The ISO received comments on the topics discussed at the February 17 and February 28, 2017 stakeholder meeting from the following:

1. Bay Area Municipal Transmission Group (BAMx)
2. California Public Utilities Commission (CPUC) Staff
3. Center for Energy Efficiency and Renewable Technologies (CEERT)
4. Cogeneration Association of California
5. Eagle Crest Energy (ECE)
6. GridLiance West Transco LLC
7. Imperial Irrigation District (IID)
8. LS Power Development, LLC
9. Office of Ratepayer Advocate (ORA)
10. Pacific Gas & Electric (PGaE)
11. Quanta Technologies
12. San Diego Gas & Electric (SDGaE)
13. Sierra Club
14. Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (collectively, the “Six Cities”)
15. Smart Wires
16. Southern California Edison (SCE)
17. Transmission Agency of Northern California (TANC)
18. TransCanyon, LLC
19. TransWest Express, LLC
20. Valley Electric Association (VEA)
21. Nevada Hydro Company – Received after close of comment window

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
1	Bay Area Municipal Transmission Group (BAMx) Submitted by: Kathleen Hughes	
1a	Introduction BAMx is highly encouraged by the findings within this transmission planning cycle concerning the reduced need for reliability driven transmission upgrades. Due to changes in forecast of California's load and changes in both state policies and customer behavior, only two new reliability projects have been identified and many previously approved projects are under review. Many of the BAMx comments have been driven by a concern about achieving a balance between customer reliability and cost in the face of past and forthcoming substantial increases in the Transmission Access Charge (TAC). As such, TAC forecasts are an integral part of the transmission plan and BAMx looks forward to reviewing the CAISO's updated TAC model that is expected to be incorporated into the Final Draft Transmission Plan. BAMx supports the CAISO's initiative to review previously approved projects and recognizes the significant resources required to conduct such a review. As the load forecast in many planning areas has significantly decreased, the previous finding of need for approved projects merits review of both whether the need still exists or if the approved project scope is still appropriate. In this planning cycle, the CAISO has proposed the cancellation of 13 projects and placed another 16 projects on hold. Based upon PG&E's most recent cost estimates provided to the CPUC, these projects represent a cumulative cost of almost $4.5 billion. For those reliability projects that either did not make the list or those on the list that may ultimately proceed in some form, BAMx encourages the CAISO to provide more transparency to the process used in its evaluation and the deciding factors in concluding that the project is still needed.	The comment is noted.

No	Comment Submitted	CAISO Response
1b	Reliability Transmission Projects BAMx supports the CAISO approval of the Lugo-Victorville 500 kV Upgrade. The Lugo- Victorville 500 kV Upgrade is a low cost upgrade that facilitates access to a wide range of resource options as well as addresses congestion issues. The CAISO's findings suggest that this project also has elements of being both economic and policy driven project. With respect to the Big Creek Rating Increase Project, BAMx is concerned about the lack of stakeholder review of the SCE Transmission Line Rating Remediation (TLRR) program that proposes to spend almost $400 million on improvements on the 230 kV transmission in the Big Creek corridor. Such fragmentation makes it difficult for stakeholders to understand whether the current plan is the most cost effective approach for addressing both the line clearance issues and transmission capacity needs in this area. This highlights the need for future process improvements whereby stakeholders are included in a more comprehensive review of planned capital expenditures. .	Regarding the Big Creek Rating Increase Project, the ISO notes that the incremental expansion project recommended for approval represents a relatively small expenditure relative to the SCE capital maintenance project cost, and that the maintenance project is proceeding in any event to address the clearance issues identified by SCE. Concerns with the SCE capital maintenance programs should be discussed with SCE. Since the ISO's start-up, there has been a FERC-approved division of roles and responsibilities between the ISO and its participating transmission owners that distinguishes system expansions from other types of transmission-related work. This distinction is reflected in the FERC-approved Transmission Control Agreement ("TCA") that sets forth the respective roles and responsibilities of the ISO and each participating transmission owner. TCA Section 11, entitled *Expansion of Transmission Facilities,* provides that ISO Tariff Sections 24 (Transmission Planning Process) and 25 (Generator Interconnection) will apply to any expansion and reinforcement of the transmission system. On the other hand, TCA Section 4.3 provides that the participating transmission owners are responsible for operating and maintaining the transmission lines and associated facilities placed under the ISO's operational control in accordance with the TCA, applicable reliability criteria, and the ISO operating procedures and protocols. TCA Section 6.3 requires participating transmission owners to inspect, maintain, repair, replace, and maintain the rating and technical performance of their facilities under the ISO's operational control in accordance with the applicable reliability criteria and performance standards established under the TCA. Appendix C of the TCA defines maintenance as "inspection, assessment, maintenance, repair, and replacement activities performed with respect to Transmission Facilities." The TCA does not require that non-expansion, non-reinforcement, maintenance and compliance-type projects be approved through the CAISO's transmission planning process.

No	Comment Submitted	CAISO Response
1c	While the Caltrain Electrification Project is a load interconnection project under the PG&E Transmission Owner's Tariff and therefore not formally part of the CAISO's approved transmission plan, BAMx is concerned about the high cost ($228 million) for two 115 kV load interconnections. BAMx appreciates the CAISO's review of the proposal, but requests that greater information concerning its finding that alternatives are infeasible. (For example, were alternative substation configurations considered.) Also, greater information concerning the cost allocation for the proposed facilities should be provided by PG&E to clarify who is bearing the cost for the proposed design. If a customer reliability requirements, such as redundant Interconnection Facilities, are driving such an expensive mode of interconnection, they should pay for the associated cost.	An alternative interconnection configuration of looping PG&E's lines to Caltrain's Traction Power Substation (TPS) were considered to avoid upgrades needed at existing substations. However, the alternative was found to be infeasible due to siting, permitting and land acquisition required for the construction of switching station adjacent to Caltrain's TPS in these highly congested urban areas in the required timeline. Regarding cost responsibility, utility terms and conditions of service will be applied.
1d	With respect to the review of previously approved projects, BAMx supports an earlier CPUC Staff request for a list of all previously approved projects that have not yet begun construction and were reviewed by the CAISO. With the increased reliance on Preferred Resources, where the location may not be determined toward the end of the planning horizon, and with the recent legislative mandate to double the energy efficiency goals, BAMx recommends maintaining a list of approved projects that have not yet begun construction, so that the continuing need and timing can be reviewed as part of future planning cycles. BAMx also supports tracking the ballooning cost projections of all previously approved projects. For example, just looking at the four projects for which the CAISO recommends continued development but not filing for permitting and certificates of public convenience and necessity,4 the total cost forecast when each was approved was $440 million. However based upon PG&E's latest estimates, these projects are forecast to cost a total of $1.74 billion, an increase of almost 300%.5 A review of other projects on the list show a similar trend toward spiraling project costs.	The ISO updates the status of the approved projects within Section 7 the annual Transmission Plan. The participating transmission owners (PTO) provide updates on these projects to the CPUC in their Quarterly AB 970 Project Status Report submission under Proceeding Number I0011011, Decision Number D.06-09-003. Please contact the CPUC Process Office to be added to the list service for these reports.
1e	BAMx supports the CAISO's review and findings with respect to the ten Request Window projects for the San Diego area. The CAISO's recommendations for four special protection systems and four operational mitigations to address the reliability concerns reflect an appropriate concern for consumer costs in addressing compliance with the Planning Standards. If	The comment is noted.

No	Comment Submitted	CAISO Response
	proponents wish to continue to recommend more costly capital upgrades, quantitative analysis is needed to demonstrate why such upgrades are in consumers' interest.	
1f	BAMx would also like to comment on some of PG&E's previously approved projects that the CAISO has put on hold during this year's transmission planning cycle. Midway-Andrew 230kV Project Midway-Andrew Transmission Project was approved during the 2012-2013 transmission planning process. The original approval cost estimate of the Midway-Andrew Tranmission Project was $120-$150 Million. The Project was approved under the following justification: "The Midway-Andrew 230 kV Project will fully mitigate the voltage collapse problems presently observed in the Mesa and Divide 115 kV system and protect against approximately 270 MW of load drop following loss of any two of the 230 kV sources at the Mesa substation (Category C5, C2 and C3 outages). For the Divide area, the project will avert system voltage collapse and protect against approximately 145 MW of load shedding following loss of Mesa-Divide #1 & 2 115 kV Lines." Based on the above description for the need of Midway-Andrew 230kV Project, as well as some other approval documents, there were no single contingency violations supporting the need for the Midway-Andrews transmission project. Midway-Andrew 230kV Project mitigates contingencies associated with a loss of two transmission elements around the Mesa 230kV Substation. This is a low probability event for which the CAISO Planning Standards allow for the controlled interruption of load in non-urban areas. Currently there is an SPS in place to protect against the described risk of voltage collapse and thermal overloads. When the project was initially approved, BAMx asserted that the system was in compliance with the applicable reliability criteria and additional improvements should be subject to a cost/benefit assessment. More recent estimates reflect an increase of over 350% to $600-$700 million.6 This accentuates BAMx's previous comments and spotlights the question of how much is reasonable to spend to improve the reliability to an area that already	As the ISO has noted, this project will be reviewed in the 2017-2018 transmission planning cycle.

No	Comment Submitted	CAISO Response
	meets the system performance requirements. BAMx recommends that this project be held indefinitely until a framework is in place to address this question.	
1g	<u>Northern Fresno 115kV Area Reinforcement</u> The Northern Fresno Reinforcement Project was also approved during the 2012-2013 Transmission Planning Cycle. The cost estimate from the request window application submitted by PG&E for the project was $110 to $190 Million. The following was provided as a justification to build this project: "A fault on the 230 kV bus tie breaker at McCall substation would cause overloads of up to 126% on 4 facilities and low voltage throughout Southern Fresno. McCall UVLS would initiate for this contingency and drop 260 to 290 MW of load. An additional 50 MW of load may need to be dropped via SCADA to alleviate overloads of the Herndon-Barton and Herndon-Manchester 115 kV lines." "There are several other outages that lead to overloads. During peak the Herndon 230/115 kV transformers #1, #2 and #3, McCall 230/115 kV transformers #1, #2 and #3, Herndon-Barton 115 kV line and Herndon-Manchester 115 kV line all overload for NERC category C2 and C3 (N-1-1) outages. In order to take clearances at McCall extensive switching would need to be performed to radialize the 115 kV system. This would make routine maintenance difficult, expensive and would significantly increase the risk of customer outages. The Northern Fresno 115 kV Area Reinforcement project will strengthen the system so that it can withstand the Herndon 230 kV bus tie breaker fault without relying on SPS or dropping any load. The system will also be strengthened enough to withstand the McCall 230 kV bus tie breaker fault and will mitigate overloads on 20 additional facilities resulting from at least 10 separate contingencies. This project will also increase operating flexibility, load serving capability, customer reliability and reduce losses. The impact on Helms pumping capability will be negligible." Similar to Midway-Andrew 230 kV Project, this project is being justified to avoid dropping load in non-urban areas for multiple contingency events. Also similar to the Midway-Andrew 230 kV Project, the cost estimate has increased by over	As the ISO has noted, this project will be reviewed in the 2017-2018 transmission planning cycle.

No	Comment Submitted	CAISO Response
	250% to $600 Million-$700 Million. Again, BAMx recommends that this project be held indefinitely until a framework is in place to address the question of how much is reasonable to spend to improve the reliability to an area that already meets the system performance requirements. As part of the review of the previously approved projects whose reliability need is driven by multiple contingency events, the review should identify those areas where non-consequential load dropping is allowed under the CAISO Planning Standards. Where an alternative is selected that provides a higher level of service than identified by the standards, a quantitative justification should be included as to how the customer benefits exceed the costs. (This is similar to the type of analysis already required by the CAISO Planning Standards for reliability versus cost assessments.[8])	
1h	Other Projects Recommended For Re-Evaluation In addition to the 13 projects cancelled and an additional 16 projects placed on hold in this transmission planning cycle, BAMx recommends that further investigation is merited for the following previously approved projects: Diablo Canyon Voltage Support Project The Diablo Canyon Voltage Support Project was approved during the 2012-13 Transmission Planning Cycle. The project entails building a Static Var Compensator at the Diablo Canyon Substation. The need for the project was to address low voltages below 0.90 pu after a double contingency outage of Morro Bay-Diablo 230kV circuit in addition to Morro Bay – Mesa 230kV circuit. In addition the project is to assist in PG&E meeting NERC NUC-001-2.9 Based on BAMx analysis conducted on the latest CAISO Summer Peak and Winter Peak 2026 cases, the post contingency voltages at Diablo Canyon and surrounding buses are substantially above the 0.90 threshold without the Diablo Canyon Voltage support project in service, therefore BAMx would recommend the CAISO evaluate the project for cancellation. Also, if the project is needed to meet NUC-001-3 NPIRs and given the announced retirement plans for Diablo Canyon, there is an issue of potential stranded costs. If this project does proceed, Diablo Canyon Power Plant should be responsible for the stranded project costs upon Diablo Canyon's retirement.	The ISO is not aware of any tariff provision requiring cost recovery from the Diablo Canyon Power Plant. The ISO will be continuing to assess voltage issues in the 2017-2018 transmission planning process.

No	Comment Submitted	CAISO Response
1i	Metcalf Evergreen 115kV Lines The Metcalf-Evergreen Reconductoring Project is located in the San Jose area and was approved in 2002 with a scope to reconductor both circuits between Metcalf substation to Evergreen Substation with a 477 kcmil SSAC. The justification for the project was an overload on one of the Evergreen-Metcalf circuits for the loss of the other circuit. However, the latest reliability results produced by the CAISO do not show any overloads on the Metcalf-Evergreen circuit for this or any other contingency. Also, applying this contingency to the latest Summer and Winter 2026 Peak cases did not produce loadings in excess of current conductor ratings. The CAISO assessment did show some value of this project in mitigating P6 (N-1-1) overloads on the Trimble-San Jose 'B' 115 kV line. If this is the only driver however, it would appear questionable whether reconductoring 21 circuit miles of the Metcalf-Evergreen line to avoid upgrading the 3.4 mile Trimble-San Jose 'B' 115 kV line is a reasonable solution. BAMx recommends that the CAISO re-evaluate the need for the Metcalf-Evergreen Reconductoring Project.	The Metcalf-Evergreen Reconductoring Project is modeled in the base case and hence no overloads on these lines were identified in the latest reliability results. Overloads on these lines were identified in the reliability study performed for project review under P6 contingency in the baseline scenario. Additional overloads under P2 contingencies were also identified under no-PV and no-PV-EE sensitivity scenarios. Furthermore, loads served from these lines are within high density urban area and non-consequential load shedding as mitigation is not permitted based on the ISO Planning standards.
1j	Special Study – 50 Percent Renewable Energy *Adequacy of Existing Transmission Infrastructure to Meet 50% RPS Goal* BAMx is highly encouraged by the findings of the investigation into the feasibility and implications of using energy-only procurement to integrate the additional renewable resources necessary to meet California's 50% RPS goal. In addition to the report's recognition that the need for future renewable generation to provide system resource adequacy capacity is diminishing, BAMx notes that the study demonstrates that the maximum of 15,000 MW of incremental renewables needed in the CAISO balancing authority area to transition from 33% to a 50% RPS goal can be accommodated on the existing transmission without any major issues barring certain potential reliability issues in the Tehachapi, Mountain Pass and Eldorado, VEA and Nevada SW zones. BAMx believes that this information should be fed into the CPUC RPS Calculator or the future Integrated Resource Planning (IRP) capacity expansion tool to develop more refined resource portfolios to avoid such potential reliability issues going forward.	The comment is noted.

No	Comment Submitted	CAISO Response
1k	*Renewable Curtailment Primarily Driven By Oversupply Rather Than Lack of Transmission* The availability of congestion and curtailment information, such as presented, is important for the market to make informed resource development and selection decisions. One of the major takeaways of the 50% RPS Special Study that the renewable curtailment in all the portfolios were found to be over-supply related rather than transmission related. In other words, these 50% RPS Special studies indicate that building additional transmission may not be a suitable solution to reduce the level of potential renewable curtailments. Rather the ability of the CAISO to export excess renewable energy during a certain period would have a much more significant impact in terms of reducing the level of curtailments. In other words, the ability to manage and export surplus resources is critical to the integration of high penetrations of in-State solar resources. BAMx, therefore, supports increasing use of the interties in the studies to expand exports during times of over-generation.	The comment is noted.
1l	*Need to Account for Authentic ELCC-based Deliverability Dispatch* Regarding the CAISO's attempt to incorporate "Effective Load Carrying Capacity (ELCC)- based deliverability dispatch into deliverability assessment10," this proposal calculates the expected renewable generation within a three-hour window around the shifted system peak that results from increased behind-the-meter generation. We understand the CAISO has applied its current exceedance-based deliverability methodology to the resultant expected renewable generation during this three-hour window. BAMx notes, 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 final 2016-17 transmission plan must carefully and properly ensure that the description of the CAISO studies make clear that deliverability methodology itself is not ELCC based. Table 1 compares the current wind and solar exceedance factors in the SCE area in 2026 assumed in the CAISO generation interconnection studies and Net Qualifying Capacity (NQC) studies with those assumed in the CAISO's 50% RPS Special study with the ELCC amounts utilized in the CPUC RPS Calculator Version 6.2. Although the Peak Shift NQC value (31%) for PV is	We understand that there was some confusion caused by a slide presented during the November 16 stakeholder meeting. The slide said "First attempt to incorporate ELCC data into deliverability assessment". While we relied on the data from CPUC's ELCC-related work, the intent was to capture the impact of peak-shift on exceedance value assumptions. We have already clarified this the Feb 17th presentation that the ISO did not attempt to incorporate "ELCC-based dispatch". We have ensured that the transmission plan is clear on this issue. The comparison of "exceedance values deduced by capturing the impact of peak-shift" to "ELCC numbers" can be misleading since the two numbers try to quantify two completely different variables. ELCC is a percentage that expresses how well a resource is able to meet reliability conditions assuming there are no deliverability

<table>
<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td></td><td>lower than the Current NQC values (92%-93%), they are not as low as they would be based upon the ELCC calculations. Furthermore, although the wind ELCC values (14%-28% range) are considerably lower than the Current exceedance values (38%-47%), the Peak Shift values used in the 50% RPS Special study at 60% are even higher than the Current exceedance values.

Table 1: Comparison of Wind and Solar Exceedance Factors in the SCE Area in 2026
<table><tr><th>Technology</th><th>Current 50% Exceedance</th><th>Peak Shift 50% Exceedance</th><th>ELCC*</th></tr><tr><td>Wind</td><td>38% - 47%</td><td>60%</td><td>14%-28%</td></tr><tr><td>Solar PV</td><td>92% - 93%</td><td>31%</td><td>2%</td></tr></table>*Source: Marginal ELCC as reported in the CPUC RPS Calculator Version 6.2, ELCC_Interp tab

The transition to ELCC resource counting reflects the shortcomings of the existing exceedance methodology for RA counting as the renewable penetration increases.11 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 an input to the CAISO studies. CAISO needs to address why, in order to comply with this state mandate, the deliverability methodology is not being aligned with the resource counting methodology.</td><td>constraints and reduce expected reliability problems or outage events. It is calculated via probabilistic reliability modeling, and yields an equivalent percentage value for a given facility or grouping of facilities. Whereas, the exceedance numbers are based on the dispatch of resources during a certain time window around the shifted peak. ELCC numbers consider the equivalent reliability contribution considering all of the modeled hours (usually 8760), while the exceedance values are the dispatch assumptions during a specific snapshot. So it is not unreasonable if these numbers differ.

With regards to aligning the deliverability methodology with the resource counting methodology, the ISO will continue to follow progress on changing the resource counting methodology and consider options for changing the deliverability study assumptions and methodologies, as needed.</td></tr>
<tr><td>1m</td><td>Need to Better Understand Whether EODS Truly Has More Reliability Issues Than FCDS
The CAISO, during the February 17th stakeholder meeting, observed that the in-state Energy Only Deliverability Status (EODS) portfolio has more severe reliability issues than the in-state Full Capacity Deliverability Status (FCDS) portfolio.[12] BAMx notes that these two portfolios have a very similar amount of resources selected in the Tehachapi zone, i.e., 3,625MW (in-State FCDS) and</td><td>In the Tehachapi area, the Midway – Whirlwind 500 kV, Antelope-Vincent 500 kV and Antelope – Whirlwind 500 kV line overloads are observed in both In-state EODS and In-state FCDS scenarios. The loadings in the FCDS portfolio are only slightly lower (~1% to 4% lower). The only facility that showed an overload in EODS portfolio but not in the FCDS portfolio is Magunden – Antelope 230 kV. This facility</td></tr>
</table>

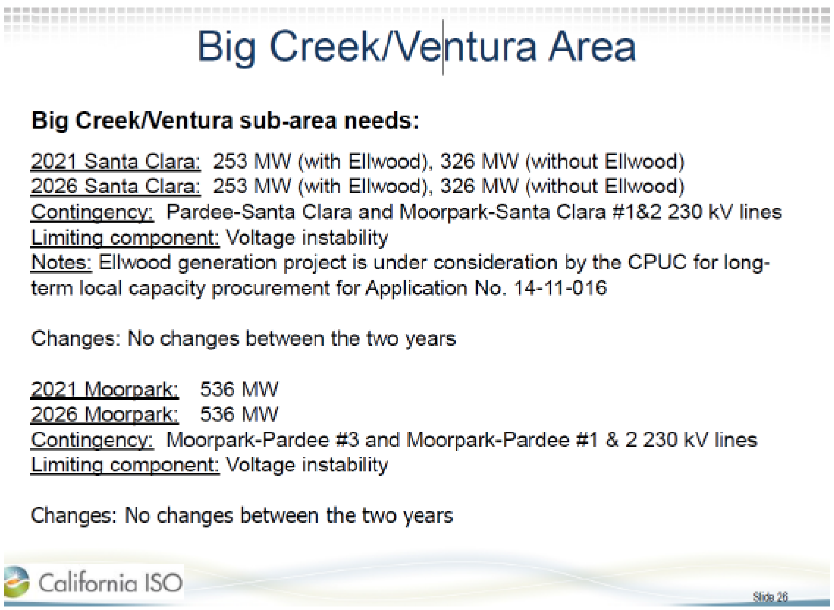
No	Comment Submitted	CAISO Response
	3,791MW (in-State EODS). It is not clear why only 166MW of incremental renewable resources in the in-State EODS portfolio results in several additional N-1-1 overloads.[13] BAMx requests the CAISO to provide some additional insights into this apparent anomaly.	has a much smaller rating than the facilities around it. So contingencies that involve 500 KV lines result in much more severe impacts on this line. The additional ~166 MW in the EODS portfolio results in more than 120 MW of incremental flow on Antelope - Magunden 220 KV lines and very little incremental flow on the 500 kV lines. This amplifies the post-contingency percentage overload on the 220 kV system when 500 kV facilities are part of the contingency. Hence the overloads on Antelope – Magunden 220 kV line under contingency conditions are observed only in the EODS portfolio.
1n	*Need to Update the Transmission Capability Data Going Forward* The CAISO provides information to the CPUC RPS Calculator regarding the capability of the existing transmission to accommodate fully deliverable and energy-only resources in each transmission area. It also provides information on the amount of new fully deliverable and energy-only resource capacity that can be incrementally accommodated with additional delivery network upgrades. BAMx encourages the CAISO to provide the very useful information that it has gathered characterizing transmission cost and availability for fully deliverable and energyonly resources to update the RPS Calculator or the future Integrated Resource Planning (IRP) capacity expansion tool. For example, the current version (6.2) of the RPS Calculator, which assumes that 2,628MW of fully deliverable (or 3,794MW energy-only) resources can be accommodated in the Tehachapi zone on the existing transmission.[14] Meanwhile data developed under the RETI 2.0 efforts indicates an availability of 4,500MW (5,600MW).15 Information from these most recent CAISO studies should be used ensure that the RPS calculator utilizes the most current information.	The comment is noted. The ISO has coordinated with the CPUC in undertaking the special study efforts, and expects to provide the study results to the CPUC.

No	Comment Submitted	CAISO Response
2	California Public Utilities Commission (CPUC) Staff Submitted by: Justin Hagler	
2a	**1.** The CPUC is requesting a more detailed discussion under Section 2.5.9 (Review of Previously Approved PG&E Projects) of what is meant by the statements "until the ISO completes the reviews" and "all development activities are recommended to be put on hold until a review is complete" to enable more adequate planning for project filings at the CPUC. In the Draft 16/17 Transmission Plan, the ISO has indicated at section 2.5.9 that they conducted a separate and standalone review of a number of low voltage transmission projects in the PG&E service territory that were mainly load forecast driven, and whose approvals date back several years in order to assess their possible cancellation. Based on this assessment, the ISO is recommending that 13 projects be cancelled; four projects not be filed at the CPUC until the ISO completes the reviews; and all development activities on 11 projects be put on hold until a review is complete. The CPUC is pleased to see that the CAISO has continued the practice of reviewing previously approved projects with the most up-to-date load forecasts for assessing continued need. However, as the ISO and PG&E are aware, the CPUC has a lengthy licensing process for CPCNs and PTCs involving contracting with environmental consultants prior to filing (at least a six-month process, preparing the appropriate CEQA documentation, and conducting a general proceeding for a CPUC decision). The language in the Draft TPP Section 2.5.9 addressing the ISO's project review process is vague and lacks the necessary specificity for the CPUC to anticipate project filings both in terms of filing dates and the number of projects. The ISO should provide more details on the review processes used for evaluations of the projects held, with major milestones for the reviews communicated as early as possible so that the CPUC can have a better understanding of which projects will be moved forward and when they will be filed with the CPUC.	Note that in the revised draft 2016-2017 Transmission Plan, one additional project is recommended to have the design and siting work that is underway completed, to aid in the review of the project in the 2017-2018 planning cycle, rather than having all activities cease until the review is complete. We are aware of the impact the review process has on the subsequent licensing processes of the CPUC and construction processes of the utilities, and does not undertake these steps lightly. The next opportunity for review is in the 2017-2018 transmission planning process and the ISO will continue to update stakeholders including the CPUC through that process.

No	Comment Submitted	CAISO Response
2b	2. CPUC Staff requests greater transparency when presenting cost estimates of reliability projects. While it is understood only capital costs are presented by the CAISO, approved projects regularly result in significantly higher costs than what is estimated in the TPP. CPUC Staff request greater transparency in cost estimations for reliability projects. While the cost estimates at the planning level are limited to capital costs, it is misleading upon review when final project costs are often much higher. For multiple projects, there seems to be a large jump in cost estimates provided in the Transmission Plan to when the utilities file the projects' applications to completion of the project. Some examples include (but are far from limited to) the following: a) Tehachapi Renewable Transmission Project: When it was first approved in the 2007 Transmission Plan, the cost estimation was approximately $1.8 billion. Currently, the estimation as provided by SCE in their 2016 Q4 AB970 Report is within the range of $2.3 to $2.4 billion. This is an approximately $550 million rise in cost, which is a 30% increase since CAISO approval. b) Ocean Ranch Substation: When the project was first discussed in the 2014-15 Transmission Plan, the cost estimation was approximately $34 million. When the project was discussed in the 2015-16 Transmission Plan, which no longer included reconductoring of a line from San Luis Rey Substation and two loop-ins, the cost estimation was within the range of $25 to $30 million. Currently, the estimation as provided by SDG&E in their Application for a Permit to Construct is $72.4 million. Therefore, the current cost estimation is over two times greater than the estimation originally given for the project when it had a greater scope. c) Estrella Substation: When the project was first approved in the 2013-14 Transmission Plan, the cost estimation was within the range of $35 to $45 million. Currently, the cost estimation as provided by PG&E in their 2017 Q1 AB970 Report is confidential, but the cost figure is significantly higher. It should also be noted that it is unclear if the	The comment has been noted. The ISO agrees that cost information is important in considering planning decisions and looks to the best available information at the planning stage. The ISO understands that that the utilities rely on the available information at the time of developing planning cost estimates, but also recognizes the practical uncertainties affecting cost estimates at such early scoping stages. It is not clear which costs the comment is suggesting are being omitted in making the statement "only capital costs are presented by the CAISO". The ISO also refers to the quarterly updates that the participating transmission owners (PTO) provide for these projects to the CPUC in their Quarterly AB 970 Project Status Report submission under Proceeding Number I0011011, Decision Number D.06-09-003.

No	Comment Submitted	CAISO Response
	current cost estimation includes the NEET components or strictly includes the PG&E components of the project. In order to further conduct full and reasonable transmission planning, CPUC staff believes it to be imperative to be aware and transparent of the cost differences to project completion. Costs presented should be clear that they are fluid, incomplete estimations provided by the utilities that are subject to increase. Ideally, costs should be more reflective of future changes and account for costs past only capital costs.	
2c	3. **The CAISO posted its final 2021 LCR study, but did not provide stakeholders with an opportunity to comment on a draft version of this study, consistent with past practice and with requirements for an open and transparent stakeholder process.** Energy Division staff encourage the CAISO to repost the final study as a draft, take comments, and issue a final version only after this process is complete. In addition, Energy Division staff encourages CAISO to ensure that stakeholders are provided with an opportunity to comment on the local studies in a draft form on an on-going basis in the future.	The ISO does provide opportunity for comments on the longer term LCT study performed annually that is discussed in section 4.2.3 of the ISO's Business Practice Manual for Transmission Planning Process. For example, comments on the 2018 and 2022 LCT study are due March 23. However, ISO would like to make a distinction between the purposes of the year-ahead and five-year out analyses. The year-ahead results are used for procurement processes so the ISO would appreciate timely comments from stakeholders. The five-year out results, on the other hand, are provided as informational only and are not binding – they are not used for procurement purposes. The LCT study is intended to forecast potential LCR needs over a longer planning horizon that can inform the ISO's transmission planning process and be used to identify the need for longer lead time economically-driven transmission elements, which would reduce LCR needs. The longer-term LCT study also provides market participants with information to utilize in their individual long-term procurement activities, but is not used by the ISO to allocate responsibility for local capacity area resource procurement. These results are informational only and are not binding – they are not used for procurement processes. However, while the ISO may provide updates to the report to address specific corrections that have been found to be necessary (as noted in the response to the next comment below), the ISO does not provide updated analysis and documentation based on comments received.

No	Comment Submitted	CAISO Response
		Rather, those comments are used to inform the next year's studies – both the binding year ahead results and the next longer term LCT study. This practice is also consistent with the provision of the High Voltage TAC projection provided in the annual transmission plans, where stakeholder comments are received and incorporated into the next year's model. Both of these sets of analyses are provided on an informational basis and without being required by tariff.
2d	4. The CAISO should revise its final 2021 LCR study to clarify that the 326 MW need in the Santa Clara sub-area is premised on the retirement of the Ellwood generating facility and should indicate that the need is only 253MW assuming that Ellwood is operating. In its "Final 2021 Long-Term Local Capacity Technical Report," CAISO states that the Santa Clara sub-area need is 326 MW: "The most critical contingency is the loss of the Pardee- Santa Clara 230 kV line followed by the loss of Moorpark – Santa Clara 230 kV #1 and #2 lines, which would cause voltage collapse. This limiting contingency establishes a local capacity need of 326 MW (includes 91 MW QF generation, 5 MW of battery storage and 2 MW of preffered [sic] resources) as the minimum capacity necessary for reliable load serving capability within this sub-area." (Final 2021 LCR Study, p. 89). However, in its presentation on this study February 17, 2017, CAISO indicates that the need is 253 MW (with Ellwood) and 326 MW (without Ellwood), as shown in CAISO's presentation slide below. Energy Division staff believe that CAISO should update its "Final" 2021 LCR study to explain this assumption, otherwise it could be mistakenly assumed that the need is 326 MW in all circumstances. Moreover, CAISO should clearly explain in its study, why the need changes depending on whether Ellwood is assumed in the study and not (i.e., why the need is not constant, irrespective of available resources).	The comment has been noted. The ISO is considering the suggestions and plans to provide updates to the "Final 2021 Long-Term Local Capacity Technical Report" for the Santa Clara subarea.

No	Comment Submitted	CAISO Response
	 	
2e	5. The CAISO Should Revise its Gas/Electric Coordination Special Study based on recently available information. Energy Division staff believe that CAISO should update its assumptions based on recently available information. In the Draft TPP study, CAISO indicates that it did not take into account the Energy Division's "Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity and Well Availability Report – Revised Report" (see Draft TPP, p. 228, fn. 96). Energy Division staff believe that tightened balancing requirements, which reduce the curtailment by 150 MMcf per day, should be included in the TPP analysis. The Energy Division report states: "A key summer mitigation measure was to tighten the mismatch between the amount of gas that noncore customers use and the amount they bring	The ISO has incorporated benefits of balancing rules in Tables 6.3-2 and 6.3-3 as well as including a note regarding potential impact due to tubing operation only in the revised draft transmission plan. Additional information continues to become available regarding Aliso Canyon and will be incorporated in future studies.

No	Comment Submitted	CAISO Response
	in on a given day…. Operating experience suggests that tightening balancing can eliminate the mismatch during the summer of 150 MMcf. Eliminating the mismatch (essentially increasing supply by 150 MMcf) directly reduces the amount of the original curtailment identified in the four Summer Technical Assessment scenarios. Accounting for the reduction allows Scenario 2 to be solved without the use of Aliso. It also reduces the amount needed to solve for Scenario 4, and by default, Scenario 3.[1] Taking the tighter balancing rules into account would reduce line 1 on both Tables 6.3-2 and 6.3-3 and would reduce the potential estimated customer impact to only Scenario 4 (i.e., with Aliso out of service and a also a storage and gas pipeline also out of service).	
2f	6. The CAISO should clearly explain why the local area needs have increased in the San Diego area. The local need in the San Diego/Imperial Valley (IV) area increases by considerable amounts in the 2021 and 2026 timeframe, as highlighted in the table below. This table shows the historical local capacity need, as well as results from the mid- and long-term studies and illustrates that for 2021 and 2026, the local needs in the San Diego increase dramatically in 2021 (4,357 MW) from 2020 (2,868 MW). While this may be the result of moving the need from the LA Basin to San Diego, this should be thoroughly explained. The large increase in the San Diego local requirement is concerning given the trends in load forecasts (see 2016 v. 2021) and the significant transmission investments that have been made in the southern California area generally and the San Diego area in particular. In addition, the CAISO should consider combining these two areas and providing effectiveness factors, rather than drawing a bright line between the need in LA and San Diego.	Regarding the suggestion of combining the LA Basin and San Diego areas and providing effectiveness factors for the critical constraints that affect both of these areas, the ISO must and has been studying these two areas together due to the electrical interdependency between these two areas since the shutdown of San Onofre Nuclear Generating Station (SONGS). The study of the combined two LCR areas of the LA Basin and San Diego subarea were recognized by the CPUC in the Scoping Memo for the Long-Term Procurement Plan Track 4 study. The ISO also provides effectiveness factors for the common constraints that affect both of these areas in either the LCTA reports or the transmission plan reports. LCR requirements cannot generally be assessed based on a simple comparison of the level of loads alone. While this is one of the factors that affect the LCR requirements, other factors such as specific generation retirement, planned transmission upgrade assumptions (either internally within the ISO BAA, or on the interfaces with other BAAs), availability and locations of resource assumptions, could affect the LCR needs. Without attempting to deconstruct each of the past LCR studies or considering each incremental impact of each of the many study assumptions involved in each study, the ISO can offer the

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	LCR Need			1-in-10 Load Forecast				
	San Diego or SD/IV	LA Basin	SD & LA Combined	San Diego	LA Basin	SD & LA Combined	Notes	
	Based on San Diego Local Area							
2006	2,620	8,127	10,747	4,578	18,839	23,417		
2007	2,781	8,843	11,624	4,742	18,809	23,551		
2008	2,919	10,130	13,049	4,873	19,648	24,521		
2009	3,113	9,728	12,841	5,052	19,836	24,888		
2010	3,200	9,735	12,935	5,127	20,058	25,185		
2011	3,146	10,589	13,735	5,036	20,223	25,259		
2012	2,849	10,865	13,714	4,844	19,931	24,775		
2013	2,938	10,295	13,233	5,114	19,460	24,574		
	Based on San Diego/ IV LCR Area							
2014	3,605	10,430	14,035	5,200	19,694	24,894	3,394	San Diego Sub-Area
2015	3,910	9,097	13,007	5,407	19,970	25,377	3,103	San Diego Sub-Area
2016	3,112	8,887	11,999	5,283	20,168	25,451	2,850	San Diego/IV Sub-Area
2017	3,570	7,368	10,938	4,840	18,890	23,730	2,915	San Diego Sub-Area
2018								
2019	*3,160*	*9,119*	*12,279*	*5,538*	*20,506*	*26,044*	*2,508*	San Diego Sub-Area
2020	*2,868*	*9,229*	*12,097*	*5,412*	*20,764*	*26,176*	*2,868*	San Diego Sub-Area
2021	*4,357*	*6,898*	*11,255*	*4,980*	*19,506*	*24,486*	*2,514*	San Diego Sub-Area
2022								
2023								
2024								
2025	*4,868*	*7,346*	*12,214*	*5,394*	*22,376*	*27,770*		
2026	*4,649*	*7,234*	*11,883*	*5,307*	*19,243*	*24,550*	*2,807*	San Diego Sub-Area

following general observations of the LCR needs versus loads provided in the CPUC table on the left:

- The LCR needs are non-linear and are dependent on the locational assumptions where the loads are modeled, specific transmission upgrades, where generators retire, and where additions of new resources are located.
- The LCR needs cannot just be compared using spreadsheet for simplified comparisons. In addition to the non-linearity discussed above, some issues such as voltage collapse are inherently not linear, and even for thermal situations, locations can affect relative effectiveness, e.g. once the most effective unit has been considered, it will take more MW of a less effective unit to generate the next increment of relief. Also, different constraints can "compete" for being the most binding depending on the factors discussed above, creating further nonlinearities between load and local capacity requirements.
- From 2006 – 2013, where the LCR needs are shown, LCR needs for the San Diego subarea generally trend with load levels. This was expected as these studies had one common assumption: SONGS was assumed to be operational in the study case. While SONGS was technically off-line starting 2012 timeframe, the decision to officially retire SONGS was not announced by SCE until June 2013 timeframe.
- From 2014 – 2026, SONGS is retired in these LCR studies. The highest LCR need for the San Diego subarea during these periods was observed for 2014 (3,394 MW). For other years in this 12-year range, the San Diego subarea needs are shown as less than 2014 timeframe, reflecting the effectiveness of long-term procurement and the transmission upgrades planned and to be implemented for both the LA Basin and San Diego areas.
- The CPUC comments about higher San Diego needs should be characterized as San Diego-Imperial Valley LCR area needs. The increase in San Diego-Imperial Valley LCR need

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		from 2020 to 2021 is primarily related to updated assumptions for IID's planned transmission upgrades. In October 2015 IID informed the ISO of its plans to cancel three transmission projects. These project cancellations were captured in the 2021 LCR study, resulting in an increase in San Diego-Imperial Valley LCR needs. As mentioned above, changes in the transmission assumptions for tie-lines with other BAAs and ISO BAA could have negative impact to the adjacent area's LCR needs, and in this case, it is the overall San Diego-Imperial Valley area.
2g	7. CPUC Staff commends the CAISO for the continued practice of assessment, holding for review, and cancellation of previously approved transmission projects deemed no longer needed under declining load forecasts. Staff encourages the continuation of the review process for <u>all</u> load areas, as well as transparency of maintenance cost implications of cancelling utility projects.	
	CPUC staff appreciates the CAISO's continued effort to analyze current need for previously approved transmission projects in PG&E's service territory. Staff notes that the standards for cancellation are considerably high- The CAISO used a value of 0 Behind the Meter PV to simulate peak shift, while assuming 0 AAEE on a 2016 transmission system elevated to 2026 load levels. This evaluation should be conducted periodically for all load areas and service territories, in light of significant policy driven changes. The CPUC generally supports this level of rigorous reliability testing, which ensures cancelled projects are less likely to re-appear with potentially higher costs in subsequent transmission plans.	The comment is noted. In addition to the base case assumptions, the ISO studied two sensitivities to assist in the assessment of the previously approved projects taking into account the uncertainties of the assumptions. The sensitivities assessed the impacts of the PV Peak Shift effect and the "without AAEE" on the PV Peak Shift case to help identify if the project was relying on the AAEE to materialize.
	As mentioned in Comment #1, Staff requests the CAISO provide updates on projects held for additional study and re-scoping as soon as such information is available. The ISO should seek as much collaboration as is feasible with Commission staff in the development and siting of re-scoped reliability	As noted above, the ISO will provide updates as available in the ISO planning process throughout the planning cycle.

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	recommendations to minimize potential permitting litigation issues after projects have been filed. Additionally, for any projects that have been canceled in the 2016-17 Transmission Plan and in any future transmission plans, the CAISO should be clarify whether or not the projects encompassed any needed maintenance as identified by the utilities. It is understood that utilities coordinate with the CAISO consolidate maintenance projects with reliability projects. The CPUC requests the CAISO note whether this has occurred with any canceled projects, so that the CPUC is kept aware that some aspects may still need to be carried out under maintenance needs. This improves process transparency in terms of identifying that certain projects may not be canceled in their entirety, but may in fact lead to the need for other maintenance projects, which are still subject to accruing costs.	 The comment has been noted and we will seek to address this in future project cancellation communications.
2h	8. CPUC Staff notes that there is no change in the finding of need for PG&E's Martin 230kV Bus Extension project, or Ravenswood- Cooley Landing 115kV Reconductoring project. Staff believes the Martin project may trigger a complex permitting process, and the Applicant has not yet filed for at the CPUC. Given the magnitude of the project and the length of time between CAISO approval and Applicant filing at the CPUC, the CAISO may want to consider whether there is any new information pertaining to the continued need for the project. As the CAISO authorization for the project ages without an ensuing application from PG&E, so does the load forecast assumptions under which the project was approved. When PG&E files a CPCN for the construction of the Martin project, expected by staff in September 2017, CAISO staff may be interested in providing information to the proceeding pertaining to the continued need for the project, as well as the continued preference for this particular transmission solution above other alternatives, given the now dated information about costs and benefits of the project. The CPUC raises this issue in case the CAISO can provide that confirmation in this year's TPP.	 The need identified in the 2014-2015 Transmission Plan for the Martin 230 kV Bus Extension Project has not been impacted by changes in the forecast assumptions.

No	Comment Submitted	CAISO Response
	The Ravenswood- Cooley Landing Reconductoring project was proposed in PG&E's 2010 Electric Transmission Grid Expansion Plan, which then appears as approved in the CAISO's 2012-2013 Transmission Plan. In PG&E's initial proposal, the project online date is 2013. In the 2012-13 TPP, the online date is May 2016. CPUC Staff notes that the online date has again been pushed back to May of 2021, which means the project will be coming online more than 10 years after its initial study. Staff recommends the CAISO reexamine the load and system assumptions that contributed to the finding of need for this project in the upcoming Transmission Planning Process.	Overloads were identified in the reliability study performed for project review under P2, P6 and P7 contingencies in the baseline scenario as well as the sensitivity scenarios. Furthermore, loads served from these lines are within high density urban area and non-consequential load shedding as mitigation is not permitted based on the ISO Planning standards.
2i	9. The CAISO should continue to engage with the CPUC and other stakeholders on clear documentation of alterations to inputs and study methodologies used when translating the CPUC's and CEC's planning inputs into use for sensitivity cases in the TPP. Reliability assessments are an integral part of stakeholder participation in the Transmission Planning process, and therefore must be presented in a clear and accessible manner. The CAISO should identify key snapshot conditions which produced a reliability need in any given area. The study scenario conditions should be supplied "up front", with clear footnotes directing stakeholders to documentation of the details of the particular base case(s) and sensitivities which created a need for the project being presented. This format should then be applied consistently across all regions/load areas, for ease of stakeholder access and understanding. The clear documentation of changes and assumptions made from state agency planning inputs in the Transmission Planning Process will reduce time and effort spent on litigation of projects after Transmission Plan approval. Improved alignment on transmission planning assumptions also has the added benefit of the CPUC being able to more closely align with the CAISO in presenting a unified California front at WECC in the development of the Anchor Data Set (ADS). The ADS will use data directly from CAISO and the other planning	The ISO agrees that documentation of the study scenarios is important. Within the study plan for the 2016-2017 (section 4.11) as well as in the draft 2016-2017 Transmission plan (section 2.3.8) documented the base case scenarios and sensitivity studies that were assessed for each planning area. The ISO will continue to document the assumptions within the transmission planning documentation and will review if clarification of the documentation can be made to further assist stakeholders with the reliability assessments.

No	Comment Submitted	CAISO Response
	regions' transmission plans, which makes CPUC/CAISO process alignment on the discussion and vetting of inputs all the more important. In addition, the alignment of study scenario assumptions and clearly defined modifications to base cases will be increasingly important when the CPUC's IRP provides policy preferred portfolios in upcoming TPP cycles. The provision of new portfolios and assumptions from IRP reflecting the state's GHG emissions reduction goals is likely to create a significant uptick in policy driven projects presented to stakeholders and the CAISO board for approval. It is imperative that CAISO and CPUC staff coordinate the implementation of a clear system of documenting study scenario assumptions which drive new projects before the completion of the first IRP.	The ISO expects to continue to coordinate with the CPUC in its development of its IRP process as reflected in the 2017 Assumptions and Scenarios for Long-Term Planning.
2j	10. CPUC Staff Commends the CAISO for the clear documentation of "No AAEE" and "No BTM- PV" Sensitivity results in the appendices of the Draft 2016-2017 TPP. Staff also thanks CAISO staff for present and future coordination in the 50% Special Study effort. CPUC Staff appreciates the continued documentation of "0 AAEE" and "0 BTM PV" sensitivity results in Appendix C of the Draft TPP, and encourage the CAISO to continue the practice of updating these significant and useful results in each study cycle. CPUC staff also commends CAISO for its work on the 50% RPS Special Study, and looks forward to continued staff collaboration in the analysis of the 50% study and other special studies, to maximize the expediency and inter-agency value of study results.	The comment has been noted.

No	Comment Submitted	CAISO Response
3	Center for Energy Efficiency and Renewable Technologies (CEERT) Submitted by: Jim Caldwell	
3a	50% RPS Special Study - Please clarify when results labeled “in-state” and “out of state” refer to the geographical boundaries of California or the CAISO Balancing Authority. Given that approximately one-third of California load is located in other Balancing Authorities and the CAISO BA includes Southern Nevada, it will be easy to become confused. Based on the two recent presentations, CEERT assumes that most if not all of the results refer to the CAISO BA as “in-state,” but this point needs to be explicit and consistently worded.	The ISO has provided more detailed explanations of those terms in section 6.4.6 of the transmission plan.
3b	- On a similar note, please document the resource mix assumed for both non-CAISO CA BAs and fully “out of state” BAs in the study. How were the portfolios, presumably consistent with a statewide 50% RPS requirement, selected for the non-CAISO CA BAs and do they vary between the scenarios?	The resource mix for non-CAISO BAA was assumed to be the same across all portfolios (in the production cost simulations as well as in the power flow studies)
3c	- Please consider publishing the annual production cost and CO2 emission differences between the scenarios along with the dispatch gas price used in order to provide some context for the value of the changes observed. A simple three row (”in-state” FD, “”in-state” EO, “out of state “ FD and EO) by six column (CAISO, CA total, WECC wide for Annual Production Cost and GHG Emissions) table along with a short explanation should suffice.	The table below shows the production and emission costs. Please note the production and emission costs were calculated based on footprint instead of ownership. These costs were the results of economic dispatch based on the baseline assumptions in the ISO’s PCM. These costs are meaningful only in the context of comparing between renewable portfolios.

Portfolio	WECC footprint Production Cost ($M)	WECC footprint Emission Cost ($M)	CA footprint Production Cost ($M)	CA footprint Emission Cost ($M)	CAISO footprint Production Cost ($M)	CAISO footprint Emission Cost ($M)
In state FC	20,907	3,415	5,389	1,299	4,011	921
In State EO	20,924	3,408	5,576	1,353	4,145	954
OOS	21,040	3,617	5,738	1,352	4,318	972

No	Comment Submitted	CAISO Response
3d	- Please explain in detail how the "net export limit" is modeled – especially in light of the above geographic boundaries. How much of the 2k limit is taken up by "in-state" exports.	Additional explanations of this issue has been provided in section 6.4 of the transmission plan. In summary, Net export = Sum of Line flow of all lines from the ISO to other BAAs + Sum of Generation output of out of state resources with dynamic schedule to the ISO
3e	- Please explain how the "out of state" wind is dispatched. Is it "must take" in every hour? Is it subject to economic curtailment? Does it have dispatch priority over other contractual imports such as Palo Verde or existing RPS eligible imports?	Out of state wind is modeled as fixed schedule but curtailable.
3f	It is clear that the results of this Special Study largely depend on the details of how imports and exports from the CAISO BA are modeled and how the proposed import portfolios interact with the RPS legislative direction (commonly referred to as the "Bucket Rules") and the CPUC and CEC regulations implementing the legislative intent. There needs to be a cogent explanation of this in the text as well as detailed documentation for the practitioners. Going forward, this model and these data bases represent the only current tool that can simultaneously deal with dispatch, deliverability and reliability. Thus it could be critical to inform at least the CPUC IRP process as well as the CARB Scoping Plan GHG reduction target setting process. The CAISO must stand ready to exercise this tool in an open source process where stakeholders can propose questions to be studied, consensus can be reached as to how to perform the modeling exercise and communicate the results. The current formal process of the CPUC transmitting a single set of inputs and a single portfolio for study will simply not be sufficient to allow a robust exploration of alternatives.	The ISO will consider this comment – as well as the practical limitations posed by the computationally and labor intensive analysis – in exploring next steps for this work.
3g	Bulk Storage Special Study At the Feb 28 Stakeholder meeting, there was little time to absorb the meaning of the results of the Bulk Storage Special Study and the relatively large difference in the results from previous work. In response to the specific request for ideas on other scenarios/ value streams to consider, CEERT suggests that a	Pumped storage will take energy from other generation resources to pump in order to provide the services. The ISO expects these issues to be considered in the upcoming CPUC proceeding regarding Aliso Canyon Please see

No	Comment Submitted	CAISO Response
	potentially large value stream for locational value of at least the LEAPS and/or San Vincente projects could be mitigating the potential "need" to invest large sums in increased reliability of the gas transmission/storage infrastructure in Southern California. Think the two recent incidences of shortages on the interstate pipeline system leading to potential curtailments of gas supplies to generate electricity, think Aliso Canyon, think the $600 M proposal currently before the CPUC to retire Line 1600 (a 1949 vintage pipeline that does not meet the safety standards promulgated following the San Bruno incident) and replace it with a 36 in diameter line that would increase the send out capacity of the SDG&E system by some 30%. A principal justification of these proposed projects is to improve electric sector reliability due to the need for local in-Basin gas capacity on peak. CEERT is not in any way endorsing the need for any of these projects. However, in light of the imperative that overall gas burn must significantly decrease over the next ten to twenty years in order to meet the State's climate policy, is bulk electricity storage a more cost effective way to achieve this "reliability" as opposed to large investments in new gas infrastructure?	http://docs.cpuc.ca.gov/publisheddocs/published/g000/m175/k467/175467144.pdf

No	Comment Submitted	CAISO Response
4	Cogeneration Association of California Submitted by: Donald Brookhyser	
4a	INTRODUCTION The Plan relies on the capacity provided by CHP resources, particularly in assessing local capacity requirements. The continued availability of existing, efficient CHP resources is an express policy objective of the California Public Utilities Commission's (CPUC) QF/CHP Program.[3] This program explicitly called for the encouragement of the continued operation of existing CHP, and for policies and procedures to support that goal. In an apparent disregard for this objective, the CPUC, pursuant to an Assigned Commissioner ruling[4] adopted a CHP planning assumption that all existing CHP resources will retire at the end of a 40-year life, or at the expiration of their current Power Purchase Agreement (PPA), whichever is later. Thus, the Plan may not accurately reflect the risks associated with the loss of continued CHP availability. The Plan should assess the important contribution that existing, efficient CHP resources make to the grid, and what the loss of this generation supply to VAR support, frequency support, demand and stability of the market, particularly in the LA Basin, would mean. Existing, efficient CHP resources have provided and should continue to provide electric grid reliability, relief for constrained distribution and transmission locations, and locational and needed generation supply for load pockets. In addition, these attributes sustain California's economic competitiveness, employment, tax base and many other benefits. A recently published quote attributed to the Center for Energy Efficiency and Renewable Technologies (CEERT) explains: *"…the solution [to addressing resource integration] involves much more than simply adding energy storage or substituting more wind or solar generation for the 55 percent of energy the state now derives from natural gas-fired generation. The key is to have the right mix. What you choose must also keep the grid properly synched, instantaneously balancing supply and demand, and maintaining the standard frequency and voltage needed to avoid blackouts."*[5]	The ISO cannot accommodate a change in study assumptions and study scope at this stage in the planning cycle. The ISO will consider these comments for future planning cycles and encourages that the comments be submitted into the study plan consultation process for the 2017-2018 planning cycle.

No	Comment Submitted	CAISO Response
	The assumptions in the Plan, related to retirement of CHP resources from an electrical system that relies on balance and diversity of resources are not consistent with a responsible balancing of diversified generation assets. CHP projects are generally located at unique thermal and electric demand locations, and eliminating these existing, efficient resources is imprudent for balancing the State's complex interests. To provide a more accurate reflection both of the threats to the grid support provided by CHP and of the future potential of these resources, CHP proposes three modifications to the Plan. First, the Plan must recognize the potential risks that CHP resources may no longer provide a material portion of the capacity in the State, particularly in the local areas of the Western LA Basin and Big Creek. CAISO studies, particularly of local capacity requirements, seem to assume that capacity will be on-line for the duration of the planning period. However, that capacity will remain on-line only as long as the resource has a PPA providing reasonable compensation; there are significant risks that the state will abandon its commitment to CHP and will not provide for renewal or extension of such PPAs. CAC also notes that the study of risk of retirement in Section 6 of the Plan does not seem to include retirement of any CHP unit in either Big Creek or the LA Basin, although, as discussed below, there is a substantial risk of such retirements within the planning horizon of this Plan. Moreover, the impact associated with the loss for CHP resource is not confined to the amount of export capacity. Without CHP, there is a potential risk for increased system load associated with behind-the-meter load. Additionally, the environmental considerations associated with thermal production could exacerbate the risk of increased electrical load. Second, the Plan must also address the problems with the assumptions approved by the CPUC6 that all such CHP resources will retire at the end of a 40-year life, or at the expiration of their current PPA, whichever is later. The ISO must recognize that several large CHP resources, including in the LA Basin, will reach their 40 year life in 2026 at the end of the planning period for the current Plan, and within the planning period for the 2017-2018 plan currently being developed. Although this assumption of a 40-year life ignores the continuous upgrades and maintenance provided for these units, the CPUC assumptions	

No	Comment Submitted	CAISO Response
	(unless corrected) force the ISO to reflect in its plans the contingency that those resources will not be available to provide local capacity, reliability and voltage support.	
4b	ASSUMPTION AS TO EVERGREEN PPAs The CPUC assumptions[7] signal to existing CHP resources that they are at risk of retirement as soon as their current PPA expires, given that they also nearing the expiration of that assumed 40-year operating life. Such an assumption of retirement and decreasing CHP capacity is inconsistent with the original intent of the CPUC's QF/CHP Program and representations made to the Federal Energy Regulatory Commission to sustain the state-administered program. The CPUC QF/CHP Program was expressly intended, in part, to create an on-going procurement program for existing, efficient CHP resources. The Settlement itself promised the platform for an ongoing CHP retention program. *1.2.2.9 [Among the CHP Program objectives] Establishes a platform for a State CHP Program with identified features through 2020, and sets a framework for a sustained State CHP Program beyond 2020.* Moreover, express policy objectives of the CPUC QF/CHP Program call for the encouragement of the continued operation of existing CHP, and for policies and procedures to support that goal. *1.2.1.3 The purpose of the State CHP Program is to encourage the continued operation of the State's Existing CHP Facilities, and the development, installation, and interconnection of new, clean and efficient CHP Facilities, in order to increase the diversity, reliability, and environmental benefits of the energy resources available to the State's electricity consumers.* *1.2.1.4 These policies and purposes will be achieved by a State CHP Program that procures CHP as set forth in this Settlement, retains existing efficient CHP, supports the change in operations of inefficient CHP to provide greater benefits to the State, and replaces CHP that will no longer be under contract with the IOUs with new, efficient CHP.*[8]	The comment has been noted.

No	Comment Submitted	CAISO Response
	Although inconsistent with the original intent of the QF/CHP Settlement, it seems the abandonment of these resources after their current PPA reflects an abandonment of the stated commitment to provide a sustained CHP procurement beyond 2020. This abandonment was effected by the Commission's decisions on procurement requirements for the Second Program Period of the Settlement (2015 – 2020). The decision on CHP policy issues in the 2014 LTPP proceeding set a new target for the Second Program Period: *While we will reduce the GHG Emissions Reduction Target, we are persuaded by EPUC/CAC and others that the Second Program Period GHG Emissions Reduction Target needs to be robust enough to achieve the CHP policy objectives established in D.10-12-035 beyond GHG emissions reductions.*[9] The target established for the Second Program Period relied on the same ICF Study for the CEC upon which the 2012 assumptions were based: *[W]e will use the June 2012 CEC Report's Medium Case to establish the Second Program Period GHG Emissions Reduction Target. The Medium Case has assumptions that reflect policies in effect today.*[10] That decision recognized the benefits that continued use of CHP could provide to the grid and to California's environment: *Ideally, CHP would be situated at locations where inefficient boilers are displaced by a system that can generate both industrial-grade heat and electricity. We note that CHP, as a form of distributed generation, both displaces electric load and delivers baseload generation onto the grid. Thus, if we drastically alter the GHG Emissions Reduction Target associated with CHP procurement, we may unintentionally cause efficient existing CHP facilities without future contract certainty to shut down, and undermine the state's efficiency and distributed generation goals.*[11]	

No	Comment Submitted	CAISO Response
	This decision on the Second Program Period seems to represent an evolution in the CPUC's implementation of the QF/CHP Settlement, and an abandonment of any sustained procurement of existing, efficient CHP resources. CAISO's Plan must reflect that contingency and the loss of those units upon the expiration of their existing PPAs. Certainly, such an eventuality represents a risk of economic retirement that should be reflected in the Plan's study of risk of retirement. Appendix C to the Plan models retirement of QF units only for certain local areas of PG&E. It appears to only model retirements that may be caused by thermal overloads. It does not model retirement for any SCE area. CAC's interactions with the ISO reveal that the ISO recognizes the value of the continued availability of these resources. Although the Plan should recognize the real possibility of the early retirement of these units, the ISO, as the entity responsible for the reliability of the grid, should be advocating in any available forum for the continued support and retention of these existing, efficient CHP resources.	
4c	OPERATING LIVES AND CHARACTERISTICS OF CHP RESOURCES The CPUC assumption that CHP resources will retire after 40 years of operation is misplaced. CHP operations typically undergo major maintenance overhauls in five-year cycles. This regularly scheduled maintenance provides opportunities to upgrade equipment, enhance efficiency and effectively refresh anew the physical plant. These units have demonstrated superior capacity and on-line performance factors, i.e., sustainable operating characteristics, and there is no reason to assume they will not continue to do so. Moreover, the host facilities that rely on these CHP resources are not typically planning on terminating operations. These hosts, usually industrial facilities, have longevity requirements for thermal output far beyond what the CPUC Staff assumptions would support. Many of the units owned by CAC's members are approaching 40 years in operation, would likely be classified as exporting CHP units, and continue to operate efficiently (all of which are greater than 20 MW). The industrial operations that they support will continue to need the most efficiently-produced and reliably supplied thermal and electrical energy for decades in the future.	Please refer to the above responses.

No	Comment Submitted	CAISO Response
	The assumptions utilized by the CAISO should not contemplate a decrease in the amount of CHP capacity on the grid from existing, efficient resources for the period of this TPP planning cycle (2016-2026) without a compelling factual basis. Even with California's commitment to reduce (not eliminate) fossil-fuel use, particularly in existing, efficient applications, the "other 50%" of grid resources relying on clean natural gas generation matter, and need to be prudently sustained. The ISO should embrace a responsible and balanced set of assumptions that supports a policy that industries relying on existing, efficient CHP should obtain their thermal and electrical requirements in the most feasible and proficient means possible.	
4d	CONCLUSION The ISO transmission plan should accurately reflect the contribution made to grid stability by existing, efficient CHP resources. But it must also reflect the risk that such CHP resources may be untimely removed from service pursuant to policies adopted by the CPUC. The expiration of current PPAs may force these resources to close, eliminating their multiple benefits to the grid. The ISO's modeling of system requirements, particularly of local capacity requirements, should incorporate the presumption that within the planning horizon of this plan, these units may be eliminated. Moreover, the CAISO should take the lead in demonstrating the cost and operational implications of the loss of these resources in order to fairly address options that include consideration of contracts that sustain the resources in contrast to the cost of losing the resource.	Please refer to the above responses.

No	Comment Submitted	CAISO Response
5	Eagle Crest Energy (ECE) Submitted by: Susan Schneider (Consultant to ECE on this matter)	
5a	Eagle Crest Energy (ECE) appreciates the opportunity to comment on the initial conclusions presented in the Large Energy Storage Special Study update (Update) and discussed at the February 28th Transmission Planning Process (TPP) meeting (Meeting). ECE recognizes the challenges of conducting a study of this nature to assess the benefits of large energy storage, given the uncertainties in the resource mix and the dynamics of the grid, as California approaches the current 50% renewable energy mandate and ambitious carbon goals (and considers higher future targets). The Update covered work to date on this third large storage study the CAISO has conducted in the prior and current t TPP, and the first to consider a project larger than 500MW under a 50% RPS scenario. ECE supports the CAISO's efforts to assess and compare the benefits and costs of large storage facilities of different sizes. ECE also supports the CAISO's plan to continue to refine the current study by using a range of feasible values for key assumptions, to provide a range or "bookend" cost and benefit estimates of large storage facilities. The CAISO should take the time necessary to build a solid set of analytics on the benefits of large storage projects (such as pumped storage), and consideration of a range of realistic assumptions will result in a study with durable and reliable conclusions. This rigorous assessment is an important first step toward constructing a solid analytical framework that policy makers can use to decide on future development of large storage facilities. The size, cost, and long lead times of large storage projects, and the benefits that they can provide beyond those monetized in electricity markets, make them difficult to sponsor by any one entity. Thus, approval and construction of such facilities will likely have to result from larger policy decisions.	The ISO agrees that additional analysis is necessary to assess a broader range of assumptions than the initial assumptions employed in the analysis conducted to date. The initial analysis has been critical, however, in enabling the ISO and stakeholders to focus on where further sensitivities are necessary.

No	Comment Submitted	CAISO Response
	ECE is concerned, however, the CAISO may feel obligated to include study results in the final 2016-2017 Transmission Plan (Plan), given the firm TPP timelines, despite the incomplete status of the study. Despite the CAISO staff's considerable expertise and hard work, the study results presented at the Meeting were apparently completed very shortly beforehand, and they provided system-level benefits estimates based on only one set of assumptions (not ranges or "bookends"). Those assumptions did not seem to be fully supported by CAISO staff, may be inconsistent with other TPP study results (e.g., 50% RPS Special Study estimates of significant potential renewables curtailments), and showed much smaller benefits estimates than the Bulk Energy Storage Special Study supplement issued just last fall. Moreover, the summary information provided at the Meeting, and the very short deadline for these comments (just three days later), do not allow a meaningful opportunity for stakeholder review and comment on that information. Likewise, the CAISO will not have sufficient time for careful consideration and incorporation of any such input by the current March 31st deadline for completion of this year's TPP cycle and issuance of the final Plan. For these reasons, ECE suggests that the study results presented on February 28th not be included in the Plan, and that the CAISO's work in this area continue separate from the TPP during 2017. Specific recommendations are given below.	
5b	Recommendations • Remove the Large Energy Storage Special Study from the TPP, by excluding the study results presented on February 28th from the final 2016-2017 Transmission Plan.	The ISO has included the results developed to date in the planning cycle in the revised draft transmission plan. The ISO has qualified the concerns with various aspects of the study results and indicated that further analysis is necessary to properly bound the range of benefits the large energy storage may provide. However, documenting the work to this point is necessary to provide a sound basis for framing and scoping the next levels of analysis expected in 2017.
5c	• Continue this work outside the TPP framework through 2017 in a separate stakeholder process. This work would include refining the study assumptions and analytical framework to develop a range of benefits or	The ISO intends to continue its analysis, focusing largely on additional sensitivity analysis considering the assumptions driving the results.

No	Comment Submitted	CAISO Response
	"bookend" estimates needed to support policy decisions on large-scale storage. These assumptions should be consistent with available public information and vetted in the stakeholder process. ECE is prepared to provide technical information in the coming weeks.	This work will be conducted as an extension of the 2016-2017 planning cycle on a separate track from the 2017-2018 planning cycle that is commencing.

No	Comment Submitted	CAISO Response
6	GridLiance West Transco LLC Submitted by: N. Beth Emery	
6a	GridLiance West Transco LLC (GridLiance) appreciates the opportunity to submit comments on the CAISO's 2016-2017 Transmission Plan draft dated January 31, 2017 (Draft Plan). GridLiance has interest in this issue both because of GridLiance's partnership as the future owner of the Valley Electric Association, Inc. (VEA)-area high voltage transmission facilities (HVTS) and because of the fundamental policy issues related to the transmission plan recommendations. In particular, GridLiance both seeks more information about, and offers comments regarding, the CAISO's noted congested element between the Bob Tap Substation (Bob SS) and the Mead Substation, once the VEA system is physically interconnected with the balance of the CAISO grid at the Eldorado Substation. The CAISO draft identifies nearly $24 million of expected congestion annually, affecting approximately 600 hours, in its 2026 study year on the Bob Substation (Bob SS) to Mead line.[1] The path is also shown in the CAISO's preliminary 50% in-state results to be overloaded under N-0 and N-1 conditions,[2] and the study shows that the number of congested hours increase to 1,229 hours under higher level of renewables.[3] The draft also seems to suggest that significant renewable curtailment would result without upgrades.[4] The draft recognizes that this is the first time that the congestion on this path has arisen in the CAISO's Transmission Planning Process (TPP). This is due to the fact that the bulk of the CAISO system will not be physically interconnected to VEA until the Bob SS is energized, which is expected to occur in 2018. The draft indicates that CAISO did not study this congestion in detail as part of its 2016-2017 TPP. Of particular interest is the explanation offered by the CAISO, that "…[m]itigating the congestion will not bring benefit to ISO's ratepayers." [Draft plan p. 178]. GridLiance's understanding of the economic assessment approach is that the CAISO will examine both the WECC-wide	The congestion on BOB SS to Mead S was observed on the direction from BOB SS to Mead S, which is exporting to outside of the ISO system, therefore, it should not impact the service to VEA customers, although.it contributed to renewable curtailment in the ISO system. Renewable modeling for the ISO and the out of state systems affect the congestion on BOB SS to Mead S line. The ISO will work with other planning regions to further validate the renewable modeling and explore this congestion. However, for clarity, the ISO's application of the TEAM methodology has focused over time to the ratepayer benefits in considering economic driven reinforcements, recognizing the offsetting cost responsibility borne by those ratepayers.

No	Comment Submitted	CAISO Response
	benefits and the CA-participant benefits. In the case when there are WECC benefits but not CA-participant benefits, the CAISO coordinates with the adjacent balancing area authorities. In its draft plan the CAISO has reported that the benefits to CA ratepayers does not warrant a path upgrade. The CAISO does not report on the benefits to CA participants, where participants include both loads and suppliers, even though the CAISO Transmission and Economic Assessment Methodology (TEAM) approach calls for assessing benefits to participants.5 Given that without upgrading the constraint renewable curtailment results, GridLiance expects that there would be significant benefits to CAISO suppliers if the path were upgraded under the CAISO study conditions. GridLiance requests that the CAISO include in its final 2016 – 2017 Transmission Plan further and more comprehensive details about the benefits of addressing the identified congestion, including CAISO load, supplier, and participant benefits. GridLiance appreciates the CAISO's further consideration about this constraint that seems of particular value to the grid.	

No	Comment Submitted	CAISO Response
7	Imperial Irrigation District (IID) Submitted by: Nisar Shah, P.E. (Consultant, on behalf of IID)	
7a	1. IID appreciates CAISO engineers' analysis in which IID's updated transmission model was used and the results confirmed IID's internal findings that IID's "S" line (Imperial Valley – El Centro 230 kV line) will be overloaded for the outage of N.Gila – Imperial Valley 500 kV line. This overload has been identified at least at four locations in the presentation especially when discussing LCR study, economic evaluation, and 50% renewable study results. What is missing in the presentation is that no mitigation has been proposed. IID is offering its staff to work with CAISO staff in mitigating this overload in a way that is practically achievable and is economical for the benefit of all California ratepayers.	The Draft 2016-2017 ISO Transmission Plan indicates on page 151 that the reliability concern on the Imperial Valley – El Centro 230 kV tie with IID "could be mitigated by the ISO electricity market and operation procedure. The ISO is aware that the operational solution could potentially limit the power transfer capability through the North Gila – Imperial Valley 500 kV line and is exploring other possible mitigations as a policy-driven or economic-driven solutions". The report also specifies in its economic planning study described in section 4.7.2 that further evaluation needs to be done on the congestion concern on the 230 kV line. Stakeholders may submit economic project study ideas as requests for economic planning studies during the comment period following the first stakeholder meeting of the 2017-2018 transmission planning cycle, and submit comments on the ISO's economic planning studies or policy project throughout the 2017-2018 transmission planning processes. The ISO will consider the economic planning study requests in accordance with the ISO tariff and section 3.2.2.2 of the business practice manual.
7b	2. On page 123 of the presentation, IID contingency Coachella – Mirage and Ramon – Mirage with RAS is identified as causing "S" line overload. What "RAS" was applied?	The RAS was assumed to trip generation in the IID area under the contingency.
7c	3. On page 124, Miguel 230/500 kV transformers #1 and #2 are shown overloaded and a potential mitigation is identified. On this same slide "S" line is shown overloaded but no mitigation is specified. Consistency issue?	The ISO shows that approximately 150 MW of renewable generation would not be deliverable as a result of the S-line constraint in the 50% RPS special study, based on the preliminary assumptions.
7d	4. While discussing 50% renewables on page 141 of the presentation, "S" line constraint shows up again for Greater Imperial and Riverside east and Palm Springs area analysis. What are CAISO thoughts in finding a long term solution to this bottle neck?	Please see response to Comment 7a. .
7e	5. CAISO report did not provide enough details about overloading of IID's "S" line so the relevant portion of Appendix C, "San Diego Bulk Transmission"	

No	Comment Submitted	CAISO Response
	was reviewed. The results indicated that "S" line was overloaded in the range of 100% to 139% under various contingencies throughout the study span of 10 years. Just in 2018, it was overloaded to 123% and 139% in Summer peak conditions. How is it that these significant results were not brought forward in the body of the report?	The 2016~2017 TPP study plan and the power flow base cases posted have covered all details that are relevant to Appendix C. The overload concern and potential mitigations are discussed in section 2.9.3 on pages 148 and 151.
7f	6. CAISO has rightfully identified 102% loading of the "S" line on page 166 Table 3.2-2 while discussing deliverability results. A reduction of 20 MW renewable generation is also identified to mitigate overload. IID would like to see similar representation of the Reliability results in which 139% overload is identified. How much generation curtailment would be necessary to mitigate this overload?	The operational mitigation identified by the ISO to mitigate the reliability concern that the "S" line was overloaded up to 139% under the category P3 contingency would not require to curtail renewable generation but rely on dispatching local generation resources in the greater San Diego-Imperial Valley area.
7g	7. Table 6.4-7 on page 276 identifies IID MIC of 702 MW modeled under Import Assumptions for 2017. On page 205 it says MIC from IID is 702 MW in 2021. Which statement is correct?	Both statements are correct; Table 6.4-7 lists the 2017 MIC plus the approved MIC expansion on IID-SCE and IID-SDGE branch groups for a total of 702 MW.
7h	8. First line on page 1 of the report says "Forward to DRAFT 2016-2017 Transmission Plan". It seems like a typo. Forward should be "Foreword" and it should be the only word on the top line.	The typographical error has been corrected.

No	Comment Submitted	CAISO Response
8	LS Power Development, LLC Submitted by: Sandeep Arora	
8a	COI vs PACI/COTP modelling: We commend the CAISO staff for making good enhancements in this year's planning cycle to model COI congestion; however, much more work needs to be done in the next planning cycle on this front. While the modelling enhancements did lead to a modest increase in COI congestion from the baseline study ($0.84 mm with enhancements vs $0.44 mm without), the quantified congestion is a mere fraction of the actual congestion that has routinely been reported in CAISO DMM reports over the last few years1. We understand that the historical congestion is not expected to perfectly align with the forecasted congestion for a 10-year out case, but we believe the primary reason for the misalignment is not the difference in time frame but it is the way congestion is quantified in the study vs. how it occurs and gets quantified for CAISO DMM reporting. More details on this in the following paragraphs. 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 4,800 MW (and de-rated as driven by operating nomogram). Two of these 500 kV lines are owned by California IOUs and operated by CAISO. This path is known as the Pacific AC Intertie (PACI), with a TTC of approximately 3,200 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 1,600 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. We understand that while CAISO conducts its production cost simulation that incorporates a representation of the transmission system across WECC, the simulations used to evaluate transmission needs for CAISO does not reflect the realities associated with the way actual transmission is used by various entities, particularly those that directly affect the amount of power that can be scheduled	There are number of factors that may impact COI flow and congestion. The ISO has developed a framework to model COI nomograms and scheduled maintenances with derates. With this enhanced framework, the ISO's PCM can reflect the physical limit on COI given the resources assumption in the PCM. Resource assumption has impact on COI flow in the production cost simulation. For example, potential surplus of renewable inside California would push flow on COI from south to north during many hours of the year in the future. This will reduce COI flow coming into California hence potentially reduce congestion. In the meantime, generator retirement in Northwest and other areas in WECC will further reduce the flow on COI coming into California, if there is not established replacement plans for the generator retirement. Regarding the transmission right between PACI and COTP, the hurdle rate between BANC and the ISO in the PCM plays a role to allocate flow between PACI and COTP in economic dispatch. Any MW of flow that wheels through COTP to the ISO is subject to the hurdle. The Malin hub was defined in the TEPPC PCM based on the recommendation of - and agreement among - related planning regions. Regarding the scheduling limit, the ISO will further investigate the gap between the day-ahead scheduling constraints and real time actual flow, and its implication on production cost modeling.

No	Comment Submitted	CAISO Response
	across various interties and paths. For instance, in the TEPPC case used for transmission planning, CAISO does not assume any hurdle rate for energy to flow out of the Malin HUB to CAISO or BANC system, while CAISO assumes that there is a $2.53/MWhr hurdle rate for energy to flow from BANC to CAISO. Such simulation methodology would automatically force a portion of the power flowing to CAISO from Malin and Captain Jack to flow through the COTP into CAISO. There is a significant inconsistency and disconnect between the simulated outcome and the real life experience. In reality, the power scheduled at PACI and COTP should be scheduled independently, and the capacity that is reserved for TANC use should not be available to flow into CAISO through COTP without incurring a wheel-through hurdle charge. This reality should be modelled in the production cost simulation runs, perhaps by modeling hurdle rates as charges on transactions between balancing authority areas rather than physical flows, as appropriate to mimic this. Further the PACI and COTP path limits should be separately enforced in the production cost simulation runs. Again, in real life experience, the transmission congestion that occurs appears to be mainly associated with scheduling limits and thus, we believe the CAISO’s simulation should reflect such reality -by setting specific constraints that reflect the realities of how entities schedule across the transmission system, and appropriate costs to move schedules between interties. We believe that CAISO could improve its modeling capabilities to reflect the real system conditions. If modelled correctly, congestion on the PACI interface will likely be similar to historical PACI congestion that has been noted by CAISO’s DMM for the last several years. We understand that the tool CAISO currently uses may not be adequate for accounting for scheduling constraints such as those over the PACI path. We encourage CAISO to investigate either the use of new tools or make enhancements to its existing tool such that this scheduling constraint can be modeled and congestion calculated accurately. LS Power recommends that the CAISO incorporate simulation of contract path transaction and market scheduling limits to more realistically capture the	

No	Comment Submitted	CAISO Response
	transaction costs and congestion charges actually faced by bilateral transactions and market operations.	

No	Comment Submitted	CAISO Response
9	Office of Ratepayer Advocates (ORA) Submitted by: Joseph Abhulimen	
9a	California's transmission planning should be based on accurate information about the impact of changing load characteristics. California is undergoing a fundamental change in the way customer load interacts with and demands services from the CAISO-controlled grid. With the steady growth of customers embracing behind-the-meter (BTM) generation, the recent legislative mandate to double the energy efficiency goals, and the greater reliance on preferred resources,[1] including distributed generation, the forecast of both the net peak demand and load profile are in transition. While the California Energy Commission's (CEC) nascent efforts in estimating the changes in the magnitude and timing of the peak system demand are only just becoming available, the impacts of increased energy efficiency goals on transmission grid demands are yet to be quantified. Until the impacts of changing load characteristics are understood and quantified, expansion of the transmission grid should be limited to those critical areas that are necessary to maintain compliance with reliability standards or to support public policy direction in the most cost effective manner.	Your comment is noted and the ISO agrees that there is uncertainty within the assumptions and coordinates with the CEC and CPUC with respect to these assumptions. The ISO also conducts base case and sensitivities to understand these uncertainties to ensure that the transmission system is planned accordingly to maintain reliability per the required reliability standards.
9b	ORA supports the CAISO's continued review and evaluation of previously approved projects including the previously approved projects placed on hold, and recommends that the CAISO should narrowly define the allowable scope of ongoing work on all remaining proposed reliability projects. In light of the fundamental changes in the load characteristics described above, ORA supports the CAISO and Participating Transmission Owners' (PTO) efforts to review previously approved reliability projects to determine whether the reliability needs still exists and if so, whether the currently identified scope of work is appropriate. In this planning cycle, the CAISO has proposed the cancellation of thirteen reliability-driven projects and placed another sixteen reliability-driven projects on hold in Pacific Gas and Electric Company's (PG&E's) service territory. Based upon PG&E's most recent cost estimates provided to the CPUC, these projects represent a cumulative cost of almost $4.5 billion. Most of these costs are associated with the sixteen projects that have been placed on-hold rather than cancelled.	The ISO will be reviewing the projects on hold as a part of the 2017-2018 transmission planning process.

No	Comment Submitted	CAISO Response
	ORA supports CAISO's reevaluation of the proposed reliability projects in San Diego Gas & Electric Company and Southern California Edison Company's service territories, as well as the PG&E reliability projects placed on hold, and recommends that their reevaluation be prioritized. For those projects that the CAISO ultimately determines should proceed with either the original or a reduced scope, the CAISO should provide transparent documentation demonstrating the current project area reliability needs and the project's contribution to identified reliability needs. For the four projects that the CAISO has instructed PG&E to proceed with, but not filed at the CPUC for the required certificate or permit, ORA is concerned about continuing to accrue costs on these projects that may ultimately be cancelled or significantly revised. For this reason, ORA recommends that the CAISO clearly define the exact work and information needed to assist with a project decision, and requests that PG&E proceed with only this defined scope of work. Finally, the decision to either cancel or change the project scope should be made as soon as possible in order to avoid unnecessary customer costs. While the CAISO indicated that such a decision would not be formalized until the Board action in the next planning cycle (March 2018), the CAISO should inform PG&E and stakeholders of its findings at the earliest opportunity in order to minimize unnecessary costs.	
9c	<u>The CAISO should consider whether operational measures that meet applicable planning standards, rather than new transmission projects, are a better solution to avoid performance violations.</u> The CAISO's transmission assessment revealed that in some instances where long-term transmission projects are proposed to resolve system performance violations, operational standard measures are effectively addressing system requirements. With the current declining load projections and the uncertainty in load characteristics described above, ORA recommends considering these operational solutions as permanent long-term solutions, unless the incremental reliability benefits associated with a long-term transmission project justify the cost.	Mitigation plans are developed to meet the required reliability requirements; however at times interim mitigation may be required due to the lead time required to develop projects required to mitigate the identified reliability needs. These interim operational solutions are not long-term solutions and address the near-term needs until the mitigation plan is in-service.

No	Comment Submitted	CAISO Response
	For example, the Midway-Andrew Transmission Project was approved during the 2012-13 transmission planning process to replace an existing Special Protection System (SPS) that would drop load in event of a multiple contingency. As this load is not in a High Density Urban Load Center, short-term and long-term reliance on such a SPS is an acceptable mitigation under the North American Electric Reliability Corporation (NERC) and CAISO Planning Standards. Nevertheless, the CAISO approved the Midway-Andrew Transmission Project at a forecast cost of $120-$150 Million. More recent estimates reflect an increase of over 350% to $600-$700 million. While ORA was concerned with the lack of a cost/benefit analysis in the original project approval, these concerns have been greatly amplified as the costs spiral higher. This is an example where CAISO should consider the success of the interim, more cost effective solution instead of implementing unnecessary development. The CAISO, through a stakeholder process, should establish a process to evaluate options for projects with operational standard measures in place. This evaluation should take into account the value of improved reliability versus the cost of a new project. Furthermore, the CAISO should maintain an on-going list of all such projects and update the evaluation as new cost information about the cost of long term transmission solutions becomes available.	The ISO will be continuing to review the scope for the Midway-Andrew project in the 2017-2018 transmission planning process. The ISO will continue to assess the reliability needs of the system in the ISO transmission planning process.
9d	<u>The CAISO should defer additional deliverability assessments for determination of policy-driven transmission until the role of energy only (EO) resources in achieving a higher renewable portfolio standard (RPS) is understood.</u> Although the Draft 2016-17 Transmission Plan does not identify any need for new policy-driven transmission projects, ORA remains concerned that the CAISO continues to perform the deliverability assessment assuming that all the renewable portfolio resources need to be fully deliverable. Rather than designating transmission projects as policy-driven solely to allow intermittent renewable projects to satisfy the state's system Resource Adequacy (RA) needs, the CAISO should undertake a cost-benefit analysis to determine whether any proposed new transmission project is needed to assure deliverability of renewable resources and/or to decrease envisioned congestion. Further, the CAISO should determine whether the new proposed transmission is both necessary and is the most economical alternative to meet the state's RA	The comment has been noted.

No	Comment Submitted	CAISO Response
	needs. Given the key role Energy Only (EO) resources are expected to play in meeting the 50% renewable portfolio standard (RPS) goal, the CAISO should continue to defer additional policy-driven upgrades until the role of EO resources in the 50% RPS is understood.	
9e	<u>The CAISO should provide information from its 50% RPS Special Study for use in the RPS calculator.</u> ORA supports the CAISO's ongoing efforts to study the feasibility and consequences of using energy-only procurement to integrate the additional renewable resources necessary to meet the 50% RPS goal. ORA's prior comments asserted that the energy-only transmission option, would allow California to achieve the 50% RPS requirement using the existing transmission infrastructure. The CAISO's 2016-17 Transmission Planning Process (TPP) 50% RPS Special Study findings seem to confirm that assertion, where no major incremental reliability issues were observed in the In-State Energy-Only Deliverability Status (EODS) portfolio relative to the In-State Full Capacity Deliverability Status (FCDS) portfolio, except for a few renewable zones such as, the Tehachapi, Mountain Pass and Eldorado, Valley Electric Association and Nevada SW zones. A majority of these reliability issues can likely be avoided by appropriately adjusting and rebalancing the renewable portfolios that would be developed by the CPUC going forward. For example, the existing transmission capability of the El Dorado and Mountain Pass area to accommodate EODS resources could be lowered from the current 2,735 MW to an appropriate level to avoid major reliability issues. ORA respectfully requests that the CAISO provide the CPUC with the critical information it has gathered as part of the 50% RPS Special Study characterizing transmission cost and availability for FCDS and EODS resources to update the RPS Calculator for developing the 2017-18 TPP renewable portfolios and the Integrated Resource Planning (IRP) model for the 2018-19 TPP portfolios. Another key finding of the 50% RPS Special Study is that renewable curtailments in all the portfolios was primarily driven by over-generation rather than internal transmission constraints. Therefore, building additional delivery network upgrades may not be an appropriate economic and/or reliability solution to reduce renewable curtailments. Moreover, increasing the ability of the CAISO to export excess renewable energy during over-generation periods would likely	Your comment is noted. The ISO will ensure that the CPUC is provided the results of the study effort. The export scenarios considered in the 50 percent special study tried to bookend the study by assuming a "2,000 MW net export limit" and a "no net export limit" scenario. The assumption was that a 5,000 MW net export scenario would result in performance that lies in between these two sensitivities.

No	Comment Submitted	CAISO Response
	have the most meaningful impact in respect to lowering the renewable curtailments. Therefore, ORA encourages the CAISO to perform an assessment of realistic levels of net exports that can be achieved by the CAISO Balancing Authority Area in the 10-year planning horizon. As a reference, ORA notes that the CAISO had assumed 5,000 MW of net exports in the Mid-case, and 8,000 MW for the High-case in the CAISO's SB 350 Study.	

No	Comment Submitted	CAISO Response
10	Pacific Gas & Electric (PG&E) Submitted by: Matt Lecar	
10a	Project Re-evaluations PG&E appreciates CAISO's continuing commitment to re-evaluate previously approved projects in the PG&E service territory that may no longer be needed, due to changing assumptions. PG&E strongly supports CAISO efforts toward maintaining affordability for PG&E customers, by avoiding the construction of unnecessary capacity, and re-sizing or re-scoping projects that have not yet begun construction, to better meet the current projection of future needs. In the Draft 2016-2017 TPP, CAISO recommends placing 15 PG&E projects on a hold status to allow completion of CAISO's review. Four of the projects are placed in a category for "Hold, but Continue" with the design, siting, and permitting activities necessary to inform CAISO review. The remaining 11 projects are placed on "Hold", with all development activities to cease until the CAISO review is complete. PG&E requests that CAISO re-classify (move) three projects from the current designation of "Hold" to "Hold but Continue", for the reasons stated below: • Northern Fresno 115 kV Area Reinforcement - There are critical project interdependencies for a minor portion of the project work slated to be done within Herndon and McCall Substations. If this work cannot be completed in the next 12 to 18 months, numerous critical upgrades at both of these substations cannot proceed. Therefore, PG&E is requesting to move forward only with the Herndon and McCall Substation portions of the overall project scope, which involves installing sectionalizing circuit breakers at both of the substations. PG&E confirms that the remainder of the project will remain on hold, and no other project work will proceed until the CAISO has completed its review and reached a decision on the project.	The ISO has modified the revised draft 2016-2017 Transmission Plan to reflect that the Northern Fresno 115 kV Area Reinforcement is recommended to be on hold with the exception of the sectionalizing breakers at McCall and Herndon which are to proceed as per the original scope for the project.

No	Comment Submitted	CAISO Response
10b	• Vaca-Davis Voltage Conversion Project - PG&E requests that this project be moved to "Hold, but Continue" to facilitate PG&E ability to perform the studies necessary to inform CAISO review of this project. In addition, PG&E is currently working with transmission level customers in this local area and by allowing some minor work to continue it is possible to capture efficiencies in evaluating potential options that would serve the customers and the long terms reliability needs associated with this project. PG&E confirms that the project as a whole will remain on hold, and no other project work will proceed until the CAISO has completed its review and reached a decision on the project. •	The ISO has modified the revised draft 2016-2017 Transmission Plan to reflect that the Vaca-Davis Voltage Conversion Project is on hold however additional work to assist in the review of the project is recommended to continue similar to the four projects that were identified in the draft 2016-2017 Transmission Plan as such.
10c	• PG&E is requesting to move forward only with a small but critical portion of the overall project scope, driven by a critical system need during summer peak conditions which is currently being addressed by a temporary system set-up (shoo-fly) at Weedpatch Substation. The work requested to continue is the reconductoring of the 3/0 Cu section of the line between Weedpatch Substation and structure 9/119 (approximately 5.5 miles). Completion of this work will allow the removal of the temporary shoo-fly which will mitigate system and customer risk. PG&E confirms that the remainder of the project will remain on hold, and no other project work will proceed until the CAISO has completed the review and reached a decision on the project.	The ISO has modified the revised draft 2016-2017 Transmission Plan to reflect that the Wheeler-Ridge Weedpatch 70 kV Line Reconductoring project is recommended to be on hold with the exception of the exception of the reconducting the 3/0 Cu section of the line between Weedpatch Substation and structure 9/199 (approximately 5.5 miles) is recommended proceed to remove the shoofly that was installed in June 2013 as an temporary interim measure to address operational loading needs..
10d	PG&E requests the CAISO expedite the review of capital projects put on Hold as part of the 2016-2017 TPP in order to ensure the evaluation is completed within the 2017-2018 TPP planning cycle. Completion of this review in the October/November timeframe, coincident with the conclusion of the reliability assessment and request window, would allow PG&E to maintain project continuity, design completion, and in some cases permit work, allowing CPUC application submittal as soon as practical, so that those projects that are still needed may move forward (with either the original or a revised scope).	The ISO will be reviewing the projects on hold as a part of the 2017-2018 transmission planning process.

No	Comment Submitted	CAISO Response
10e	Economic Planning Study PG&E would like to thank the CAISO for further investigating the COI congestion as part of this year's TPP economic planning studies. PG&E also appreciates the CAISO updating its model to consider historical scheduled outage information. While the study results do not appear to have been significantly impacted by the inclusion of this new information, adopting these changes is a step in the right direction in being able to perform better congestion studies in the future. As it relates to the COI, PG&E recommends the CAISO continue to work closely with the OCOA parties to ensure analysis methods and results are understood, and to look into further analysis as requested on the matter as the COI path operator.	The comment is noted
10f	Gas/Electric Coordination Special Study The Gas/Electric Coordination Special Study utilizes information and analysis related to the Aliso Canyon constraint prior to 2017. This study does not include more recent information contained in the documents listed below or the impacts of the rules pertaining to storage fields expected from the California Department of Oil, Gas, and Geothermal Resources (DOGGR) this year. PG&E requests that the CAISO continue to update the Gas/Electric Coordination Study in next year's TPP with relevant information as it becomes available. • "Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity and Well Availability for Reliability" – Revised Report – Public Utilities Code 715, Energy Division, January 17, 2017. • SoCalGas' Storage Safety Enhancement Plan, as described in letters to the CPUC on February 15, 2017 and February 17, 2017. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/SoCalGasStorageSafetyEnhancementPlan.pdf	The ISO has updated the transmission plan to incorporate the benefits due to balancing rules per the CPUC Utilities Code 715 report. However, in regards to potential impact due to tubing only operation as outlined in the SoCalGas' Storage Safety Enhancement Plan, the ISO noted in the final draft transmission plan that there are potential deliverability impacts due to tubing flow only operation of the remaining gas storage fields at Goleta, Playa Del Rey and Honor Rancho. More study is necessary to understand the impact of the tubing only production.
10g	50% RPS Special Study PG&E is concerned that 33% RPS resource portfolios are being used for the 2016-2017 TPP. PG&E recognizes the interdependencies between CAISO transmission planning and resource planning processes at the CEC and CPUC. We encourage the CAISO to accelerate coordination with the other planning agencies during the 2017-18 TPP cycle, to begin proactive examination of	The ISO will continue to coordinate with the planning agencies in order to proactively examine the 50% RPS future.

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<tr><td></td><td>capacity needs to meet RPS procurement beyond 33%, as a necessary pathway to affordably achieve 50% or even higher objectives by 2030 and beyond.

In addition, PG&E requests the following information:
A detailed explanation of the net export constraint should be provided in the final TPP. Curtailment for a 50% RPS portfolio increased from ~9.5% in the 2015-16 Special Study to ~20% in the 2016-17 Special Study. PG&E requests the CAISO provide the details for how the changes to net export modeling between the two studies may have contributed to this increase.</td><td>In 2016~2017 study the Net Export was modeled as:

Net export = Sum of Line flow of all from the ISO to other BAAs + Sum of Generation output of out of state resources with dynamic schedule to the ISO

In 2015~2016 study, the Net Export did not consider the second item. Therefore, the 2000 MW limit on Net Export in 2016~2017 study is more stringent than in 2015~2017 study</td></tr>
<tr><td>10h</td><td>The deliverability results and the conclusions regarding energy-only resources should be provided to the CPUC for incorporation into the IRP model (currently E3's RESOLVE), which PG&E views as the venue for generating portfolios for the CAISO to examine policy driven transmission upgrades. This role was previously provided by the RPS Calculator and now more appropriately fits into the IRP proceeding, where the cost of new transmission to access RPS resources can be weighed against other resource options. The CAISO should also inform the CPUC of how the deliverable or energy-only capacity changes under different RPS resource assumptions (e.g. X MW of deliverability if wind is sited in a given zone vs. Y MW of deliverability if solar and geothermal are sited there).</td><td>The ISO works with the CPUC so that a reasonable number of renewable portfolios can be studied to determine the transmission impacts. The objectives of these studies generally align with the comment.</td></tr>
<tr><td>10i</td><td>Benefits Analysis of Large Energy Storage Special Study
The results of the Large Energy Storage Study were released on February 28. Based on PG&E's limited review of the analysis and results, PG&E offers the following comments at this time:
PG&E recommends that the CAISO develop a levelized value of capacity that captures future RA capacity prices in the benefit calculations. The CAISO's RA capacity benefit assumption ($35/kw-year in 2016$) appears to underestimate the capacity benefit of pumped storage in that it does not account for potential future capacity</td><td>The $35/kw-year is from the CPUC RA report. It is very likely that the capacity price could change in the future, and additional sensitivities will be considered in the future.
Treating RA values of the pumped storage as a benefit or reduction of cost is a matter of presentation. It will not change the conclusion of the study. The ISO will consider the comment in the presentation of future results.</td></tr>
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<tr><td></td><td>price increases when new capacity may be needed. In addition, PG&E recommends that the capacity value should be considered as a benefit, rather than as reduction to the cost of pumped storage as it is currently treated in the CASIO analysis.</td><td></td></tr>
<tr><td>10j</td><td>The 0.7% renewable curtailment amount is lower than previous CAISO study results. As such, PG&E recommends a more thorough review of the curtailment results to ensure that the level of curtailment observed in the Plexos simulations is reasonable. PG&E notes that in the CAISO’s Large Energy Storage Study shows a very low level of curtailment (app. 740 GWh or 0.7%) compared to the renewable curtailment amounts (~16%-21%) in the 50% RPS Special Studies and the renewable curtailment amounts in CAISO’s previous studies, including the SB350 studies.</td><td>These two studies focused on different aspects and have different assumptions. As indicated in the presentations in the previous stakeholder meetings, the following differences in assumptions contribute to the result differences. In 2017~2018 planning cycle, the ISO will further reconcile the modeling assumptions with considering the corresponding focuses of individual studies.
<table>
<tr><th></th><th>Plexos model</th><th>TPP model</th></tr>
<tr><td>Double AAEE</td><td>Yes</td><td>No</td></tr>
<tr><td>Allow renewable providing load following down</td><td>Yes</td><td>No</td></tr>
<tr><td>Full network model and transmission constraints</td><td>No</td><td>Yes</td></tr>
<tr><td>CHP dispatchable</td><td>50% dispatchable</td><td>Netted to load unless showing in power flow model</td></tr>
</table></td></tr>
<tr><td>10k</td><td>Finally, PG&E recommends that the CAISO consider other benefits streams such as the ability to provide Black Start capability, the reduction in CO2 emissions, reduction in curtailment, and any improvements in system efficiency from Pumped Storage in its benefits calculations.</td><td>The ISO already suggested that the benefits in cost reduction of CO2 emission, renewable overbuild, and production cost be attributed to the pumped storage. In the future the ISO will consider the possibility of including the benefits of providing Black Start.</td></tr>
<tr><td>10l</td><td>In future updates of the Large Energy Storage Study, PG&E encourages the CAISO to include the following in their assessment:</td><td>The ISO will consider the suggestions in the future studies.</td></tr>
</table>

No	Comment Submitted	CAISO Response
	• Use more than one snapshot (i.e., only 2026). One snapshot is very helpful, but it is not sufficient to perform a convincing economic analysis of a Pumped Storage asset having a very long useful life. • Consider the impact and price swings of real-time LMP prices, congestion prices, and ancillary services prices on pumping and generation dispatch. Considering only day-ahead price behavior may not be sufficient to capture the full value of a large energy storage investment. • Study the neighbors' need for and size of CAISO's seasonal and hourly exports, and also assess the likelihood that CAISO and neighbors are both long simultaneously, and thus curtailments occur inside and outside CAISO. PG&E appreciates the opportunity to provide these comments on the Large Energy Storage Study and looks forward to engaging with the CAISO on continued review of the analysis and results.	

No	Comment Submitted	CAISO Response
11	Quanta Technologies Submitted by: Ali Daneshpooy	
11a	1. In the energy storage special study, does the 50% RPS solar and wind overbuild scenario, only include an overbuild of renewables in the CAISO region?, or does it include other regions within California, not covered by CAISO as well.	The overbuild includes areas outside the ISO where there are RPS resources in the original 505 RPS portfolio.
11b	2. In the 50% RPS study, do the instate FCDS and EODS portfolio only account for the CAISO region ? or do they include other regions in CA as well.	The portfolios only account for the ISO balancing authority area.
11c	3. Is there any particular reason for focusing on the 2000 MW export limit? Would it be possible for CAISO to share results on transmission congestion outside of CA for the instate and out of state portfolio when there are no export limits imposed.	The net export limit is based on a perception of non-wires reasons the other parts of WECC may not be willing or able to accommodate higher transfers from California – it is not a wires rating issue. The 2000 MW limit on the net export is used as a baseline assumption in consistent with other studies for renewable integration and LTPP performed by the ISO. The results of transmission congestion outside of CA as a comparison between the In-state and out-of-state portfolios were shared during the February 28 stakeholder meeting.
11d	4. From the results of the storage special study, it shows that the wind overbuild to achieve 50% RPS portfolio is comparable to the current scenario (no overbuild) in the basecase. How would this affect the economics of new transmission projects that are part of the out of state portfolio to bring renewable resources into California, when in house renewables within California can drive the economics.	It is difficult to speculate about how the economics of out-of-state transmission will be affected.
11e	5. The study results from storage special study indicate that levelized revenue requirements with pumped storage is much higher than depending alone on wind and solar. Is this finding dependent on any study assumption?	The findings are sensitive to the assumptions, such as the dispatchability of CHP, the level of AAEE and distributed PV, etc. That is why the ISO is conducting additional sensitivity studies.

No	Comment Submitted	CAISO Response
12	San Diego Gas & Electric (SDGaE) Submitted by: Shivani Sidhar	
12a	<u>The CAISO's 50% Out-of-State Renewable Portfolio Standard (RPS) Study Should Not Model the Unbuilt GateWay West Transmission Segments</u> According to page 4 of the "50% RPS Special Study – Out-of-State Portfolio Assessment, Results and Next Steps" presentation, the out-of-state portfolio evaluation aims to "examine the transmission implications of meeting part of the 50 percent RPS obligation by relying on renewable resources outside of California." By including the currently unbuilt GateWay West transmission segments in the modeling, the CAISO is unable to address the threshold questions of (1) whether some, or all, of the unbuilt GateWay West transmission segments are critical to the development of wind resources in Wyoming, and (2) whether there are other transmission projects that would provide comparable access to new wind resources in Wyoming. Instead, the CAISO's 50% out-of-state RPS study should evaluate the transmission implications of developing Wyoming wind assuming no major transmission upgrades are built. Once these implications are understood, it will be possible to determine whether there is a "need" for new transmission to access new wind resources in Wyoming, and subsequently, to assess how different transmission expansion options perform in meeting this need. Page 8 of the CAISO's presentation lists three different proposed Interregional Transmission Projects (ITPs) in the CAISO, Northern Tier Transmission Group (NTTG) and WestConnect planning regions. SDG&E notes that at least one of these projects, the TransWest Express transmission line, has acquired environmental permits and land rights comparable to the unbuilt GateWay West transmission segments. Given the CAISO's competitive process for selecting projects that meet an identified need, it is important that all alternatives, including the unbuilt GateWay West transmission segments, be given the opportunity to compete for a place in the CAISO's 2017-2018 TPP. The CAISO should not assume as an input assumption that the unbuilt GateWay West transmission segments will get built.	The transmission assumptions for the system outside of California were based on the TEPPC models for production cost simulations and were based on the approved WECC base cases for power flow studies. The power flow cases built for the 50% RPS special study were shared with the western planning regions and their input was invited before the simulations were run. We cannot comment on the assumptions in 2017-2018 TPP since there are no plans to perform a similar special study in the upcoming planning cycle. However, the assumed transmission project assumptions will be reviewed prior to the continuation of the Out-of-State/Interregional studies in the 2016-2017 planning cycle.

No	Comment Submitted	CAISO Response
12b	<u>The Specific Locations and Quantities of Wyoming and New Mexico Wind Additions Should be Made Public</u> According to page 7 of the CAISO's presentation, "NTTG and WestConnect provided resource location information for ~2,000 MW wind in WY and ~2,000 wind in NM". Using CAISO's currently published information, SDG&E is unable to determine the specific locations and quantities at which the CAISO modeled the Wyoming and New Mexico wind additions. This information is critical for assessing the reasonableness of the wind development assumptions, for identifying the scope of transmission upgrades required to connect such wind to the existing transmission network, and for determining exactly which existing transmission facilities are likely to be congested in different hours of the year if no major transmission upgrades were built. SDG&E recommends the RPS database the CAISO uses in its studies be available entirely in a commonly used format such as Excel.	The power flow models and production cost simulation models will be published to the Market Participant Portal. The RPS data base used for this study is the RPS calculator that is made publicly available by the CPUC. It is important to note that by definition, the portfolio modeling exercise contains some level of uncertainty in resource location selection.
12c	<u>A Full Evaluation of Out-of-State Renewable Portfolios Requires an Assessment of Non-CAISO Transmission Availability and Wheeling Costs</u> The GridView economic grid simulation model assumes transmission access within all balancing authorities is provided on a marginal economic basis; i.e., the ability of wind resources to access the transmission grid is subject only to the physical availability of transmission and the wind owners' willingness to accept the Locational Marginal Prices (LMPs) at the nodes where the wind resources connect to the grid. This modeling approach is consistent with how resources connecting within the CAISO balancing authority obtain transmission access. This modeling approach is not consistent with how resources connecting within non-CAISO balancing authorities obtain transmission access. Outside of the CAISO balancing authority, generating resources obtain transmission service via contract and the availability of such transmission service is dependent on the host utility's assessment of its own needs as well as on other transmission service commitments the host utility may have made. Anecdotal evidence suggests the ability to secure long-term firm contractual commitments for transmission service across non-CAISO balancing authorities is both limited and costly. SDG&E believes an important element of "examin[ing] the transmission implications of meeting part of the 50 percent	The comment is noted.

No	Comment Submitted	CAISO Response
	RPS obligation," is a deep dive into the likely availability and cost of obtaining transmission service within non-CAISO balancing authorities.	
12d	<u>Bulk Energy Storage Resource Special Study – Locational Benefits.</u> The CAISO presented the results of analysis as to the locational benefits of additional pumped storage in the CAISO system. Two of the sites assessed would be electrically connected to the SDG&E transmission system, within the San Diego LCR area (San Vicente and Lake Elsinore). On page 5 of the presentation of the results of this analysis, the CAISO states, "Both Lake Elsinore and San Vicente storage projects would be interconnected at locations that would be effective in meeting the San Diego area local capacity needs." This is true; however, past analysis by the CAISO has indicated that generation in the San Diego load center is also effective at meeting or reducing local capacity needs in the Los Angeles load center. We recommend including this observation in the study results.	The ISO agrees that for constraints that affect both the LA Basin and San Diego area local capacity needs, generation at these two locations relieve those constraints.
12e	<u>2021/2026 LCR Analysis for San Diego/Imperial Valley Area</u>. The CAISO presented the results of the 2021/2026 LCR analysis for the greater San Diego/Imperial Valley area (see slide 34 of the presentation). SDG&E notes that the proposed REX transmission project would significantly reduce the LCR need in this area by effectively mitigating the limiting contingency (the N-1 of the Imperial Valley-North Gila 500 kV line). A sensitivity analysis of the LCR need with this project in place for the 2026 study year would provide useful information for determining the economic benefits of reduced LCR procurement costs.	The purpose of the long-term LCR study is to provide information whether the current or projected resource procurement and ISO-approved transmission upgrades will provide sufficient resources for meeting local capacity requirements in the long-term planning horizon. Proposed transmission upgrades for long-term planning horizon will need to be evaluated based on the appropriate needs if there are identified deficiencies. The ISO understands that part of the justification for the proposed REX transmission upgrades is also policy-driven and would be dependent on the CPUC's final determination for the 50% RPS portfolio. In addition, based on the ISO's preliminary analysis of this project, the necessary analysis of such a complex project could not be appropriately addressed in a simple sensitivity study.

No	Comment Submitted	CAISO Response
13	Sierra Club Submitted by: Matthew Vespa	
13a	1) Use of a low-mid Additional Achievable Energy Efficiency ("AAEE") forecast for the San Diego area appears to be inconsistent with CPUC precedent and inappropriate where a utility service territory is entirely within its local capacity area. In determining local area need for the SDG&E area, the Draft TPP uses the 1-in-10 year forecast with low-mid additional achievable energy efficiency ("AAEE") assumptions. The rational that has historically been given for use of a low-mid AAEE forecast to determine local capacity need is uncertainty on where EE will show up in a utility service territory. Because the service territory of SDG&E is entirely within its local capacity area, this concern does not apply for the purposes of assessing San Diego local area need. Accordingly, please explain what justifies the use of a low-mid AAEE scenario when considering reliability needs for San Diego. The CPUC addressed this exact issue in Track 4 of the 2012 LTPP (D.14-03-004). In the Track 4 Decision, the Commission concluded: > Normally, the low estimate would be used to account for the uncertainty of locational impacts of energy efficiency within a utility's service area. As NRDC's witness Martinez testified, "The amount included in the local area should simply be the amount reasonably expected to occur in SDG&E's service territory, since they are the same geographical area." We agree with SDG&E and NRDC that the revised Scoping Memo should have used a different methodology with the midlevel energy efficiency estimate.[1] Therefore, use of the low-mid AAEE scenario appears to create conflict with CPUC decision making. Because it is Sierra Club's understanding that EE reductions may not necessarily correspond to a 1:1 reduction in local area need, applying the mid-case scenario now will avoid additional needed analysis and delay when the time comes for the CPUC to make	In the Assigned Commissioner's Ruling Adopting Assumptions and Scenarios for Use in the California Independent System Operator's 2016-17 Transmission Planning Process and Future Commission Proceedings (Rulemaking 13-12-010), filed May 17, 2016, the following is assumption is stated: > The 1-in-10 weather year, Mid-Baseline-Low-AAEE forecast should be used for local reliability studies. The Mid-Baseline-Low AAEE scenario is appropriate for local reliability studies given the difficulty of forecasting load and AAEE at specific locations. As constraints identified in the local capacity requirement studies can change from time to time based on changes in the assumptions at the nodal level for loads modeled at bus level, transmission upgrades and resource additions or retirements, it is appropriate, as the CPUC A&S document stated, to use the low AAEE assumptions due to difficulty of forecasting load and AAEE at *specific* locations. In addition, within the San Diego-Imperial Valley LCR area there are subareas requiring specific LCR needs based on different contingencies. It is of the granular levels of the subareas that would need more accurate forecast of AAEE at bus levels, thus low level of AAEE is appropriate given the difficulty of forecasting future AAEE at specific nodal locations.

No	Comment Submitted	CAISO Response
	procurement decisions for San Diego, both with regard to resource adequacy and any procurement that may occur under the Integrated Resource Plan ("IRP"). Please include an assessment of local area need for San Diego that assumes a mid-level of AAEE savings.	
13b	2) The benefits resulting from recently implemented transmission improvements in the San Diego area are not adequately explained. It is Sierra Club's understanding that the main purpose of investment in the transmission system to address local area need is to avoid investments in generation that would otherwise be needed to meet local reliability concerns. Done properly, transmission investments would provide superior value and result in reduced reliance on local area resources. Yet, it is unclear how local area need in San Diego has benefited from recent investments in the transmission system. Page 139 of the Draft TPP identifies three "significant" changes to the SDG&E transmission system: the Imperial Valley phase shifting transformers, the Suncrest SVC (static VAR compensator) project, and implementation of an operational mitigation of bypassing the series capacitor banks on SWPL and Sunrise Powerlink 500 kV lines under normal system conditions. The Draft TPP then states, without any further analysis that "[t]hese three projects substantially improve the reliability to southern California load and the deliverability of Imperial area generation."[2] *Please clearly identify how these transmission investments function to "substantially improve" local reliability and deliverability.* For example, to what extent have they resulted in reductions in local capacity need or increased import capability into the San Diego area? Sierra Club raises this concern because it does not appear that the significant ratepayer investments in transmission improvements, such as Sunrise Powerlink, have resulted in improvement to local area need. The graph below identifies 1-in-10 peak demand in the San Diego area in 2024 under a mid-case mid-level AAEE scenario under the past several CEC forecasts and CAISO's corresponding identification of LCR need for the San Diego area in Appendix D of the Draft TPP. Despite declines in demand and additional	The needs and benefits of the referenced transmission upgrades were discussed in further detail in the 2013-2014 Transmission Plan. Regarding the specific comments: • The loads that were provided in the table are from the Mid-Case Mid-AAEE scenario. As discussed in the comments regarding which level of AAEE to use in local capacity requirement study, the CPUC A&S document specified the use of Mid-Case Low-AAEE scenario, recognizing the difficulty of forecasting loads at the specific locations (i.e., nodal level). Using these load forecasts as included in the appendix section of individual transmission plans, the peak demand assumptions for San Diego do not drop off as significantly as shown in the table by Sierra Club. The 1-in-10 peak demands using Mid-Case Low-AAEE scenario are 5513, 5394 and 5300 MW for 2024, 2025 and 2026 long-term LCR studies included in the 2014-2015, 2015-2016, and 2016-2017 Transmission Plans. • Regarding studying the LA Basin and San Diego LCR areas as one large LCR area due to interdependency between these areas, the ISO has been evaluating these areas as one large LCR area since the studies performed for the CPUC long-term procurement plan Track 4 proceeding. The LCR requirements are evaluated based on the needs of the combined LCR area. However, the procurement is still based on individual load serving entities due to the CPUC resource adequacy rules that require the LSEs to procure the local capacity resources located within their respective local capacity requirement areas.

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transmission investment, LCR need is higher than need identified several years ago. Moreover, the differential between demand and LCR need is decreasing with LCR need identified in the Draft TPP now appearing to be higher than demand.
<table>
<tr><th></th><th>Demand in 2024 for SDG&E Service Territory Under Mid-Case Mid-AAEE Scenario</th><th>San Diego/Imperial Valley LCR Need Category C Identified in TPP Appendix</th></tr>
<tr><td>2017-2027 Forecast</td><td>4,397 MW</td><td>LCR need identified in 2017-2018 TPP</td></tr>
<tr><td>2016-2026 Forecast/2016-2017 TPP</td><td>4,553 MW</td><td>4,649 MW</td></tr>
<tr><td>2015-2025 Forecast/2015-2016 TPP</td><td>5,190 MW</td><td>4,868 MW</td></tr>
<tr><td>2014-2024 Forecast/2014-2015 TPP</td><td>5,348 MW</td><td>4,174 MW</td></tr>
</table>
Please answer the following:

Please specify the reliability benefits the San Diego area has received from the transmission upgrades identified in the Draft TPP.
To the extent Aliso Canyon has resulted in shifting local capacity obligations between the LA Basin and San Diego and is all or part of the reason for increased LCR need in San Diego, please explain how this shift functions to mitigate reliability issues related to Aliso Canyon.
To the extent CAISO is shifting local area need from the LA Basin to the San Diego area, please explain how this shift functions to decrease local reliability need in the LA Basin.
To the extent CAISO is shifting local area need from the LA Basin to the San Diego area, please explain why the LA Basin and the San Diego areas should not now be considered a single local capacity area and what justifies continuing to consider these areas as separate.
It is Sierra Club's understanding that the customers of a given utility assume the costs of meeting local reliability need. To the extent this is the case and CAISO is shifting local area need from the LA Basin to the San Diego area, please explain why SDG&E should assume reliability costs formerly incurred by SCE customers.

</td><td>

In terms of local capacity benefits, one of the main objectives of having procurement of approved resources and implementation of transmission upgrades within the LA Basin and San Diego subarea is to address their LCR needs without causing deficiencies while about 7,300 MW of existing local resources are affected due to the need for compliance with the State Water Resources Control Board's Policy on once-through cooling generation. The objective was to balance the local capacity needs with just the right amount of investment in transmission upgrades and procurement of local resources.
Lastly, local capacity needs for a large area such as the combined LA Basin and San Diego area are subject to changes in the assumptions of transmission that connect the LA Basin and San Diego LCR areas with adjacent balancing authority areas such as the Imperial Irrigation District and CFE. Changes in transmission upgrade plans for transmission interties by the adjacent balancing authority areas can affect the local capacity requirements for the ISO BA's LA basin and San Diego LCR areas.

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No	Comment Submitted	CAISO Response
13c	3) The TPP should not assume generation is operational that is not yet both contracted and permitted. The Draft TPP should not assume proposed generation that has not yet received permitting approval is operational. In its need assessment of the Big Creek/Ventura area, Appendix D now assumes Puente (identified as new units, MNDALY_7_UNIT 1 and 2) is operational.3 Puente has not yet been approved by the California Energy Commission and faces significant opposition in that forum by the City of Oxnard, environmental justice and environmental groups. The Coastal Conservancy and Coastal Commission have expressed serious concerns with the project due to the vulnerability of the project location to sea level rise and flood risk, which, after thorough analysis, led the Coastal Commission to conclude that "there is substantial evidence that the project site could be exposed to flooding during its proposed 30-year operating life, and that over the long-term, this possibility would become acertainty."[4] State legislators, including Senate Pro Tem Kevin DeLeon, have also expressed their deep concern with this project.5 It is not appropriate for CAISO to get ahead of agency decision-making and presume resources that have not received required approvals will be operational. *The Draft TPP should continue the practice of the 2015-2016 TPP, which did not include Puente in the assumed list of resources and simply acknowledged as part of the Moorpark area need finding that this resource was contracted with following the LTPP Track 1 decision.*	Following the 2015-2016 TPP, "which did not include Puente in the assumed list of resources and simply acknowledged as part of the Moorpark area need finding that this resource was contracted with following the LTPP Track 1 decision", would not acknowledge that the contract for this resource has now been approved. It would also not appropriately acknowledge that the 262 MW project continues to be needed to accommodate the retirement of 1930 MW of OTC generation in the same vicinity.
13d	4) Please provide further explanation of the need finding with and without Ellwood and provide additional specificity on the nature of the need in identified need findings. Slide 26 of the February 17th presentation states that Santa Clara sub-area need in the Big Creek/Ventura area is 253 MW with Ellwood and 326 MW without Ellwood. Ellwood is a 54 MW facility. *Please explain why removing a 54 MW facility would increase need by an additional 73 MW (for a total of 127 MW).* To the extent this is because the Draft TPP assumes the next available resource to meet a deficiency is the 130 MW Mandalay 3 unit, this is not clearly articulated, nor an expression of need.	Two LCR values were provided for the Santa Clara subarea in the February 17th presentation due to the following: • The smaller amount of LCR need (i.e., 253 MW) is based on the assumption of continuing to have Ellwood generation, or electrically equivalent resources, in 2021 and 2026 timeframe. However, in the event that if Ellwood, or electrically equivalent resources, are not available, the ISO made the assumption of utilizing the next available resource that has obtained a power

No	Comment Submitted	CAISO Response
	As a more general matter, the need findings in the Draft TPP lack needed granularity and explanation. For example, Appendix D of page 93 states that the limiting contingency for the Moorpark sub-area is voltage collapse. Voltage support could potentially be addressed by energy storage and non-fossil resources such as renewables with advanced inverters. For example, CAISO's recent test with NREL and First Solar demonstrated that advances in inverter technology enable solar systems to provide reactive power even where output is near zero. Yet although the identified contingency is voltage collapse, there may be a need for generating resources at a MW level below that identified to address the voltage collapse issue. As currently presented in a single MW need number, it is impossible to divine how to parse out the extent to which need is based on voltage and if voltage is provided, at what point other reliability needs emerge. This lack of granularity frustrates the ability to identify alternative solutions to meet reliability requirements and the extent to which resources that provide voltage support without necessarily providing energy, or simply reduce load, can function to minimize the need for generating resources. *In the case of the Moorpark need finding, please identify the extent to which resources that provides voltage support, but may not necessarily provide energy, would lower the identified local area need.*	purchase agreement approved by the CPUC for local resource adequacy purpose. The only resource that has obtained a CPUC PPA is the Puente generation. For voltage instability mitigation, a whole unit is included in the LCR need in the event that there is no other smaller unit that would meet the residual need. In the final draft version of the transmission plan, however, the ISO has made a correction to include up to the Pmin value of the Puente generation in the event that Ellwood is not available. Therefore, for the scenario without Ellwood but with Puente generation, the updated value for the Santa Clara subarea need is 279 MW instead of 326 MW when only Pmin (80 MW) is counted.
13e	5) **Please explain how available qualifying capacity in Appendix D is used to determine any residual sub-area reliability need.** As one of many examples, page 91 of Appendix D states that for the Vestal Sub-area, "[t]he limiting contingency establishes a local capacity need of 693 MW (includes 46 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within the sub-area." *Please answer the following:* • *To determine the total amount of MW of resources available to meet local need in the Vestal sub-area, would one simply add up the NQC of every resource in the total unit list (here pages 86-90) that lists Vestal in the LCR sub-area name column. If not, please explain.* • *Is the referenced QF generation in the statement ("includes 46 MW of QF generation") included in the qualifying capacity list set forth for this*	Each bulleted item is responded to in turn below: • Yes, the list of units that was provided is the detailed list of all resources that are assumed to be available in a subarea or an LCR area. • The QF generation that was referenced is included in the qualifying capacity list. In fact, the total QF generation capacity is derived from that list. The reason that QF generation is mentioned is because the QFs have a contractto sell energy and capacity to a utility.

No	Comment Submitted	CAISO Response
	local area (here pages 86-90)? If so, what is the purpose of specifically noting QF generation in identifying local need and not identifying other types of resources?	
13f	6) Please explain why local capacity need is identical under a Category B and Category C Contingency for some of the Draft TPP's need findings. In several areas of Appendix D, such as the need determinations for the San Diego area, the Draft TPP identifies identical LCR need for a Category B and Category C contingency. Previous TPP iterations for these same local capacity areas identify a higher local capacity need for a Category C contingency. A higher need for a Category C contingency would seem logical given this contingency assumes loss of multiple system elements. *If this is not an error, please explain why these numbers are identical.*	In this case for the San Diego subarea, the LCR determined for the Category B (G-1, system readjustment, followed by an N-1) is the same for the Category C (N-1, system readjustment, followed by a G-1). The LCR need was determined to be the same because the effect is the same for either a G-1/N-1 (a Category B), or an N-1/G-1 (a Category C). The only difference is the order which element would have a forced outage first.

No	Comment Submitted	CAISO Response
14	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (collectively, the "Six Cities") Submitted by:	
14a	In particular, the Six Cities request that the CAISO clarify its description of the Lugo-Victorville 500 kV Upgrade project. As described in Sections 2.7.3.4 and 2.7.3.5, the Lugo-Victorville 500 kV line is jointly owned by the Los Angeles Department of Water and Power ("LADWP") and Southern California Edison Company ("SCE"). However, five of the Six Cities1 hold contractual Entitlements to transmission service over the LADWP portion of this line, and one City has an Entitlement to service through the Victorville Substation. 2 These Entitlements are reflected on the Cities' respective Appendices A to the Transmission Control Agreement and are under the Operational Control of the CAISO. The Cities also have related Entitlements over the SCE system, which are likewise under the CAISO's Operational Control. The Six Cities suggest that the CAISO include a footnote at Section 2.7.3.4 noting that the CAISO also has Operational Control over the Cities' Entitlements to transmission service on the LADWP and SCE portions of the Lugo-Victorville 500 kV line and at the LADWP Victorville Substation. Similarly, in the final paragraph of Section 2.7.3.5, the Six Cities request that the CAISO again note that the Cities hold Entitlements to transmission capacity over the LADWP portion of the line and at the Victorville Substation. To the extent that any of the $16 million cost of LADWP's portion of this project is recoverable from the Six Cities, the Six Cities are entitled to reflect such costs in their respective Transmission Revenue Requirements. The foregoing clarifications reflect that the CAISO's finding of need for this project pertains to the entirety of any project capacity that will be under the CAISO's Operational Control.	The ISO has added footnotes to the revised draft transmission plan to address the identified concern.

<table>
<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td>15</td><td>Smart Wires
Submitted by: Todd Ryan;</td><td></td></tr>
<tr><td>15a</td><td>Comment 1: The emerging trend of short-term transmission needs. Is CAISO seeing the same emerging trend?

There appears to be an emerging trend of an increasing number of short-term reliability issues. By this we mean a reliability need (e.g., thermal overload) that exists for a few years, much less than the useful life of transmission infrastructure. An example of such projects in this year’s process are the Mission – Old Town[2] and Mission – Miguel[3] reconductorings. As the CAISO noted, the reliability issues that create the justification for these reconductorings exist for a limited time, or as we call it, a short-term need.

In this particular instance, the short-term need exists until the completion of a new line. Other short-term needs may be driven by thermal generation retirements; by increased adoption of distributed energy resources, renewable energy, energy storage, or energy efficiency; by construction delays; or a host of other possibilities.

Does CAISO frequently see short-term needs in its transmission plan?
Is CAISO seeing an increased number of short-term needs?

Traditional investments tend to have long lifetimes and be permanent. This means that the consumer continues to pay for that traditional investment long after the reliability need has disappeared.

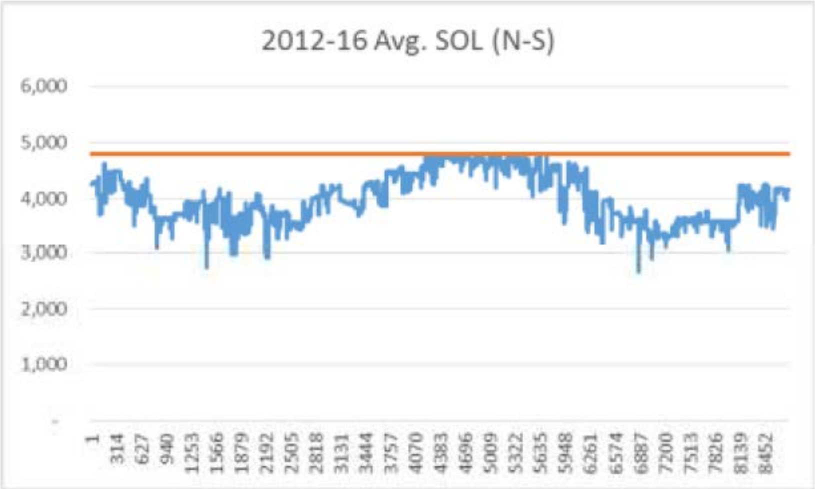
Smart Wires would like to remind CAISO and stakeholders that a host of advanced transmission technologies exist that can be quickly deployed, and redeployed as the system evolves, creating a short-term investment that matches the duration of the short-term need – saving consumers money. Smart Wires power flow control technologies and energy storage are just two examples of such redeployable transmission technologies.</td><td>Short term/interim needs can occur when there is significant uncertainty in the on-line dates for transmission projects and generation projects or generation retirement dates. In addition, load forecast uncertainty can create short term/interim needs. The ISO is investigating the feasibility of an interim upgrade and an interim operating procedure for the Mission-Old Town constraint.</td></tr>
</table>

No	Comment Submitted	CAISO Response
15b	*Comment 2: There appears to be an emerging trend of uncertainty creating "bubble" projects. Is CAISO seeing the same emerging trend?* Contrary to transmission planning of the past century, modern efforts must address the needs of today's grid while accounting for quickly-changing power flows and an uncertain future. Smart Wires has noticed, in working with our utility partners, that transmission line loading is highly sensitivity to major many uncertainty: load growth; adoption of distributed energy resources, renewable generation, energy storage, or energy efficiency; thermal generation retirements; weather patterns; and construction delays, to name a few. The confluence of all of these developing variables, in combination with the sensitivity of transmission line loading, is resulting in reliability needs that are highly uncertain and could pop into existence, or disappear, with small changes in case assumptions. All of this uncertainty leads to a set of projects that are "on the bubble", that is, could be needed or might not be needed in the future, depending on how the uncertainty that exists today resolves in the future. Evidence of this can be seen in the sensitivity to the AAEE assumptions, where CAISO notes that a number of reliability issues exist, or disappear, based on the AAEE assumption.[4] Does CAISO frequently see "bubble" projects in its transmission plan? Is CAISO seeing an increased number of "bubble" projects in recent years? Traditional investments have long lead-times and tend to be lumpy5 in nature. These two facts mean that the TPP needs to try to predict 5, 10, even 20 years into the future in order to justify the project and guard against stranded asset risk, which is increasingly difficult. Often times the near-term need is much more certain, i.e., there is high confidence about the reliability need in the next five years. This near-term certainty begs to be solved with a more flexible investment strategy where CAISO and California utilities could economically meet the near-term need and then update the investment, by adding or subtracting capability, as the uncertainty of the future resolves.	The comment has been noted.

No	Comment Submitted	CAISO Response
	Smart Wires would like to remind CAISO and stakeholders that advanced transmission technologies exist that are capable of such a flexible investment strategy because the technologies are scalable, rapidly deployed, and rapidly redeployed. Energy storage and Smart Wires power flow control technologies are just a two examples of such technologies which can be used to invest incrementally with time, adding or redeploying as needed, as the uncertainty of a need resolves. Smart Wires encourages CAISO and stakeholders to remain mindful of the importance of planning for uncertainty and the value of an agile system capable of reacting quickly and handling future unknowns.	
15c	*Comment 3: Smart Wires encourages CAISO to continue to look into low cost, flexible solutions that could address the Mission – Old Town and Mission – Miguel overloads and mitigate the risk of shedding load in San Diego.* Since the publishing of the draft report, San Diego Gas & Electric has received CPUC approval to build the Sycamore - Penasquitos transmission line.6 Until this line is operational, a risk of load shedding in San Diego exists. We agree that the CAISO was correct to suggest pursuance of alternative solutions based on the nature of the project: a 40-year investment for an interim need; the uncertainty as to whether a reconductoring can be completed; the permanent environmental and visual impact; and the high sunk cost to consumers. However, there exist risks that are beyond the control of San Diego Gas & Electric that could extend or increase the risk of dropping load in San Diego. For example, a delay in the Encina generation repowering or a delay in the Sycamore-Penasquitos construction would extend the reliability risk to San Diego customers. Smart Wires encourages CAISO and its stakeholders to consider flexible short-term solutions that are well-suited to these types of short-term needs: a quickly deployable and redeployable solution that can offer a low-cost, short-term insurance policy for consumers.	Please see response above.

No	Comment Submitted	CAISO Response
16	Southern California Edison (SCE) Submitted by: Garry Chinn	
16a	SCE had characterized its Transmission Line Rating Remediation (TLRR) program as "CPUC approved" which CAISO has reflected in the 2016-2017 draft Transmission Plan and presentation materials at the February 17, 2017 stakeholder meeting. SCE would like to clarify that the California Public Utilities Commissioners have not approved the program but SCE over the past several years has closely coordinated with California Public Utilities Commission (CPUC) staff regarding the TLRR program. In 2011, using Light Detection and Ranging (LiDAR) technology, SCE completed an assessment of SCE's Bulk Electric System facilities that are under CAISO operational control. Upon completion of this LiDAR assessment, SCE generated a plan for remediation of spans identified as potentially not meeting CPUC's General Order 95 clearance requirements under specified operating and atmospheric conditions. In 2011, these results were reported to the Western Electricity Coordinating Council, CAISO, and CPUC's Safety and Enforcement Division (SED). As SCE agreed during a March 30, 2012 briefing with SED, SCE provides quarterly updates to the SED on the progress made in the TLRR program. The CPUC staff has been informed and continues to monitor SCE's efforts to remediate General Order 95 violations on SCE's system.	The ISO has revised the report accordingly.

No	Comment Submitted	CAISO Response
17	Transmission Agency of Northern California (TANC) Submitted by: David Oliver	
17a	TANC appreciated the efforts of the CAISO to perform sensitivities, from the CAISO's Base Case, regarding California-Oregon Intertie (COI) system operating limits (SOLs) that would more accurately reflect the routine and regular maintenance that occurs on the three-line 500-kV AC system (and associated underlying system) interconnecting California with the Pacific Northwest. TANC also appreciates that the CAISO agreed to perform the assessment of the economic study submitted by TANC and the other owners of the COI (Pacific Gas and Electric Company, PacifiCorp, and the Western Area Power Administration). As previously communicated, TANC is concerned that prior CAISO studies and the approach utilized in the TPP planning studies does not provide a realistic assessment of the operating conditions on the COI, thereby failing to reflect the impacts on transfer capability and market performance of known maintenance activities on the COI. Pursuant to the commitment made to the CAISO, TANC and the other COI Owners provided information and data related to historic and future maintenance practices that result in limitations on COI pursuant to CAISO Operating Protocols. From an engineering perspective, sensitivity analyses utilizing this data should result in modelling results that would reflect SOLs on COI that would be comparable, or at least reflective to historic COI ratings. However, the results in the draft TPP did not meet this expectation. In fact, in our opinion the analysis still fails to accurately represent the reduction in COI capability due to known and planned routine maintenance (regardless of unexpected outages or limitation). By not accurately representing the known reduction in COI capacity, the draft 2016-17 TPP significantly overstates the amount of COI transfer capability that will be available and dramatically understates the cost and frequency of congestion. The draft Plan discusses the expanded COI analysis in Section 4.7.1. The base case modeling for COI accounted for just $330,000 of congestion costs over 38 hours. The three scenarios analyzed in Section 4.7.1 have increasing numbers of planned, known maintenance outages. The new scenarios forecast a range	As the comment indicated, the ISO has incorporated the routine and regular maintenances and derates on COI provided by the facility owners in the 2016~2017 study. The results were also presented to the stakeholders and included in the draft TPP report. The ISO will continue to work with the COI facility owners as they provide further information on the routine maintenances on COI.

No	Comment Submitted	CAISO Response
	of the congestion costs of $840,000 - $1,190,000, and the number of hours of congestion from 120-185. As an immediate reference point, according to the CAISO's own data on COI from January-February 2017, there already has been 502 hours of congestion, at a cost of over $6.1 million (59 days – an average of over 8.5 hours of congestion every day). TANC has frequently made clear that the COI does not run at the capacity levels that are modeled in the CAISO economic studies. And while the expanded analysis in this year's cycle shows some limited reflection of the actual COI capability, the most recent analysis still comes far short of representing actual transfer capability available on COI. The following charts show the actual system operating limits (SOLs) on the COI from 2012-2016 and year-to-date for 2017. 	

No	Comment Submitted	CAISO Response
	 TANC welcomes the initial steps that the CAISO has taken to better the COI analysis, and is hopeful that the CAISO will continue to work with the OCOA parties to make even more improvements.	

No	Comment Submitted	CAISO Response
18	TransCanyon LLC Submitted by: Jason Smith and Bob Smith	
18a	50% RPS Special Study With regard to the 50% RPS Special Study, TransCanyon recommends that the continuation of the out of state analysis of Wyoming and New Mexico wind resources include a determination of availability of long term firm transmission rights outside of California to ensure that the wind resources can be contractually delivered to California Load Serving Entities (LSEs) inside the CAISO. TransCanyon believes that it would be extremely difficult to implement the changes necessary to procurement contracts to allow for energy only delivery of out of state resources that rely on non-firm transmission service outside of the CAISO. Therefore it is imperative that the CAISO study out of state wind resources in terms of full deliverability both outside and inside California, including consideration of necessary long term firm transmission service contracts.	The comment is noted.
18b	Risk Of Early Economic Retirement Of Gas Fleet TransCanyon requests that the CAISO reconsider the assumption that economic retirement of resources inside Local Capacity Resource (LCR) constrained areas can only occur up to the LCR requirement. Such an assumption does not take into account the cost of future LCR contracts which may exceed the cost of transmission reinforcements to relieve the LCR constraints. The CAISO should ensure that the most cost effective solutions including transmission are utilized to address constraints. Transmission solutions have the additional benefit of reducing local area emissions.	The ISO will consider the assumptions in the further assessments that were identified to be included in the 2017-2018 transmission planning process.

No	Comment Submitted	CAISO Response
19	TransWest Express, LLC Submitted by: David Smith	
19a	Introduction TransWest Express LLC (TransWest) appreciates the opportunity to comment on the Draft 2016-2017 Transmission Plan prepared by the California Independent System Operator (ISO). TransWest has focused its comments on the 50% RPS Special Study and in particular the Out-of-State Portfolio Assessment (OOS Assessment). As such, these comments are in response to the materials provided at the February 28, 2017 stakeholder meeting as the Draft 2016 – 2017 Transmission Plan issued on January 31, 2017 did not include specific information on the status of the OOS Assessment. As TransWest stated in its July 5, 2016 comments on the OOS Assessment, this assessment, although for information purposes only, is very important because it will help inform various agencies and market participants about the potential solutions to the integration challenges associated with supplying over half of California's electric energy needs with renewable resources. Unfortunately the CAISO has not completed the OOS Assessment as initially planned. There were a number of factors that caused this lack of progress, including the amount of work in other areas of the TPP, other related planning work like RETI 2.0, the Integrated Resource Planning (IRP) process and the coordination and progress of the Northern Tier Transmission Group (NTTG) and WestConnect planning efforts. The CAISO Regionalization initiative was another effort that touched on many of the same issues that are contemplated in the OOS Assessment and therefore required the same limited resources as these other efforts. TransWest has participated in all of these various initiatives and planning processes and understands the focus and volume of resources required to participate as a stakeholder and developer in these efforts. The required resources for the CAISO, as the Regional Transmission Planning entity, to lead and directly participate in these efforts are enormous. The CAISO should be commended for their efforts in all these related work streams. However as the Regional Planning Entity, the CAISO is the only entity that can perform certain	The ISO agrees that while the goal was to advance the studies as far as possible within the 2016-2017 planning cycle study timeline, issues of coordinating these types of studies for the first time under the FERC Order No. 1000 interregional coordination processes did raise unanticipated challenges. In fact, identifying and moving though those issues was in itself a valuable learning experience while conducting these studies on an informational basis.

	functions such as transmission planning to inform recommendations for project approvals to the CAISO Board. Given the complexity of the transmission issues associated with accessing potential OOS wind resource areas in New Mexico and Wyoming, the OOS Assessment, as an information-only special study, should be prioritized by the CAISO to be certain it can if and when called upon perform a formal TPP and prepare appropriate recommendations in a timely fashion, most likely the 2018-2019 TPP, to help California meet its environmental goals. Another factor attributed by the CAISO at the February 28, 2017 stakeholder meeting for a lack of progress on the OSS Assessment, is the lack of a “road map” to complete the OOS Assessment, inform the IRP and ultimately perform the TPP along with Regional Coordination. TransWest Express provides these comments on OOS Assessment update to help the CAISO and stakeholders consider the appropriate the road map. Within these comments we pull in results from these other processes to help build a solid foundation for the road map. Apologies in advance for any errors within these comments, they were prepared in a short time frame (3 days) given the CAISO schedule to include changes based on stakeholder comments to the California ISO 2016 – 2017 Transmission Plan. We request these comments be considered as the CAISO prepares the final version of the Transmission Plan and completes the OOS Assessment during the 2017-2018 TPP.	The ISO is intending to continue the evaluation of the OOS resources and the interregional transmission projects in 2017 as an extension of the 2016-2017 study process. The ISO indicated at the stakeholder session that the next step after completion of the documentation of the results to date is to map out the path forward for scoping and completing the further studies. This could only practically be done after the initial results were completed and the next steps informed by the progress to date. That being said, the suggestions and comments below will be considered in scoping next steps.
19b	Key Assumptions and Sensitivities: Below is a listing of the key assumptions and sensitivities the CAISO needs to consider to complete the OOS Assessment. The subject of these key assumptions are ordered to help present a road map of the various considerations within the Assessment to provide useful information to the policy decision process within the CPUC’s IRP proceeding. Several of these assumptions have been highlighted by the CAISO in the update provided on February 28, 2017 and others have not been discussed to date with stakeholders. For each subject TransWest has listed either the CAISO assumption or provided a suggested assumption along with some explanatory	The ISO worked directly with WestConnect and NTTG to determine the location of the renewable generation modelled in our 50% study. Information specific to the resource location was communicated to WestConnect in December 2016. The power flow and production cost cases will be posted on the ISO’s Market Participant Portal.

	notes to help build a road map (or study plan) for the Assessment. In several areas, sensitivity analysis may be warranted that include alternative assumptions on some of these key subjects. Without careful consideration of these assumptions, including the assumed outputs needed from the study to inform the IRP, the modeling framework and assessment of results cannot be adequately informed. 1. Resource Type, Location and Aggregate Size a. Assumptions: SB350 Product Content Category (PCC) 1 New Mexico and Wyoming wind resources (requesting FCDS and/or EODS as separate portfolio analysis) with an aggregate size of 2,000 MW in each state. The Study Update outlined these assumptions used within the Assessment. The SB350 PCC assumption was not specifically delineated. However, the RPS Calculator portion model that uses transmission input from the CAISO TPP is focused on PCC1 resources. This assumption is important in the CAISO's assessment of OOS transmission implications (e.g. modeling, results, etc.) because they require connection directly to a California BA, scheduled into a California BA without substituting energy from another resource, or dynamically scheduled. This PCC 1 requirement requires that the modeling in the assessment capture the extent of the CAISO BA and these scheduling requirements as applicable. TransWest requests the CAISO to provide stakeholders the specific locations within New Mexico and Wyoming were the resource areas are being modeled.	
19c	2. BA/OATT Topography a. Assumption: current/planned (2026) BA/OATT Topography with option to expand BA through Regional and/or Interregional Transmission Project This assumption needs to be clarified as the base assumption for the OOS Assessment. Given the PCC 1 direct connection and/or scheduling requirements, it is important to use the current BA/OATT topography in the base case and to determine if existing transmission	As noted above, these suggestions and comments will be considered in scoping next steps.

	capacity is available to schedule deliveries to the CAISO BA. When assessing potential transmission capacity expansion projects, the CAISO should consider how potential projects would serve to expand the boundary of the CAISO BA, such that potentially the assumed resources could be connected directly to a CAISO BA through expansion of the BA to these OOS areas. This expansion would be similar to how the current CAISO BA boundary is impacted by other transmission infrastructure to other states such as Arizona, Nevada, Oregon, Utah and New Mexico. b. Sensitivity assumption: regional BA/OATT Topography As outlined in TransWest's comments on the 50% Special Study in June 2016 (and noted by the ISO), the CAISO should also consider including a sensitivity analysis that considers a Regional BA/OATT topography. However, given the status of the regional expansion initiative and the unknown status of the future BA/OATT topography (e.g. one BA/Transmission Network or multiple "sub-regions") it may be difficult to arrive at an agreed upon topography to model at this time.	
19d	3. CAISO OATT Project Type (Primary Driver) a. Assumption: Policy-Driven Project The CAISO should initially limit its assessment within the 50% RPS OOS assessment to consideration of Policy-Driven Projects, given the purpose and objective of the study is to help inform California RPS policy decisions through the Integrated Resource Plan. b. Sensitivity assumption: enhanced Policy Driven Project with additional Economic benefits It is very likely that any large multi-state transmission projects could be enhanced to provide reliability and economic benefits beyond the California policy needs. Although this is likely the CAISO's information-only assessment should first focus on the Policy-Driven only analysis as modeled within the RPS Calculator. This additional benefits analysis could be performed later if and when an OOS resource area is included within a portfolio that is formally submitted to the CAISO TPP.	As noted above, these suggestions and comments will be considered in scoping next steps.

19e	4. Project Participation a. Assumption: CAISO Regional Project The CAISO and the other western regional planning entities have established their planning processes on a Regional basis that requires first a Regional Assessment followed by Interregional Project Coordination. In addition to this, California RPS policy for the CAISO BA cannot and does not have any authority over the transmission planning within the other western regional planning entities. Therefore the CAISO should perform the 50% RPS OOS assessment by considering existing transmission capacity that is/will be available for scheduling and CAISO Regional (Policy-Driven) Transmission Capacity Expansion Projects first. This Regional Project analysis is required to establish an "avoided cost" metric to use within any subsequent benefit/cost allocation analysis performed by two or more western planning regions. b. Sensitivity assumption: Interregional Transmission Project with participation by WestConnect and/or NTTG TransWest is concerned that the CAISO has conflated the 50% RPS OOS Assessment with the Interregional Planning Coordination process. While there is overlap between the two, the Regional process has primacy and needs to be completed as a standalone assessment prior to completion of the Interregional Planning Coordination process. TransWest believes coordination and cooperation between the western planning regions is required to complete each Regional transmission planning process. These groups have been and will continue to coordinate and cooperate throughout this and any other bulk power system transmission planning process. The distinction TransWest is making here is in the formal CAISO Regional process and the assumed participation within transmission solutions (Projects) considered in the CAISO Regional TPP.	As noted above, these suggestions and comments will be considered in scoping next steps.

19f	5. Existing (2026) Transmission Network a. Assumption: WECC Regional Planning Coordination Group 2026 Common Case Transmission Assumptions (CCTA) TransWest agrees with using the CCTA within the 50% RPS OOS Assessment. The CAISO should confirm that all of the CCTA projects were included within the analysis to date. The CAISO proposed some next steps included developing/identifying some additional stress cases for the 50% RPS OOS assessment in part due to the apparent lack of congestion in the OOS transmission system after including the assumed OOS wind resources. The CAISO should confirm whether the Gateway West and Gateway South projects within the NTTG Region we assumed in-service in the assessment. These massive multi-state projects interconnecting Wyoming to the PAC East BA would substantially reduce congestion and the CAISO may not be able to develop the anticipated additional stress cases with these projects included within the models. Inclusion of these projects in the CCTA and the CAISO assessment leads to the assumption that the projects are NTTG Regional Projects and not CAISO Regional projects. Therefore the assessment would include potentially the cost of transmission service over these projects to schedule the resources to the CAISO BA. b. Sensitivity 2.b. assumption: 2026 CCTA w/o Boardman – Hemingway,Energy Gateway West and Energy Gateway Projects TransWest suggests the CAISO perform a sensitivity analysis with several of the assumed CCTA projects removed from the model in the NTTG region to better understand the impact these proposed projects have on the system and potentially consider potential benefit/cost allocation between the CAISO and NTTG (PacifiCorp). This assumption would also preserve the status, if desired, of these Gateway Projects as potential “new facilities” in the proposed TAC Options for the Regional Expansion.	As noted above, these suggestions and comments will be considered in scoping next steps.

19g	Assumed Potential Solutions (Implications) 6. Potential non-CAISO Existing Transmission Paths available capacity and costs a. Assumption: existing/planned 2026 NTTG and WestConnect transmission paths with available capacity for scheduling resources to the CAISO BA. The CAISO SB350 Study Renewable Energy Portfolio Analysis performed by E3 using the RESOLVE model included assumptions on the amount of existing (2030) available transmission capacity and the cost for transmission service on the non-CAISO system. Similar data is required within the RESOLVE model for the IRP analysis. With respect to the available capacity, it isn't clear if or how the CAISO plans to arrive at the amount of available transmission capacity to schedule PCC1 resources to the CAISO BA. The CAISO and some stakeholders suggested that the lack of congestion found within the Production Cost Modeling (PCM) results indicated that there is available transmission to schedule resources to the meet the PCC1 requirements. Unless the PCM has including these PCC1 scheduling constraints (or the CAISO is assuming an expanded regional CAISO BA/OATT), the PCM results will overstate the available capacity by assuming all transmission capacity cannot be reserved and will be used to maximize the efficient inter-regional dispatch of all western resources. TransWest request the CAISO to clarify if and how the PCM model is including the scheduling constraints. As an alternative, the RETI 2.0 Western Outreach Project surveyed regional transmission and OOS resource development experts and found "there is limited capability [on the existing system] for delivering significant amounts of Wyoming and New Mexico wind to California."	The current ISO's production cost model (PCM) is based on the TEPPC Common Case for production cost simulation, in which a full network model is used to represent the transmission system of WECC system. The physical transmission limitation such as WECC path ratings and transmission line ratings are enforced in the PCM, while scheduling limits are not modeled. The simulation results indicated congestions in Wyoming and New Mexico systems, and other areas in the WECC system, which impact the renewable resources in these systems. In the 2017~2018 planning cycle, the ISO will work with other planning regions in WECC to further validate the resource and transmission modeling in the PCM for areas outside the ISO footprint. As noted above, these suggestions and comments will be considered in scoping next steps.
19h	7. Potential CAISO Policy-Driven Transmission Projects a. Assumption: The four Interregional Transmission Projects (ITPs) submitted to the CAISO: TransWest (multiple configurations proposed), Cross-Tie, SWIP-N and HVDC Conversion plus the four	As noted above, these suggestions and comments will be considered in scoping next steps.

		additional regional projects with "advanced permitting" identified within the RETI 2.0 Final Report: Gateway West (dependent on whether assumed in service or not), Gateway South (same as Gateway West), Southline and SunZia. Given the SB350 targets of a 40% RPS by 2024, 45 % RPS by 2027 and 50% RPS by 2030 plus the recent calls for advancing the target date to reach the 50% RPS by 2025, and the very unique position the CAISO is in to evaluate a range of multi-state transmission projects that are significantly de-risked form an environmental permitting perspective, the CAISO should focus its attention on these projects as suggested in the RETI 2.0 Final Report. Although all of these projects are not Interregional Transmission Projects, these projects have all been presented to the RETI 2.0 for consideration in meeting California's policy needs. Each of these projects could potentially be used to either schedule resources to the CAISO BA and/or be used to expand the CAISO BA. Several projects will require scheduling on existing transmission facilities as noted in the RETI 2.0 Final Report. The four ITPs have formal Evaluation Process Plans developed in June 2016. Unfortunately, the CAISO has not made sufficient progress in the 50% RPS assessment to actually evaluate any of these projects within their analysis this past planning cycle. The 50% RPS Assessment Next Steps include "test[ing] the effectiveness of the ITPs in mitigating [transmission] issues". TransWest suggests the CAISO review the draft NTTG Regional Transmission Plan to understand the relationship NTTG identified between wind resource development in Wyoming, the capacity of the existing transmission system in Wyoming, Utah and Idaho, and the need case for the Gateway Projects. This review should help progress the coordination between regions and the initiation of the ITP and other multi-state, advanced permitting project evaluations. b. Sensitivity Assumption: other Western transmission projects in final RETI 2.0 Final Report, conceptual projects	

	TransWest recommends not including this sensitivity. The seven multistate projects with advanced permitting took seven to ten years to receive federal permits. Assuming the ISO is in position to approve Regional Policy-Driven Transmission Projects at the conclusion of the 2018-2019 TPP, these projects without advanced permitting would not be placed in service in time to complete the process of bringing on 2,000 MW of wind resources prior to 2030.	
19i	Modeling TransWest suggests that the CAISO de-emphasize the use of PCM analysis in the 50%RPS assessment unless the PCC 1 transmission scheduling constraints can be included within the model. In lieu of the PCM analysis, the CAISO should review the WECC Path Rating analysis performed for the various advanced permitting multi-state projects and determine what additional reliability and/or deliverability power system analysis is required and the appropriate models for these analyses.	The comment is noted.
19j	Assessments and Key Findings and Next Steps TransWest agrees in general with the key findings on curtailment, transmission congestion, and the California reliability/deliverability assessments provided during the update. TransWest does not agree that additional efforts are needed at this time with the PCM simulations. The CAISO should focus on the validity of the assumptions suggested above and the on developing a road map to provide useful input to the policy decision process in the form of MWs of capacity and costs for transmission service on existing/planned non- CAISO facilities potential investments in transmission to access the OOS resources.	As noted above, these suggestions and comments will be considered in scoping next steps.

No	Comment Submitted	CAISO Response
20	Valley Electric Association (VEA) Submitted by:	
20a	Valley Electric Association, Inc. (VEA) appreciates the opportunity to provide these brief comments on the CAISO's 2016 – 2017 draft transmission plan (Draft Plan). VEA's high voltage transmission system partner, GridLiance, submitted detailed comments in response to the CAISO's Draft Plan. VEA is also very interested in having the CAISO provide further study of, information regarding, and can facilitate the resolution of anticipated congestion on the Bob Substation (Bob SS) to Mead constraint. This expected constraint reflected the largest congestion impact measured in the CAISO's Draft Study. It has the possibility of impacting the cost of service to VEA customers and the delivery of VEA-area renewable generation interconnecting at or through Eldorado. Separately, the level of congestion warrants being addressed, by the CAISO or by the region, as described in detail in GridLiance's comments. VEA requests that the CAISO provide more detailed information about the nature of its findings in its final plan and that the CAISO develop by its final plan a process for coordinating with the other relevant balancing authority area if the CAISO continues to believe that resolution of the congestion would warrant cooperation of adjacent areas. VEA appreciates the CAISO's further efforts on this new, but important, constraint.	Please see response above to a similar comment from Gridliance.

No	Comment Submitted	CAISO Response
21	Nevada Hydro Company Submitted by: Rexford Wait	
21a	The Nevada Hydro Company ("Nevada Hydro") has reviewed the California Independent System Operator's ("ISO") draft 2016–2017 Transmission Plan ("Draft Plan") as well as the presentations and discussions at the February 17, 2017 stakeholder meeting. Nevada Hydro has also reviewed the original and update on the special study looking at the Benefits Analysis of Large Energy Storage ("Special Study") that is identified as "a part of the 2016-2017 transmission planning process", and the discussion at the February 28, 2017 stakeholder meeting. The ISO has now for a number of years considered the value and benefits of Nevada Hydro's two projects: ☐ The Lake Elsinore Advanced Pumped Storage (LEAPS) project is a 500 MW advanced pumped storage facility. The facility was being licensed in Federal Energy Regulatory Commission (FERC) Docket P–11858, and is presently under review in Docket P–14227. LEAPS is located less than 25 miles from the San Onofre Nuclear Generating Station SONGS, within the Southern California load pocket. Its southern grid connection is barely 10 miles from SONGS on Path 44 – South of SONGS. ☐ The Talega–Escondido/Valley–Serrano 500 kV Interconnect (the TE/VS Interconnect) project. The TE/VS Interconnect is a 32 mile transmission connection between the service territory of San Diego Gas & Electric Company (SDG&E) and the State's 500 kV electrical backbone that currently terminates in the southern end of the service territory of the Southern California Edison Company (SCE). This project will also connect LEAPS to the Southern California grid. As the ISO is well aware, LEAPS has an advanced position in the ISO queue and executed Large Generator Interconnect Agreements (LGIA). Both projects have been thoroughly vetted environmentally by both FERC and the PUC. Regarding the TE/VS Interconnect, FERC approved rate base provisions in	For clarity, the system analysis did not consider the specific location of a resource other than being in the San Diego zone for purposes of the zonal Plexos analysis. In the discussion of locational benefits, the ISO noted that there were two potential locations for a 500 MW pumped storage resource considered; Lake Elsinore and San Vicente. Further, the special studies – as noted in the draft transmission plan and presentations - were undertaken for informational purposes only and are not the basis for any recommendation regarding project approvals. Accordingly, no recommendations have been made in the 2016-2017 Transmission Plan regarding the need for a pumped storage project.

	Docket ER06–278. The facility was under permit review in California Public Utilities Commission's Docket A. 10–07–001. This link is to the PUC's web site where Nevada Hydro's last complete application may be found. In the Draft Plan, the ISO noted on page 115 that in connection with its LEAPS project, the ISO "is studying the benefits of the project." Following the publication of the Draft Plan, the ISO released the Special Study. Although the Special Study did not specifically identify what project was the focus of the 500 MW analysis, it was clear to all that the Special Plan could only be referencing the LEAPS project. Although it was also clear the Special Study (1) omitted consideration of a number of significant value streams that LEAPS (or any similarly situated pumped storage project) can provide (all ancillary services and black start capabilities, for example), and (2) reduced the benefit assumptions that appeared in the earlier version of the report on the Special Study based upon directives from the PUC, the Special Study nonetheless found significant net economic value to the 500 MW pumped storage project it analyzed. The Draft Plan's Executive Summary notes that one "key analytic component" of the ISO's planning process is to perform "economic analysis that considers whether transmission upgrades or additions could provide additional ratepayer benefits." Clearly, the Special Study was undertaken to serve this need. The plan requires inclusion of economic-driven solutions that provide net economic benefits to consumers as determined by ISO studies. Such projects are those that create opportunities to reduce ratepayer costs within the ISO's footprint. As noted in section 4.9.1 of the Transmission Planning Process Business Practice Manual, "Economically-driven solutions which the CAISO determines to be needed as mitigation solutions . . . will be described in the transmission plan . . ." As such, Nevada Hydro can only logically conclude that LEAPS is now included as an identified project providing economic benefits in the Draft Plan, and awaits confirmation when the Draft Plan is approved by the ISO Board. NHC therefore, looks forward to working with the ISO to bring the beneficial facility online so as to meet the ISO's needs.	