The ISO received comments on the topics discussed at the September 21-22, 2016 stakeholder meeting from the following:

1. Alameda Municipal Power (AMP) and the Port of Oakland (Port)
2. Bay Area Municipal Transmission group (BAMx)
3. Boston Energy Trading and Marketing, LLC
4. California Energy Storage Alliance (CESA)
5. California Public Utilities Commission (CPUC)
6. Imperial Irrigation District (IID)
7. LS Power Development, LLC (LS Power)
8. NextEra Energy Transmission West, LLC (NEET West)
9. Pacific Gas & Electric (PG&E)
10. San Diego Gas & Electric (SDG&E) – Jontry submission
11. San Diego Gas & Electric (SDG&E) – Moussa submission
12. Silicon Valley Power (SVP)
13. Transmission Agency of Northern California (TANC)
14. TransCanyon LLC

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	Alameda Municipal Power (AMP) and the Port of Oakland (Port) Submitted by: Nicolas Procos and Barry Leska	
1a	CAISO Reliability Assessment - East Bay Area Sensitivity Study AMP and the Port appreciate the special focus on the East Bay area, but continue to be concerned about the need for a long-term reliability plan for the East Bay. As the reliability of the East Bay area is currently dependent on aging local generation1 and Special Protection Systems (SPSs), analysis of the performance of the East Bay area absent such generation is important in understanding the future reliability risks. The CAISO's analysis continues to recognize the dependence on SPSs to drop load to comply with NERC reliability standards as a function of the availability of local generation. As the East Bay is a high density urban area under the CAISO Planning Standards, SPSs should only be used as a short term bridge while long term solutions are being implemented.[2] Also for the most heavily loaded circuit in the analysis (Moraga-Oakland Station X), there is no SPS currently installed.[3] In the CAISO's sensitivity analysis, three levels of local generation are presented, all generation available, all generation off-line and Oakland CTs available. While the inclusion of multiple generation levels is useful in understanding the potential consequences of generation retirements, AMP and the Port recommend that an additional intermediate case be added that reflects the NCPA CTs available and the Oakland CTs off-line. AMP and the Port believe that a long term plan is needed to address the eventual loss of the NCPA and Oakland CT's. In addressing southern California's reliability, the planning criteria has been to model aging generation units more than 40 years old as off-line, which is consistent with the CAISO "2016-2017 Transmission Planning Process Unified Planning Assumptions and Study Plan." The Oakland CTs will achieve this milestone in the next few years. Furthermore, the Oakland CTs have been relying on year-to-year Reliability Must Run (RMR) Contracts from the CAISO to stay on-line, the only such generation RMR contracts in the CAISO footprint.4 At the same time, the NCPA CTs are owned by NCPA member cities as part of their resource portfolios and are eight years younger than the Oakland CTs. Therefore, an additional	The ISO recognizes concerns regarding long-term reliability need in East Bay area due to dependency on aging local generation and SPS. As such, the sensitivity assessment was performed to identify long-term need without the local generation being available and also reliance on existing SPS was assessed. Regarding the SPS for Moraga-Station X, the assessment results don't show need for such SPS when local generation is available. For the long-term solution, this alternative will be considered along with other transmission and non-transmission alternatives. Assessment of the scenario with Alameda CTs ON and Oakland CTs OFF will be considered for next cycle. The ISO is currently working with PG&E to identify low cost station upgrades that could support future needs in the area to some extent. Given the uncertainty of future of local generation in the area and potential development of preferred resources, the ISO is continuing to assess the transmission needs without the generation being available.

No	Comment Submitted	CAISO Response
	intermediate case with the Oakland CTs offline and the NCPA CTs available would better reflect a mid-term case and a reasonable forecast of the sequence of future retirement. Had this been included in the sensitivity analysis, it is expected that the tables presented in the stakeholder meeting would have shown a much greater dependence on load dropping to meet the NERC Planning Standards in the intermediate resource case. AMP and the Port are also concerned that the power flow models of the East Bay understate the reliability issues. For instance, the CAISO has previously identified that "real-time operations data for 2015 and 2016 shows a need of at least 98 MW for a 1-in-3 heat wave and instances where all three Oakland generators were on-line simultaneously to maintain local reliability."5 This is significantly more than the 45 MW identified in the CAISO's Local Capacity Requirements analysis that presumably use system models similar to those in this Transmission Planning Process. The CAISO has attributed the difference to be due to the load distribution in the power flow base cases that understates the need for local resources in the East Bay to maintain reliability.6 These discrepancies need to be resolved to better understand the timing and scope of a long-term solution. This resolution should include consideration of the timing of the peak load in the East Bay and whether it coincides with the timing of the 1-in-10 year Bay Area peak load in the base cases. For example, in the case of AMP, its load tends to peak in the early evening hours. Most importantly, while the study results are informative, there appears to have been little progress from last year in developing plans to address this reliability concern. Repeating last year's language that "the ISO is continuing to assess the transmission needs in the Oakland area without the generation being available" is troubling. AMP and the Port are concerned that such delays in developing a long-term plan will lead to a crisis that is readily anticipated and could be avoided. As identification and implementation of solutions will likely take many years, it is past time to move forward with addressing this reliability concern.	

No	Comment Submitted	CAISO Response
2	Bay Area Municipal Transmission group (BAMx) Submitted by: Joyce Kinnear	
2a	CAISO Reliability Assessment Results BAMx continues to be very interested in the studies of overlapping outages on the Tesla-Metcalf-Moss Landing-Los Banos 500 kV loop. The potential mitigation identified is to increase the dispatch generation in the Moss Landing/San Jose area. Such dependence on local generation, some of which is market based generation currently without a long term Power Purchase Agreements (PPA), should be considered in the Economic Early Retirement of Gas Fired Generation Special Study. BAMx recommends that the amount of local generation required to maintain local reliability be coordinated with the CPUC Long Term Procurement Process and that both the permit and commercial status of the Moss Landing units be monitored closely. The outcome of the local procurement activities and the OTC compliance progress then must inform future transmission planning cycles. Consideration should be given for developing contingency plans, including execution of PPAs, in the event generation upon which the system depends for local reliability announces that it may potentially exit the market. It is encouraging to see that the only transmission issues attributable to the future retirement of the Diablo Canyon Nuclear Generating Station are high voltages in the Diablo Canyon area. Though it was not discussed during the stakeholder meeting, BAMx notes that there are 500 kV and 230 kV reactors at Gates and Midway substations. These reactors were an important operational tool in managing the 500 kV voltages in the southern system when the Pacific AC Intertie was built in the late 1960s until Diablo Canyon became operational in 1985. The assessment should make full utilization of the available reactive resources in the area. An additional potential mitigation may be to disconnect the Diablo-Midway No. 2 500 kV circuit, subject to additional study of the resultant system performance. If a circuit can be removed, it could potentially be repurposed as a 230 kV circuit to lower the cost of the Midway-Andrew Project, which includes a new 230 kV circuit from Midway to the coastal area for which the estimated project cost has escalated above $500 million.	Your suggestion regarding the Moss Landing Power plant and generation in San Jose will be considered in the future studies. We will explore other alternatives also. Mitigation for the overlapping Tesla-Metcalf-Moss Landing-Los Banos 500 kV loop outages will be studied in more detail in this and the subsequent Transmission Plans. Regarding retirement of the Diablo Canyon Nuclear Generation Station and high voltages, the reactors at the Midway and Gates Substations were modeled, but they didn't reduce the voltages to acceptable levels, especially not at the Diablo 500 kV bus. Opening one of the Diablo-Midway 500 kV circuits was also considered as one of the alternatives of reducing voltage. However, in some cases, it appeared not to be sufficient. The CAISO will investigate other alternative of maintaining voltages, such as additional reactive devices.

No	Comment Submitted	CAISO Response
2b	PTO Request Window Project Applications PG&E Request Window Submission: Placer 115 kV Area Voltage Support PG&E has proposed a +100/-200 MVAR Static VAR Compensator (SVC) to be installed at Placer 115 kV substation to address high voltages during minimum load periods and low voltages during low hydroelectric generation conditions. Further justification is needed as to why a less expensive mechanically switched device would not adequately address the voltage issues at lower cost.	The ISO is reviewing the project and is in discussions with PG&E to ensure that an optimum mitigation is selected to address the identified voltage criteria violations is the area. The type, location, size, and timing of the voltage support device, and its coordination with other voltage support projects in the area are being reviewed in the process.
2c	PG&E Request Window Submission: Caltrain Electrification Project In response to an interconnection request for two Caltrain Traction Power stations, PG&E has proposed interconnection and substation rebuilds for East Grand 115 kV and FMC 115 kV. In both cases, PG&E has proposed that the station be rebuilt in a breaker-and-a-half (BAAH) configuration. With the twin 115 kV circuits from the nearby Caltrain stations, the value of the extra redundancy and expense of a BAAH design is unclear and appears to build redundancy on top of redundancy. Further justification is needed to support the costlier design for these lower voltage facilities. Also to what extent are Network Upgrades associated with the second service be classified as Special Facilities under PG&E Electric Rule 2? The proposed use of Gas Insulated Switchgear (GIS) at the FMC also needs further explanation, especially in light of the potential to utilize an alternative breaker arrangement.	The ISO is currently reviewing this project and is in process of working with PG&E obtain more details.
2d	SCE Request Window Submission: Tehachapi and Big Creek Corridor Area Both this and last year's assessment investigated potential reliability issues in the Big Creek Corridor associated with low hydroelectric generation in the Big Creek system. In the last TPP cycle, SCE proposed a set of four Thyristor Controlled Series Reactors (TCSRs), one on each of the 230 kV lines to optimize the flow within the conductor ratings, with an estimated cost of $135 million. In this cycle, SCE has given notice that they will reconductor the lines to resolve G.O. 95 clearance safety issues. While the reconductoring will not replace all the equipment necessary to increase the capacity of the lines, an incremental investment of $6 million will allow an increase of 62%. While BAMx supports maintaining the safety of the transmission system, we are concerned that SCE had not identified this safety issue prior to proposing the TCSRs in the previous planning cycle. We note from SCE's 2018 General Rate Case application at the CPUC that SCE plans to spend over $240 million under their Transmission Line Rating	Projects necessary to resolve G.O. 95 clearance safety issues are maintenance projects and are not subject to the ISO transmission planning process. The utilities coordinate with the ISO to ensure maintenance projects are not in conflict with transmission plans.

No	Comment Submitted	CAISO Response
	Remediation (TLRR) to address clearance issues on the 230 kV lines north of Magunden Substation. At such a high capital cost this remediation, BAMx questions whether there may be lower cost alternatives and requests the CAISO to consider the total TAC impact of any proposed solutions to the issues in the Big Creek Corridor.	
2e	SDG&E Request Window Submission: Add 2nd Sycamore Canyon 230/138 kV Transformer Bank SDG&E proposes to install a second 2nd Sycamore Canyon 230/138 kV Transformer Bank to address alleged 2017 Category P0 and 2018 Category P1 overloads. However, the preliminary Reliability Assessment Results for the SDG&E area do not show any P0 or P1 overloads on this transformer and no concerns were identified for this transformer in the CAISO presentation. Given these discrepancies and the 812 MW reduction in the load forecast for the San Diego area from the last planning cycle, this project should not be approved.	This comment has been noted.
2f	SDG&E Request Window Submission: Old Town -Mission 230 kV Lines Reconductoring This project proposes to reconductor the Mission-Old Town and Mission-Old Town Tap 230 kV lines to address N-1-1 overloads in the event of a delay in the Sycamore-Penasquitos 230 kV line. The preliminary Reliability Assessment Results for the SDG&E area shows a modest overload of less than 2% for this contingency that no longer appears once the Second Miguel- Bay Blvd 230 kV line is in service.2 The recommendation in the assessment of relying on short term operating procedures is a much more reasonable mitigation for a small, short-term overload that would only occur under low probability events.	This comment has been noted.
2g	SDG&E Request Window Submission: New Pala 230 kV Substation Loop-In SDG&E proposes to install a 230/70 substation to address a G-2 event coupled with a N-1-1 for an estimated cost of $20 million to $30 million. This represents an extreme event that is significantly beyond the level of service required in the Planning Standards. The generation, Orange Grove Energy Center, is a two unit, 96 MW plant that came on-line in 2010. SDG&E has not presented any information concerning the risk of the plant being unavailable for operation and SDG&E's justification in the stakeholder meeting was an assertion that it is not SDG&E practice to rely on local generation. BAMx questions whether such an assertion is reasonable in that reliability to the entire San Diego County is dependent on local generation.3 Without significant further support as to why	This comment has been noted.

No	Comment Submitted	CAISO Response
	SDG&E cannot rely on these local units for both local and SDG&E system support, this project should not be approved.	
2h	<u>SDG&E Request Window Submission: Renewable Energy Express</u> This SDG&E project would convert a portion of the 500 kV Southwest Powerlink (SWPL) to a three-terminal HVDC system at a project cost of $1 billion. SDG&E's objective of the project would be to reduce congestion, increase the SDG&E import capability and reduce SDG&E Local Capacity Resource (LCR) requirement. No economic analysis has been presented to support the value of reducing the local generation requirement and nothing of this scope has been identified as needed for reliability mitigation in the preliminary Reliability Assessment Results for the SDG&E area. In fact, we would have concerns that importing 3,000 MW over this project would create new reliability issues for P7 contingencies involving the bipole DC line outage in both the San Diego and SCE areas. Such a project is more properly considered in the CAISO Order 1000 process where the project can be considered along with other alternatives as to the benefits of increasing the CAISO import capability or considered by way of the CPUC portfolios for the 50% RPS, when they become available.	This comment has been noted.
2i	<u>SDG&E Request Window Submission: TL23022 & TL23023 Reconductor (Mission -Miguel)</u> The SDG&E proposal to reconductor the two Mission-Miguel 230 kV circuits was submitted in a prior planning cycle and presented again in this planning cycle. In support of this proposal, SDG&E cites a number of alleged NERC Planning Standard violations. However, none of these violations are supported by the preliminary Reliability Assessment Results by the CAISO for the SDG&E area. Given these discrepancies and the 812 MW reduction in the load forecast for the San Diego area from the last planning cycle, this project has not been justified and therefore should not be approved.	This comment has been noted.
2j	<u>SDG&E Request Window Submission: New Miramar GT 230 kV Substation Loop-In</u> This project proposal is to install a new 230/69 kV substation to eliminate a Local Capacity Reliability requirement. While SDG&E identifies that the maintenance cost on the CTs is $1 million/year, there is no support for these costs nor do they appear to be sufficient to justify a $28 million capital expenditure for electric transmission improvements. Furthermore, given the presentation of the CEC LCAAT, it is unclear whether these units would be shut down in absence of a LCR requirement. Therefore, this project should not be	This comment has been noted.

No	Comment Submitted	CAISO Response
	approved without a clearer demonstration that the economic benefits exceed the total project cost.	
2k	Special Studies Review of Approved Projects The increasing CAISO TAC rates continue to be an on-going concern. Therefore, BAMx is highly encouraged by the CAISO's efforts to review previously approved projects. While the significantly reduced load forecast is a major driver of this effort, the review should consider a broad range of drivers and not be limited to load forecast impacts. For example, re-assessment of currently approved transmission projects should also focus on those projects that are designed to provide a level of reliability that exceeds Federal, Regional and CAISO requirements in nonurban areas. In such cases, before the project moves forward there should be quantified affirmation that the reliability benefits exceed the project costs.	Your comments have been noted. The reliability assessment of the previously approved projects is performed based upon the applicable NERC Reliability Standards, WECC Regional Criteria and the ISO Planning Standards. Further, the ISO reviews projects if material changes in circumstance are identified.

No	Comment Submitted	CAISO Response
3	Boston Energy Trading and Marketing, LLC Submitted by: Michael Kramek	
3a	PG&E Capital Maintenance Projects Approved in the 2014/2015 Transmission Plan The 2014/2015 transmission plan discussed 115 kV cable upgrades associated with SF Peninsula extreme events reliability assessment. The ISO characterized the 115kV cable upgrade as capital maintenance work to be conducted by PG&E. Given the transmission elements are part of the ISO-controlled transmission system, Boston Energy request the ISO include narrative in the plan regarding the status of these projects. At a minimum the CAISO should provide market participants with an estimated in-service date for these upgrades.	PG&E provides 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.
3b	Greater Transparency on the Status of Approved Transmission Projects Transparency around the status of transmission projects approved by the ISO as part of the transmission planning process is inadequate and needs to be improved as part of the 2016/2017 transmission planning process. Compared to other ISOs, the CAISO's current process of providing a one-time project in-service date update at the end of each annual transmission plan significantly lacks transparency. Boston Energy requests the CAISO provide all market participants with periodic updates , no longer than quarterly, on the status and projected in-service dates of all projects approved by the ISO as part of the annual transmission planning process.	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.

No	Comment Submitted	CAISO Response
4	California Energy Storage Alliance Submitted by: Jin Noh	
4a	<u>Preliminary Study Results</u> In the September 21-22, 2016 stakeholder meetings, the preliminary reliability results revealed that there are no significant changes in the reliability assessment from last year, due to reduced load forecasts overall and because most potential problems of the issues will be addressed by projects that have been already approved by the CAISO, even though there are still peak-shift and ramping issues. Notably, PG&E's bulk system assessment summary included the retirement of Diablo Canyon in 2026 cases, but CESA believes it is premature to assume the replacement resource mix for its generation, which is still being determined at the California Public Utilities Commission ("CPUC"). Overall, CESA is encouraged to see that preferred resources and energy storage solutions were again highlighted as potential mitigation solutions to address several reliability issues. While the consideration of non-wire alternatives is commendable and a step in the right direction, CESA believes that the true test of non-wires alternatives being treated on a level playing field with traditional wires solutions will be when the IOUs or third parties actually propose a non-wires project as the preferred solution. During the 2015-2016 TPP cycle, none of the participating transmission owners ("PTOs") proposed energy storage projects as an alternative to new transmission infrastructure. The CAISO did indicate in the Board-approved 2015-2016 Transmission Plan that it would "consider energy storage as part of the overall preferred resource umbrella in transmission planning, in particular opportunities for large scale energy storage to help address flexible capacity needs."[1] However, CESA hopes that these considerations and discussions of the potential for non-wires alternatives can progress to actual project proposals, to illustrate how such non-wires alternatives will be compared to (and selected over) traditional wires solutions. CESA encourages the CAISO to work with the CPUC, the PTOs, and other state agencies to identify non-wires reliability solutions that can be selected in place of transmission projects.	The ISO does not agree that non-transmission alternatives, including storage, are being unfairly evaluated in the ISO's transmission planning process. In the ISO balancing authority area, procurement of resources to participate in energy and ancillary serves markets occurs principally through bi-lateral procurement by load serving entities. Electric storage resources are eligible to participate in these procurements and offer their output as system or local capacity to address transmission system needs. In the latter instance, these resource procurement processes support electric grid reliability and the ISO's preference is to coordinate those procurements with the responsible local regulatory authority (e.g., the California Public Utilities Commission) rather than develop duplicative procurement processes. Although the ISO does not approve non-transmission alternatives in its existing transmission planning process, the ISO promotes opportunities for non-transmission resources such as storage to serve as the preferred solution, and the ISO does work to support regulatory approvals for those projects if the ISO's transmission planning process identifies them as the preferred alternative. The ISO also prefers that operation of these resources occur through the ISO's energy and ancillary services market processes rather than the ISO controlling the operation of a resource outside of its market processes. This approach ensures that system resources or resources within a transmission constrained area operate together to meet grid reliability needs, and enables the resource to participate most broadly in providing value to the market. In the case of electric storage resources, procurement also may result in distribution-connected resources and behind-the-meter resources that do not participate in the ISO's wholesale markets.

No	Comment Submitted	CAISO Response
	These discussions should also address cost recovery issues for non-wires reliability alternatives. A transparent methodology that considers specific benefits of non-wires alternatives and allocates costs accordingly is needed to determine whether partial rate recovery and/or market participation are appropriate for non-wires alternatives that may function as both a reliability solution and a market resource. Until these cost recovery issues are resolved, energy storage and other non-wires alternatives will be unfairly evaluated and continue to face barriers to being part of actual project proposals.	The ISO acknowledges that there may be instances where a dedicated electric storage solution could support local transmission needs with limited or no alternatives. In these instances, it is likely that the ISO may need to constrain or narrowly define the operation of the electric storage resource so that it is available to meet the local transmission need.
4b	<u>Special Studies</u> The CAISO indicated that the preliminary reliability results used existing 33% Renewable Portfolio Standard ("RPS") results and existing 2014 Long-Term Procurement Plan ("LTPP") assumptions and scenarios because there is still no direction on 50% RPS goals and the new 2016 LTPP assumptions and scenarios are not available yet. The CAISO added that it will likely start the TPP process under 50% RPS scenarios starting in the 2017-2018 or 2018-2019 TPP cycles. CESA agrees with the CAISO in that major emphasis should therefore be placed on its six special studies, especially the 50% RPS Special Study, which builds on last year's study by incorporating interregional coordination and out-of-state resource mapping. CESA's main concern with this special study concerns the transmission cost assumptions and the assumed benefits of transmission buildout to Californian ratepayers. These assumptions should be vetted by stakeholders to ensure that in-state benefits to ratepayers (including reliability benefits) are appropriately accounted for. Another key Special Study is the Large-Scale Storage Benefits Special Study. The CAISO conducted a similar study last year of a generic 500-MW pumped-storage resource, and the CAISO said it will use 2016 LTPP assumptions and scenarios in the 2016-2017 planning cycle, including a 50% RPS and Diablo Canyon plant retirement. CESA is encouraged to see the CAISO recognize that pumped hydro storage ("PHS") can provide benefits and generate sufficient revenues from the system to cover the revenue requirement. Similarly, CESA also commends the CAISO for considering not just system-level renewables generation impacts, as was done in last year's iteration of the special study, but to also consider congestion relief, transmission line loss benefits, and other locational impacts. This expanded scope will provide	As noted in the stakeholder presentation material, the ISO has expanded the study scope for the Large-Scale Storage Benefits Study to consider local and transmission benefits of several storage locations. For clarity, the ISO's annual economic study process conducted within the transmission planning cycle is part of its FERC-approved planning process and can be relied upon for requesting approval of transmission projects by the ISO Board of Governors based on the assumptions set out in the study plan. The special studies, however, are conducted for informational purposes and not for project approval purposes. Much of the same economic modeling is consistent between the two studies.

No	Comment Submitted	CAISO Response
	additional information for the cost-recovery discussions CESA mentioned above.. CESA looks forward to the results of this updated special study. However, the relationship of this study to the Economic Planning Study as described in the Study Plan for this cycle, is not clear. CESA assumes that these will be two separate studies, but the CAISO should clarify its intent for this planning cycle.	

No	Comment Submitted	CAISO Response
5	California Public Utilities Commission Submitted by: Keith White	

5a	1. When Reliability Studies Identify Events Requiring Mitigation, the CAISO Should Consistently Identify Not Only the Violation(s) and Contingency(ies) Involved, But Also the Time Horizon(s) and Study Scenarios(s) Involved.
	Specific scenario and time horizon information is sometimes not provided (e.g., in the September 21 TPP meeting presentation), but is important for stakeholder understanding. In particular, scenario assumptions such as loads and dispatch of resources representing particular "snapshot" system conditions for the 2018, 2021 and 2026 time horizons are informative for resource planning purposes. Therefore, CPUC Staff recommend that this information be provided in a more widely accessible form that actually accompanies reliability assessment interpretation and conclusions (e.g., at the September meeting and subsequently), which should not be overly burdensome.
		The detail requested is provided on the ISO website, as set out below. This amount of information is far too voluminous to be incorporated into the PowerPoint presentations presented at the September stakeholder session, and the ISO assumes interested parties review this information before the session, or after in preparing their input after hearing the summaries presented at the stakeholder session.
		
		• The study scenarios for the reliability assessment both Base Scenarios and Sensitivity Scenarios are included within the 2016-2017 Transmission Planning Process Unified Planning Assumptions and Study Plan (http://www.caiso.com/Documents/Final2016-2017StudyPlan.pdf). The final copy of the Study Plan was posted on the ISO website on March 31, 2016. The ISO posted the draft Study Plan on February 22, 2016 and held a stakeholder meeting to discuss and allow for comments on the Study Plan on February 29, 2016.
		  o Base Scenarios are included in Table 4.11-1 on pages 35 and 36. The table includes the scenario for each planning area and year for which the analysis will be conducted. In addition the note below the table provides a description of the scenario condition.
		  o Sensitivity studies are included in Table 4.11-2 on page 37 and includes the scenario, year and planning areas that the sensitivity assessment will be conducted for.
		  o Further to this information with respect how the renewable generation is dispatched within each area and for each scenario is included in section 4.7.2.1 on pages 18 and 19.
		• The results for each of the study scenarios identified in the 2016-2017 TPP Study Plan are included within the detailed Preliminary Reliability Assessment Results that were posted

No	Comment Submitted	CAISO Response
		on the ISO website on August 15, 2016. (http://www.caiso.com/Documents/2016-2017PreliminaryReliabilityAssessmentResults.zip). In addition the final results based on any updates as a results of stakeholder comments or if we make any adjustments will be posted around October 31, 2016 and are included Appendix C of the annual transmission plans. The ISO will consider the comments in the drafting of the Transmission Plan for possible changes to improve ease of understanding.
5b	2. Scenario and Time Horizon Information Described Under Comment 1 Should Be Accompanied by a Complete and Updated Description Of (1) What Specific Base and Sensitivity Reliability Study Scenarios Were Run For Each Grid Area1, and (2) The Key Assumptions for Each Scenario.2 CAISO reliability study scenarios should also describe what specific base and sensitivities were run for each grid area and the key assumptions for each scenario. Specifically, documented scenario assumptions should include: • Typical time of day/week/season the scenario represents (e.g., winter peak hours 17-18) • Load level (e.g., x% of the summer 1-in-2 peak from a particular CEC IEPR load forecast) • Assumed output levels for different categories of renewable generation (e.g., as % of nameplate/Pmax /NQC) • Assumed BTM PV output level. This information is needed for the same reasons discussed in Comment 1 above: for stakeholder understanding generally, but more specifically for clear linkage between drivers of identified reliability problems and the relevant planning, market and policy developments and options. As an accompaniment to results and conclusions, key assumptions for the study scenarios could be presented in tables such as the following tables in the Final Study Plan of March 31,	For comment (1) refer to bullet 1 above. For comment (2) refer to bullet 1 above. The assumptions for the Reliability Assessment are outlined in Section 4 of the ISO 2016-2017 Transmission Planning Process Unified Planning Assumptions and Study Plan.

<table>
<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td></td><td>2016:
• Table 4.7.1 (Summary of Renewable Output)
• Table 4.11 (Summary of Study Base Scenarios)
• Table 4.11-2 (Summary of Study Sensitivity Scenarios)

These tables should be updated and expanded relative to what was provided on March 31. Updating is required because some of the assumptions are missing from the March 31 Tables. For example, Table 4.7-1 includes some "TBD" entrees and contains no renewable generation output assumptions for spring off-peak scenarios, spring light load scenarios or summer peak with heavy/high renewables scenarios. Furthermore, notes for Table 4.7-1 provide very limited documentation of what typical times each scenario represents, e.g., summer minimum load = PG&E hours 2-4 AM). The table also doesn't adequately explain what the modeled load level represents, e.g., it might be 1-in-10 summer peak from CEC's IEPR mid-demand/mid- AAEE/mid-BTM PV forecast or it might be 50% of 1-in-2 summer peak from the same IEPR forecast level, etc. This documentation of hours/times and load levels represented by particular study scenarios is only provided for several example study scenarios in the March 31 Study Plan, and should be expanded to cover all study scenarios, since the scenarios are now finalized.</td><td></td></tr>
<tr><td></td><td>Additionally, it should be made explicit in the above-requested tables what a study scenario with no BTM PV represents. If a particular "summer peak with no BTM PV" scenario represents the summer peak load from a particular identified load forecast, and that load peak is assumed to be at the same MW level as in the original peak load hour (such as 4-5 PM), with BTM PV removed but without adjusting the peak load MW to represent a later hour when no PV output is expected - - then this method should be made explicit. The preceding example represents how CPUC Staff understands that "no BTM PV" scenarios were developed. Also, CPUC Staff request clarification regarding how BTM PV output assumptions for different study scenarios were or were not harmonized with assumed wind and solar output levels for the same scenarios. For example, if there is no BTM PV output in a particular summer peak scenario, is there also no output from larger scale, wholesale PV and CSP resources?</td><td>The ISO recognized that the PV peak shift phenomenon deserves more detailed analysis in the future, and the CEC is the appropriate organization to perform these analyses in future stakeholder process. At the time of the ISO sensitivity study that incorporates the potential PV peak shift impact, the ISO based its approach on the limited data that was available. The source of data for the ISO was from the CEC published document of "California Energy Demand 2016-2026, Revised Electricity Forecast, Volume 1: Statewide Electricity Demand and Energy Efficiency" Figures B-8 (PG&E system load vs. PV Production) B-9 (SCE system load vs. PV production) and B-10 (SDG&E system load vs. PV production). These data, while limited in quantities, indicated a very small drop in peak load (1 to 2%) at 6 PM and 7 PM compared to the peak loads historically at 4 PM and 5 PM (i.e., 98 – 99% of the load level at 4 PM). These small drop in peak loads, when spreading out a larger area such as in the LA Basin and</td></tr>
</table>

No	Comment Submitted	CAISO Response
	In summary, the tabular documentation of study scenario assumptions requested above would be very helpful for planning and collaboration purposes and should not be burdensome, especially compared to the effort of developing, modeling, interpreting and drawing conclusions from the studies.	San Diego areas, wouldn't significantly change the study results. Due to these limited and inconclusive available data points and recognizing that the impact of AAEE in reducing load forecasts also drops from 4 PM to 6 PM, the ISO added the amount of PV generation that was netted out at 4 PM back to the CEC 1-in-10 netted peak demand. The ISO recognized that this assessment of PV peak shift would need to be explored further in details by the CEC demand forecasting team in future stakeholder process and would use the results of these assessments when available.
5c	3. There Should be a "Big Picture" Evaluation of How The Continuing Trend of Identifying Needs for Voltage (Especially High Voltage) Controls in the PG&E Area May be Mitigated or Exacerbated by Foreseeable System-wide Developments Such as Increased Wind and Solar Generation, Increased BTM PV, EV Penetration and Various Demand Management Measures. CPUC Staff request that the CAISO and PTOs consider whether and how they can shed more light on how the trending voltage issues and related mitigation investments could be impacted (reduced or exacerbated) by foreseeable system-wide changes such as increased wind and solar generation, increased BTM PV, EV penetration and various demand management measures. This could help integrate this issue into the broader planning context.	The ISO will consider additional narrative in the transmission plan.
5d	4. For the East Bay Special Reliability Study, CPUC Staff Request Clarification of (1) Whether "Eliminating Reliance of SPS Under New CAISO Planning Standards" Arises Only In the Event of Significant Retirement Of Local Generation, and (2)Whether Study Results Would Materially Change if Replacing Alameda GT Retirement Scenarios with Oakland GT Retirement Scenarios.3 CPUC Staff understand and request confirmation that: a. "SPS under new ISO planning standards" refers to allowing nonconsequential (planned) load shedding under certain contingencies in dense urban areas only as a temporary measure until already-planned solutions are in service; and b. Activation of such SPS under reliability planning contingencies (P0, P-1, etc.) is a foreseeable development only with significant retirement of local generation without replacement by other measures, i.e., a retirement that is not currently planned.	Your comment regarding importance of focus on demand-side and distributed measures has been noted. Your understanding of SPS under new ISO planning standards and activation of existing SPS only under contingencies and with retirement of local generation is correct. However, the Moraga-Oakland J and Grant SPS are not directly linked with the level of local generation in Oakland area and could activate under contingencies at any generation level. Need for these SPS were not found following the implementation of E. Shore-Oakland J reconductor project.

No	Comment Submitted	CAISO Response
	CPUC Staff look forward to CAISO's assessment of potential and/or actual proposals from the market, regarding local replacement resources that could offset potential GT retirements. We also note that the any future reliability risk is lower than assessed in the previous planning cycle due to a lower load forecast. This highlights the importance of continued focus on demand-side and distributed measures, including realistic forecasting and modeling.	
5e	5. CPUC Staff Look Forward to CAISO's November Update on the Review of Approved Projects in the North Area Including the Roles of Increased BTM PV and AAEE. Forecasting and modeling of BTM PV, AAEE and other demand-side or distributed measures play an increasingly important role in California energy planning. CPUC Staff look forward to learning how these rapidly evolving market trends factor into the CAISO's review of approved projects, including issues regarding locational specificity of such resources and measures.	The comment has been noted.
5f	6. CPUC Staff Look Forward to the CAISO's Assessment Regarding the Gates-Gregg Transmission Project, Including Both Reliability and Renewables Integration Considerations as Well as the Roles of Updated Information and Forecasts for BTM PV, AAEE, and Renewable Generation in the Fresno Area. Assessing the need for the Gates-Gregg transmission project using updated information in the 2016-2017 TPP cycle especially regarding load forecasts takes into account (1) the need to manage anticipated renewables-driven over-generation situations; and (2) rising expectations for distributed resources penetration, including demand management measures. CPUC Staff's interest in understanding how the above developments impact the CAISO's Gates-Gregg assessment parallels our interest (see Comment 5) in how updated information impacts the review of other previously approved projects. Furthermore, when physical and economic "renewables integration" benefits are considered in the Gates-Gregg assessment , CPUC requests that the CAISO consider a transparent range of assumptions regarding net exports and energy pricing (exports and internal) under over-generation conditions, similar to our recommendations regarding the Bulk Energy Storage Resource Case Study (Comment 10).	The comment has been noted.
5g	7. CPUC Staff Thank the CAISO for Efforts to Refine Informational 50% RPS Special Studies, and are Especially Interested in Understanding the Modeling of Out-Of-State Transmission, Net Export Limits and	This comment has been noted. The ISO plans to model the 50% portfolios provided by the CPUC and provide the models to regional planning entities. This input is expected

No	Comment Submitted	CAISO Response
	Assumed Energy Pricing Under Over-generation Situations - - Which Appear to Be Important but Highly Uncertain. Other studies including the previous 50% RPS study and SB 350 studies have clearly indicated both the importance and the modeling challenges associated with WECC-wide renewable transmission planning and assessing the export limits and assumed energy pricing of both exported and internally delivered generation under over-generation situations. While we acknowledge that there is no clear "right" way to model the above issues at this moment in time, CPUC Staff request that the CAISO provide and document a transparent and robust approach that helps us move forward. In addition, CPUC Staff also request that the CAISO clarify if and how information from the current 50% RPS study may inform interregional planning studies pursuant to Order 1000, and vice versa.	to inform the interregional planning studies pursuant to FERC Order 1000. The ISO also plans to incorporate the input provided by the relevant planning entities into modeling of the out-of-state portfolios.
5h	8. For the CAISO's Longer Term (2026) Electric-Gas Coordination Study Focusing on the Aliso Canyon Storage Situation, CPUC Staff Recommends Considering a Range of Gas Supply/Storage Circumstances Ranging From Present Conditions to a Return to Full Storage Availability and We Look Forward to Discussion at the November TPP Meeting. [for Molly: keep or delete this comment?] CPUC Staff understand that the CAISO's longer term 2026 gas-electric coordination study will reflect OTC generator retirements/replacements plus approved resource, storage and transmission additions by 2026. However, it is unclear what gas supply/storage restrictions will be assumed. CPUC Staff recommend that the CAISO consider an informative, transparent range of restrictions from current gas supply restrictions to a return to full storage availability. We look forward to discussion of this study at the November TPP stakeholder meeting.	The scope of the 2026 Gas-Electric Coordination Special Study was presented during a June 13, 2016 stakeholder conference call and is posted on the CAISO website. http://www.caiso.com/Documents/AgendaandPresentation-2016-2017TransmissionPlanningProccess-SpecialStudies.pdf This presentation describes the range of restrictions that will be assumed. The ISO will also look forward to coordinating with the various state agencies regarding the report that the Division of Oil, Gas and Geothermal Resources, the California Public Utilities Commission, the California Air Resources Board and the California Energy Commission have been directed to submit to the Governor's Office assessing the *long-term viability of natural gas storage facilities in California* in response to the Governor's January 6, 2016 proclamation. The ISO understands that the report should address operational safety and potential health risks, methane emissions, *supply reliability for gas and electricity demand in California*, and the role of storage facilities and natural gas infrastructure in the State's long-term greenhouse gas reduction strategies

No	Comment Submitted	CAISO Response
5i	9. The CAISO's Special Study Regarding Frequency Response Modeling Refinements Appears to Have Value For Both Near-Term Compliance and Long Term Planning, and We Request Clarification Regarding (1) the Extent To Which Frequency Response is Now Limited by Practices Versus Capabilities, (2) Plans for Developing a Frequency Response Procurement Mechanism, and (3)How Nonconventional Providers of Frequency Response Are Being Considered. Given FERC requirements, the changing composition of the electric supply system, and the state's energy and environmental goals, how the CAISO-operated grid will reliably and economically provide frequency response in combination with other flexibility and reliability services is clearly an important challenge. CPUC Staff understand that addressing this challenge involves several changing and interacting elements; including modeling improvements, communications with PTOs and generation owners; studies of system frequency response under future scenarios; near-term compliance in a manner that economically and reliably meets NERC and FERC requirements; potential development of a market product or other efficient frequency response procurement mechanism; and possibly other "pieces of the puzzle." We request that the CAISO 1. Clarify the extent to which system frequency response (apparently inadequate for NERC/FERC compliance today) is limited by physical capabilities as opposed to practices that might be altered by incentives including procurement mechanisms; 2. Clarify the timeline and milestones for developing a frequency response procurement mechanism that applies to both conventional (e.g., gas and hydro generation) and nonconventional providers; and 3. Explain how potential frequency response provisions by nonconventional providers (such as renewable generation, storage and demand management measures) are being factored into planning studies.	We agree that it is critical to correctly and accurately identify the system frequency response, including frequency response from the CAISO. Thus, the items listed in this comment are important. In the last years, the ISO performed several studies of over-generation and frequency response. All the studies showed that there might be a deficiency in frequency response provided by the CAISO, although the total response from WECC was sufficient. Unfortunately, for some CAISO generation units, the study results did not match frequency response observed under real-time conditions. Therefore, this year's TPP effort is concentrated in obtaining and developing accurate models of the generation, including renewables. 1. Frequency response is indeed limited by physical capabilities of the equipment, especially generation that is inverter-based, as well as base-operated units. To improve reliability of the CAISO system and compliance with the BAL-003 Standard, the CAISO is working on incentives to procure frequency response outside of the ISO. 2. The CAISO issued Frequency Response Proposal that describes a frequency response procurement mechanism that can be applied to all types of providers. It includes milestones and timeline for the procurement mechanism. It can be found on the CAISO website at http://www.caiso.com/Documents/DraftFinalProposal_FrequencyResponse.pdf 3. Potential frequency response by non-conventional providers is being factored into planning studies by developing dynamic stability models for each type of equipment (renewable generation, storage and other) and using these models in the studies.
5j	10. The Bulk Energy Storage Resource Case Study Should Examine Multiple Sensitivities Regarding Next Export Limits and Regarding Energy Pricing Assumptions (Exports and Internal) Under Over-generation Conditions.	The comments have been noted. The ISO does expect that as this work is an informational study, a practical limitation on the number of scenarios studied will be needed and as such, we intend to focus on the 2000 MW net export limit scenario. As noted elsewhere, consideration

No	Comment Submitted	CAISO Response
	For the storage valuation study, assumptions regarding export limitations and pricing of energy under over-generation conditions can strongly impact the calculated economic valuation of storage in helping to manage over-generation. And yet the "correct", or at least best, assumptions regarding export limitations and pricing under over-generation conditions are unclear. CPUC Staff request that the CAISO 1. fully document modeling assumptions regarding net exports and pricing of exported and internally delivered energy under over-generation conditions; 2. examine at least two sets of contrasting assumptions regarding net export limits and energy pricing under over-generation conditions (e.g., prices received for exports, prices paid to internally delivered and internally curtailed generation under overgeneration conditions); and 3. examine multiple renewable resource portfolios having contrasting over-generation implications.	of appropriate export limits for study purposes will need to be considered in future planning cycles.
5k	11. In the Described Economic Retirement of Gas Generation Special Study the Generator Retirement Criteria and the Impact of Non-Energy Revenues in Forestalling Retirements are Very Uncertain, and These Aspects of the Analysis Should be Clearly Documented While the Study Itself Should be Viewed as Exploratory and Informational. Modeled generator capacity factors relative to historical utilization are very crud indicators of potential economic retirements. Specifically, gas-fired generator capacity factors are expected to decline with increased renewable generation at the same time that increases in revenues from various non-energy (e.g., flexibility and reliability) services are unclear. Furthermore, major system changes will impact operating margins further making capacity factors per se poor predictors of economic viability. Beyond this, selection of which generators will be "LCR resources" is uncertain. For example, should it be based on projected capacity factors, electric effectiveness relative to binding constraints, or something else? In addition, future revenues for providing local capacity are uncertain. CPUC Staff request that the CAISO clearly document the criteria used for selecting generators for "economic retirements", or the alternative sets of criteria used to select alternative sets of generators for economic retirements. Additionally, if initially-projected economic retirements produce system shortfalls in reliability and flexibility services, then the magnitude of shortfall and the	The comment has been noted.

<table>
<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td></td><td>revenue/procurement consequences of meeting the shortfall (instead of retiring) should be documented and interpreted. For example, would some “economically retired” generators have to be incentivized to not retire, or should they be expected to already be incentivized by market design and revenues for nonenergy services? To what extent are non-conventional sources of reliability and flexibility services (presumably not at risk of economic retirement) considered?

Thus, there appears to be a somewhat circular logic. If certain generators are projected to be at risk of economic retirement based on capacity factors and not being needed for LCR, and such retirement leaves need for additional ancillary/flexibility or other services the provision of which would provide additional but uncertain revenues - - how are study results to be interpreted?

Given the above situation, CPUC Staff’s concluding recommendation is that the Economic Risk of Retirement Special Study, while potentially providing useful information, should be viewed as exploratory and not as a conclusive study.</td><td></td></tr>
<tr><td>5l</td><td>12. CPUC Staff Appreciate the Preview of the CAISO’s Economic/Production Cost Model Development, and Look Forward to Clarification of How Reliability Driven Resource Commitment Will be Modeled (Including But Not Limited to Local Capacity and System Frequency Response) as Described Below.
Commitment of resources for local reliability, ancillary services, and flexibility has significantly impacted a variety of production simulation studies by the CAISO and others, including the SB 350 studies and the flexibility studies for last year’s LTPP proceeding. We request and look forward to a full description of the updated approach being used for modeling reliability-driven resource commitments for production simulation studies associated with the 2016-2017 TPP, including commitments for local capacity, traditional ancillary services, flexible reserves and frequency response. This includes variation (if any) in this modeling methodology across different studies. Additionally, the CAISO should report and discuss with stakeholders the assumed (currently modeled) and potential (not yet modeled) roles of nonconventional resources in helping to meet the above reliability/flexibility needs for the 2026 time horizon. “Nonconventional” resources may include renewable generation, battery storage, and demand management measures.</td><td>The frequency response requirement is enforced to combined cycle generators and battery storage as proposed in ISO’s frequency response requirement initiative stakeholder process. The ISO’s economic planning database adopts the same approach to model the frequency response requirement. Ancillary services including regulation, load following, and operation reserves are modeled in the ISO’s economic planning database in the co-optimization model, which mimics the ISO’s market operation.

Local reliability constraints are also modeled in the database, such as N-1 or N-2 contingencies as identified in reliability and LCR studies.

More details of the modeling approaches and assumptions will be included in the ISO’s transmission plan report and will be available in the database, which will be posted after the planning cycle finished.</td></tr>
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No	Comment Submitted	CAISO Response
5m	13. The CAISO Should Prioritize and Expedite the Review of Proposed Reliability Projects that Support Large Electrified Transportation Infrastructure Programs. Slides 4-5 of PG&E's 2016 Request Window Proposals presentation describes the scope, transmission impact assessment, and requested in-service dates of proposed upgrades to South San Francisco's East Grand and San Jose's FMC substations, which are necessary to support the Caltrain Electrification Project. Caltrain's project schedule states that full electrification will be achieved within five years, with system testing commencing in just two years. The CAISO should prioritize and expedite review of PG&E's proposed projects so as not to cause unnecessary delay of a major infrastructure project. Additionally, the High Speed Rail project's initial operating segment falls within the 10- year transmission planning horizon, and therefore should be studied for reliability impacts as soon as is feasible. To this end the CAISO should collaborate with PG&E and the California High Speed Rail Authority (CHSRA) in the development of Technical Study Reports, which detail the scope of electrical interconnections required to support the project's load on a granular, region by region basis. CPUC Staff understands that neither finalized system impacts nor proposed reliability projects have been publicly submitted to the CAISO by PG&E or CHSRA, but urge continued efforts by all of the above parties to commence study on the network reliability needs of the High Speed Rail project.	The ISO is currently reviewing project Request Window submission for the Caltrain Electrification Project and is in process of working with PG&E to obtain more details. The ISO will continue to work collaboratively with PG&E and California High Speed Rail Authority (CHSRA) as information becomes available with respect to the load requirements either included in the CEC Energy Demand Forecast or within the PG&E and CHSRA interconnection requirements.
5n	14. SDG&E Proposes Approximately $125M of Subtransmission and 230 kV Reliability Projects, But the Underlying Study Assumptions are Unclear and Should be More Fully Documented in the Same Manner as Requested in Comments 1 and 2 for the CAISO's Reliability Studies. In the September 22 TPP meeting, SDG&E indicated that studies supporting the proposed subtransmission and 230 kV infrastructure investments assumed a high load forecast by incorporating a low level of AAEE. However, the load and generation assumptions used for these studies, including BTM PV output levels and overall correspondence to specific CEC IEPR forecast(s) were not fully provided. It was also unclear whether SDG&E ran additional studies using the same assumptions as used in the CAISO's base scenarios, and what the results were.	The ISO will work with SDG&E to better understand any study assumption differences and include any relevant information in our documentation of results in the transmission plan.

No	Comment Submitted	CAISO Response
	Thus, justification of proposed SDG&E investments requires greater clarity regarding what specific scenarios were studied for what years. This could be achieved by documenting study scenarios in the same manner that CPUC Staff request for the CAISO's reliability assessment case, in Comments 1 and 2 above. Otherwise it is not possible to understand the relationship between SDG&E's study results versus the CAISO's study results.	
5o	15. SDG&E's Proposed Renewable Energy Express Project Estimated to Cost $0.9-1.0B Should be Justified Based on (1) Reliability Studies, (2) Economic/Congestion Studies and (3) Policy/RPS Benefit Studies, Where CPUC Staff Assume (Confirmation is Requested) that (2) and (3) Will be Assessed in the Interregional Projects Portion of the CAISO's Transmission Planning Process. SDG&E claims a number of reliability, economic and RPS policy benefits from this large investment, including "congestion management", "increase San Diego import capability by 500- 1000 MW", "mitigate Southern California LCR needs" , and "reduce reliance on …loadshedding." Such benefits are qualitatively plausible but specific quantitative analyses including documented analytic assumptions and benefits are not reported. Thus CPUC Staff request clarification that the applicable reliability, economic and policy-oriented studies remain to be done.	The ISO will consider this project in the 50% RPS Special Study and Interregional Transmission Planning process for informational purposes.

No	Comment Submitted	CAISO Response
6	Imperial Irrigation District (IID) Submitted by: Nisar Shah	
6a	IID comments are focused on the "San Diego Gas & Electric Bulk Transmission Preliminary Reliability Assessment Results". 1. IID appreciates CAISO engineers' analysis in which CAISO has identified one IID facility overload caused by five CAISO contingencies. IID is very supportive to work with CAISO in mitigating this overload such that it provides a superior technical and economic solution for the benefit of all California ratepayers.	This comment has been noted.
6b	2. On slide # 11 of the above presentation, CAISO has identified IID's Imperial Valley – El Centro line (aka "S" line) as overloaded under one contingency condition. Although the details of overload levels are not on this slide, those are found in the Preliminary results posted on the CAISO website. These details indicate **five** contingencies would overload the "S" line in the range of 100% to 139%. The proposed mitigation offered by CAISO is to use Operating procedure to manage the reliability of the Grid. IID's question is: What other mitigation measures were considered and evaluated by CAISO besides Operating Procedure?	As noted in the ISO's presentation material, operating procedures can mitigate the reliability issues. The ISO intends to explore other possible mitigations as possible policy-driven or economic-driven options.
6c	3. "S" line emergency rating is 407 MW, meaning an overload of 139% would load this line to 566 MW (an increase of 159 MW above emergency rating). The protective relays will trip this line immediately if this loading was to occur in real time, thus initiating cascading events. IID understands the CAISO operating procedure, in fact, decreases the pre-contingency flow on the N.Gila-Imperial Valley 500 kV line (NG-IV) to avoid this kind of overloading and consequent cascading events. In this scenario, CAISO has to curtail pre-contingency NG-IV flow by about 480 MW. IID' question is two-fold: (1) Can CAISO operators curtail about 480 MW of NG-IV flow typically within 30 minutes? (2) Is there a better option than pre-contingency curtailment?	Please refer to the above response.

No	Comment Submitted	CAISO Response
6d	4. Given the history and the devastating impact the loss of the Southwest Power Link (SWPL) had on the grid on 9/8/11, IID believes that it is irresponsible to rely on real time to mitigate such an extreme overload. IID encourages CAISO to explore other alternatives including upgrading the "S" line.	Please refer to the above response.

No	Comment Submitted	CAISO Response
7	LS Power Development, LLC Submitted by: Sandeep Arora	
7a	<u>Economic Studies:</u> Consistent with the comments we have made in past, CAISO's Economic Studies have been significantly under-estimating the congestion on California Oregon Intertie (COI) path, and we offer the following suggestions for CAISO staff to implement for this year's study: (1) COI path flows: The 2026 TEPPC common case model should be adjusted, as needed, so it reflects baseline flow patterns on the COI path that are consistent with actual flows documented and expected on the path. This includes reviewing generation capacity assumptions for BC Hydro, reviewing generation assumptions for Northern California Hydro and reviewing the impacts of Diablo going offline.	The ISO has been working with WECC and other planning regions in the TEPPC Common Case development including the modeling of BC Hydro capacity and northern California hydro assumptions. Diablo nuclear units are set to be off in the TEPPC Common Case as the baseline assumption.
7b	(2) Hurdle rate assumptions: Hurdle rates for transfers across the COI path should be carefully scrutinized. It is suspected that the way hurdle rates are currently modeled results in artificial flow limits on the COI path. (a) Generators that sell energy to CAISO LSEs under long term contracts via existing transmission rights should be modelled free of any hurdle rates. (b) COI path should be modelled as two separate parallel paths – one that goes to CAISO LSEs, which should have very little to no hurdle rate, and a second path to non CAISO entities, such as TANC members which should have very high hurdle rates. Absent this modelling detail, COI congestion is artificially masked as the model will incorrectly predict energy flows on each of the three COI lines.	The hurdle rate in the TEPPC Common Case is modeled as export hurdles, which means only the generation that is exported from a balancing authority area will be charged the hurdle. The hurdle is not on the interface lines, such as COI.
7c	(3) COI de-rates: The COI path very frequently gets de-rated due to maintenance work. It is our understanding that a relay maintenance and replacement program has been underway for a number of years. This causes PTOs to schedule outages of the transmission segments on the COI path and transmission segments adjacent to the COI path boundary. Every time a transmission segment is taken out of service, it causes de-rates on the COI path. COI de-rates lead to congestion in CAISO's Day Ahead and Real Time markets. We understand that this relay maintenance and replacement program will continue for the next several	In addition to the outage and derate that have been modeled in the database in the previous cycles, the ISO is working with the owners of COI segments to obtain further historical and scheduled maintenance data including the relay maintenance. Once the data are available, the ISO will review them and incorporate into the database based on the review results.

No	Comment Submitted	CAISO Response
	years and that the program has a 10-year replacement cycle, meaning every 10 years or so relays may need to be maintained and/or replaced. This is more frequent than typical transmission outages and hence CAISO should further research this. If these COI de-rates are expected to be a normal operating practice then these should be accounted for in the Economic Planning studies. We understand that CAISO does incorporate transmission outages in economic studies, but these outages do not correctly capture the impact of COI de-rates referenced above since these assume all lines in service as the baseline scenario.	
	In addition, LS Power supports CAISO performing the special economic study on the 50% RPS scenario in this year's planning cycle. As discussed at the stakeholder meeting, we would recommend CAISO conduct both sensitivities for the 50% scenario, including the one with out of state renewables. We recommend that CAISO should also perform a study with the CPUC 43.3% RPS portfolio, similar to what will be done by CAISO under the Bulk Energy Storage study. This scenario should provide insights into any congestion issues for the intermediate RPS target case for 2026, and since this falls within the 10-year planning cycle, this would give CAISO a look into any potential solutions that may be needed prior to 2030.	A sensitivity with out of state renewables is being considered depending upon available resources to complete the additional special study. The 43% requested additional analysis is beyond the current scope of the special study this year.
7d	<u>The interplay of Bulk System Reliability Studies and Economic Studies:</u> CAISO's Transmission Planning studies for the Bulk System, similar to several previous cycles, have shown reliability concerns due to Category B and Category C contingencies on major 500 kV lines in the Pacific AC Intertie (PACI) transmission interface in Northern California. CAISO's proposed mitigation for these issues is to reduce the COI flow and stay within the operating nomograms. While reducing COI flows may address the reliability issue, it will likely create congestion on the COI interface. Reducing COI flows for reliability reasons means artificially reducing the COI path transfer limit, which will disallow the flow of economic energy from Pacific Northwest to California and increase costs to ratepayers. On the Economic Study side, since congestion on COI has not been captured in CAISO's previous study cycles, the true cost of maintaining reliability (by reduction in COI limits) is also not being captured. We would once again reiterate the importance of correctly modelling COI flow limits for the Economic studies so congestion on this path	As to the comments on the COI limit and derate, please refer to the response to comments 71~7c. The ISO's transmission planning methodology has included the coordination between the reliability assessment and production cost simulation, as described in the study plan and the transmission plan reports.

No	Comment Submitted	CAISO Response
	is accurately accounted for, including the impact of any reliability solutions that are implemented. For instance, if an economic transmission solution also helps improve reliability, then overall benefits of this solution should be accounted for. As an example, LS Power's SWIP North transmission project helps relieve 300 to 400 MW of North to South flows on COI, Path 26 and Path 15. This not only helps in reducing congestion but at the same time also helps address some of the reliability issues identified in CAISO's 2016-17 TPP reliability analysis for Bulk Studies. LS Power had previously submitted findings of a power flow analysis1 it had conducted which shows that SWIP North project helps address reliability issues. LS Power recommends that reliability and economic planning solutions should be implemented in a coordinated fashion to result in an optimized solution for both issues.	
7e	<u>Interregional Transmission Project Review & 50% RPS Special Study:</u> LS Power supports CAISO's review of proposed Interregional Transmission Projects (ITPs) using the 50% RPS Special Study in this planning cycle. . Rather than simply evaluating a proposed ITP to see if it is more efficient and/or cost effective as compared to a Regional solution, the analysis should quantify all benefits from the proposed ITP including economic, public policy and reliability. These benefits should be evaluated not just for the 50% RPS with out of state renewables scenario but also perhaps an intermediate 43.3% RPS target for Year 2026 which would be the tenth year under this year's planning cycle. As CAISO further develops its study plan for these studies, we recommend CAISO to share this information with the stakeholders and seek feedback. As with any planning study, study assumptions including transmission, generation, load, season assumptions are key inputs and stakeholder should have an opportunity to comment on these before CAISO kicks off its study efforts.	As SWIP-North project has been submitted by LS Power as an Economic Planning Study Request, this project will be considered for a comprehensive economic study in the context of the 33% RPS portfolio assumptions. Because the 50% RPS portfolios are informational portfolios and the ITP studies are informational studies, they may be limited in scope.
7f	<u>Bulk Energy Storage Study</u> LS Power supports CAISO performing a study to analyze the benefits of Bulk Energy Storage in addressing over supply & renewable curtailment, CO2 emission reduction and preventing renewable overbuild. With reference to this study, we have the following recommendations. (1) CAISO should reconsider how it defines a bulk energy storage project. As currently proposed by CAISO, a large scale pump hydro project with	The comments have been noted. The ISO is considering one alternative battery storage configuration, subject to adequate resources to accommodate the expanded scope. However, we anticipate remaining with consistent requirements to provide comparable results.

No	Comment Submitted	CAISO Response
	duration of 8 hours and above is considered Bulk Energy Storage. Can projects with duration of 4 hours help address the same needs? These projects may operate at 50% of nameplate capacity for 8 hours, or cycle twice in a day, but if these can address the need CAISO sees, then these should be looked at under this study. (2) Another recommendation is that instead of modelling a large scale 600 MW Bulk Energy Storage project in one location on CAISO grid, CAISO should look into modelling 100 MW, 4 hour duration projects spread out in several locations within CAISO footprint. Some key locations to consider would be high concentration renewable zones such as Imperial Valley, East of Devers. Also, some locations in load pockets both within NP15 and SP15 would be good locations to study the benefits of storage. Running these additional scenarios should provide better understanding of the range of benefits storage can offer and also help understand the congestion relief and peak reduction benefits. (3) Lastly, we would recommend that CAISO also make modelling enhancements as suggested to correctly capture COI congestion for this study.	

No	Comment Submitted	CAISO Response
8	NextEra Energy Transmission West, LLC Submitted by: Michael Sheehan and **Edina Bajrektarević**	
8a	NEET West Recommends CAISO Develop a Long-Term Reliability Transmission Solution for the Pacific Gas &Electric (PG&E) Oakland Area in 2016-2017 TPP To improve reliability and mitigate thermal overloads within the Oakland area, NEET West plans to submit two new transmission solutions that consist of a new 230 kV transmission source connecting Sobrante 230 kV substation or Moraga 230 kV substation to a new Oakland C 230 kV substation. In the 2015-2016 TPP CAISO indicated that they will continue to consider transmission, generation or non-transmission solutions as they revisit the assessment of Oakland area needs in the 2016-2017 TPP cycle. In the near-term, the Oakland area relies on Special Protection Systems (SPS) with a relatively small amount of load shedding as allowed per the CAISO Planning Standards; however CAISO will consider alternatives for the long-term horizon. • NEET West would like to emphasize that the reliability needs of the East Bay area are greatly dependent on the existing local generation that faces potential near-term retirement due to age[1] of Oakland area combustion turbine (CT) generation. It should also be noted that previous versions of the CAISO Planning Standards included the Greater Bay Area Generation Outage criterion, which recognized a higher unavailability of these units due to their age and forced outage rates. We observed during the September 21-22, 2016 meeting, that Oakland CT retirement is not certain yet and this was one of the reasons for CAISO not currently approving any transmission and/or non-transmission solutions as part of the 2016- 2017 TPP study cycle. NEET West requests that the CAISO seeks resolution to the retirement of this very important generation in East Bay area and that the appropriate assumptions are updated and reflected in the existing studies during the current 2016-2017 TPP study cycle as well as that long term solutions are developed to address all the identified issues in the East Bay. Consequent to this:	Your comment regarding need for an Extreme Event Reliability Assessment in Oakland area has been noted. The ISO looks forward to receiving proposed transmission solutions and will review them along with giving consideration to other non-transmission alternatives and/or mix of transmission and non-transmission alternatives in identifying the long-term mitigation for the area.

No	Comment Submitted	CAISO Response
	• NEET West requests that the CAISO's 2016-2017 TPP cycle include a special assessment of the Oakland/East Bay area and to evaluate the NEET West project alternative against all other transmission and non-transmission alternatives being considered to determine the most cost effective solution. Due to its characteristics, long-term planning for the Oakland/East Bay Area should incorporate an approach similar to the San Francisco Peninsula Extreme Event Reliability Assessment previously performed in the CAISO's 2015- 2016 TPP cycle. The Oakland East Bay assessment should explore all viable mitigation options that address the special circumstances for this area; some of these circumstances include: o A high-density urban area consisting of over 400 MW of load. o Retirement of Oakland area CT generation. o Elimination of the reliance on SPS or Remedial Action Schemes (RAS) per the CAISO's new High Density Urban Load Area planning standard, which no longer allows "non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability" to mitigate NERC TPL standard contingencies and transmission system impacts (for facilities ≥115 kV). NEET West recognizes there are multiple existing SPSs in the East Bay (PG&E Greater Bay Area: Moraga-Oakland J 115 kV line OL RAS, Grant 115 kV OL SPS, Oakland 115 kV C-X Cable OL RAS, Oakland 115 kV D-L Cable OL RAS); these schemes are designed to drop load in order to comply with NERC TPL contingency events. o The environmental restrictions and economic impacts of the Oakland combustion turbines (that are Regulatory Must Run (RMR) units) and the Northern California Power Agency (NCPA) combustion turbines in Alameda have on the system and how these restrictions and economics may be impacted with the addition of the NEET West Oakland Project. o Exposure and restrictions of transmission system topology. Existing critical overhead transmission sources (Moraga-Claremont, Moraga-Station X, and Moraga Station J 115kV circuits) are confined to multiple-circuit corridors and traverse	

No	Comment Submitted	CAISO Response
	heavily-wooded areas, foothill ridges and canyons. These conditions limit accessibility, and expose these facilities to causes of common-corridor outages (such as fire). Likewise, downtown Oakland's aging network of 115 kV underground cables (gas-filled pipe-type cables constructed in the 1960s) offer limited access due to heavy urban development, and are also exposed to seismic considerations (proximity and orientation to the Hayward Fault). All these factors complicate the timely restoration and/or reinforcement of existing circuits, and likewise present routing challenges for new facilities. Planning studies should consider the implications of multiple-circuit/extreme outages, and the potential for sustained unavailability of one or more circuits.	
8b	NEET West Recommends CAISO Develop a Long-Term Reliability Transmission Solution for the SCE Big Creek Area in 2016-2017 TPP To improve reliability, and mitigate thermal overloads and transient stability concerns in the Big Creek area, NEET West plans to submit a proposal to construct a new Pittman Hill 230 kV substation project that will tie the following transmission lines together: • Helms – New E1 230 kV #1 & #2 Lines (PG&E) • Big Creek 3 - Rector 230 kV Line #2 (SCE) • Big Creek 4 - Springville 230 kV Line (SCE) • Big Creek 1 - Rector 230 kV Line (SCE) NEET West requests that TPP 2016-2017 evaluation include the following key factors regarding the SCE Big Creek Area: • Evaluate all alternatives[2], including NEET West Pittman Hill project, for reliability and performance by testing system thermal loading, voltage performance and control, stability performance, short-circuit margins, extreme contingency performance, and interface impacts (internal/external). • NEET West requests that the 2016-2017 TPP evaluation include a comparison of the NEET West project alternative against alternatives being considered to determine the most cost effective solution, including any alternatives whose proposed costs are to be split	The ISO is continuing its review of the preliminary reliability assessment results. If a reliability need is confirmed in the Big Creek area the ISO will evaluate potential mitigation options with respect to the identified need, including the NEET West proposal described. All the key factors listed by NEET West have been noted and would be considered in the evaluation of potential mitigation options in our comprehensive transmission plan for the Big Creek area As documented in the study plan, ISO considered low-hydro drought conditions while establishing base case assumptions. ISO modeled low-hydro generation levels in all the big creek summer peak base cases (2018SP, 2021SP, and 2026SP) for this planning cycle. The ISO found no reliability concerns in the Big Creek area base cases. The ISO also spent significant effort in developing generation assumptions for the (extreme) low-hydro sensitivity scenario, based on real time generation data for summer 2015. The ISO identified thermal overloads in the sensitivity scenario for one Category P1, two Category P3, one Category P7, and twelve Category P6 contingencies. Further

No	Comment Submitted	CAISO Response
	between the Transmission Access Charge (TAC) and operations and maintenance. • Evaluate the Midway 500 kV Substation Extreme Event outage and capture additional reliability benefits that the NEET West Pittman Hill Project has over any other alternatives. • Evaluate impact of various alternatives in relieving congestion on Path 26[3]. NEET West observed that impact of the project on Path 26 will need to be carefully examined as this path is sensitive congestion flowgate that is currently being evaluated as part of the economic assessment and that should be included in both a 33% RPS and a 50% RPS evaluation. The studies and evaluations we observed suggest that Path 26 ugprades will be required and therefore NEET West suggests consideration of a Pittman Hill substation which will provide relief on this very important path. • Evaluate potential for less reliance on Helms Pumped-Storage RAS. • Evaluate load dropping RAS at Rector under contingency conditions for all alternatives. • Determine the necessary reliance on Big Creek Generation under contingency conditions. • Quantify benefits for potential increased operational flexibility of the Helms Pumped- • Storage Plant.	market investigation of summer 2015 data reflected sufficient hydro energy availability in the market for reliable operation. According to NERC Standard TPL-001-4, corrective action plans do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed.
8c	NEET West Recommends CAISO Develop a Long-Term Reliability Transmission Solution for the West of Devers Area in 2016-2017 TPP To improve reliability and mitigate thermal overloads of the existing 230 kV transmission network in the West of Devers area[4], NEET West plans to submit a proposal to construct a new 500 kV transmission system from Mira Loma 500 kV substation to Red Bluff 500 kV substation with 50% compensation. A new Mira Loma – Red Bluff 500 kV Transmission System would provide a long term solution that: • Will eliminate and/or minimize the congestion management cost. Presently, congestion management is used to mitigate thermal issues on the existing West of Devers 230 kV and 500 kV transmission network. Depending on the amount of congestion that occurs on this	The ISO did not identify any reliability needs in the SCE Eastern area. All system performance issues can be mitigated by operation procedures or re-dispatching resources.

No	Comment Submitted	CAISO Response
	path, the costs could be significant. Construction of a new Mira Loma – Red Bluff 500 kV transmission system would reduce the amount of congestion management necessary (including generation curtailments) to alleviate the thermal issue and consequently economic savings could be realized. Further analysis would be required to quantify the economics of congestion management costs expended annually in order to maintain system reliability for this transmission line. • Minimize generation curtailment, and also continued reliance on the existing SPS, specifically Inland SPS and West of Devers SPS, and continued reliance on operating procedures for voltage and thermal control. • Complement integration of CAISO approved participating transmission owner's projects[5] and the approved competitive transmission solicitation projects. • Support Eastern LA Basin Local Capacity Requirement (LCR) Sub-Area process. The LCR need for the Eastern LA Basin sub-area is based on the need to mitigate post-transient voltage instability that is caused by the loss of the Alberhill – Serrano 500 kV line, followed by an N-2 of Red Bluff-Devers #1 and #2 500 kV lines. The LCR need to mitigate this post-transient voltage instability concern is determined to be approximately 2,230 MW (source: CAISO TPP 2015-2016), which is to be met by available resources in the Eastern LA Basin sub-area. • Reactive Power Deficiency. With the continued load growth and addition of renewable generation in the Eastern area, there is voltage degradation to the system that was observed. With the inclusion of the new proposed Mira Loma - Red Bluff 500 kV transmission system, as required to mitigate thermal overload problems, the base case voltage issues identified at the previously mentioned substations were improved. Furthermore, the study identifies the need for additional voltage support at both Red Bluff and Colorado River, and Serrano substation. This analysis will need to be conducted separately to determine an accurate amount of reactive support needed at these existing substations. • Continue to support integration of the renewable generation in CAISO. NEET West's proposed project will support the integration of renewable generation. The most recent Cluster 8 Phase 1	

No	Comment Submitted	CAISO Response
	Interconnection Study Report, SCE Eastern Bulk Area Report (January, 2016), identified numerous thermal overloads and low voltages conditions with all facilities in-service. This constraint is commonly referenced as the "West of Devers Area Deliverability Constraint". This constraint is of primary importance to California renewable integration because it affects the deliverability of generators in several energy zones, including Riverside East, Tehachapi, Imperial, San Diego South and other non-CREZ. NEET West requests that the 2016-2017 TPP evaluation include the reliability evaluation of the NEET West Mira Loma – Red Bluff 500 kV transmission project, to take into account all benefits of the project and to perform a comparison of the NEET West project alternative against alternatives considered to determine the most cost effective solution.	
8d	NEET West Recommends CAISO Develop a Long-Term Reliability Transmission Solution for the PG&E Fresno Herndon Area in 2016-2017 TPP To improve reliability and mitigate thermal overloads within the Herndon area[6], NEET West plans to submit a proposal to construct a new 230 kV transmission system that consists of a new 230/115 kV transformer at Bullard Substation and a new 230 kV transmission line from Ashlan Ave to Bullard Substations. The NEET West 230 kV transmission line between Ashlan Ave to Bullard removes the identified transient stability issues for a Bus 2 fault at Herndon 115 kV. NEET West requests that the 2016-2017 TPP evaluation include the reliability evaluation of the NEET West Herndon project and a comparison of the NEET West project alternative against alternatives being considered to determine the most cost effective solution.	Your comments have been noted. The ISO is still evaluating the need for the upgrade.
8e	NEET West Recommends CAISO Develop a Long-Term Reliability Transmission Solution for the Mesa Area in 2016-2017 TPP To improve reliability and mitigate thermal overloads within the Mesa area[7], NEET West plans to submit the project that consists of: • A new Andrew-Santa Ynez 230 kV Line • A new 230/115 kV Santa Ynez Transformer	Your comments have been noted. The ISO is still evaluating the need for the upgrade.

No	Comment Submitted	CAISO Response
	The NEET West Andrew-Santa Ynez project resolves the identified thermal overloads for a Divide- Mesa 115 kV line and Divide-Purisma 115 kV Line outage combination. It also raises the post voltage profile above 0.9 pu in a Census defined Urban Load Area. The low voltage areas identified include Santa Ynez, Buellton, Lompoc, and Solvang which are all identified on the 2010 Census identified Urban Areas (UA's) of 50,000 of more. The project provides several other important benefits including improving reliability to the Vandenberg Air Force Base[8], meets additional reliability needs not addressed by the Andrew-Midway 230 kV Project, Morro Bay Transformer Bank Project, or the Midway-Temblor 115 kV re-conductor project, introduces a redundant source into the area. Sections of the Sisquoc-Santa Ynez 115 kV line are located within High-Very High Fire Hazard Severity Zones, as defined by CAL Fire. Adding a second source into Santa Ynez from an alternative right of way would improve the reliability to the area. NEET West requests that the 2016-2017 TPP evaluation include the reliability evaluation of the NEET West Mesa project and a comparison of the NEET West project alternative against alternatives considered to determine the most cost effective solution.	
8f	**NEET West Recommends CAISO Evaluates New Pala 230 kV Substation and if Found Needed Should Be Competitively Bid in 2016-2017 TPP** To improve the reliability and thermal overloads within the Pendleton, San Luis Rey, and Ocean Ranch area[9], NEET West respectfully requests the ISO to evaluate the project that consists of: • New Pala 230 kV Loop-In Substation. Per participating Transmission Owner's presentation, this project includes: o Loop-in TL23030 into Pala o Add 230/69 kV transformer & equipment o Cost: \$20M -\$30M NEET West requests that CAISO confirm the identified overloads and if validated the project should be competitively bid.	Your comments have been noted. The ISO is still evaluating the need for the upgrade.

No	Comment Submitted	CAISO Response
9	Pacific Gas & Electric (PG&E) Submitted by: Marco Rios and Brad Wetstone	
9a	Reliability Studies – PG&E Area <u>Oakland East Bay Sensitivity Study</u> PG&E appreciates the CAISO evaluating as a sensitivity scenario the potential retirement of the current RMR contract with the ageing local generation plant in the Oakland area and the assessment of local reliability needs in the event this plant is taken out of service. We look forward to the next step in the evaluation, which should consider mitigation options and specify the requirements for any new local reliability resources that may be needed. As both the PTO and an LSE serving load in the local area, PG&E is performing its own studies and will coordinate its activities in front of both the CAISO and CPUC to ensure procurement of the best combination of resources that balances the interests of affordability with the reliability needs of PG&E customers.	Your comments have been noted. The ISO requests that the alternatives PG&E is considering be submitted into the ISO Request Window for consideration of mitigation alternatives.
9b	<u>Fresno Local Area/Re-evaluation of Previously Approved Projects</u> PG&E generally agrees with the CAISO's presentation during the Stakeholder Meeting of the revised load forecast in the Fresno Area, including increased growth in behind-the-meter PV, which has the effect of pushing out the reliability need that was the primary driver for approval of the Gates-to-Gregg (Central Valley Power Connect) 230 kV project.[2] In light of the diminished reliability driver, PG&E Transmission Planning and CAISO continue to evaluate the economic value of the project, which was a supporting factor in the original approval. We look forward to presenting the results of this analysis at the November meeting.	Your comments have been noted.
9c	Bulk Energy Storage Special Study PG&E supports the CAISO's efforts on bulk energy storage study in the 2016-17 planning cycle and offers the following recommendations. <u>Study assumptions:</u> • PG&E supports the use of the LTPP default scenarios and recommends that since the bulk energy storage case study is being conducted for 50% RPS, the 43.3% RPS portfolio should be replaced with a 50% RPS portfolio.	• The ISO is considering moving to use the 50% RPS portfolio, instead of the 43.3% RPS portfolio. • While the ISO agrees that using a single model would be simpler and help avoid discrepancies, the ISO's experience with the two models used is that they provide unique benefits in better modeling of local issues versus renewable integration and ramping requirements. We will be continuing to look to standardize and simplify this analysis in the future.

No	Comment Submitted	CAISO Response
	• Since the CAISO is planning to use a Grid View nodal model for locational benefits analysis, PG&E recommends using the same model for system-wide study also. This approach will eliminate any risk of discrepancies between the results of a zonal model study and a nodal model study. • With the assumptions that the CAISO will adopt the "Mid-case" assumptions of 2,000 MW net exports for this study, PG&E recommends at least one additional level of net export level ("High-case" assumption of 5,000 MW net export level) for a sensitivity study to capture any interaction between storage and exports. • CAISO's previous studies have assumed a $300 curtailment price for renewable energy. PG&E recommends that the CAISO revisit the curtailment price assumption and revise it to reflect the latest CPUC assumptions.[3] • Revenue Requirement Assumptions: • Generation Resource: The revenue requirement assumptions for generation resources are higher than the latest assumptions used by the CPUC for developing the renewable portfolio. Therefore PG&E recommends that the revenue requirement assumptions for this study should be aligned with the assumptions used in CPUC's RPS calculator. • Transmission Upgrade: The information included in the CAISO's presentation is not sufficient to understand the source of the transmission upgrade costs. PG&E recommends that the CAISO include the source of the transmission upgrade costs in the assumptions. • NQC factor: PG&E recommends that the NQC factors should be aligned with the most recent ELCC values for the renewable resources to ensure that the NQC factors reflect the impact of the different technologies on peak load.	• As noted earlier, due to resource constraints and the more limited scope of the special studies, the ISO will only be focusing on the 2000 MW net export case in this study cycle. • The curtailment prices of renewable will reflect the CPUC 2016 LTPP assumptions. • The ISO will update revenue requirement assumptions when the new data are available. • Source of transmission upgrade will be included. • The ISO will look into the ELCC values from the CPUC.
	Other comments: • The CAISO has listed reduction in line losses (calculated using a power flow analysis) as one of the potential locational benefits. Since a power flow model captures a single snapshot of the system only, use	Yes, line loss analysis relies on both the production simulation studies for energy and power flow analysis for the demand impact, and this

No	Comment Submitted	CAISO Response
	of a power flow analysis may not be sufficient to quantify the change in line losses Therefore in order to determine any change in line losses for the whole year, the CAISO may have to supplement the power flow analysis with the results from the nodal model production simulation results. • PG&E concurs with CAISO's recommendation to study distributed batteries as a sensitivity scenario. This sensitivity study will allow a comparison of the benefits of the two different types of storage technologies.	detail was omitted from the slides presented. The ISO relies on production simulation results if available. Many smaller projects are not suitable for production simulation analysis and power flow analysis is used in those cases with estimates extrapolated from a reasonable number of cases.

No	Comment Submitted	CAISO Response
10	San Diego Gas & Electric Submitted by: John Jontry	
10a	See the presentation, “San Diego Gas & Electric Bulk Transmission Preliminary Reliability Assessment Results”, slide #8. The 230 kV line between Sycamore Canyon and Palomar will be looped into a new Artesian 230 kV/69 kV substation in 2019. It is not clear if the study year for the load flow case represented in this diagram should have the Artesian project.	The load flow result represented in the diagram was obtained either in the 2018 summer peak or in the 2018 spring off-peak case without the Artesian 230/69 kV project. The Artesian project was modeled in the 2021 and 2026 cases.
10b	See the presentation, “San Diego Gas & Electric Bulk Transmission Preliminary Reliability Assessment Results”, slide #9. SDG&E strongly recommends against an SPS to mitigate the loss of the ECO-Miguel 500 kV line that would open the only remaining 500 kV path into the San Diego load center. Under some system conditions, this SPS would then trigger the “safety net” load shed scheme and shed up to 1000 MW of load. Note that previous iterations of the TPP relied on bypassing series capacitors upstream Suncrest to mitigate this and other overloads; however, that mitigation is no longer effective, and as SDG&E has stated repeatedly, is not an appropriate planning response for a chronic, long-term system constraint.	The SPS would basically make the N-1-1 contingency of the loss of the ECO-Miguel 500 kV line (TL50001) followed by the loss of either of the two Suncrest-Sycamore 230 kV lines (TL230054 or TL23055) similar to the N-1-1 contingency of the loss of TL50001 followed by the loss of the Ocotillo-Suncrest 500 kV line TL50003. Since the announcement of the SONGS nuclear power plant retirement, the ISO has demonstrated that the SDG&E bulk system can meet the N-1-1 contingency performance requirement by relying on System Adjustment between the 1st contingency and the 2nd contingency, which includes reducing import level via San Diego Import Transmission (SDIT) and adjusting the IV phase shifting transformers. The “safety net” was designed to shed the load under Category Extreme Event to cover circumstance under which TL50001 and TL50003 are forced out of service prior to System Adjustment or the 2nd contingency happens prior to System Adjustment.
10c	See the presentation, “San Diego Gas & Electric Bulk Transmission Preliminary Reliability Assessment Results”, slide #11. The thermal overload identified on this slide is a NERC category P3, and cannot be mitigated with controlled load shedding. The same contingency is the limiting factor determining the LCR requirement for the Greater IV/San Diego area. This constraint is forcing the procurement of generation capacity in this area; this allows the market to mitigate this contingency, but at a cost. A better approach is to mitigate the transmission constraint with a transmission solution, and allow the market to procure the required resources system-wide, rather than forcing procurement in a limited area and allowing the continuation of a constrained local market indefinitely.	Options will be considered as economic or policy-driven analysis.
10d	See the presentation, “San Diego Gas & Electric Bulk Transmission Preliminary Reliability Assessment Results”, slide #12. SDG&E has the delegated task of	The ISO looks forward to working with SDG&E and NEET West on these voltage control options.

	maintaining voltage control at Suncrest according to the CAISO's FERC-approved tariff, and is unlikely to cede control of the shunt device at Suncrest. However, SDG&E is open to exploring options to mitigate the high-voltage concerns at Suncrest identified by the CAISO, including taking control of and issuing voltage set points for the Suncrest SVC.	
10e	See the presentation, "50% Special Study and Interregional Coordination Update", slide #4. What was the selection criteria for testing the potential benefits of SWIP North and the Cross-tie project without out of state renewables? SDG&E urges CASO to investigate the benefits of all four projects both with and without out-of-state renewables. Also, was the SunZia project included in the baseline assumptions for the 50% RPS special study?	Both the SWIP North and the Cross-tie projects were portrayed as providing interregional benefits through increased ratings on other parallel paths, in addition to potentially accessing out of state renewables. The other two projects appeared to provide primarily regional benefits setting aside out of state resources being procured, and can be studied inside the appropriate regional processes. The SunZia project was not included in the baseline assumptions for the 50% special study
10f	See the presentation, "50% Special Study and Interregional Coordination Update". SDG&E agrees that the 50% renewables study should be evaluated using the AC-DC line conversion project Renewable Energy Express (REX), as proposed to ISO in the current transmission plan. We support the CAISO's efforts to evaluate the benefits of this and other interregional projects and how they support the new RPS goal.	This comment has been noted.
10g	See the presentation, "Characteristics of Slow Response Local Capacity Resources Special Study". SDG&E agrees with the need to look at Demand Response and other slow-response resources as part of a short term studies and analyze the impact of these resources in our system from an operational flexibility perspective and not as a congestion mitigation tool. The precision of the forecast of the Demand Response program does not exactly follow physics laws; as it there is the need to trust that customers will participate when needed. Our recommendation is to set an upper limit of DR to be counted for local RA, or it should not be relied on at all.	This comment has been noted. This comment should also be provided into the joint stakeholder efforts for local resource adequacy resource considerations, as consistency between resource adequacy and transmission planning analysis needs to be maintained.
10h	See the presentation, "Gas-Electric Coordination Summer 2017 Transmission Planning Assessment for Various Gas Curtailment Scenarios with the Aliso Canyon Gas Storage Outage". During the CAISO's assessment for various gas curtailment scenarios involving the Aliso Canyon gas storage constraints, a series of reliability concerns were identified. SDG&E agrees that current approved infrastructure upgrades and rearrangements (e.g. Mesa Rim Loop-in)	This comment has been noted.

	in the Southern California area need to be approved and built in order to avoid some of the risk involved in the Aliso Canyon Gas Storage Outage.	
10i	See the presentation, "Frequency Response Assessment-Generation Modeling Special Study – Update". SDG&E is currently participating in most of the WECC efforts to upgrade the model of the generators in our system. We are current in all their requests to provide data needed to achieve this goal.	The ISO looks forward to working with SDG&E on improving dynamic data modeling as part of MOD 032 and MOD 033 compliance.
10j	See the presentation, "A Bulk Energy Storage Resource Case Study with 50% RPS". SDG&E is currently working to meet the CA 2013 mandate to procure energy storage for our system in all three levels of operation including transmission, distribution and behind the meter sites. Potential sites for Bulk Energy Storage could be at locations where transmission infrastructure is available and renewable generation plants are close by (e.g. Imperial Valley). Dispatch and operation of these units have been discussed for a while now and they seem to add a significant benefit to congestion management and resource adequacy for LCR studies, but further investigation needs to be done in the power flow and dynamic stability areas.	This comment has been noted.

No	Comment Submitted	CAISO Response
11	San Diego Gas & Electric Submitted by: Effat Moussa	
11a	The CAISO's September 21-22, 2016 presentation on the "50% Special Study and Interregional Coordination Update Performed as part of 2016-2017 Transmission Planning Process" indicates that four interregional transmission projects (ITPs) were submitted to the three of the four Western Planning Regions. The presentation states that "California ISO, NTTG, and WestConnect developed evaluation plans for each of the ITP proposals." SDG&E has reviewed the June 14, 2016 "ITP Evaluation Process Plan, AC to DC Conversion Project"[1] referenced on Page 4 of the presentation. According to the evaluation plan: The objective of the California ISO analysis will be to assess, at a "high" or "cursory" level, the AC to DC Conversion Project within the framework of California's 50% renewables portfolio. Using New Mexico wind portfolio information provided by the California Public Utilities Commission (CPUC), the assessment will attempt to capture the following with and without the AC to DC Conversion Project: • transmission capability to deliver New Mexico wind resources to California; • identify renewable curtailments; • coordinate topology and resource modeling with WestConnect; • jointly working with WestConnect, consider analysis results and as appropriate, develop recommendations and input refinements should further analysis be conducted in future study cycles While the "ITP Evaluation Process Plan, AC to DC Conversion Project" references "benefits" on page 7, there is no explanation of how such benefits will be estimated, or indeed, whether "benefits" will be estimated at all. SDG&E recommends that the 50% Special Study and Interregional Coordination Update Performed as part of 2016-2017 Transmission Planning Process include an evaluation of the benefits of adding the REX transmission project as compared to not adding the project.	Thank you for the analysis.

	This evaluation should estimate the benefits associated with (i) the REX transmission project's ability to facilitate the development of new wind resources in New Mexico, as compared to the development of renewable resources in other areas, (ii) the reduction in production costs that may be associated with the addition of the project, and (iii) the reduction in Resource Adequacy (RA) costs that can be achieved if the project is built. SDG&E believes that this latter category of benefits may, in fact, provide the largest share of the project's benefits. SDG&E bases its belief on its own conceptual evaluation of the RA benefits that the project provides. This evaluation is summarized below and SDG&E recommends that the CAISO and WestConnect perform their own independent evaluation of these benefits. For purposes of modeling the conceptual economic feasibility of the REX transmission project, SDG&E performed analysis to estimate the amount by which the addition of the project would reduce Local Capacity Requirements (LCRs) in the Greater Imperial Valley-San Diego (GIV-SD) LCR area, in the San Diego (SD) LCR area and in the Los Angeles (LA) basin LCR area. The reduction in LCRs means that load serving entities (LSEs) within these areas are able to reduce their purchases of relatively costly local Resource Adequacy (RA) capacity, with a corresponding increase in the amount of relatively less costly system RA capacity that must be purchased. The LCR analysis determines the maximum reliable level of imports into each LCR area under the most limiting N-1-1 contingency condition, assuming peak load during an extreme 1-year-in-10 summer weather condition. Given the maximum level of imports and the peak load within the LCR area, it is possible to calculate the amount of dependable capacity that must be procured within each LCR area in order to maintain service to all loads under the studied condition. Based on SDG&E's analysis, constructing the REX transmission project reduces LCRs in the GIV-SD LCR area, in the SD LCR area and in the LA basin area by the following amounts:	

Table 1
Change in System and Local RA Requirements
(MW for the period 2025 through 2085)

GIV-SD LCR Area	(1531)
SD Area LCR Area	(858)
LA basin LCR Area	(196)
System	1727

To estimate the net reduction in RA procurement costs that will occur over the life cycle of the REX transmission project (assumed to be 2025 through 2085) as a result of reduced LCRs, long-term projections of local and system RA costs were made without and with the REX transmission project. These projections are based on known or estimated current local and system RA capacity prices ($/kW-year), a forecast of the year in which the amount of dependable capacity within each of the LCR areas (accounting for expected retirements) drops below the respective LCRs, a forecast of the year in which the amount of dependable capacity within the WECC region (accounting for expected retirements) drops below WECC system load plus a 15% planning reserve margin, and the cost of a new gas turbine net of estimated market revenues (Cost of New Entry or "CONE").

It is assumed that when dependable capacity drops below the requirement, new gas turbine capacity would be added as necessary to close the deficiency. Linear interpolation was used to estimate the RA capacity prices between current levels and the price of a gas turbine at such time as each LCR area, and the WECC system as a whole, become deficient in dependable capacity.

Estimated local and system RA capacity prices without and with the REX transmission project are shown below.

Table 2
RA Capacity Prices
(levelized $/kW-yr for the period 2025 through 2085)

	w/o REX Transmission Project	with REX Transmission Project
GIV-SD LCR Area	205	201
SD Area LCR Area	238	231
LA basin LCR Area	278	278
System	175	175

Based on the reduction in required local RA capacity and the associated increase in system RA capacity shown on Table 1, and the RA prices shown on Table 2, SDG&E estimates that the REX transmission project will provide $110 million/year in levelized benefits over the sixty year life of the project as compared to not adding the project.[2]

As a key element of the ITP evaluation to be conducted in the 50% Special Study and Interregional Coordination Update Performed as part of 2016-2017 Transmission Planning Process, SDG&E looks forward to the results of the CAISO's and WestConnect's evaluation—comparable to the evaluation described above—of the REX transmission project's benefits.

No	Comment Submitted	CAISO Response
12	Silicon Valley Power Submitted by: Joyce Kinnear	
12a	Support the Comments of BAMx As a member of BAMx, SVP supports the comments made by BAMx concerning the PTO Request Window submissions and the CAISO Special Studies.	Please refer to 2 above.
12b	PTO Request Window Project Applications PG&E Request Window Submission: Caltrain Electrification Project For the FMC location, PG&E identifies the need to increase capacity of the Trimble - San Jose 'B' 115 kV line due to several P2, P3 and P6 contingencies. The CAISO also identified that this line appeared as limiting element in its bulk system studies of the PG&E area. Furthermore, this line also appeared as a limitation in the study of SVP's Phase Shifter project. As such, SVP supports that the upgrade of this line be included in the Caltrain Electrification Project scope.	Your comment has been noted.

<table>
<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td>13</td><td colspan="2">Transmission Agency of Northern California
Submitted by: David Oliver</td></tr>
<tr><td>13a</td><td>The Transmission Agency of Northern California (TANC) appreciates this opportunity to provide comments on the California Independent System Operator's (CAISO) 2016-2017 Transmission Plan September 21-22, 2015 stakeholder meetings primarily detailing results of the reliability studies performed by the CAISO and the Investor Owned Utilities (IOUs). TANC is discouraged by the CAISO's continued reliance on potential derates to the California-Oregon Intertie (COI) to mitigate identified reliability issues on the CAISO system when, in several instances, other options exist to mitigate such problems.

TANC urges the CAISO give more credence to and explore alternative solutions that do not limit the import capacity of the COI. During the first day of the stakeholder meetings, the CAISO presented its reliability results for the Pacific Gas & Electric's (PG&E) Bulk System, within which the COI facilities are located. As shown in Table 1, the CAISO identified multiple reliability issues that could be mitigated by upgrading the impacted facility; by bypassing the series capacitors in the affected line (or a "downstream" line); or by reducing the imports over the COI.

<table><tr><th colspan="2">TABLE 1</th></tr><tr><td>Impacted Facility</td><td>Potential Mitigation</td></tr><tr><td colspan="2">P1 (N-1) Outages</td></tr><tr><td>Round Mt-Table Mt #1 or #2 500-kV line</td><td>Bypass series capacitors in overloaded line or in the Table Mt-Vaca Dixon line or reduce COI</td></tr><tr><td colspan="2">P6 (N-1-1) Outages</td></tr><tr><td>Round Mt-Table Mt #1 or #2 500-kV line</td><td>Bypass series capacitors in the overloaded line or in the Table Mt-Vaca Dixon line or reduce COI</td></tr><tr><td>Cottonwood-Round Mt #3 230-kV line</td><td>Upgrade the line or limit COI flows during on-peak conditions</td></tr><tr><td colspan="2">P7 (N-2) Outages</td></tr><tr><td>Cottonwood-Round Mt #3 230-kV line</td><td>Upgrade the line or limit COI</td></tr></table>
TANC believes the reliance on curtailing COI imports and limiting the transfer capabilities between the Pacific Northwest and California, is inefficient and inappropriate for the CAISO to use as a mitigation resource. As a Balancing Authority (BA), the CAISO should not be taking actions that limit transfer</td><td>The reliability assessment conducted in the ISO 2016-2017 transmission planning process for the PG&E Bulk System did not identify any reliability violations with the system operating with flows on COI within a nomogram or operating system configurations. This stage of the ISO transmission planning process and stakeholder meeting was to present the results of the reliability assessment. The ISO will be conducting economic analysis as a part of the ISO transmission planning process and presenting the preliminary results of the economic analysis at the November 17, 2016 stakeholder meeting and including the results in the ISO Draft 2016-2017 Transmission Plan that will be posted for stakeholder comment on January 31, 2017 per the ISO Tariff.

Further to this the ISO has conducted economic analysis in previous ISO transmission planning process per the ISO Tariff. Within the previous ISO transmission planning processes the ISO has identified economical-driven projects as indicated; however the economic assessments have not identified benefits to support upgrades to COI. The ISO will continue to assess the ISO system through the reliability, policy and economic assessments of the ISO transmission planning process per the ISO tariff to develop the transmission plans for the system.</td></tr>
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	capabilities. Such actions do not only effect the import of the CAISO BA but also adversely affect the Balancing Authority of Northern California (BANC) and Turlock Irrigation District (TID) BAs, as well as market participants in the Pacific Northwest. The CAISO's proposed regional expansion also should lead the CAISO to seek solutions that do not limit transfers between balancing regions. As has been noted in the CAISO SB350 studies and the PacifiCorp Economic benefits study, the benefits are increased by maximizing the transfer capability between regions based both on increased economic dispatch and resource adequacy savings. Furthermore, with additional[2] Pacific Northwest participants in Energy Imbalance Market (EIM), the economic benefits of higher transfer capability will also increase. Additionally the CAISO has not provided any economic analysis to show that limiting the COI is more economic than other alternative mitigation measures. This violates the CAISO Tariff at 24.4.6.2, "The CAISO will determine the solution that meets the identified reliability need in the more efficient or cost effective manner." CAISO has approved several projects in the Southwest, such as Devers-Colorado River and Harry Allen-Eldorado, primarily on the economics of increased intertie capacity and/or increased flows on existing paths. Therefore it is puzzling why the CAISO would so readily rely on a mitigation strategy that would limit the intertie capacity between the Pacific Northwest and Northern California, when it is contrary to the practice the CAISO has employed on other parts of the California grid. As a BA, the CAISO should not be taking actions that limit intertie transfer capabilities. During the presentation of the PG&E Bulk system, flows along the COI were presented including approximately 2,000 MW of South to North flow during the 2018 and 2019 Spring Off-peak case. TANC notes that South to North flows are very rare on the COI especially at levels of 2000 MWs, and are the result of very specific system conditions. TANC understands that a growing amount of overgeneration in the state may have an effect on the direction of flows, but most of this occurs in Southern California. TANC requests that the CAISO provide a complete and detailed description of the case studies load and generation as well as the mechanism by which they lead to this dramatic change.	

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11b	Finally, TANC commends the CAISO for its continuing evaluation of the needs of previously approved projects within the PG&E service territory. TANC would recommend, in light of the anticipated declining loads and increased energy efficiency and distributed generation expected in the next decade (per the California Energy Commission (CEC)) that the CAISO should examine all previous projects that have been approved, not just those in the PG&E's service territory. As an example, TANC would strongly suggest a second look at the Harry Allen – Eldorado 500-kV Project that was approved in the 2013-14 TPP. The "Scenario 2016 in Excel v1.2" from the CEC, dated August 5, 2016,[1] shows a resource surplus of around 30-40% through 2036. A significant amount of the economic benefits of the Harry Allen – Eldorado Project came from anticipated capacity benefits that the CAISO economic studies perceived – from studies that indicated that SP26 would be resource 'short' by 2019-20. Based upon the current CEC analysis and the CAISO's own push through the RETI process for Energy-Only interconnections – this Project may no longer provide the economic benefits or justification that the CAISO previously stated.	Transmission projects that are driven by load growth – such as many in the PG&E area that are being reviewed - are the most likely candidates to be considered for review, but as noted earlier in response to other comments, the ISO reviews projects where a material change in circumstance has been identified. While there have been increases and decreases on the various factors supporting the increased transfer capability, the ISO considers that the need remains, especially in light of increasing transfer opportunities, renewable generation integration, and the increasing RPS requirement to 50%. For clarity, the ISO has supported the RETI initiative by providing information both on the capability of the system as currently planned to accommodate energy-only generation, and providing information on the limitations and potential mitigations on additional deliverable generation. It is incorrect to characterize that support for the process and information the CPUC may find helpful in future procurement considerations as a "push" for energy-only interconnections.

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14	TransCanyon Submitted by: Jason Smith and Bob Smith	
14a	TransCanyon, LLC ("TransCanyon") appreciates CAISO's efforts in producing the reliability assessment presented at the 09/21-22 stakeholder meetings. We are in general agreement with the reliability results and study methodologies for special studies presented at the stakeholder meeting. We encourage the ISO to continue to monitor the Once-Through Cooling ("OTC") generation along with retirement of aging assets and early economic retirement of generating units and their impact on overall system reliability. TransCanyon understands that the reliability analysis and results indicate the need and dependency on various potential mitigation plans, interim action plans that include load transfer, or re-dispatch of generation, in addition to use of preferred resources under many outage conditions. Recognizing the value of such measures under certain circumstances, TransCanyon also notes that operating the current transmission infrastructure by means of numerous operating procedures could lead to compromised reliability or other undesirable consequences during real-time system operations. TransCanyon generally agrees with the findings presented in the reliability assessment for minimum generation requirements for the LA Basin and San Diego areas and is looking forward to understanding system capability from the long-term assessment at the next stakeholder meeting. In addition we are also keen on understanding the results of the economic early retirement of gas generation based on the proposed methodology. Based on the reliability analysis, especially in the LA Basin and SDG&E system under stressed system conditions, the CAISO needs to maintain minimum generation based on Local Capacity Requirements, which may be difficult based on the gas-electric coordination study and early economic retirements study. We expect new transmission capacity into the region will be complementary to other proposed mitigations and will make the system more robust and reliable.	Your comments have been noted.

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	TransCanyon appreciates the CAISO's facilitation of the 50% scenario work with the Northern Tier Transmission Group and WestConnect as a part of the Interregional Transmission Planning project evaluations. Consideration of the 50% Special Study, Interregional Coordination Update, and RETI 2.0 objectives for considering wind renewables in Wyoming and New Mexico are important to the overall scope of the 2016-2017 regional studies.	