period of deferral or reduction in local capacity requirement determined for TEAM? Please provide an example.</li><li>Please provide details of how the CAISO calculates import capability for system capacity purpose.<ul><li>Given that the total CAISO transfer capability is greater than the import capability assigned for system capacity purpose, how does an increase in the total CAISO transfer capability impact the import capability for system capacity purpose?</li></ul></li><li>What proxy capacity cost ($/kw-year) does the CAISO use for increases in RA deliverability related benefits?</li></ul></td><td>Responding to each of the bulleted comments in turn:<ul><li>Yes, and it can be more complicated than that simply limiting the benefits by the corresponding number of years. The LCR benefit needs to be calculated with consideration of the potential changes of LCR needs in the future years associated with load and network changes.</li><li>To calculate LCR benefit, separate LCR-type studies need to be performed instead of relying on the results of previous LCR studies.</li><li>System capacity benefit can only materialize when three conditions are met: 1) increase of import capability; 2) resource deficit (including import and internal resources); 3) marginal capacity cost difference. Please refer the presentation from the Nov. 16 stakeholder meeting for further details</li><li>The capacity cost is determined on case-by-case basis</li></ul></td></tr>
<tr><td>9g</td><td>Page 27<ul><li>Please explain how benefits from avoiding over-supply RPS would be calculated.</li><li>How would the amount of over supply be determined?</li><li>How does the CAISO quantify the benefits of reducing RPS curtailment?</li></ul></td><td>In the transmission planning process, we particularly consider transmission congestion-related curtailment and over-supply issues. If the curtailment changes between two cases with and without congestion, then potentially there is benefit of mitigating the congestion. This type of benefit may be difficult to quantify as dollar value since it is also related to the many other factors, such as overall portfolio calculation, actual or potential renewable build-up (location, technology, and cost), curtailment cost, etc. The actual calculation needs to be on a case-by-case basis.</td></tr>
<tr><td>9h</td><td>Page 29<ul><li>Please explain whether and how any element of EIM is considered in TEAM given the last bullet on page 29, “It is not recommended to consider the full effect of EIM in project justification” (emphasis added)?</li></ul></td><td>Please refer to the 2016-2017 draft Transmission Plan section 4.5.5.</td></tr>
<tr><td>9i</td><td><u>General Comments on CAISO’s TPP Economic Assessment Process</u><br>PG&E recommends that the CAISO revisit its Economic Assessment Process to make it more robust and aligned with the recent changes in the energy industry.</td><td>The comment has been noted.  As discussed earlier, the ISO’s current focus is to update the TEAM documentation to reflect current practices and clarify and remove obsolete detail.</td></tr>
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| No | Comment Submitted | CAISO Response |
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| | The energy industry has undergone, and is expected to continue to undergo, significant policy, economic, and technology changes, and uncertainty. These market fundamentals can affect the need for and use and value of transmission. Therefore, a more comprehensive integrated planning approach is needed to evaluate and incorporate cutting-edge innovations, including evolving Energy Imbalance Markets, Balancing Authority consolidation, the interface between the bulk power system and distribution systems, electrification, high penetration of roof-top solar, the many alternatives between system solutions and planning objectives (e.g. moving from RPS targets to GHG reduction goals), inter-regional coordination, and the effects of climate change.<br><br>PG&E recommends that the CAISO enhance TEAM and the TPP process to assess economic benefits. In determining economic benefits, PG&E requests the CAISO update the TEAM to:<br><br>• Better consider the value to producers, consumers, and society by region.<br>  o Example: For out-of-state wind resources, the economic value to the state producing the energy and associated impact on the local economy should be considered.<br>• Better capture the value of transmission in light of transporting system variability and/or operational flexibility<br>• Better assess how changes in greenhouse gas (GHG) emissions and GHG reduction credits are economically considered and allocated to/between regions.<br><br>In addition, PG&E requests that the CAISO expand the economic assessment process to include expanded alternatives assessments. The potential alternatives could include different transmission upgrades or resource alternatives. | |
| 9j | <u>Comments on CAISO's Economic Planning – Preliminary results of congestion and economic assessment</u><br>CAISO's November 16th presentation on Economic Planning studies does not include sufficient information to allow stakeholders to provide meaningful feedback to the CAISO on preliminary study results. PG&E therefore requests | The updated results have been included in the draft Transmission Plan. |

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| | the CAISO provide additional information underlying the congestion and economic assessment results before presenting the final results and recommendations.<br><br>In addition to responses to the questions for TEAM methodology listed above, PG&E requests the CAISO provide the following additional information:<br>1. A table including historical (2015 and 2016) day-ahead congestion costs (for areas or branch groups) and a discussion on CAISO expectations on changes in future congestion due to addition/retirement of resources and changes in network topology.<br>2. Access to the Grid View model and<br>a. A list of and the duration of transmission outages modelled in the analysis.<br>b. Nomograms used in the analysis and any adjustments made to the nomograms to reflect the impact of transmission outages or unavailability of generators (either because the generators are offline or due to forced/planned outages) participating in RAS schemes.<br>3. CAISO has included a limited number of congested area/branch groups for further discussion on results or potential mitigations (refer to slides 49-54). Also on slide 55, CAISO states that the "Next Steps" will be to "perform detailed production cost simulations and economic assessments" and "finalize [the] list of economic studies being undertaken and perform economic assessments if needed". Based on the limited information presented on November 16th, it is not clear what additional studies will be performed and what criteria will be used to "finalize [the] list of economic studies". Can the CAISO provide a list of the criteria used to finalize the list of economic studies to be undertaken? | 1. The historical day-ahead congestion on COI can be found in ISO DMM annual reports. (http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx)<br><br>2. The GridView database is planned to be posted after the draft transmission plan is posted. All the models then become accessible to stakeholders.<br><br>3. Please refer to the draft transmission plan. |
| 9k | 50% RPS Special Study<br>Since only partial results from the 2016-17 TPP 50% RPS Special Study were available for stakeholder input, PG&E reserves the right to make further comments upon release of the full Special Study results.<br><br>Regarding the comparison of curtailment between energy-only and fully-deliverable RPS portfolios, PG&E urges the CAISO to provide more granular analysis in the final study results to pinpoint which locations in the system | The deliverability approach was tested one way to look at the issue and relying on the data being considered in the ELCC discussion. It does not represent an "ELCC deliverability methodology" per se. |

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| | showed congestion driven curtailment and ensure this information properly flows back to the CPUC for transmission planning via updates to the energy-only transmission availability in the RPS Calculator and/or RESOLVE models. PG&E suggests continued alignment between the CPUC and the CAISO regarding how both the Special Study results and the ELCC-based deliverability approach will impact the RPS transmission planning activities in the RPS or IRP proceedings. As the CPUC moves to an integrated planning approach in the new IRP proceeding, properly capturing the availability of both fully deliverable and energy-only transmission for RPS resources and the costs associated with new transmission to unlock further RPS resources will ensure a fair comparison between supply-side and demand-side GHG-reducing resources.<br><br>PG&E is generally supportive of the CAISO's efforts to consider updates to its deliverability assessment methodology. However, more information is needed to assess the impact of the proposed "ELCC-based deliverability" approach, including examples showing the impact of the change on a sample project's deliverability and calculated ELCC values from the ELCC methodology outlined by the CAISO (slide 61). The latter will allow stakeholders to compare the results of this approach to the ELCC methodologies being developed in the RA and RPS proceedings. Additionally, further clarity is needed regarding whether the ELCC-based deliverability approach impacts the available FCDS capacity assumed in capacity expansion planning models. | |
| 9l | <u>Review of Previously Approved Projects</u><br>PG&E thanks the CAISO for continuing the process of re-evaluating projects that were approved in previous transmission planning cycles, and for which the need may be altered due to more recent changes in the load forecast and other factors. In particular, PG&E appreciates the efforts of the CAISO staff to reassess the reliability need and economic benefits associated with the Gates-Gregg 230 kV Transmission Line Project. PG&E is supportive of the CAISO's option to defer the Project, rather than canceling, until further uncertainties in the Greater Fresno Area (GFA) have been resolved.<br><br>PG&E's most recent analysis is consistent with the CAISO's conclusions based on current assumptions of the demand forecast. However, the demand forecast greatly depends on the adoption of rooftop solar and energy efficiency | The comments have been noted. Please refer to the draft Transmission Plan posted on January 31, 2017. |

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| | programs by individual customers within the GFA. While PG&E is a strong advocate of these initiatives, which are aligned with California's environmental goals, the long term impact of state and federal policies on the adoption of Distributed Energy Resources (DER) is uncertain. It will likely be two to three years before we understand the direction of these policy impacts. In the meantime, PG&E will continue to work with the CAISO to ensure electric service reliability of the GFA.<br><br>We believe the Project deferral option is the practical and economic choice for PG&E's customers. Project deferral would help salvage the majority of the development costs invested thus far, thereby providing significant savings to customers, if the Project is eventually reinstated, at little additional cost. Therefore, PG&E supports the deferral of the Project until there is more clarity and further uncertainties in the demand forecast are resolved.<br><br>In regards to the other 15 lower voltage projects being recommended for cancelation, PG&E appreciates the CAISO's study and careful consideration of reliability, generation deliverability, LCR and operational flexibility benefits of each project which led to identification of these projects. PG&E supports cancelation of 11 of these projects given that their need is no longer evident under current and projected load forecasts. However, PG&E does not support cancelation of four of the recommended projects as they are still needed to improve service reliability for PG&E customers. Furthermore, in the case of two of these projects, they are well into the construction phase and it would not be prudent to cancel them. Specifically, the projects that PG&E believes should not be canceled are:<br><br>• Christie 115/60 kV Transformer No. 2 – this project is needed for meeting the single transformer standard, improving customer service reliability and is already in its implementation phase.<br>• San Bernard – Tejon 70 kV Line Reconductor – this project is needed for service reliability, summer set-up removal and is already in its implementation phase.<br>• Mosher Transmission Project – Portions of this project are needed to address back-tie capability limitations in the local area which will improve service reliability to customers in Stockton division. | |

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| | • Evergreen-Mabury Conversion to 115 kV – Portions of this project are needed to address back-tie capability limitations in the local area which will improve service reliability for customers in the San Jose division.<br>• | |

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| 10 | San Diego Gas & Electric (SDGaE)<br>Submitted by: Effat Moussa | |
| 10a | <u>TEAM Overview</u><br>SDG&E supports the use of the CAISO's Transmission Economic Assessment Methodology (TEAM) to estimate the potential economic benefits of proposed transmission projects as compared to a reasonable range of other plausible alternatives, both transmission and non-transmission, that meet the same planning objectives.<br><br>The version of the TEAM documentation currently posted on the CAISO website is dated June, 2004. SDG&E understands that this documentation is being updated to reflect current information and practices. Despite its age, SDG&E finds the June, 2004 documentation thorough, informative and still relevant. SDG&E encourages stakeholders to read this document.<br><br>There is one point discussed at the November 16, 2016 stakeholder meeting that SDG&E believes warrants further consideration. Page 24 of the CAISO's presentation package indicates that the producer surplus from "other generators under contracts of which the information is available for public may be reviewed for consideration" as a CAISO consumer benefit; i.e., the producer surplus from merchant generators would be subtracted from gross CAISO consumer costs in calculating net CAISO consumer costs only if there was a public contract between the generator and a CAISO Load Serving Entity (LSE). Based on the discussion at the stakeholder meeting, SDG&E understands that the CAISO believes this approach will result in "conservative" outcomes because it would tend to reduce the amount of producer surplus credited to consumers.<br><br>SDG&E questions whether this approach will actually yield "conservative" outcomes, and whether, in fact, conservatism should be criteria in the first instance. A very simple example illustrates how this assumption (whether or not a generator's producer surplus will be credited against gross consumer costs) can result in a non-conservative outcome. | The comment has been noted<br><br><br><br><br><br><br><br><br><br><br><br>"Conservativeness" was not a factor in ownership definition. |

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| 10b | Public Contract between Generator and Load<br>Assume a two node system connected by a 30 MW transmission line. Node A has 100 MW of load, a 65 MW generator with a variable cost of $25/MWh, and a 20 MW generator with a variable cost of $30/MWh. Node B has a 50 MW generator with a variable cost of $20/MWh. The economic dispatch of this system results in a Locational Marginal Price (LMP) of $30/MWh at Node A and $20/MWh at Node B. Assume that there is a public fixed-price contract between the load at Node A and the $25/MWh generator for the output of the generator.<br><br>Gross consumer costs at Node A would be $3000 (100 MW x $30/MWh). Net consumer costs would be calculated as $3000 minus $300 in congestion rents minus $325 in producer surplus from the $25/MWh generator (65 MW x ($30/MWh - $25/MWh)) = $2375.<br><br>Now assume a 10 MW upgrade of the transmission line costing $100 is being evaluated. The economic dispatch of this system results in a Locational Marginal Price (LMP) of $25/MWh at Node A and $20/MWh at Node B. Gross consumer costs at Node A would be $2500 (100 MW x $25/MWh). Net consumer costs would be calculated as $2500 minus $200 in congestion rents minus $0 in producer surplus from the $25/MWh generator (60 MW x ($25/MWh - $25/MWh)) = $2300.<br><br>Based on these assumptions, the line upgrade results in a $75 benefit for load ($2375 - $2300). This benefit is less than the $100 cost of the line, so the line upgrade should not be pursued. | The ISO appreciates the examples, which supports ISO's point that "conservativeness" is not a factor in the ownership definition.<br><br>It worth noting that the real system is much more complicated than the SDGE's examples. Also, "fixed price contract" is confusing language that is not used in the production cost simulation. |
| 10c | No Public Contract between Generator and Load<br>Assume the same facts as above, except that there is no public contract between the generator and load; i.e., it is assumed that the producer surplus from the $25/MWh generator accrues to the benefit of business tycoons housed in Trump Tower. The economic dispatch would be the same in both the case with the existing transmission capability and in the case with the 10 MW upgrade. Net consumer costs in the case with the existing transmission capability, however, would be $2700 since there is no producer surplus that would be credited against gross consumer costs ($100 MW x $30/MWh - $300 in congestion rents). | |

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| | In the case with the 10 MW transmission upgrade, net consumer costs would be $2300 (100 MW x $25/MWh - $200 in congestion rents).<br><br>Based on these assumptions, the line upgrade results in a $400 benefit for load ($2700-$2300). This benefit is more than the $100 cost of the line, so the line upgrade should be pursued. | |
| 10d | <u>CAISO's Approach is Not Necessarily "Conservative" from the Standpoint of Loads</u><br>As the above example illustrates, assuming a fixed-price contract (between loads and a generator for the output of the generator) will not be in place, does not necessarily result in a conservative outcome for loads. In this example, the CAISO's default assumption would lead to the conclusion that the transmission upgrade should be built. SDG&E does not believe this result is "conservative" from the perspective of loads since loads will have to pay $100 for the transmission upgrade. If, in fact, a fixed-price contract for the output generator did exist -- whether it is public or not – loads would be worse off under the CAISO's default assumption.<br><br>SDG&E believes the real question is not whether a public, fixed-price contract for the output of the generator exists; but whether it is reasonable to assume for the period of time covered by the economic life-cycle of the transmission upgrade (which can be 60 years or more), that a fixed-price contract for the output of the generator is likely to be in place. Recent history suggests that to remain in business, most merchant generators need a contract that provides a revenue stream sufficient to cover a substantial portion of the generator's on-going fixed costs. This would suggest that the default assumption for attributing producer surplus from merchant generators should be that the generator will be contracted to an LSE.<br>There are ancillary questions as well. For example, which merchant generators should be assumed to retire and when? If the default assumption is that a merchant generator is contracted to an LSE, is the LSE a CAISO LSE or a LSE in a different balancing authority? Should it be assumed that the contract is for the entire output of the merchant generator (in which case the producer surplus clearly accrues to the benefit of the LSE), only for the merchant generator's | The ISO's assumption does not rule out merchant generators under contract from being classified as "owned generators", as long as the information is publically available. Of course, the term of the contract is also relevant, and ownership can be a partial ownership, i.e. less than 100%. |

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| | Resource Adequacy (RA) capacity (in which case the producer surplus clearly does not accrue to the benefit of the LSE), or somewhere in between?<br><br>These are difficult questions to answer. SDG&E believes the CAISO and stakeholders need to further consider the appropriate default assumption for merchant generators which do not have publicly available contracts with a CAISO LSE. | The ownership in the production cost model is only used for calculating energy benefit, not for other benefits.<br><br>The ISO agree that it needs future effort to improve the accuracy of the data and modeling in a consistent manner. |
| 10e | <u>50% Special Study Update</u><br>In SDG&E's Comments on the CAISO's September 21-22, 2016 presentation regarding the 50% Special Study and Interregional Coordination Update Performed as part of 2016-2017 Transmission Planning Process (which are posted on the CAISO website), SDG&E recommended that the 50% Special Study and Interregional Coordination Update Performed as part of 2016-2017 Transmission Planning Process include an evaluation of the benefits of adding the Renewable Energy Express (REX) transmission project as compared to not adding the project. In particular, SDG&E recommended that the CAISO and WestConnect perform an evaluation of the reduction in Resource Adequacy (RA) costs that could be achieved if the REX transmission project were built.<br><br>At the November 16, 2016 stakeholder meeting the CAISO acknowledged SDG&E's earlier comments. SDG&E reiterates its recommendation that, as part of the Interregional Coordination process, the CAISO and WestConnect evaluate the full range of potential economic benefits provided by the REX transmission project. | The REX project was submitted as a reliability request window project as well as an interregional project submittal. The San Diego area sections of Chapter 2 and Appendix B of the Draft Transmission Plan provide a summary of the ISO's analysis of this project as a request window project. The ISO's analysis of the project as an interregional project submittal within the 50% RPS Special Study is still ongoing. |

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| 11 | Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities)<br>Submitted by: Margaret E. McNaul | |
| 11a | The Six Cities support the CAISO's reassessment of previously-approved transmission projects. While the CAISO has focused its current re-study efforts on projects involving the Pacific Gas and Electric Company ("PG&E") low voltage network (and, as discussed below, the Gates-Gregg 230 kV Line Project), as a general matter, the Six Cities concur in the CAISO's efforts to re-visit the need for previously-approved (and uncompleted) projects in light of changed circumstances.<br><br>With respect to the Gates-Gregg 230 kV Line Project, the Six Cities support deferring cancellation of the Project for 1-2 transmission planning cycles. As the CAISO is likely aware, the Approved Project Sponsors for the Gates-Gregg Project have received authorization from FERC to recover prudently-incurred abandoned plant costs in the event the Project is cancelled for reasons outside of the Project Sponsors' control. *See, e.g., Citizens Energy Corp.*, 157 FERC ¶ 61,150 (2016); *Pac. Gas and Elec. Co*., 148 FERC ¶ 61,195 (2014); *MidAmerican Cent. Cal. Transco, LLC*, 147 FERC ¶ 61,179 (2014). Rather than immediately cancelling the Project, it would be reasonable to defer cancellation for a limited period of time, in anticipation that circumstances might change and the Gates-Gregg Project becomes needed once again for reliability reasons or qualifies as an economic project. Resuming work on the Gates-Gregg Project could be more cost-effective for ratepayers than commencing an entirely new project, as would be needed if the Gates-Gregg Project were cancelled at this time and the CAISO determined within the next 1-2 planning cycles that the same or a similar project is needed or provides economic benefits. Because the CAISO has determined in this planning cycle that the Gates-Gregg Project is no longer needed, the Approved Project Sponsors should take steps to cease work on the Gates-Gregg Project and avoid incurring any further costs to develop the Project until such time as the Project is officially cancelled or the Approved Project Sponsors are directed by the CAISO to resume development activities. | The comments have been noted. The ISO recognizes the uncertainties associated with the factors influencing the need for the project, and is recommending that the project be reviewed next year and no application for permit be filed until the review has been completed. |

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| 12 | Smart Wires<br>Submitted by: Todd Ryan; | |
| 12a | CAISO Should Ensure the TEAM Methodology Includes Advanced Transmission Technologies<br>We encourage the CAISO to ensure that the TEAM methodology includes advanced transmission technologies, such as modular power flow control, dynamic line rating, and energy storage technologies in the analysis of transmission solutions to identified economic1 needs.<br><br>At the November 16 Stakeholder Meeting, CAISO noted in the presentation that it was considering resource alternatives to transmission expansion (page 18). CAISO also responded verbally that advanced transmission technologies will be included in the TEAM methodology; Smart Wires encourages CAISO to verify it has the necessary models and information to do so.<br><br>Advanced transmission technologies are often more cost-effective and more flexible than traditional solutions, such as reconductoring or phase-shifting transformers. Therefore, it is important that CAISO is able to evaluate these technologies to find economic projects with ratepayer savings and a benefit to cost ratio of greater than 1.0.<br><br>There are a number of initial steps that the CAISO could consider, such as:<br><br>• Verify that advanced power flow control can be appropriately modeled in technical and economic studies. There is a bare minimum amount of information that one needs to model a transmission solution2; the CAISO should verify that it has all this information to minimally represent advanced power flow control technologies such as Smart Wires PowerLine Guardian®, Power Guardian™ and Power Router™. Additionally, advanced power flow control technologies are more easily dispatched, have greater granularity and accuracy in dispatch, and allow for more intelligent control than traditional power flow control technologies. These details matter when evaluating two similar, but different technologies. We | The comment has been noted<br><br>While the ISO considers the possible application of various technologies in the course of planning activities, the planning process also relies heavily on the ISO identifying early in the process reliability and other needs, and seeking proposals to address those needs. Further, given the information made available in each year's transmission plan, the ISO encourages meaningful economic study requests proposals focusing on areas where the developers of these technologies see there may be opportunities for particular applications.<br>. |

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| | would ask that CAISO verify that these differences can be ppropriately represented, or approximated, in models and software.<br><br>• Verify that advanced power flow control is included in the set of transmission solutions, along with the traditional upgrade options. CAISO is required to "*consider the comparative costs and benefits of viable alternatives to the particular transmission solutions*."3 We are asking CAISO to consider advanced power flow control in the evaluation and selection of transmission alternatives to best meet California's future transmission needs. | |

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| 13 | Transmission Agency of Northern California (TANC)<br>Submitted by: David Oliver | |
| 13a | The Transmission Agency of Northern California (TANC) appreciates this opportunity to provide comments on the California Independent System Operator's (CAISO) 2016-2017 Transmission Planning Process (TPP) November 16, 2016 stakeholder meeting pertaining to the results of the economic and policy studies and an overview of the Transmission Economic Assessment Methodology (TEAM). The CAISO 2016/17 Transmission planning cycle finds itself at a very interesting and uncertain time in the California energy market and TANC believes that the CAISO's cautious approach toward approving new projects and willingness to look and re-evaluate the need for certain projects is appropriate. Also, TANC is pleased that the CAISO is considering ways to improve its current modeling, particularly as it relates to the interties and specifically the California-Oregon Intertie (COI) to potentially provide modelling results that are more in line with historical tendencies and far more likely to be representative of future market realities. | The comment has been noted |
| 13b | COI Modeling<br>As a party to the Owner's Coordinating Operating Agreement (OCOA), TANC and the other COI Owners are continuing to work with the CAISO to provide requisite data and future operation and maintenance requirements to allow the CAISO to improve upon its modelling of the COI. We believe that this is critical to illustrating the operational realities of the integrated bulk electric system realistically. Accurate and improved information regarding historic and future operational and maintenance realities should assist in effort to capture the true costs of congestion at Malin. Prior to additional model runs with realistic operational data, the 2016/17 planning cycle shows just $330,000 of congestion costs over 38 hours on the COI. While this result is consistent with previous planning cycle estimates, it does not come close to replicating historical levels of congestion at Malin. From 2011-2015, congestion at Malin averaged over $58 million and 2,500 hours annually. By underestimating the cost of congestion at the COI the CAISO is hindering its ability to find economic solutions that could potentially save CAISO customers and California consumers millions of dollars annually. Recent discussion between the OCOA Parties and the CAISO to explore and find ways to improve the economic modeling to better reflect true market and operational conditions (and the | As LS Power's comment (6c) indicated, most historical COI congestion is associated with the scheduling limit. After reviewing data from actual system operation, the ISO noticed that there is a gap between the real-time scheduling limit and the limit which is used in transmission planning. .  Further investigation of this gap is needed to have a better understanding of its implication to the economic transmission planning |

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| | associated limitations and increased costs) is welcome and TANC looks forward to continuing to support the CAISO's efforts in this area. | |
| 13c | TEAM Needs a Separate Stakeholder Process<br>TANC is appreciative of the CAISO's discussion and overview of the TEAM model and is looking forward to the updated documentation that has been promised as well as an opportunity to comment on the document and methodology. Going forward TANC would encourage the CAISO to make regular updates, as necessary, to the TEAM documentation, with appropriate stakeholder notice, and to include more detail on the assumptions that will be used in the annual development.<br><br>While TANC understands the 2016/17 TPP may not the ideal forum for stakeholders and the CAISO to discuss the methodology of the TEAM, TANC recommends the initiation of a separate stakeholder process to allow a complete vetting of TEAM. The TEAM approach was developed in 2005 during a very different energy environment which by itself would call for a complete evaluation of the model that includes current stakeholders and market conditions. Additionally, the CAISO is proposing to use the TEAM as a primary determinant in its Transmission Access Charge (TAC) sub-regional cost allocation in the event of a regionalized CAISO footprint. The use of the model for such a potentially contentious annual process would require that TEAM undergo proper scrutiny in advance to insure it is being properly and fairly applied. Addressing this potentially critical component of a future Regional ISO (and a current integral tool for the CAISO TPP) is not only prudent at this time; but is likely a prerequisite for stakeholders and potential future CAISO participants to understand and vet how TEAM is not only used today, but how it will be applied in the future. | The ISO is not ruling out future consideration of a broader scope at some point in the future. However, we consider it necessary to update the documentation to reflect current practices and interpretations, and remove obsolete detail from existing documentation, as process improvement for the current planning processes as well as to set a more meaningful foundation for any future discussions. |
| 13d | CAISO Should Expand its Review of Projects<br>The review of Projects previously approved by the CAISO for the Pacific Gas & Electric Company ("PG&E") area has revealed several projects that the CAISO has determined are no longer needed. TANC appreciates the CAISO review of the projects and agrees with the recommendation to cancel these projects. The CAISO did not commit to a recommendation during the Stakeholder Meeting as to whether it would cancel the previously approved Gates-Gregg project or put the project on hold. TANC suggests that should the CAISO determines it | The ISO has broadened its review to a wider range of projects. However, the ISO's view of the Harry Allen-Eldorado project remains unchanged. |

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| | wishes to place the project on hold as opposed to cancellation, that it makes clear that no project costs incurred during the deferral period should be recovered in the project sponsor's transmission rate base.<br><br>Finally, TANC continues to recommend that the CAISO review all projects that have been approved in previous planning processes. Specifically, TANC would strongly suggest another look at the Harry Allen – Eldorado 500-kV Project that was approved in the 2013-14 TPP. The "Scenario 2016 in Excel v1.2" from the CEC, dated August 5, 2016,1 shows a resource surplus of around 30-40% through 2036. A significant amount of the economic benefits of the Harry Allen – Eldorado Project came from anticipated capacity benefits that the CAISO economic studies included based on studies that indicated that SP26 would be resource 'short' by 2019-20. Based upon the current CEC analysis and the CAISO's own push through the RETI process for Energy-Only interconnections – this Project may no longer provide the economic benefits or justification that the CAISO previously stated. TANC made the same request in the prior round of comments and the CAISO responded that it felt there was still enough reason to believe this project was needed. However, given that a fundamental driver for the project has changed, the project warrants re-evaluation to determine if the project remains economically viable and should continue to move forward. TANC respectfully requests that this project be vetted the same as the CAISO used to determine that Gates-Gregg is no longer required. TANC believes that it is paramount for the CAISO to utilize identical approaches for determination of a projects need.<br><br>Without a similar examination of Harry Allen – El Dorado it would appear that the CAISO is favoring projects (or project sponsors) in one portion of the grid over another region (by not reexamining). | |
| 13e | 50% Portfolios<br>TANC was concerned with the CAISO's indication during the November 16 meeting that it is not expected that the next planning cycle will include 50% Renewable Portfolio Standard (RPS) portfolios for its studies (i.e., beyond the information-only special studies). The RPS statute, SB350, was signed into law on October 7, 2015, a fact that has existed throughout the current TPP. By the time the policy studies are reported for the 2017/18 TPP it will have been over | As indicated in the stakeholder session, the ISO will act on the policy direction regarding future RPS-based generation when it is provided through the state agency processes. |

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| | two years since Governor Brown approved the statute. It is imperative that the CAISO work with the appropriate state agencies to include at least a 45% portfolio for the 2027 study in the next planning cycle. It is vitally important for grid reliability and renewable deliverability that the CAISO models the future system as accurately as possible for the planning horizon. | |

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| 14 | The Utility Reform Network (TURN)<br>Submitted by: Matthew Freedman and Kevin Woodruff | |
| 14a | Congestion Costs: The CAISO stated that "ISO's Transmission revenue" – including "congestion costs" – is subtracted from "gross load payments" to yield "net load payments".1 TURN understands that when the TEAM was developed last decade, such congestion costs were assumed to be fully allocated to load at no extra cost to load. Since congestion costs are assumed to accrue fully to load, the amount of such costs needed to be subtracted from a scenario's gross benefits to avoid double-counting benefits. However, the assumption that congestion costs are allocated fully to load is not necessarily valid for energy markets like the CAISO's. For example, the PJM Interconnection is now addressing concerns that only about half of its congestion costs are returned to customers.2 In implementing TEAM, the CAISO should assess whether the assumption that all congestion costs are allocated to load is reasonable for the CAISO and, if appropriate, adjust its implementation of TEAM if less than 100 percent of congestion costs are allocated to load. | The ISO's production cost model has already addressed this. If a congested transmission line is not an "owned facility" then its congestion revenue is not used in net load payment calculation. If a congested transmission line is a partially owned facility, e.g. 50%, then only 50% of the congestion revenue is used in net load payment calculation. |
| 14b | Capacity Benefits: The CAISO stated that "system capacity benefits" may also be attributed to transmission projects and listed in its bullets some of the drivers of such possible value.<br><br>However, documentation of how such estimates are made is lacking. TURN recommends the CAISO provide clear documentation of and criteria for how it makes such estimates. Further, such documentation should reflect whether such assumptions will be the CAISO's own assumptions or whether it will rely on the conclusions of other authorities, such as the California Public Utilities Commission or the California Energy Commission. The CAISO's documentation of capacity benefits in specific TEAM studies should also provide the basis for such specific studies' assumptions. | The comment has been noted |