The ISO received comments on the topics discussed at the September 21-22, 2016 stakeholder meeting and the October 3, 2016 Joint ISO/CPUC Workshop from the following:

1. California Large Energy Consumers Association (CLECA)
2. NRG Energy, Inc. (NRG)
3. Pacific Gas & Electric (PG&E)
4. Southern California Edison (SCE)
5. Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities)
6. San Diego Gas & Electric (SDG&E)

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	California Large Energy Consumers Association (CLECA) Submitted by: Nora Sheriff and Barbara Barkovich	
1a	<u>Initial Results Demonstrate that Local Resource Adequacy (RA) Response Time Requirements Do Not Need To Be Changed in the CAISO's 2016-2017 TPP and the CPUC's June 2017 RA Decision</u> The workshop examined how Demand Response or any slower-response energy limited resource can contribute to local RA needs. The initial premise was that these resources could not respond quickly enough after a contingency to meet the local need. The workshop reviewed initial analyses of how much "pre-dispatch" would need to occur to have those resources ready. For example, on hot days in case of a contingency, the pre-dispatch would line the resources up and have them ready for dispatch ahead of time. CLECA appreciates the time and effort put in by the utilities, CAISO staff and CPUC staff to examine these important issues. Initial results are reassuring; while more work is needed to critically and accurately examine the issues, it does appear that most of the current suite of DR resources can meet local RA needs. Notably, based on the initial study results and the discussion at the workshop, the existing response time requirements for local capacity resources do not need to be altered in this 2016-2017 transmission planning cycle or for the June 2017 RA decision by the CPUC for the 2018 RA compliance year. Stakeholders, the CAISO and the CPUC can and should continue to study the slow-start, energy limited resources; this continued study does not need to hold up the CAISO's conclusion of its 2016-2017 TPP. Slide 33 shows that for SCE, as Commissioner Florio stated at the workshop, "most of the DR can meet the sufficient energy criteria." Slide 69 elaborates on the data showing that most of the existing SCE DR "can meet local RA needs at current levels" and for El Nido, the forecasting issues (discussed below) distort the results. It is likely that the existing DR in the El Nido area is sufficient. Accordingly, given the results of the analysis and the workshop discussion, stakeholders and the CPUC and CAISO should undertake more analysis and develop workable methodologies and consider reasonable performance requirements for these resources; this ongoing work could be concluded in the next TPP cycle and the June 2018 CPUC RA decision.	It is not clear what the statement "the CAISO's conclusion of its 2016-2017 TPP" is referring to. As per the CAISO executive decision, the ISO will use its discretion not to exercise its Capacity Procurement Mechanism authority to address annual resource deficiencies that are directly attributable to a discrepancy between a local regulatory authority's resource adequacy counting rules for demand response resources and ISO's Local Capacity Technical Study. The CAISO agrees that this special study work and RA integration policies are finalized and implemented by the 2018 RA compliance year.

No	Comment Submitted	CAISO Response
1b	Additional Analysis Is Needed The timeline for the 2016-2017 TPP provides only a 30-day period to refine the results based on comments (October 11-Nov. 11), an update to stakeholders on Nov. 16, and one opportunity for stakeholder comments after that. The discussion at the workshop recognized the concerns with the initial, overly simplistic methodologies for analyzing these DR resources, including the issues with how to accurately scale-up a flat load shape for a one-in-ten forecast that doesn't overestimate the amount of "sufficient energy" or number of "calls" of DR.	The schedule will be reasonably extended to give the utilities and ISO time to update the input data and study results.
1c	Slides 23-24 describe the scaling up process for load. However, for areas with flat load shapes, such as El Nido (which consists primarily of industrial load), the scaled up forecast will be greatly overstated for the one-in-ten scenario. This leads to results that represent not an average of what is needed, but an extreme of what is needed. To set the 1 in 10 correctly, flat load should not simply be scaled up; while slide 24 shows how "peaky" load can be scaled up, if the load curve is flat, scaling up in this manner to create a 1 in 10 forecast results in an inflated estimate of how much DR would be required. For industrial or flat loads, most of which are not temperature-sensitive, consideration should be given to actual recorded loads, or other approaches, rather than a simplistic scaling up.	Please refer to the above comment.
1d	At the workshop, utility personnel agreed that thirty days is not enough time to resolve the issues with load forecasting for industrial areas. Fortunately, given the initial results, more time than the thirty days in the TPP schedule can be devoted to this issue.	Please refer to the above comment. As noted above, however, these issues require expeditious consideration to avoid unduly impacting transmission planning decisions as well as 2018 local resource adequacy procurement decisions.
1e	Per slide 4, the following also needs to be developed: "Identify a method to ensure that resources are not overly dispatched pre-contingency without good cause" "Identify a method to calculate the portion of a slower responding DR program that can reliably respond within the required period, and therefore be counted for Local RA" Additional work is required on these topics. And stakeholders and staff of the CAISO and CPUC need to address the potential mis-alignment of local areas with sub areas.	PDR bids are not subject to local market power mitigation, i.e. they can bid up to the energy cap, as appropriate, and can include commitment costs. Thus, PDR bids can incorporate customer opportunity costs in their energy bids up to the energy bid cap, and PDRs can submit PMin and start-up (shutdown) costs. Additionally, use-limited PDRs can incorporate a market opportunity cost adder to their commitment costs with implementation of the CAISO's commitment cost enhancements phase 3 initiative.

No	Comment Submitted	CAISO Response
		The CAISO is unclear about what "mis-alignment" exists between local areas and sub-areas. Identifying sub-areas needs is, and has been a core element of the CAISO's LCR technical study.
1f	It could also be informative to examine the history of TOP-007 which sets the NERC requirements for stability and review how the 30 minutes response time requirement was developed; it could be that the circumstances dictating a 30 minute response time are no longer fully applicable or may have changed since the standard was developed.	TOP-007 is a NERC vetted and approved mandatory standard the ISO is required to follow.
1g	Additionally, regarding the presentation's reference to a Day Ahead dispatch, this could be 4 hours or 12 hours in advance; it was unclear in the workshop discussion what "sufficiently in advance" means for operational purposes; these "sufficiently in advance" parameters were not defined and perhaps not developed. The parameters around what is sufficient advance predispatch need further exploration.	The ISO will rely on day ahead dispatch of pre-contingency dispatch resources through its Minimum Online Commitment constraint.
1h	Finally, the next iteration of the analysis should study the LA Basin area and the SDG&E area on a stand-alone basis. According to the workshop presentation (slide 59), the analysis combined the two; the explanation for the combination was that it was due to the interdependence that developed between the areas after the SONGS retirement, and that the load characteristic of the combined area is what is important. LA and San Diego should be analyzed on their own under Method 2.	For one of the most limiting contingencies, the N-1-1 loss of Sunrise and SWPL, the combined area load is the load that impacts the voltage collapse concern. Thus, the combined load shape of the two areas must be studied even if resource procurement responsibilities are split between the two areas. The CPUC Track 4 scoping ruling specifically recognized the electrical interdependence of the two areas, which noted "Due to the interdependency of the LA Basin local area and San Diego sub-area on the SONGS facility, one comprehensive set of studies will be conducted. Collectively this area is referred to as the SONGS Study Area."
1i	<u>Need to Connect the Dots Between Planning and Operations</u> Planning focuses on meeting peak load in a stressed August month; operations focuses on meeting load all 8,760 hours in the year. Planning's peak August load is turned into a monthly	The framework for local capacity requirements and the rules for determining local RA requirements is set out in the ISO's tariff, and is not attributable to "planning" or "operations".

No	Comment Submitted	CAISO Response
	RA requirement, but it is not clear how operationally the minimum online commitment (MOC) process (run on a day-ahead basis) relates to the monthly planning RA requirement. There is a real concern that the analysis presented at the workshop would lead to consistent overprocurement of local RA – and perhaps not just from DR resources. This needs further exploration.	The analysis presented at the workshop was for the purpose of identifying the required characteristics for slow response resources—not for determining the amount of local capacity procurement.
1j	<u>Real-time Contingency Triggers for Reliability Demand Response Resources Must Be Acknowledged</u> It is not clear to CLECA, based on the discussion at the workshop, that all stakeholders are fully aware of the contingency requirements for RDRR's participation in the real-time market and there are questions on how they interact with voluntary participation in the day-ahead market. RDRR participates in the real-time market on a contingency basis pursuant to Tariff section 34.18 "for reliability or to perform a test." CAISO Operating Procedure 4420 expands on the reliability real-time dispatch triggers. Under OP 4420, to "prevent, mitigate or otherwise manage a system emergency", RDRR may be dispatched in real time in response to the following: • A declaration of a transmission emergency per section 3.3 of OP 4420; or • A warning notice of an operating reserve deficiency per section 3.4.2 of OP 4420; One of these contingencies must occur before RDRR is entered into the real time market bid stack; RDRR's real time bid price is set at 95% of the bid cap. RDRR participation in the realtime market should be rare and infrequent, as it is an emergency resource intended to "prevent, mitigate or otherwise manage a system emergency." Voluntary participation in the day-ahead market is very different and not predicated on these contingencies. A Reliability Demand Response Resource's voluntary participation in the day-ahead market in a manner similar to price-responsive Proxy DR (PDR) as opposed to contingency-triggered reliability DR in the real time market must be separately and carefully considered.	As CLECA notes, RDRR is eligible for dispatch by the CAISO when: • A declaration of a transmission emergency per section 3.3 of OP 4420; or • A warning notice of an operating reserve deficiency per section 3.4.2 of OP 4420; However, the statement that *"[o]ne of these contingencies must occur before RDRR is entered into the real time market bid stack*" is not fully accurate. If either of the above conditions is met, the CAISO can release RDRR for dispatch in real-time. RDRR resource are allowed up to 40 minutes to reach their full curtailment amount, and RDRR resources can elect to participate economically in the DA market. If a RDRR can participate economically in the DA market, it is not subject to the 2% RA cap per the RDRR settlement agreement. A RDRR resource could qualify as local capacity as a post-contingency, fast response resource based on its response time recorded in the ISO masterfile. Other RDRR resources that are slow responding, up to 40 minutes (per the settlement agreement), are suitable as system RA resources. RDRR comes in two flavors, 1) an emergency only resource that is only eligible for dispatch in real-time under the conditions stated above, and 2) an RDRR that can be bid economically in the DA market, but subject to the dispatch provision described above in real-time, if not already fully committed in the DA market. Slow response RDRR resources that can be economically bid in the DA are well-suited for pre-contingency dispatch as local RA resources and can help avoid transmission and generation procurement. Economically bid slow response RDRR can

No	Comment Submitted	CAISO Response
	SCE's slide 106 notes the current inability to bid RDRR "economically" in the real-time market in order to decrement a Day-Ahead award to the RDRR resource. We speculate that this may be a result of SCE's treatment of its Summer Discount Program in the CAISO market as RDRR. SDP behaves very differently from other RDRR such as Agricultural Pumping-Interruptible (API) or the Base Interruptible Program (BIP) since it has triggers that are not reliability-based. SCE suggests as a potential solution that "RDRRs with Day-Ahead awards could be exempt from the current requirement for RDRR RT bids at 95% of bid cap." (SCE slide 106.) CLECA has serious concerns about this proposal for AP-I or BIP, which have reliability-based triggers to participate in the real time market and not price-based triggers. CLECA believes that far more attention must be paid to the different characteristics of RDRR and PDR for different programs before the implications of proposals such as SCE's can be considered. While CLECA strongly supports finding a way to enable customers that provide contingency-triggered RDRR in the real time market to also provide economic or price-responsive demand response on a voluntary, dayahead basis, CLECA cautions against turning a proven emergency resource into an unproven economic resource.	manage its use and availability through economic bids that reflect energy, commitment costs, and opportunity costs. The RDRR product was the result of a multi-party settlement agreement approved by the CPUC. Reconfiguring the RDRR product is not in the scope of this special study.
1k	<u>Conclusion</u> As Commissioner Florio recognized at the end of the workshop, "we need to dig into [this] a bit more." Specifically, we need a more detailed analysis of the meaning of commitment or predispatch for a DR resource, and whether there is a difference. We also need to understand how much pre-dispatch is really likely to be required. In addition, the forecasting methodologies need additional work to improve their accuracy, particularly for flat industrial load shapes. CLECA appreciates this opportunity to provide its comments and looks forward to the continued efforts of all involved on demand response integration into the CAISO's markets.	

No	Comment Submitted	CAISO Response
2	NRG Energy, Inc. (NRG) Submitted by: Monica Berry and Brian Theaker	
	NRG Energy, Inc. ("NRG") provides these comments on the Slow Response Local Capacity Resource discussions presented October 3, 2016 at the CAISO-CPUC Joint Workshop. NRG appreciates this opportunity to contribute to the discussions on how to integrate more effectively demand response ("DR") and behind the meter ("BTM") energy storage resources into the CAISO markets, and how to maximize the value of such resources. For purposes of these comments, NRG focuses on CAISO's efforts to address how "slow response" DR can help the CAISO effectively address NERC, WECC and ISO reliability standards applicable to local areas. In particular, NRG submits that pre-dispatching DR to meet local area reliability needs is an inefficient use of demand response, and ought to be a last resort where approaches adopted in other markets may be better suited to capture the value and reliability benefits that DR can provide to California's electric grid. Preliminary results of CAISO and IOU analyses conclude that DR in the existing programs could be "pre-dispatched" to meet local area reliability, with the exception of certain local reliability areas or sub-areas (e.g., El Nido, Big Creek/Ventura. Humboldt, Sierra, Stockton, Kern). However, pre-dispatching DR for local reliability presents substantial challenges, as discussed further below. Southern California Edison ("SCE") correctly pointed out that because some DR programs have call limits and/or a limited number of hours, the opportunity cost of deploying DR would result in sub-optimal use of DR. For example, DR resources with a limited number of calls (not MWh) calculate the opportunity cost on a per call or hour (not per MWh) basis. The result is partial DR dispatch, resulting in inefficient use of DR. Namely, a partial dispatch would recover only a fraction of the opportunity cost, where the resource could have been used at a time of higher system need (value). Moreover, a partial dispatch of DR may nonetheless count in full towards the applicable service limit, further limiting DR participation and eroding its potential contribution to grid reliability.	The CAISO appreciates NRG's comments and understands the current concern about partial dispatch, especially under the structure of existing programs and legacy dispatch technologies and procedures. The CAISO anticipates the next generation of supply demand resources, and DR program reconfiguration will introduce much more advanced dispatch capabilities at more granular levels and with greater precision. Such refinement will ensure DR is a flexible resource well suited to efficiently meet the needs of the grid and the needs of customers.

No	Comment Submitted	CAISO Response
	Pre-dispatching DR presents other challenges. For example, pre-dispatching DR would require calling on DR on a pre-contingency basis, based on forecast load levels. If loads are not accurately forecast, DR may be activated when it is not needed. This risk not only impacts the opportunity cost of DR; pre-dispatching DR could promote program fatigue and could negatively impact program enrollment. Such inefficient use of DR should not be accepted without fully exploring and vetting market design alternatives. Accordingly, NRG encourages the CAISO to look to experiences in other ISOs (notably, PJM) to identify how those ISOs have dealt with this issue. NRG looks forward to participating in this process to determine the efficient and effective use of DR for local reliability needs.	The ISO is already unique among ISOs and RTOs within the United States in utilizing demand response programs to address transmission-contingency driven local capacity needs, much less slow response demand response.

No	Comment Submitted	CAISO Response
3	Pacific Gas & Electric (PG&E) Submitted by: Marco Rios and Brad Wetstone	
3a	PG&E provides the following comments on the preliminary results of the CAISO's Slow Response Local Capacity Resources Special Study, presented at the CAISO Transmission Planning Process (TPP) stakeholder meeting held September 21-22, 2016, and further elaborated in the joint CPUC-CAISO Workshop held on October 3, 2016. The purpose of these efforts is to establish a coordinated process and set forth criteria for slow response resources to meet CAISO local capacity requirements and qualify for CPUC jurisdictional local Resource Adequacy (RA). At issue are the operational requirements for timely response to a local (N-1) contingency, in order to allow CAISO flexibility to restore the system to a secure state in the event of a subsequent (N-1-1) contingency. While some resources are able to respond in time to meet the CAISO's operational time horizon1, there is a potentially large pool of resources that may only be able to respond if notified or dispatched on a longer lead time basis. The current process seeks to clarify the operating characteristics that are necessary for slow response resources to be dispatched on a pre N-1 contingency basis in order to meet local area needs.	
3b	<u>Schedule and Timing Issues</u> During the workshop, the CAISO represented that its objective is to establish a process and have it in place in time for the CPUC's 2018 RA year. PG&E respectfully submits that this timetable is overly optimistic. Given the multitude and complexity of regulatory processes underway at both the CAISO and CPUC, it is not possible or advisable to drive this subject to a rapid conclusion. The CAISO started the 2017 Local Capacity Requirements (LCR) process with a market notice on October 15, 2015, and stakeholder meeting on October 29, 2015. Consequently, if the past is any indication of the future, the 2018 LCR process should begin in the next three weeks. Given the time necessary for the LCR process, modifying the 2018 LCR process for the inclusion of the proposed changes is likely to lead to error and inaccuracies. PG&E believes it is more important to get this done right than to get it done quickly.	While the ISO agrees that it is important to address these issues correctly, taking an overly relaxed schedule as PG&E encourages could have negative impacts on reliability if these resources are relied upon without the necessary framework to call upon them when needed. A reasonable goal for this effort is to incorporate necessary changes for slow response resources into the 2018 RA program. The next opportunity would be the 2019 RA year, which is an additional 2 years added onto this process, which is not acceptable from the CAISO's perspective.

No	Comment Submitted	CAISO Response
	Further, results from the study plan presented by the IOUs and the CAISO suggest that at current levels slow response demand response resources generally have sufficient availability to be called by the CAISO on a pre-contingency basis if needed. Based on this finding, there is no pressing need to change the existing CPUC RA counting rules with respect to slow response demand response resources. The CPUC is currently considering multiple changes to both the structure of the IOU demand response portfolios and the IOU RA procurement regime in open proceedings R.14-10-010 (Resource Adequacy) and R.13-09-011 (Demand Response). Any change to the counting conventions for demand response as an RA resource will have to be considered in the context of other changes scoped in the R.14-10-010 proceeding, including the ELCC methodology for counting of wind and solar resources, the durable definition of flexibility, and potential multi-year forward RA obligations.	
	Moreover, PG&E notes that local RA requirements of the IOUs are currently met based on annual showings where the same resource must be shown in all 12 months of the year. This may result in a general tendency to overstate monthly local area RA requirements in local areas where loads vary significantly based on seasonal characteristics. PG&E suggests that rather than taking on the slow response demand response criteria issues as an isolated issue, it would be more productive to review and update the overall study framework for local area needs to more accurately meet monthly local requirements. PG&E is also concerned with the enforcement of the doctrine of "resource neutrality." The CPUC and CAISO must assure that all resources counting for a particular requirement (e.g. local RA) can meet the standards that are required to satisfy the requirement.	There is not a requirement to show the same local capacity resources in each of the twelve months in an RA compliance year. PG&E can mix and match resources to meet its local RA requirement by month in the annual local capacity showing. Thus, PG&E can show DR in the summer months, but not in the winter months in their annual local capacity RA showing.
	Once an initial process is established for pre-contingency resources to qualify to meet CAISO local capacity requirements, PG&E notes that it will also be necessary for stakeholders to agree on when to revisit the assumptions used to define demand response resources that are included in the LCR technical study, as load profiles and local network conditions evolve. The study should be revisited routinely as a part of the CAISO's annual LCR study process.	The CAISO is proposing that the slow response resource study be incorporated into the annual LCR process, meaning assumptions can be as vetted and determined in that annual, recurring process.

No	Comment Submitted	CAISO Response
3c	Area/Sub-Area Definitions One of the challenges uncovered during development of the preliminary technical studies is the mismatch between the demand response resource breakdown by IOU Distribution Area (used to map demand response resources) and the Local Capacity Areas (LCA), as defined periodically, based on power flow analysis by the ISO. PG&E hopes that the recurring study process will include a consistent methodology mapping the LCAs with the utility demand response data to ensure accurate alignment between these two data sources. It is important for achieving the local reliability objective that the demand response resources that are shown for local requirements are, in fact, located electrically within the LCA of concern (which may vary, depending on the specific CAISO contingency scenario that triggers the LCR deficiency). For PG&E's service area, there are limited demand response resources in LCA sub-areas and Local RA procurement is conducted only at the overall local area level. Therefore, PG&E did not conduct any study at the LCA sub-area level in its initial technical study. PG&E reserves the option to conduct sub-area studies, as needed, in the future.	The boundaries of local capacity areas and the effective resources for addressing sub-area requirements are based on the electric system simulation results conducted considering the contingencies listed in the ISO tariff and consistent with mandatory planning standards. As such, the ISO agrees that a demand response provider ability to map its demand response resources to those areas will be critical to being able to reliably rely on demand response resources in lieu of transmission and generation procurement, which is the goal of this effort. While local RA is only procured through the RA program at overall local area levels, sub-area requirements are still expected to be addressed. However, the ISO does agree that at present, there does not appear to be a material amount of demand response resources in individual sub-areas and will not pursue sub-area studies at this time. Given the identification of resources reaching across a range of areas, it is unlikely that future transmission planning decisions can result in approving transmission upgrades, or future resource procurement of other resources be considered and approved, without taking into account demand response resources that are being procured for the broader area requirements that may also meet part of a sub-area need. In those cases, ignoring the potential contribution of the DR resource to the sub-area need would not be optional.
3d	Technical Study Methodology During the Workshop, each of the IOUs presented results using a common simple study methodology, developed for expediency rather than accuracy. This methodology takes a historical load shape (based on an average of 3-5 recent years' data) and scales up the entire shape to fit a single forecast 1-in-10 year	The ISO encourages the IOUs to timely update their load shape analysis so that the ISO can perform its step in the study process.

No	Comment Submitted	CAISO Response
	peak. This uniform "scaling" method likely overstates the actual number and duration of event calls that would be expected in any actual load year containing a 1-in-10 peak. This is because a single extreme peak event is only likely to be correlated with higher loads in the adjacent hours and days (e.g. during a summer heat wave) and is not predictive of an extreme high load occurring uniformly in every other period of the year. By incorrectly overstating the loading conditions and number and duration of event calls, PG&E notes that the simple study methodology artificially restricts the degree to which demand response resources will be considered available to meet planning criteria (i.e. because the demand response resources will be forecast to exceed their use restrictions at a lower percentage of area peak than would actually occur). Despite the above limitations in the study methodology, the preliminary results suggest that current levels of demand response resources should have sufficient availability to respond if called on a pre-contingency basis (e.g. when local area loads are projected to exceed the 1-in-10 year recurrence interval level). This should give the CAISO comfort with respect to the timing for developing a more detailed and accurate study methodology.	
3e	Next Steps PG&E believes the focus over the next few months should be to: • Revise the current scaling methodology employed in the initial study plan so that it more accurately reflects the likelihood of resources being called pre-contingency in each local area. • Develop the CAISO BPM language and other necessary operational tools and processes that will allow demand response resources to effectively respond on a pre-contingency basis for the purpose of mitigating local issues. • Work with the CPUC staff to develop any necessary language, operational tools and process that will reflect the value of pre-contingency demand response resources in local RA showings of the IOUs.	The comment has been noted. As noted above, the ISO encourages PG&E to update the load scaling methodology as quickly as possible as the work is foundational to the rest of the analysis. Agreed. The ISO anticipates this will be a joint effort of the ISO and IOUs.

No	Comment Submitted	CAISO Response
4	Southern California Edison Submitted by: Garry Chinn and Daniel Donaldson	
4a	The following are Southern California Edison's (SCE) comments on the California Public Utilities Commission (CPUC) and California Independent System Operator (CAISO) joint workshop on Slow Response Local Capacity Resource Assessment held on October 3, 2016. SCE appreciates the opportunity to provide comments and participate in the stakeholder process. <u>Recommendations</u> The methodology should use an average of the study years rather than maximums In order to perform the pre-dispatch analysis, multiple historical load shapes are scaled up to represent a 1 in 10 peak year. Each year is then studied separately to find the expected number of event days, dispatch hours, and other pre-dispatch criteria. SCE recommends that results from each study year be averaged together to create a single set of pre-dispatch criteria. Since every study year is already scaled to a 1 in 10 peak, averaging the results maintains the 1 in 10 standard. If maximum values were used instead of average to create the criteria, the criteria will likely be overly restrictive and not reflect a 1 in 10 condition on the system.	The ISO will consider shifting to the methodology SCE recommends. The ISO will be following up with SCE to seek more clarification on the statement that "If maximum values were used instead of average to create the criteria, the criteria will likely be overly restrictive and not reflect a 1 in 10 condition on the system".
4b	The criteria, once developed and agreed upon, should be streamlined for implementation SCE recommends developing one system (TAC)[1] wide recommendation for ease of implementation. Alternative option is to have area specific recommendations, however that may increase the complexity for regulatory compliance and operational purposes. One possible approach to developing the counting criteria is to set a % limit for slow-response DR to count. For example, looking at the SCE study, Demand Response (DR) up to a 5% of 1-in-10 peak load level meets "sufficient energy" criteria in SCE TAC area. If such a general limit is adopted, it should not prevent a Load Serving Entity (LSE) from going above it and using additional slow response DR for meeting	This implementation issue will be considered as we move through this process, including in the RA proceeding where these issues may be best addressed. The ISO questions the appropriateness of a 5% limit for the amount of slow-response DR to count for local RA given, as SCE indicated on Slide 34 of its presentation, dispatching BIP for more than 2-3 times per year will have a significant negative impact on enrollment. The table below provides the number of DR calls per year (3-year max) based on the Method 1 (Step 1) results SCE provided for the 5% slow-response

<table>
<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td></td><td>Local Capacity needs - however going above such a limit should be subject to an area specific study.

The longer term goal should be to define an operating profile definition for all “slow-response” resources (not just DR) to meet Local Capacity needs.</td><td>resource scenario. Note that Step 2 results could be significantly higher.

El Nido: 8; West of Devers: 10; Valley - Devers: 10; Western LA Basin: 6; LA Basin: 6; Rector: 19; Vestal: 19; Santa Clara: 14; Moorpark: 14; Big Creek Ventura: 14

Also, the ISO considers a limit as a percentage of LCR or as fixed MW amount instead of a percentage based on area load could be administratively more practical.

The ISO agrees that the methodology should not be specific solely to any particular technology, e.g. slow response demand response. We have not heard of other examples to cite, however.</td></tr>
<tr><td>4c</td><td>If implemented, this analysis should continue to be performed as part of the TPP
The Slow Response Local Capacity Resource Assessment study should be updated annually as part of the Transmission Planning Process (TPP). One of the reasons driving the need for annual updates is the fact that the area load shapes may change from year to year – resulting in a different need profile. E.g., El Nido area load shape from 2010 and 2011 is significantly different from the one in 2012 and later years.

The CAISO and the stakeholders should continue work on improving the methodology. One area of improvement would be using better load forecasting methodologies that are more accurate at generating a 1-in-10 peak year hourly profile than simply scaling every hour. SCE initially proposed and used this load scaling methodology as a first step in generating useful results, however this methodology should be improved.</td><td>The ISO agrees that an update process is necessary, and has been conducting this analysis as part of the current transmission planning cycle as a special study to take advantage of the efficiencies of conducting this work in parallel with other analysis. The ISO anticipates these resources be considered not only in annual RA procurement processes, but in the annual long term planning of transmission and other resource requirements – and consistent treatment will be critical. However, the concern has also been expressed that following the study process for this component inside the annual transmission planning process is burdensome for stakeholders who otherwise do not participate in the annual transmission planning process.</td></tr>
<tr><td>4d</td><td>This is a planning level analysis and recommendations, the CAISO, the CPUC and the stakeholders need to work on bridging this with various operational issues
As highlighted at the workshop, these are planning level recommendations, and they need to be bridged with operational issues. When planning for operational/implementation changes, the CAISO should consider modifying its systems to most closely match the practical design of the subject programs so</td><td>To reiterate comments made at the workshop by the ISO, the study results shared were draft and accompanied by observations, not recommendations. These results have not been incorporated into long term planning studies, as per the study plan developed for the 2016-2017 planning cycle.</td></tr>
</table>

El Nido	West of Devers	Valley - Devers	Western LA Basin	LA Basin	Rector	Vestal	Santa Clara	Moorpark	Big Creek Ventura
8	10	10	6	6	19	19	14	14	14

No	Comment Submitted	CAISO Response
	that they continue to be utilized as intended, and as they have been approved and deemed cost-effective by the CPUC.	The ISO appreciates input in future consultation stages on the extent operational systems should be enhanced or modified to enable implementation of pre-contingency dispatch of slow response resources for local capacity purposes. The ISO also seeks input on how DR resource and programs can be configured to best serve the needs of the grid so that DR can be evaluated alongside other resources in a technology neutral manner.
4e	<u>Operational Considerations</u> When would the "pre-dispatch" resources be dispatched? It is clear that "pre-dispatch" resources would have to be dispatched prior to when a potential contingency may occur (pre-contingency), since they cannot respond fast enough post-contingency. The current IOU and CAISO studies assume that this dispatch would be based on a (forecast) load trigger; e.g. when the forecast load exceeds a certain threshold, the slow-response DR would be triggered. However, it is not clear when this pre-dispatch would happen. If it happens in the Day-Ahead Market, it would result in a higher number of dispatches, due to inherent load forecast uncertainties. If this dispatch occurs in Real-Time, it would reduce the number of dispatches, as the forecast error would be smaller. However, dispatching in the Real-Time Market may need new CAISO processes (e.g. consideration of Minimum On-Line Constraints). SCE advocates that pre-dispatch of slow demand response resources be designed to happen day-of or in real-time. The primary demand response program administered at SCE that is the focus of this effort is designed around a 30-minute response time (BIP 30). If these programs are called too frequently, it would lead to diminished enrollment thus causing a decline of a resource that is designed to be a last line of defense. Any process the CAISO decides to use to dispatch these resources should be reflective of the intent of the programs as they were designed and approved by the CPUC.	As noted in the workshop, the ISO's working assumption is that the MOC function will be utilized in the day ahead market to dispatch these resources. Other options such as CME (Contingency Modeling Enhancements) are not expected to be available in the near term. However, the ISO anticipates SCE and other demand response providers will manage their resources as they do today using energy bids, commitment costs, and opportunity costs. The ISO anticipates demand response providers will use the same techniques and cost/value considerations when bidding these availability limited resources into the ISO market. The ISO appreciates SCE's perspective and focus on BIP 30; however, the slow response study effort is not being conducted around any specific program or resource attribute, other than resources cannot be dispatched post-contingency. This study effort is broader and is intended to consider both BIP 30 like programs and very long start DR programs that must have a DA notification, for example.
4f	How often would the resources be pre-dispatched? The planning studies assume a significantly higher load year than normal (i.e. a 1-in-10 load) to ensure that the system is reliable even under stressed	The ISO's intention is to study the characteristics necessary for the resources to be sufficient to meet local capacity needs. Studying the

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	conditions. Therefore the planning study is intended to calculate the required criteria to meet the reliability standards (i.e. minimum required capabilities) for a stressed year that is expected to occur once every 10 years. However, in an average year, the resource would be dispatched a lot less frequently. This is an important difference to note, as interrupting customers often each year would have a significant adverse impact on program enrollments. As these studies are improved, clear expectations should be developed with regards to frequency of dispatch for the resources, and underlying customers, in an average and in a stress year. The planning studies also assume a "perfect forecast", while real-life operations may require a safety factor, resulting in more dispatch hours. The frequency of pre-dispatch would also depend on dispatch timing (DA vs RT), as well as on the amount of slow-response resources in the supply stack.	average or "anticipated" dispatches is beyond the scope of the ISO's study plan, and the ISO expects that as the ISO's models are available (subject to the appropriate NDA) that interested parties will have sufficient information to make their own assessments. Agreed. The ISO will look for more specific feedback from demand response providers on the need for margin and resource usage anticipated for other reasons.
4g	How would pre-dispatch work with existing programs? Reliability-only programs currently require a CAISO Warning or Emergency (or a system contingency) as a condition for dispatch. Would the pre-dispatch concept work with these DR program restrictions and current CAISO rules and procedures? Is there a need to change the CAISO rules and/or the existing DR programs' and tariffs' use restrictions? As stated above, it is SCE's preference that any pre-dispatch protocol designed and implemented by the CAISO should be reflective of current program design. SCE is looking to limit major program disruption, customer confusion, customer dissatisfaction and more importantly attrition of the program megawatts. A thoughtful approach at implementation to preserve demand response resources should be a guiding principle in this effort. If changes to current programs are needed as to enable them to better meet the system needs, the timeline for this effort should be aligned with the IOU DR Application guidelines and timelines as set forth by the CPUC.	The ISO does not see an issue with how reliability programs, i.e. RDRR, fits under the construct under discussion. A RDRR resource could qualify as local capacity as a post-contingency, fast response resource based on its response time recorded in the ISO masterfile. Other RDRR resources that are slow responding, up to 40 minutes (per the settlement agreement), are suitable as system RA resources. RDRR comes in two flavors, 1) an emergency only resource that is only eligible for dispatch in real-time under the conditions stated above, and 2) an RDRR that can be bid economically in the DA market, but subject to the dispatch provision above in real-time, if not already committed in the DA market. Slow response RDRR resources that can be economically bid in the DA are well-suited for pre-contingency dispatch as local RA resources via the ISO's minimum online commitment constraint tool and can help avoid transmission and generation procurement. Economically bid slow response RDRR can manage its use and availability through economic bids that reflect energy, commitment costs, and opportunity costs, just like other resources.

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4h	Timing concerns and recommendation There are conflicting timing requirements here. On one hand, these issues should be addressed in time for the 2018 IOU DR Applications (due mid-January 2017), especially if existing programs and tariffs need to be modified. On the other hand, considering the initial stage of the studies and significant implementation issues that remain unresolved, it may be wise to delay implementation of new rules, and continue the status quo. Based on SCE's study, at current slow-response DR penetration levels, there is sufficient energy available for pre-dispatch in 2017, so SCE does not see a reliability risk in delaying this process by a year. Additionally, SCE hopes that the CAISO TPP, Local Capacity studies and related processes can be synchronized with the CPUC RA proceeding, and a consistent set of performance requirements developed for counting local resources. This would ensure system reliability, while avoiding double-procurement and minimizing customer costs.	The study timing will be reasonably adjusted so that the IOUs can timely update their load scaling methodology. The ISO is unaware of "significant" implementation issues that remain unresolved. The ISO is confident that its market systems, and its commitment decision tools are prepared to manage these resources, and bidders are able to manage the use of their resources through energy bids, commitment costs, and opportunity costs. Granted, ISO systems will evolve and be refined, as will those of demand response providers, but the ISO does not see any significant barriers to operating slow response resources. As noted in responses to comments above, we agree an efficient and effective update process is required.

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5	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities) Submitted by: Bonnie S. Blair and Rebecca L. Shelton	
5a	In response to the ISO's request, the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (collectively, the "Six Cities") submit the following comments on the Joint ISO-CPUC Workshop Discussion on Slow Response Local Capacity Resource Assessment ("Joint Workshop Discussion"). During the Joint Workshop Discussion, there was concern that slow starting Demand Response ("DR") resources could not be pre-dispatched through Minimum Online Commitment ("MOC"), the current tool used for ensuring N-1-1 security, which allows for the pre-dispatch of slow response local Resource Adequacy ("RA"). Therefore, the ISO and the CPUC discussed the potential option of creating a new tool that could accommodate the pre-dispatch of slow response DR resources. The Six Cities are not opposed to creating a new tool to accommodate the use of slow response DR resources as Local RA capacity. However, the Six Cities request that the ISO not create a tool that would limit the ability of other non-DR slow response resources from qualifying as local RA capacity. Any tool created for this purpose should avoid adverse impacts on those resources that already qualify as local RA and the ability of the ISO to pre-dispatch such resources.	 For clarity, the ISO indicated that the MOC mechanism is a mechanism used today by the ISO to commitment resources in the DA to address potential constraints and limitations on particular paths and in particular areas. There is no current plan to revisit the capabilities of existing resources, but that may arise in future consultation discussions.

No	Comment Submitted	CAISO Response
6	San Diego Gas & Electric (SDG&E) Submitted by: Victor Kruger	
6a	San Diego Gas & Electric (SDG&E) respectfully submits the following comments in response to the California Independent System Operator (CAISO) and California Public Utilities Commission (CPUC) request for stakeholder input on the potential availability requirements for slow response resources to meet local capacity area reliability needs. SDG&E appreciates the ISO-CPUC's efforts to determine the appropriate requirements for slow response resources to meet local capacity area reliability needs. However, SDG&E urges caution about new requirements that are based on inappropriate data or a flawed methodology. SDG&E supports the ISO's use of the step 2 (or method 2) analysis to properly reflect certain reliability needs like reactive support not examined in step 1 (or method 1). It is not yet clear if changing Local RA requirements is the proper solution at this early point in refining the determination of the needed slow response attributes. Some data appears to show that more than 4 hours of response may be needed in certain capacity areas. This would place a higher burden on slow response resources than other Local RA resources that only have to be available for 4 hours. A change in the minimum response time needed to count for Local RA is a major change and must be fully justified. A totally new framework like CME for SOLs may be a better solution. Additional analysis and evaluation must be done.	The ISO looks forward to receiving the updated load scaled information from the IOUs as quickly as possible. The study results are focused on identifying the minimum requirements for the resources to meet the needs of the local capacity areas for reliable service. The ISO will continue to focus on solutions that meet the technical requirements in the local capacity areas, and encourages SDG&E to participate in those processes.
6b	SDG&E also has concerns about a possible major change in the RA framework to address needs that span TAC areas. SDG&E understands the ISO must address all reliability needs even across historically separate LCR areas. However, RA may not be the only solution as in CME. Cost allocation issues become a major issue if an RA process is used to address cross TAC area reliability problems. The ISO-CPUC will have to work closely together to assure a workable solution does not favor certain ratepayers. Again a RA solution may not be optimal.	The need to consider the San Diego and Los Angeles sub-areas together in considering the implications of certain 500 kV transmission line contingencies is not new to this study process or limited to the consideration of slow response demand response resources. For clarity, CME was raised as a potential mechanism to dispatch resources on a pre-contingency basis instead of MOC – both mechanisms still contemplate acquisition of the resources as resource adequacy capacity, however.

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6c	There are a number of smaller issues that SDG&E expects clarification on as work proceeds on requirements for slow response resources to meet local capacity area reliability needs such as: • use of future load shapes or scaling of historical load, • combining resources to meet minimum standards, • accounting for uncertainty like forecasts, • honoring contractual limitations, • optimizing resource use, • handling overlapping capacity area needs, • delineating planning from operational needs, • what is pre-dispatch and should it be broken into several items, • time needed to implement changes both at ISO and CPUC, • is a "safe harbor" appropriate for low levels of penetration, • how often must studies be redone and • do must offer obligations and time periods need to change and many other details.	The ISO expects that these issues will need to be considered in the next rounds of stakeholder consultation focusing on implementation issues. For clarity, the ISO expects that the same treatment of resources in the year ahead resource adequacy program would also apply to longer term transmission planning exercises. The ISO considers it absolutely necessary to ensure that solutions that are relied upon in transmission planning processes are implementable in the operating timeframe. It is not clear what is meant by a "safe harbor" in this context.