BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

OPENING BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Nancy Saracino
General Counsel
Anthony Ivancovich
Assistant General Counsel
Judith B. Sanders
Senior Counsel
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel.: (916) 608-7143
Fax: (916) 608-7222
jsanders@caiso.com

Attorneys for the California Independent System Operator Corporation

September 24, 2012

Contents

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

OPENING BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON TRACK 1 ISSUES

The May 17, 2012 ALJ/ACR Scoping Memo and Ruling established three major tracks in this long term procurement proceeding. Track I considers whether there is a reliability need to procure new or repowered generation resources in the LA Basin and Big Creek/Ventura local capacity areas of Southern California Edison (SCE), based on the local capacity area (LCR) and once through cooling (OTC) studies conducted by the California Independent System Operator Corporation (ISO).[1] The ISO submitted opening testimony on that topic on May 23, 2012, and interested parties served responsive testimony on June 25, 2012. The ISO and other parties served reply testimony on July 23, followed by evidentiary hearings held August 7 through August 17. At the close of hearings, ALJ Gamson established September 24, 2012, as the date for opening briefs and October 12, 2012 for reply briefs. Pursuant to that schedule, the ISO hereby submits its opening brief for consideration by the Commission.

[1] Scoping Memo, pages 4-5.

I. EXE CUTIVE SUMMARY

This Track 1 proceeding involves a determination of the need for new resources in the LA Basin and Big Creek/Ventura areas, over a ten year planning horizon, that are being driven by the possible retirement of once-through cooling (OTC) generating facilities. The California Independent System Operator Corporation (ISO) presented the results of the OTC studies conducted as part of its 2011/2012 transmission planning process in collaboration with the Commission, the California Energy Commission (CEC) and the State Water Resources Board (SWRB). Those studies used the local capacity requirements (LCR) study methodology established by the Commission for use in the resource adequacy (RA) proceedings, which are conducted on an annual basis. The ISO's OTC study evaluated the four renewable portfolio scenarios used in the transmission planning process for the purposes of identifying policy-driven elements. In addition, the ISO was asked by the Commission and the CEC to conduct a sensitivity study using the environmentally-constrained renewable portfolio and a reduced load forecast.

Several parties challenged the ISO's OTC study methodology but presented no valid alternative to using the LCR methodology, which is a deterministic approach based on NERC/WECC planning criteria and ISO tariff requirements. Parties also challenged the assumptions used in the OTC study, particularly with regard to preferred resources and other non-generation resources such energy storage. As explained in testimony and on cross-examination, the ISO relied on the CEC's load forecast, from the 2009 Integrated Energy Policy Report (IEPR), which includes levels of demand response (DR), energy efficiency (EE) and combined heat and power (CHP). The ISO agrees with the CEC's concerns that forecasts of "uncommitted" EE and DR are too speculative to use for local

planning purposes as input assumptions, and that the 2009 forecast included reasonable levels of CHP. The trajectory renewable scenario portfolio contained reasonable assumptions about DG development, and the ISO modeled online energy storage projects.

Based on the OTC study results using the trajectory scenario, which the ISO believes to best reflect future load growth and renewable generation development, the ISO determined that there is a range of local capacity needs in the LA Basin of 2,370-3,741MW (depending on the location of the resources) and 430MW in the Big Creek/Ventura area by 2021. The Commission should direct SCE to immediately procure new resources in these areas, given the 5-7 year lead times for siting and construction in these heavily populated urban areas.

Because the ISO, as the transmission network operator, must be able to respond very quickly to contingencies in local areas that threaten grid reliability, the resources procured must have specific flexibility and locational attributes. The ISO is technology neutral as to the resources procured in the local areas, and will work with SCE and the Commission to develop the requirements needed for resources to compete in the procurement process. The ISO has also proposed flexibility requirements in the RA proceeding, R.11-10-023, and expects that the results of the flexibility framework being developed in that proceeding will inform the Track 1 and Track 2 procurement process.

II. DETERMINATION OF LOCAL CAPACITY REQUIREMENTS (LCR) NEED IN CALIFORNIA INDEPENDENT SYSTEM OPERATOR (ISO) STUDIES.

In the prior LTPP proceeding, Docket No. 10-05-006, the ISO described the additional study work that the ISO would be undertaking in order to inform the

Commission's procurement and infrastructure decisions. ISO witness Mark Rothleder, in testimony submitted on July 1, 2011 in that case, explained:

> …The study work that the ISO will be performing this year may provide additional insights to the plausible range of resource needs under different assumptions, which can also inform incremental procurement decisions. For example, the ISO, along with the CPUC, the CEC and other agencies, is in the process of conducting power flow and stability studies to evaluate local area capacity needs created by once through cooling (OTC) environmental restrictions. These study results will likely impact capacity input assumptions for future renewable scenarios that the ISO intends to run and will make available in the next LTPP proceeding.[2]

The ISO's intent to consider the OTC study results and present these findings as part of an evidentiary proceeding in either Docket No. 10-05-006, or as part of the next LTPP, was also reflected in the settlement agreement filed with the Commission on August 3, 2011, and approved in D.12-04-046:

> There is general agreement that further analysis is needed before any renewable integration resource need determination is made. For example, in the CAISO 2011/2012 transmission planning process, the CAISO intends to complete its analysis of local area needs driven by the OTC schedule for resource retirements or repowerings, and this work will be completed by the end of 2011. Once these study results become available, the CAISO will incorporate them into the renewable integration model using the methodology developed in this proceeding, and will complete this analysis by the end of the first quarter, 2012. Accordingly, the Commission should, in collaboration with the CAISO, continue the work undertaken thus far in this proceeding to refine and understand the future need for new renewable integration resources, either as an extension of the current LTPP cycle or as part of the next LTPP, which should be initiated expeditiously in the first quarter, 2012 and contain the procedural milestones set forth in [this] agreement.[3]

The ISO completed the OTC study on schedule at the end of 2011 and presented the results in the ISO's 2011/2012 transmission plan. The Track 1 evidentiary hearing process just completed , was described in the settlement agreement as well.[4] Specifically, the ISO was to present the results of its OTC studies, and interested parties would have an

[2] Ex. ISO-17, pages 4-5.
[3] Settlement Agreement, Docket No. 10-05-006, page 5.
[4] Ex. ISO-7

opportunity to consider the ISO's OTC study results, conduct discovery regarding the study assumptions and outputs, and present testimony addressing the need for local area resources.

In this track of the LTPP proceeding, the ISO presented the initial, supplemental and reply testimony of Robert Sparks, Mark Rothleder and Neil Millar, who described the mechanics of local area capacity/OTC studies, details about the study results, input assumptions and study outputs and potential residual system resource needs based on the ISO's renewable integration operational scenario. Twenty-one parties submitted initial and reply testimony, responding to the ISO, addressing other Track 1 issues, and responding to the July 13, 2012 Assigned Commissioners' Ruling (ACR). While this testimony presented a wide spectrum of opinions, the testimony focused on three general questions addressed in the ISO testimony and discussed in this section of the brief:

- Is the ISO's LCR/OTC study methodology the appropriate approach to use for establishing local area capacity needs?
- Are the input assumptions the ISO used in the LCR/OTC studies reasonable?
- Should the local area capacity deficiencies identified for the LA Basin and Big Creek/Ventura areas be used for a Commission procurement decision by December 2012.[5]

As discussed below, the clear answer to each of these questions is "yes."

[5] Mr. Sparks explained that the potential retirement of OTC generation in the PG&E service territory is not expected to create local capacity deficiencies; thus, the ISO did not address the need for local generation in the PG&E area as part of the immediate 2012 long term procurement process (Ex. ISO-1, page 3).

A. The ISO's Local Capacity Requirements (LCR) And Once-Through Cooling (OTC) Generation Studies

1. Characteristics and Purpose of the ISO's LCR Studies

Both Mr. Sparks and Mr. Millar explained the ISO's LCR/OTC methodology and purpose. Each year, for the purposes of the Commission's resource adequacy (RA) proceeding, the ISO conducts a local capacity technical study that is used to determine the minimum amount of resources within a local capacity area needed to address reliability concerns following the occurrence of various contingencies on the electric system. The results of this annual study are known as local capacity requirements, or LCR.[6] The ISO also conducts local capacity technical studies over a short term (five years or less) planning horizon as part of the transmission planning process.[7] A local capacity technical study is a contingency analysis that is consistent with NERC transmission planning standards (as augmented by WECC and ISO-specific planning standards) and requires the ISO to plan for reliable system operation under such contingencies as the loss of transmission facilities while generation is out of service. Contingency planning ensures that the ISO can contain potentially widespread and serious system impacts that might otherwise result from the loss of transmission and generation facilities.

A local capacity area is a geographic area that does not have sufficient transmission import capability to serve customer demand without running generation in the area. There must be sufficient generation in the local area to meet demand under stressed conditions

[6] *Id.*
[7] See, *e.g.*, Ex. ISO-22, the 2013-2015 Local Capacity Technical Study.

such as the loss of a large generating unit and one large transmission line, the outage of two large transmission lines or the outage of two generating units.[8]

The study itself consists of modeling the power system and simulating contingencies in both steady-state power flow and dynamic stability analysis to identify areas within the ISO controlled grid that have local reliability needs and to determine the minimum generation capacity that would be required to satisfy these local reliability requirements.[9] Local capacity analysis utilizes conservative assumptions, including the load forecast studied, because there is less opportunity for load diversity and generally significantly fewer operational options in a smaller local area to manage shortages. Because these load pockets or local capacity areas tend to be urban areas of high population density (which makes additional transmission into the areas challenging, prohibitively expensive or otherwise not viable) there is also less tolerance for unplanned or rotating outages. In addition, these local areas contain approximately half of the total load of the ISO controlled grid, and are particularly sensitive to electricity outages.[10]

As Mr. Millar explained, the ISO's various transmission planning studies address a wide range of circumstances and conditions and therefore require a wide-range of analysis and different input assumptions depending on the nature of the study. For both the ISO's LCR studies and the OTC study, given the need for a more conservative approach due to the limited availability of remedial options and the specific nature of the system's network topology in those areas, the ISO uses a one-in-10 peak load forecast. In contrast, the ISO's regional studies of the bulk transmission study use a one-in-five peak load forecast that recognizes the diversity of load and supply in the larger area that would be able to to

[8] *Id.,* pages 3-4.
[9] Ex. ISO-6, page 3.
[10] *Id.*, page 7.

respond to system contingencies. In other words, there are significantly more options for addressing reliability concerns on a broader regional basis than on a more localized basis. The ISO's economic planning studies use a one-in-two peak load forecast, resulting in more modest levels of economic benefits from transmission upgrades.[11]

In assessing reliability needs, the relevant NERC planning requirements call upon the system to be planned "at all demand levels over the range of forecast system demands."[12] The tests applied to examine system performance test the boundary conditions under certain assumptions, not only including highest anticipated load levels, but also idealized conditions with the rest of the system in service. As explained above, the contingencies and required system performance levels that are applied are based on the NERC transmission planning reliability criteria, as augmented by WECC regional standards and California-specific standards. These mandatory standards are deterministic. Assumptions are made regarding load levels and system conditions prior to a disturbance and then specific disturbances are simulated to test modeled performance against performance requirement scales. In general, a broader range of system impacts are permissible for more extreme, and less likely, types of contingencies.[13]

Each year, in preparation for the annual LCR analysis, the ISO conducts a separate stakeholder process outside of the transmission planning process and considers specific, relevant inputs for the analysis.[14] Before the study is conducted, the ISO publishes a detailed Local Capacity Requirements Manual (LCR Manual) that addresses the specifics

[11] *Id.,* page 6.
[12] Ex. ISO-13; NERC Standard TPL-002.
[13] Ex. ISO-6, pages 3, 6.
[14] Ex. ISO-3, page 8.

of the analysis. The ISO submitted the LCR Manual prepared for the 2013 RA proceeding as Ex. ISO-18.

The LCR Manual introduction and overview present some historical background for the local capacity studies and notes that the purpose and scope of the 2013 study is similar to that of the previous studies conducted from 2006-2012.[15] Next, the base case study assumptions are described, including the use of the 1-in-10 peak load forecast which is used in all local capacity studies, as discussed in Mr. Millar's testimony. Consistent with his testimony, the manual describes the reason this forecast is used:

> This requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is greater certainty in a regional load forecast than in the local area load forecast. The 1-in-10 load forecast standard for local areas minimizes the potential for interruption of end-use customers. In order to avoid bias among transmission, generation and demand side alternatives, all options should be validated against the same load forecast (1-in-10). Using a lower load forecast (1-in-2, 1-in-5) for LCR studies would benefit transmission alternatives (approved on 1-in-10 local load forecast during planning process) over generation or demand side.[16]

Page 11 of the LCR manual sets forth the reliability and planning standards criteria to be used in the local area studies, and the criteria tested for each of the three assessments - power flow, post-transient flow, and stability - are described at page 12-13. A step-by-step description of the assessments for each transmission planning criteria can be found at pages 16-19. These descriptions illustrate the simulations performed by the planning engineers in order to determine the amount - and location- of local generation needed to serve load both before and after the contingency events. According to the criteria discussed above, in each simulation, the planner will add generation needed to maintain path flows at rated limits while maximizing import capability into the area.

---

[15] Ex. ISO-18, pages 3-4.
[16] *Id.* page 7.

TURN witness Kevin Woodruff raised several questions about whether the ISO's OTC study deviated from the planning standards used in the annual LCR studies by making them more stringent, particularly with respect to the limiting contingencies for the Ellis and Moorpark areas.[17] Similarly, SCE alleged that the ISO appeared to have "augmented" the NERC/WECC planning standards for the purposes of the OTC study.[18] These assertions are incorrect. In response to these concerns, Mr. Sparks provided additional information in his reply testimony in which he clarified that the planning requirements for the LCR studies were used in the OTC study without change.[19] As noted above, the LCR methodology and planning criteria, which incorporate the NERC/WECC standards, are embodied in the ISO tariff at Section 40.3.1.1 and 40.3.1.2.[20] The study methodology and criteria initially were approved by the Commission in D.06-06-064 and have been approved subsequently every year in the RA proceedings.[21]

With respect to the Ellis and Moorpark areas, Mr. Woodruff argued that the limiting contingencies, described in Mr. Sparks' opening testimony-- a single line outage followed by a common mode outage -- constitute a Category D contingency that would be outside the Category C planning contingencies approved in the LCR studies. However, Mr. Sparks explained that following a single N-1 contingency, the ISO must take steps to ensure that the system can withstand a Category C common mode outage leading to voltage collapse. Where generation redispatch is not an option under these circumstances, the ISO would have to take steps to interrupt customers following the N-1 outage. Although in the Ellis and Moorpark subareas the next contingency following the N-1 is a common mode outage

[17] Ex. TURN-1, page 7.
[18] Ex. SCE-1, page 6.
[19] Ex. ISO-3, pages 6-8.
[20] See Appendix A to SCE-1
[21] Ex. ISO-6, page 6.

that technically is a Category D, the LCR resource planning criteria require the ISO to plan for this contingency to avoid the instantaneous and widespread effect of voltage collapse. Specifically, as noted by Mr. Sparks in his testimony, this system planning criterion is set forth in footnote 3 of the following matrix of LCR planning criteria, which is found at page 17 of the 2013 LCR Study (Ex. ISO-14):

Table 4: Criteria Comparison

Contingency Component(s)	ISO Grid Planning Standard	Old RMR Criteria	Local Capacity Criteria
A – No Contingencies	X X		X
B – Loss of a single element			
1. Gene rator (G-1)	X	X	X
2. Transmission Circuit (L-1)	X	X	X
3. Tran sformer (T-1)	X	X	X
4. Single Pole (dc) Line	X	X	X
5. G-1 System readjusted L-1	X	X	X
C – Loss of two or more elements			
1 Bus Section	X		
2 Breaker (failure or internal fault)	X		
3 L-1 system readjusted G-1	X		X
3 G-1 system readjusted T-1 or T-1 system readjusted G-1	X		X
3 L-1 system readjusted T-1 or T-1 system readjusted L-1	X		X
3 G-1 system readjusted G-1	X		X
3 L-1 system readjusted L-1	X		X
3 T-1 system readjusted T-1	X		
4 Bipolar (dc) line	X		X
5 Two circuits (Common Mode or Adjacent circuit L-2	X		X
6 SLG fault (stuck breaker or protection failure for G-1	X		
7 SLG fault (stuck breaker or protection failure for L-1	X		
8 SLG fault (stuck breaker or protection failure) for T-1	X		
9 SLG fault (stuck breaker or protection failure) for Bus section WECC-R.1.2. Two generators (Common Mode) G-2	X[3]		X
D. - Extreme event – loss of two or more elements			
Any B1-4 system readjusted (Coimmon Mode or Adjacent Circuit) L-2	X[4]		X[3]
All other extreme combinations D1-14	X[4]		

1 System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.
2 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.
3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.
4 Evaluate for risks and consequence, per NERC standards

In his reply testimony and on cross-examination, Mr. Sparks further explained that while the ISO studies many Category D contingencies as part of the LCR study process, it is in circumstances where a common mode outage following the single contingency leads to voltage collapse that such contingency becomes the limiting contingency.[22] For the Ellis and Moorpark areas, this limiting contingency was first identified in the 2011 LCR study (Ex. ISO-15 at page 78) and the 2012 LCR study (Ex. ISO-16 at page 88). Given the clear identification of this contingency in prior LCR studies approved by the Commission, as well as the planning criteria approved in the first RA proceeding, arguments that the OTC study deviated from the LCR planning criteria are clearly off-base.

Mr. Woodruff also claimed that the ISO's LCR studies are a "moving target" and that the actual resource needs tend to vary "quite significantly" from the forecast, posing the risk of over- or under-procurement.[23] This conclusion was based on a single statement in the ISO's 2013-2015 LCR study (Ex. ISO-22) wherein the ISO predicted that in 2015 the Western LA Basin sub-area would become the most stringent and binding local area constraint and the LCR need shown for the LA Basin dropped from 11, 304 in 2013 to 5,988 in 2015. Mr. Woodruff believed this 5,988 MW was a contradiction to the 10,743 - 12,165 MW deficiency need identified for the LA Basin in the OTC study, thus making the OTC results "a financially risky proposition for customers." Mr.Woodruff's concerns are misplaced.

In reply testimony, Mr. Sparks clarified this purported contrast in deficiency needs for the LA Basin by pointing to page 73 in the 2013-2015 LCR study where the ISO explained that, because local generation in the SDG&E and SCE areas will 'run out' by

[22] Tr. 246-249.
[23] Ex. TURN-1 pages 7-9.

2015, at least 10,800 MW of capacity is needed in the LA Basin. This amount is consistent with the 10,743 MW identified in the OTC trajectory case because the ISO added substantial renewable generation in the SDG&E and SCE areas, which increased the supply of generation in the SDG&E and SCE areas. Thus, while LCR results can have some degree of variation from year to year, these differences are not as dramatic as Mr. Woodruff suggested.[24] Certainly these concerns should not dissuade the Commission from using the OTC study results, based on the LCR study methodology and one in 10 load forecast, for procurement decisions in this proceeding. Even Mr. Woodruff did not take this position.

2. Description of the OTC Study

As explained by Mr. Sparks, the OTC study was an LCR study of local transmission constrained areas that currently have OTC generation. Rather than focusing on an annual or short-term basis, the OTC study looked at the planning horizon 2011-2021. The need for the study was driven by California's OTC policy, which establishes uniform, technology-based standards to implement federal Clean Water Act section 316(b). The OTC policy requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.[25]

The OTC study was conducted as part of the 2011-2012 transmission planning process, during which the ISO collaborated with various state agencies and stakeholders to evaluate grid impacts assuming that the OTC generation facilities were retired. In order to

[24] Ex. ISO-3, page 6. Mr. Sparks did note, during cross-examination by TURN, that, based on the OTC study, it appears that the LA Basin area will not be eliminated as a local area in 2015, which was forecasted at page 76 of Ex.ISO-22, page 76. *See* Tr. 276-279.
[25] Ex. ISO-1, pages 4-5; *see also* Ex. ISO-7, Chapter 3 of the 2011/2012 transmission plan containing the OTC study.

determine long-term (2021) local capacity area requirements for areas that currently have OTC generating units, the ISO performed the technical studies described above for the CPUC's trajectory, environmentally constrained, ISO base case, cost-constrained and time-constrained RPS scenarios.[26] These areas include the LA Basin and Big Creek/Ventura local areas, as well as the greater San Diego local area. The results of the OTC study for the LA Basin and Big Creek/Ventura areas are discussed in the next section. The Commission is considering the resource needs in the greater San Diego local area in Docket A.11-05-023.

In addition to the four RPS scenarios, the ISO, at the direction of the collaborating agencies, also conducted a sensitivity study- using the environmentally-constrained scenario and the mid net load- as part of the OTC study. This sensitivity study was described in the ISO's transmission plan (Ex. ISO-7), discussed with stakeholders at the May 3, 2012, workshop and addressed in Mr. Sparks supplemental testimony served on June 19, 2012.[27] The supplemental testimony described revisions to the sensitivity study that were posted as an addendum to the 2011/2012 transmission plan, as well as the results of the sensitivity analysis. Mr. Sparks' supplemental testimony also contained a policy discussion about whether the results of the sensitivity study should provide guidance to the Commission about local area needs in 2021- a matter with which the ISO strenuously disagrees.[28] Mr. Millar adopted this portion of Mr. Sparks' testimony for the purposes of testimony at the evidentiary hearing.[29]

---

[26] These scenarios were also used by the ISO during the 2011/2012 transmission planning process to evaluate the need for policy-driven transmission elements. Ex. ISO-1, page 16; *see also* Chapter 4 of the 2011/2012 transmission plan.
[27] Ex. ISO-2.
[28] *Id.*, pages 4-8.
[29] Ex. ISO-6, page 2.

Mr. Woodruff and other parties raised concerns that because the ISO's LCR studies are typically conducted annually, the Commission has little experience with making long-term local capacity area need determinations.[30] Most of these concerns focused on the increased uncertainty associated with the ten year planning horizon used in the OTC study, a simple fact with which the ISO does not dispute.[31] However, as Mr. Millar noted both in his reply testimony and on cross-examination, future uncertainties can affect the ISO's identified local area needs in either direction (*i.e.,* as either requiring more or less local generation, depending on the circumstances).[32] However, many of the interveners only focused on pushing the local area deficiency lower and ignored in their recommendations the ISO's more optimistic assumptions; for example, the LCR/OTC study assumed that SONGS was in operation.

Furthermore, the ISO's study assumed that all non-OTC generation would continue to operate and the ISO recommendation is to procure an amount of replacement generation identified in the study that would be located in the most electrically effective locations. Both of these optimistic assumptions result in a minimum required amount of OTC replacement generation.

Despite numerous other questions posed to Mr. Sparks and Mr. Millar about future uncertainty, no party put forward a credible argument that the longer planning horizon renders the LCR study methodology inappropriate for use in determining local area needs driven by OTC requirements in the LA Basin and Big Creek/Ventura areas. The OTC study methodology is what is used to determine local capacity needs, and will continue to

[30] Ex. TURN-1, pages 5-6
[31] *See, e.g.*, Tr. 79-80, lines 16-28.
[32] Ex. ISO-6, page 19; Tr. 369, lines 10-23.

be used during the ten-year planning horizon. Given the time frame for procuring, permitting and potentially repowering existing generation, which is currently needed for reliability, a decision is needed in this proceeding in order to stay on track with the OTC compliance schedule. In addition, to procuring and permitting time frames which in coastal areas are expected to be lengthy, the repowering schedules would likely need to sequential depending on which power plants are selected for repowering. Indeed, as discussed in greater detail below, using the other methodologies proposed by some parties would not align with the ISO's transmission planning requirements and could significantly jeopardize grid reliability. The record clearly supports the reasonableness of the ISO's OTC study.

3. Deterministic versus Probabilistic Studies

CEJA witness Julia May stated, in her opening testimony, that:

> CAISO based LCR requirements on an overly pessimistic 1-in-10 forecast (which means peak energy need during the worst year out of ten) long in advance of when these needs might occur, with multiple safety reserve margins on top of this worst case, making it very unlikely that modeled outage contingencies would ever occur .[33]

Later in her testimony Ms. May refers to the testimony of Ms. Sharon Firooz, sponsored by CEJA in A.11-05-023, wherein Ms. Firooz purportedly conducted a "simple" probabilistic calculation of the chances that the outages tested in the ISO's studies would ever occur. Based on this simplistic approach, both Ms. Firooz and Ms. May concluded that the ISO's methodology is conservative and "overly stringent."[34] This discussion highlights essential differences between deterministic and probabilistic analysis, which was explained in detail in Mr. Millar's reply testimony.

[33] Ex. CEJA-3, page 3.
[34] *Id.* page, 40.

The LCR/OTC methodology, which is used by the ISO for all of its transmission planning studies and based on NERC and WECC reliability standards, is a deterministic approach to the evaluation of the transmission grid. This means that assumptions are made regarding load levels and system conditions prior to a disturbance, and then specific disturbances are simulated to test modeled performance against performance requirements scales. The deterministic test is not an assessment of every possible operating condition and the anticipated system response to each possible operating condition.[35] This distinction between a deterministic test and a true probabilistic analysis is an important one because the two have fundamental differences-- and uses-- between which the lines must not be blurred. The deterministic approach was established based on years of industry experience and has been adopted by NERC and FERC to provide consistent and acceptable system performance evaluation across the United States, Canada and the interconnected portions of Mexico.[36] As noted above, the performance levels differ for each broad category of contingencies, which recognizes the significantly different likelihood of occurrence for each level.

In contrast, a probabilistic analysis sums the probability of a number of events, each with its own probability of occurring, and considers the anticipated impacts of all of the potential events. System-wide resource adequacy analysis lends itself to this kind of analysis because individual generators have unique performance characteristics (such as outages) that can be considered, in combination, on a probabilistic basis. However studying a transmission system on a probabilistic basis has not replaced deterministic assessments due, in part, to the complexity of studying the individual performance of

[35] Ex. ISO-6, pages 3-5.
[36] *Id.*, page 4, lines 15-21.

numerous transmission and generation elements and the interaction between those components. In addition, and largely because of these complexities and difficulties, there is no meaningful or accepted industry standard to compare forecast performance against actual performance, unlike the deterministic NERC standard.

Mr. Millar specifically cautioned against haphazardly applying probabilities to a particular contingency event as suggested at page 38 of Ms. May's testimony. Such an approach misses the point of deterministic planning studies and the application of the reliability standards completely.[37] The deterministic approach is a test consisting of assessing various contingency conditions to measure the overall reliability of the system. Ms. May selected one of those contingency conditions identified by the ISO as the most limiting within the deterministic set of contingency conditions and argued that the probability of that particular condition occurring is very low. She ignored the probability and impacts of all of the other possible contingency conditions would need to be included in a probabilistic analysis. For example, to conduct a proper probabilistic analysis, generator outages would also have to be assessed as well as the interaction of generation and transmission outages with all of the other elements of the grid. Mr. Millar likened Ms. May's argument to a medical student seeking to selectively improve his or her grade by arguing that the likelihood of being confronted with a particular disease is really very low, so the question about that disease on the test should be removed. This not only defeats the purpose of the test, but it fails to provide a comprehensive view of risk under a wide range of operating conditions.[38]

[37] *Id.*, page 9.
[38] *Id.*, page 5, lines 20-27.

4. "Mixing Apples and Oranges"

The record contains other examples of inappropriately mixing study elements and creating general confusion regarding transmission planning versus resource adequacy considerations. For example, CEJA witness May, again quoting Sharon Firooz, concludes that long term resource planning was typically done using a one in two peak load forecast "plus a 10% adder to provide an installed capacity cushion" that was later increased to 15-17%." These concepts are not applicable or particularly relevant to the ISO's OTC studies which are based on NERC transmission planning and operating standards. Rather, as explained above, May's and Firooz's comments pertain strictly to system-wide resource planning issues, which, as discussed above, could be considered using some probability assessment techniques.[39] Ms. May compounded this confusion with extensive reply testimony focusing on a June, 2012 report prepared by the Electric Reliability Council of Texas (ERCOT) that focused on the reserves needed for long-term procurement.[40] In direct testimony provided during the evidentiary hearing, Mr. Millar described the application of resource adequacy metrics "to be a bit of a common thread of mixing apples and oranges between different criteria that are being used for different purposes."

He noted that:

> In particular, in looking at these kinds of metrics for broad system resource adequacy, it's quite common to assume that there are no internal transmission limitations, the transmission system is not basically included in the study. The metrics look at the probability of available resources on a system wide basis and it is generally assumed that the transmission system will be reinforced so that that energy can actually be delivered at the time it's being produced. That's in complete contrast to the more detailed technical analysis of the transmission system with support from some local generation which is actually the purpose of the local capacity technical studies.

---

[39] *Id.*, page 4, line 26.***
[40] Ex. CEJA-5, pages 5-9.

> In particular and the one example I do need to point to in particular is the reference to, quote, 1 in 10. On a broad systemwide resource adequacy measure, the 1-in-10 number normally refers to one day of inability to supply the load that may or not be the peak day. It could be a day when a number of generators in the simulation are out for maintenance which reflected in these studies. And in fact, at times it was common for these studies to not even include all the hours in a year but often considered only 365 peak values peak load for each day in that year in doing that assessment. That use of the phrase 1 in 10 is completely different from our use of a peak demand forecast for detailed technical studies where we are studying the highest load anticipated on a 90th percentile basis or the highest load expected to occur only once in ten years.[41]

In her reply testimony Ms. May further mixed concepts by pointing out that distribution failures are the most common cause of customer outages, "swamping the separate, theoretical transmission system 1-in-10 reliability standard probability of seconds of outage per year that CAISO is aiming for."[42] Once again, pointing out statistics involving the distribution system have nothing to do with and do not particularly affect the transmission planning studies presented herein. Mr. Millar explained that while it is true that customer outages can be caused by the distribution system, there is considerably more rigor involved in studying the transmission system because transmission outages affect a far larger number of customers and regions, and the impacts are much more widespread.[43] On the other hand, distribution outages may involve individual residential streets or smaller-scale locales , but customers may still be able to visit neighbors whose power is still on, go shopping or to a restaurant, or otherwise carry on daily tasks. When there is an outage on the transmission system, entire cities and regions may be affected, and routine tasks for almost all residents may be substantially disrupted. There simply is no comparison with respect to scope, scale, and nature.

[41] Tr. 341, line 26- 343, line 21.
[42] Ex. CEJA-5, page 10.
[43] Tr. 344, lines 8-19.

Confusion between transmission planning studies and resource adequacy evaluations was also apparent during cross examination. For example, after numerous questions posed to Mr. Millar by counsel for CEJA regarding WECC operating criteria applicable to the ISO as a balancing authority, Mr. Millar explained that these criteria are not applicable to the local transmission planning:

> Q. (Ms. Behles) Are there any WECC regional criteria that require CAISO to hold reserves for a double contingency scenario in the local area?
>
> A. (Mr. Millar) Referring to it as reserves actually takes me back to the very first thing I commented on today, which was some apparent confusion between reserve criteria that are applied on a systemwide basis where we're looking at generation resources that may rely to some extent on some import capability, so transmission gets mentioned in those criteria, compared to transmission performance requirements inside an area were the transmission system capabilities into a subarea may be augmented by some generation.
>
> Those are two completely different analyses. And the reserve criteria that are applied on a systemwide balancing of load and resources, those criteria don't apply on a local basis. When we're looking at the local area, then the transmission criteria augmented by some local generation resources are the measures that we use to assess if we have enough local resources, and that's following the normal transmission planning processes that we've established.[44]

DRA witness Fagan also inappropriately mixed study methodology concepts by presenting a loads and resource spreadsheet analysis as an overly-simplified means by which to calculate local area needs.[45] Similar to the CEJA testimony, Mr. Fagan inappropriately mixes probabilistic concepts and ignores the contingency-based planning criteria which the ISO is required to follow to comply with NERC and WECC standards.[46] Specifically, Mr. Fagan states that the ISO's local capacity needs determination is based on a "number of 'worst case' assumptions concerning system events, weather and potential load, and that procurement decisions should not be based on these assumptions. In

[44] Tr. 391, lines 24-392, line 18.
[45] Ex. DRA-1, page 9-10, line 4.
[46] *Id.*, pages 7-8.

response, and consistent with Mr. Millar's extensive explanations on this topic, Mr. Sparks noted that Mr. Fagan's testimony flies in the face of the NERC and WECC reliability criteria requiring the ISO to conduct 10 year grid planning studies under stressed conditions. Mr. Sparks also pointed out that the ISO's allegedly "worst case" study assumptions actually contain one very optimistic assumption- that the SONGS nuclear unit is online. The significant uncertainty surrounding that unit makes DRA's recommendation to take a "wait and see approach to resource procurement untenable and could lead to an emergency shortage situation.[47]

With respect to the usefulness of Mr. Fagan's load and resource table, Mr. Sparks explained that it is impossible to analyze a transmission system using a resource balance approach and that it makes little sense to use one simplistic tool to address transmission options (power flow analysis) and a different tool to evaluate non- transmission options. Mr. Sparks concluded that "a spreadsheet analysis is grossly inaccurate in many LCR areas and should not be used to make procurement decisions in this proceeding."[48] In the process of identifying particular errors in Mr. Fagan's spreadsheet (Table RF-2, page 3 of his opening testimony), Mr. Sparks pointed out that the new and existing generation listed in rows K and I of the table contain many units that are not effective substitutes for and are not equivalent to the generation being retired.[49] These same concerns carried over to the new load and resources table Mr. Fagan introduced in his reply testimony at pages 6-11.[50] In sur-rebuttal testimony, Mr. Sparks again pointed out that the effectiveness factors of generation in the Western LA Basin range from 32% to 7%, but that Mr. Fagan's load and

[47] Ex. ISO-3, pages 2, line 6- page 3, line 9.
[48] *Id.* page 2, lines 18-25.
[49] *Id.*, page 3, line 21 – page 4, line 2.
[50] Ex. DRA-6.

resource table mistakenly assumes that the 2,400 MW of highly effective (at meeting LCR needs) OTC generation could be replaced, on a MW for MW basis, by resources in other areas that are significantly less effective in meeting the specific local requirements. This is simply not a valid assumption. Mr. Fagan then compounded the error by deducting even more megawatts of uncommitted EE, uncommitted DR, and other preferred resources modeled in the ISO's sensitivity study, to arrive at a local area deficiency of only 169 MW, which is simply not plausible .[51] On cross examination by DRA, Mr. Sparks further explained that such a need level, coming down from a 5,000 MW level of OTC resource retirements, is not plausible because it would cause the ISO substantial operational concerns:

> First of all, this table… is based on the ISO environmental sensitivity analysis of the environmental case, and then essentially adds even more reductions in OTC generation. But as I had stated earlier, the sensitivity analysis itself was such a dramatic change in the loss of dependable and controllable generation within this highly populated load center, the largest one in California, second largest one I think in the nation, that the ISO would have concerns that we would need to study much more in depth other seasons, such as the spring and fall, when we take maintenance on transmission lines and generation… And so rooftop solar and demand response are fairly effective during summer peak, but during other seasons solar certainly is not dependable, because the sun doesn't necessarily shine, or it is very low, and the demand response is limited to amount of usage.[52]

Finally, there seemed to be a confusion regarding import level assumptions. In response to questions posed by counsel for CEJA with regard to the import levels reflected on Mr. Fagan's revised spreadsheet, Mr. Sparks explained that DRA used the import levels provided by the ISO in a data request response solely as *inputs* to the resource deficiency calculation, whereas in the ISO's studies of the LA Basin and Big Creek/Ventura local

[51] Ex.ISO-23, page 6, line 14- page 7, line 4.
[52] Tr. 1353, line 18- 1354, line 8.

areas these import levels are an output of the analysis and are highly dependent upon the effectiveness of resources assumed in the studies. As Mr. Sparks stated:

> The ISO doesn't use import level in its LCR analysis. It is simply just a resulting value that is really not a consideration... So the difference between DRA's import level and the ISO, they are using import level as an input. It is simply a by-product of the ISO analysis. And that by-product coming out of the ISO analysis in the environmental scenario is a different level import than was used by DRA, but then just underscores the idea that the amount of import that occurs before you hit the criteria violation varies quite a bit, depending on which generation you remove from within the area.[53]

There is no basis on the record of this proceeding for using a study methodology other than the ISO's LCR/OTC contingency analysis for determining local area deficiencies. In addition and as explained in the next section, the Commission must be particularly careful not to undermine the ISO's studies by adding arbitrary and unsupportable assumptions regarding increased amounts of uncommitted energy efficiency, demand response and other preferred resources, as well as introducing resource adequacy concepts into the mix.

B. Consideration Of Preferred Resources, Including Uncommitted Energy Efficiency, Demand Response, Combined Heat and Power, and Distributed Generation, In Determining Future LCR Needs

Without question, the most highly litigated issue in this proceeding was whether the ISO should have considered additional levels of uncommitted preferred resources (and energy storage) in arriving at its OTC-driven need recommendations. Opening and reply testimony advocating modifications to the ISO's assumptions was submitted by TURN, CEJA, DRA, Clean Coalition, Vote Solar, EnerNOC, CCC, CAC, CESA, CEERT and NRDC. The testimony submitted by these parties had common threads that were addressed

[53] Tr. 1350, line 1-19.

by Mr. Millar, who also sponsored Mr. Sparks' testimony on the subject from his supplemental testimony.[54]

Simply stated, the ISO used the 2009 CEC 1-in-10 load forecast, from the 2009 Integrated Energy Policy Report (IEPR)[55] in the OTC study. This load forecast includes certain levels of energy efficiency (EE) and combined heat and power (CHP), but does not include uncommitted EE or CHP. [56] The ISO modeled storage resources on the grid and the 33% RPS scenarios used in the study contained various levels of distributed generation (DG). The ISO believes that the range of DG in three of the four scenarios -- 271 to 687 MW -- is a reasonable expectation of the DG build out during the planning horizon of the study in question. The environmentally constrained portfolio has the highest DG levels (1,519 MW). While the ISO supports achievement of the state's environmental goals, such high DG levels are unlikely to materialize with a reasonable degree of certainty and therefore would be imprudent for the ISO to rely on for planning purposes and ensuring grid reliability. This is especially true if assuming this high level of DG means "losing" some existing resources and not having sufficient available capacity in the future to address any reliability concerns that arise.[57] Maintaining reliability requires a pragmatic and prudent assessment of available resources, not hope and optimistic projections that, at this time, have no factual or financial underpinning. To be clear, the concept of "uncommitted" EE and other preferred resources was developed by the CEC and addressed in an EE Committee Report issued in May 2010.[58] However, the DG assumptions studied by the

[54] Ex. ISO-2, pages 4-8.
[55] Ex. ISO-10.
[56] *Id.* page 4, lines 10-11.
[57] *Id.* page 6, line 16-page 7, line 2.
[58] Ex. ISO-11.

ISO came from the CPUC's 33% RPS portfolios Mr. Millar explained this distinction during cross examination by TURN:

> Q. And you can't say with certainty, can you, that we're going to see between 271 and 687 megawatts in the L.A. Basin by the end of the study period?
>
> A. We think these are reasonable ranges for forecasting, but no one can guarantee any forecast materializes.
>
> Q. And it depends on – achieving these targets depends on a series of actions that have yet to be taken by a number of market actors; isn't that right?
>
> A. Oh, yes.
>
> Q. So would it be fair to call this uncommitted DG?
>
> A. I don't think that's an appropriate distinction because the committed versus uncommitted framework was developed by the CEC in their load forecast. As they developed their load forecast they specifically considered those types of issues and making different weightings of the likelihood of certain things coming to pass. The entire concept of, quote, committed versus uncommitted wasn't applied in the development of these portfolios. So we're trying to layer on a concept now that wasn't part of their development the way it was in the load forecast.
>
> Q. How would you distinguish between these targets and targets that relate to uncommitted energy efficiency, for example?
>
> A. At the end of the day we look at even though the different methodologies or the different inputs into our studies were developed through completely different processes, at the end of the day we try to assess if product is within a reasonable range for forecasting purposes. Whether there's more or less committed and uncommitted energy efficiency wouldn't directly affect whether more or less distributed generation developed in the area.
>
> So each of these forecasts was developed using a different framework, different methodology. And at the end of the day we have to look at are each of them reasonable inputs into our technical study.
>
> Q. So in the case of energy efficiency you think it is reasonable to assume zero percent of the uncommitted goal, but in the case of distributed generation there's a certain discounting of the policy goal, less than a hundred percent discounting that you think is appropriate?
>
> A. When you look at the uncommitted energy efficiency programs, the CPUC's {*sic,* CEC's} decision at the time that those contained sufficient uncertainty that

> they should not be included in the base forecast was also made taking into account the assumptions that they made as to how successful the committed programs would be at actually producing megawatt savings, which for that issue seemed to come to a reasonable amount of overall energy efficiency to include.
>
> And there is a great deal included in our technical studies. When we looked at this, this is allocating out assuming that the State's 33 percent goals will be met, what is a reasonable range to assume will come from distributed generation. So, again, these two forecasts were developed using completely different frameworks and terminology. I don't think it's fair to just apply a concept that was used in developing one forecast and assume that it fits and that it can be nicely bracketed in how that concept applies to a different forecast that was developed under a different framework.[59]

Despite the voluminous materials and reports submitted by interveners regarding uncommitted EE, the ISO does not see any reasonable or prudent basis for modifying the EE levels embedded in the CEC forecast used in the OTC study. Mr. Millar held steadfast in these conclusions despite s extensive cross-examination on this subject. The following exchange demonstrates Mr. Millar's and the ISO's commitment to its study assumptions:

> Q. (Mr. Martinez) You have mentioned that you just took the CEC's forecast and did not make determination of the uncertainty of uncommitted energy efficiency.
>
> A. (Mr. Millar) No. I said that we reviewed the forecast. We didn't see any reason to make a change from the base forecast.[60]
>
> ***
>
> We saw that the CEC described the uncommitted -- and again, we have to take it in the context of the CEC made assumptions based on studies, but made assumptions about the amount of energy efficiency benefit that would be expected or possible or should be included in the forecast first from the committed programs, and then in looking at making additional or including additional energy efficiency from the uncommitted programs concluded that at that time those programs -- not the programs themselves, but the results from those programs contained too much uncertainty regarding the timing, the impact and the location to be included in the base forecast. And based on that, we saw no reason to make a change.[61]

[59] Tr. 487, line 21- 490, line 16.
[60] Tr. 443, line 25-444, line 4.
[61] Tr. 444, line 13-445, line 2.

In reply testimony, Mr. Millar described both behind the meter CHP and CHP sales to the grid. With respect to both EE and behind the meter CHP, he explained that these resources can provide broad system benefits and local capacity requirements to the extent they can be reliably forecast and included in load forecasts on a timely basis. CHP sales to the grid can be treated as supply side resources and, to the extent that they can perform as necessary, can compete with generators to meet local capacity requirements.[62] Accordingly, the ISO strongly disagrees with CCC witness Beach's assertions that the ISO is "not encouraging" CHP. The CEC forecast includes a reasonable amount of behind the meter CHP, and the ISO anticipates that additional CHP will compete in the procurement process.[63] In Section IV below, the ISO has described the ideal characteristics needed for successful participation in the procurement process.

The ISO did not model demand response (DR) in its OTC study. Mr. Millar testified that DR cannot be relied upon to address local capacity needs unless the DR can provide equivalent characteristics and response to those of a generator in a specific load pocket.[64] DR programs have generally been considered an alternative to generation resources in meeting system-wide load and resource balances. Under those circumstances, spread over a larger system, the exact amount of DR that materializes, and the location, is not relevant (within certain bounds). In the past, and in unique circumstances, the ISO has counted on a small amount of large DR programs; these exceptions should not be taken as the rule.[65] Specifically in response to testimony presented by the ENERnoc witnesses, Mr. Millar explained that the ISO reviewed the characteristics of DR programs in place within

[62] Ex. ISO-6, page 12, lines 13-24.
[63] *Id.*, page16, lines 8-24.
[64] These characteristics are described in more detail in Section IV below.
[65] Ex. ISO-6, pages 13-14.

the controlled grid in anticipation of a summer without SONGS, and was unable to identify a material amount of DR that has the characteristics to address local capacity-driven requirements. At this time there is simply no evidence in the California experience to support assumptions that material levels will emerge with the necessary characteristics.[66] For purposes of maintaining reliability in local areas, the ISO cannot blindly rely on optimistic projections (without any factual basis) regarding potential future DR that will be available and effective in addressing needs in specific load pockets.

Finally, with regard to energy storage, the ISO generally does not disagree with CESA witness Janice Lin.[67] Like CHP, storage can compete in the procurement process providing these resources can meet the requirements for local capacity. Ms. Lin also advocates a multi-year procurement process for storage, which is consistent with the ISO's position that SCE should be directed to begin the long-term procurement process for the range of local resources, with specific characteristics, identified in the ISO's studies. This approach, which is discussed in further detail below with regard to the proposed procurement process, will encourage the development of such resources . However, as with the preferred resources, the ISO's study assumptions regarding storage should not be modified to reflect potential resources with uncertain development at this time.

C. Appropriate Assumptions Concerning Retirement of OTC Generation

DRA witness Siao provided testimony regarding the OTC compliance dates for generators in the LA Basin impacted by the OTC requirements, along with information

[66] *Id.,* page 14, line12- page 15, line 3.
[67] *Id.,* page 15, line 24-page 16, line 6. Ms. Lin was mistakenly identified in Mr. Millar's reply testimony as the Clean Coalition witness.

about factors that could extend the compliance dates.[68] DRA witness Fagan then used this information in the spreadsheet analysis discussed above.[69]

The ISO disagrees with this approach. Mr. Miller testified that making decisions now based on assumptions that the OTC compliance dates will not be met is untenable and should not be considered without substantial evidence.[70] Furthermore, the ISO supports all state policy goals, which includes coastal marine life environmental requirements, as Mr. Millar explained:

> …we have seen some indication that there was a view that this Commission could defer moving forward on alternatives to the coastal generation, and if I was going to be cruel and paraphrase, because the coastal generation really isn't going anywhere and doesn't have to go away. And we are working on supporting all of the state's goals, not just specific goals, which includes coastal generation. And the concern we have is that if we defer any procurement until some further point in the future, it will then be too late for the once-through cooling generation to be retired or retrofitted or otherwise come into compliance with the coastal generation requirements.[71]

The local area procurement decision in this proceeding should be based on the OTC compliance dates used by the ISO and not mere speculation regarding possible extensions.

D. Transmission And Other Means Of Mitigation

Similar to the ISO's other transmission planning studies, the OTC study included an analysis of transmission alternatives and other mitigation solutions to address identified reliability concerns for each of the four scenarios, including potential transmission mitigation measures, potential demand side management and the CEC's forecast of contracted resources such as CHP (discussed above).[72] The study included the same new

---

[68] Ex. DRA-2
[69] Ex. DRA-1, page 21.
[70] Ex. ISO-6, page 16 line 28 to page 17, line 13.
[71] Tr. 399, line 13 to page 400, line 1.
[72] *See* Ex. ISO-7, page 214, Ex. ISO-1, page 5, lines 14-18.

conventional generation and major transmission projects used in the policy-driven assessment because the same RPS scenarios were used in the OTC study.[73]

Mr. Sparks also described specific transmission mitigation solutions considered in the study. For example, 600 MW of load transfer at the Mira Loma West 500/230 kV bank #1 would allow the emergency rating to be utilized and could reduce the overall LA Basin need.[74] In the Ellis sub-area, the ISO considered the use of an existing SPS for the double line contingency for the double line contingency (*i.e.*, Santiago – San Onofre #1 and #2 230kV lines, with the Barre-Ellis 230 kV line already forced out of service) to drop approximately 800 MW of load at Santiago 230 kV substation. This arrangement could be relied upon to eliminate 225 MW repowered former OTC generation need in the Ellis subarea. This SPS is currently operational and is maintained by SCE. However, this specific solution must be carefully considered because generation in the Ellis subarea is highly effective at mitigating the Western LA Basin constraint, and is one of the most effective locations for replacing SONGS in any scenario where SONGS is not available on a short or long-term basis.[75] The ISO also considered the installation of reactive support in the Moorpark Sub-area to reduce the OTC replacement needs in that area.[76]

Because the ISO thoroughly reviwed transmission and other non- generation alternatives as part of the OTC studies, there is no need for further analysis before a Track 1 decision is issued. The ISO strenuously disagrees with CEJA witness May's assertions that the ISO should conduct a "comprehensive assessment" to determine whether there are more transmission options that could reduce local needs. As Mr. Sparks explains, this

---

[73] Ex. ISO-7, page 215.
[74] Ex. ISO-1, page 9, lines 7-17;; ISO-3, page 4, lines 4-19. It should be noted, however, that this proposed load transfer arrangement is not in SCE's current expansion plan. Tr. 264, line 20-265, line 14.
[75] *Id.*, page 10, lines 10-25.
[76] Ex. ISO-1, page 14, lines 9-14.

work has already been done. Not only has the ISO proposed the mitigation solutions discussed above in the context of this study, but over the past 14 years the ISO has continuously worked with its participating transmission owners to reduce the need for local generation capacity. Numerous reconductorings, transformer additions and thousands of MVAR of reactive support have been added to the transmission system to minimize dependence on local generation. It is telling that of the existing 5000 MW of OTC generation capacity in the LA Basin, the ISO has identified the need for as little as 2370 MW, which represents less than half. Ten years ago all of this generation would have been needed for local capacity, and yet after 10 years of load growth, the need for more than half has been eliminated. In light of the substantial work that has been accomplished, additional transmission studies would not produce any significant changes in the need for local generation capacity.[77]

CEJA witness May, once again referring to the testimony submitted by CEJA in A.11-05-023, suggested that load drop is available as a "safety net" that is more reliable than generation and should be considered as an alternative mitigation solution in lieu of generation or system reinforcement. Mr. Millar explained that controlled load shedding can be acceptable mitigation for Category C outages subject to careful review of the situation and consideration of such factors as the sensitivity of the load, the type of reliability issue being addressed, as well as the reliability and complexity of the means by which the load will be shed. The ISO's Planning Standards[78] set out the considerations that must be taken into account; among these are the number of potential contingencies that would cause a load-shedding SPS to operate, the number of elements that need to be

[77] Ex. ISO-3, page 4, line 20- page 5, line 13.
[78] Ex. ISO-13.

monitored and the consequences if the SPS fails to operate. Importantly, depending on system design and expected system impacts load-shedding is a *permissive* alternative to generation or transmission, as described in NERC standard TPL-003. However, the After reviewing the system design and expected system impacts, the ISO has not proposed load-shedding as mitigation solution for local capacity needs and CEJA has provided no reasonable engineering basis upon which the ISO could adopt such a proposal. Due to the anticipated complexity of the load shedding scheme, and due to the high population density in the load area, the ISO is recommending procurement of OTC replacement generation instead of load shedding.

III. DETERMINATION OF LCR NEED SPECIFIC TO LA BASIN AND BIG CREEK/VENTURA AREA

The technical details of the LCR need determination for the LA Basin and Big Creek/Ventura area were addressed in Mr. Sparks' opening testimony. The ISO performed reliability assessments using power flow and transient stability programs and a 2021 case for four RPS scenarios: trajectory, environmentally constrained, ISO base case and the time constrained scenarios. The following table is a summary of the 2021 OTC needs:

Table 1: Summary of OTC (2021) study results

Local Area	Local Area Requirements (MW)				Replacement OTC Generation Need (MW)			
	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained
LA Basin (this area includes sub-area below)	10,743	11,246	11,010	12,165	2,370 – 3,741	1,870 – 2,884	2,424 – 3,834	2,460 – 3,896
Western LA Basin (sub-Area of the larger LA Basin)	7,797	7,564	7,517	7,397				
Big Creek/Ventura (BC/V) Area	2,371	2,604	2,438	2,653	(Need is for Moorpark only, a sub-area of the Big Creek/Ventura Local area)			
					430	430	430	430

Mr. Sparks explained that Table 1 identifies ranges of the amount of generation at existing OTC sites or electrically equivalent sites in the local area (replacement OTC generation) that would be needed under each of the RPS portfolio scenarios. The replacement OTC generation needs in the LA Basin are all within the Western LA Basin, which is a sub-area of the larger LA Basin. In addition, there is also an identified replacement OTC generation need in the Ellis sub-area, which is within the Western LA Basin. The ISO has presented a range of OTC needs depending upon the location and effectiveness of the replacement generation. The lower end of the range represents the amount of capacity needed if located OTC (or electrically equivalent) sites that are highly effective at mitigating the area constraint. The higher end of the range reflects resources located at OTC (or electrically equivalent) sites that are less effective at mitigating the constraint.[79]

The ISO recommends that the Commission direct SCE to procure 2370-3741 MW of new generation resources, based on the trajectory case.[80]

A. LA Basin

As noted above, the ISO studied the need for local capacity in the overall LA Basin and the Western LA Basin, the Ellis sub-area and the El Nido sub-area. The Western LA

[79] Ex. ISO-1, page 4, line 14- page 6, line 22.
[80] *Id.*, page 16, line 26- page 17, line 16.

Basin and the Ellis sub-area drive the need for OTC replacement generation. Mr. Sparks presented tables in his testimony describing the most critical contingencies and limiting constraints for each of these areas and the local area requirements for each scenario.[81] The range of local capacity needs for each scenario was set forth on Table 6:

Local Area	Trajectory		Environmental		ISO Base Case		Time-Constrained	
	High (MW)	Low (MW)	High (MW)	Low (MW)	High (MW)	Low (MW)	High (MW)	Low (MW)
LA Basin*	10,743	10,263	11,246	10,891	11,010	10,516 1	2,165 1	1,663
Western LA Basin	9,168 7,	797	8,482	7,468	8,831 7,	421	8,833	7,397
Ellis	284 3		49 2		64		286	
El Nido	619 5		85 5		68		620	
Replacemen OTC	3,741 2,	370	2,884	1,870	3,834 2,	424	3,896	2,460

* The High LA Basin local area amounts correspond to the Low replacement OTC amounts. This is because the most effective generation sites for mitigating the Western LA Basin constraint are the least effective generation sites for mitigating the Overall LA Basin constraint.

Effectiveness factors for the OTC generation in the LA Basin and Western LA Basin areas and sub-areas were provided in the ISO transmission plan.[82]

B. Big Creek/Ventura Area

Similar critical contingency and constraint information for the Overall Big Creek/Ventura area and Moorpark sub-area was set forth on tables 7-10 of Mr. Sparks' opening testimony. The need for replacement OTC units in the overall Big Creek/Ventura area is established by the Moorpark sub-area. Approximately 430 MW of replacement OTC is required across all four RPS scenarios. This replacement OTC capacity is counted towards the total LCR need for the overall Big Creek/Ventura area.[83]

[81] *See* tables 2-5 in Ex. ISO-1.
[82] Ex. ISO- 7.
[83] Ex. ISO-1, page 14, lines 4-15.

SCE, Calpine and DRA questioned the immediate need for the 430 MW of OTC generation in the Moorpark sub-area and suggested that additional analysis be conducted to determine whether alternative mitigation solutions could reduce this need.[84] In particular, Calpine presented the testimony of Ron Calvert, who conducted a series of power flow analyses using the ISO's inputs for the trajectory scenario, and concluded that several transmission alternatives existed for the capacity needs identified by the ISO. The ISO disagrees with this conclusion, as explained by Mr. Sparks in his sur-rebuttal testimony.

Mr. Sparks first noted that, contrary to Mr. Calvert's conclusions, the purpose of the ISO's OTC was not simply to determine whether OTC generation should be retained or replaced. Rather, consistent with discussions above, the ISO studied generation and non-generation alternatives to the reliability impacts resulting from OTC retirements and the influx of renewable generation in 2021. For the Moorpark area in particular, the ISO identified a non-generation solution similar to Option 1 recommended by Calpine. However, although the studies conducted by the ISO and Calpine have a similar purpose, the ISO disagrees that non-generation alternatives present superior alternatives.[85] For example, although the ISO identified a non-generation alternative similar to Option 1, the ISO believes that the reliability and operational benefits of having 430 MW (out of an existing 1946 MW) replaced in the Moorpark area will ensure that overall changes to the operation of the area and southern California transmission will be moderated.[86] The retirement of the entire 1946 MW of flexible generation without any replacement generation can be expected to severely change the operation of the local and surrounding

[84] Ex. SCE-1, page 3, lines 1-3, Ex. DRA-1, Ex. Calpine-2
[85] Ex. ISO-23, page 2, lines 13-28.
[86] *Id.,* page 4, lines 6-14.

transmission system and create adverse impacts on transmission voltages and loadings under some operating conditions.

Mr. Sparks also questioned the validity of the cost estimates used for Calpine's Options 2 and 3, suggesting that the costs for these solutions are potentially much greater based on the cost of similar transmission upgrades.

More importantly, Mr. Calvert's assessment of the relative costs of transmission versus generation was off-base. Rather than comparing the estimated cost of $500 million for a 430 MW generating facility to the non-generation alternatives, the cost of generation to be considered should be the difference in the cost of procuring generation inside the Moorpark sub-area versus the cost of procuring generation outside the sub-area. Additionally, given the very small amount of OTC generation being replaced in the SCE area- less than 5000 MW out of 18,000 MW of total OTC generation- there is an expectation that new flexible generation must be procured. Furthermore, if not located at an existing site, then the transmission costs associated with 430 MW of generation will be much higher -- approximately $25 million to $100 million. If the generation is outside the Moorpark area, then the transmission cost, assuming the cost of Mr. Calvert's Options 2 or 3, are approximately $50 million on top of the generation costs. When the cost of generation interconnection are added, that additional costs of Options 2 or 3 would be roughly $75 million to $150 million. Thus, the results of Mr. Calvert's analysis are not compelling enough to defer procurement in the Moorpark area.[87]

For the same reasons, the ISO does not agree with SCE that the prospect of transmission options or newer generation technology support a finding that procurement in

[87] *Id.*, page 5, line 8-page 6, line 10.

this area should be deferred to the next LTPP cycle.[88] It is known that the 1946 MW of generation in the area will retire if it is not repowered. It is prudent planning to take advantage of this information and develop a plan, so we can move forward with the implementation of the plan and include it in our overall assumptions for planning the rest of the system. The ISO urges the Commission to authorize the full amount of local area capacity identified in the OTC study. Should newer generation technologies become available that ultimately will reduce the area need, this will be accounted for in the ISO's assessment of SCE's procurement portfolio.

IV. PROCUREMENT OF LCR RESOURCES AND INCORPORATION OF THE PREFERRED LOADING ORDER IN LCR PROCUREMENT

In the July 13, 2012 ACR, the Commission identified the following procurement issues to be addressed either in reply testimony, cross-examination or questions from the bench during the evidentiary hearing, or in a workshop process:

> 1) To the extent that the Commission determines that Southern California Edison Company (SCE) and/or other Load-Serving Entities in the Los Angeles basin and the Big Creek/Ventura local area must procure capacity to meet long-term local capacity needs, how should the Commission direct these entities to meet that need on behalf of the system?
>
> 2) If the Commission wishes to allow SCE to meet some or all of the identified need through "cost plus" contracts outside of a competitive solicitation, how should that work? Does AB 1576 provide clear guidance on the options available to SCE or does the Commission need to interpret the bill's meaning in this context?
>
> 3) In the past, the Commission has allowed all- source Request for Offers (RFOs) for incremental resources in which any type of resource could compete to fill an identified need. What barriers may currently exist to ensuring effective all source RFOs? What specific performance characteristics should be accounted for in this RFO to effectively enable the participation of non-traditional resources like energy storage, demand response and distributed generation? Would the Commission need to be specific about the characteristics of the resources needed to

[88] Ex. SCE-1, page 19.

meet the need (e.g., minimum hours of availability required to meet local reliability needs)? If so, what characteristics should the Commission require?

The ISO provided testimony about the characteristics required by the ISO that would enable non-generation resources to bid into an RFO, generally in response to the third question.[89] SCE and other parties also addressed these issues in reply testimony and several witnesses, including Mr. Millar, responded to questions from the Assigned Commissioner. Energy Division Staff scheduled a workshop on LTPP procurement and energy storage issues on September 7, 2012, with comments to be submitted on October 5 and reply comments on October 19. In this section of the brief, the ISO will summarize its position on how preferred resources could be accommodated in the procurement process, as well as how the ISO could assist with this process, focusing on the procurement approach presented by SCE in its opening and reply testimony.

A. Incorporation Of The Preferred Loading Order In LCR Procurement

1. Resource Characteristics Needed to Participate in Procurement Process

TURN and other parties accused the ISO of taking a "very aggressive stance" and "not honoring the state's energy policy goals" and the loading order with respect to the levels of uncommitted EE, DR, CHP and energy storage assumptions used in the OTC studies. [90] Such statements are simply off-base and unnecessarily inflammatory. In particular, the ISO's OTC assumptions are quite consistent with the statutory loading order requirement set forth in Pub.Util. Code §454.5(b)(9)(C):

> The electrical corporation shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources *that are cost effective, reliable and feasible.* (emphasis added)

[89] Ex. ISO-6, pages 18-19.
[9090] See, *e.g.* Ex.TURN-1 page 9.

Clearly the statute contemplates that the EE and DR resources included in utility portfolios must not only be available, they must also be reliable, feasible and effective in addressing the identified reliability concerns. To the extent that these resources and others in the preferred loading order meet the basic characteristics required by the ISO to ensure adequate system reliability within capacity-constrained areas, achieving energy policy goals are not incompatible with maintaining grid reliability.[91] However, at this point the ISO is unaware of DR or uncommitted EE programs that can substitute with parity the services and capabilities of a local area generator, and other parties have not justified any different conclusion. The same is true for CHP, storage and DG beyond the levels embedded in the CEC load forecast or actually on the system. These resources also lack some or all of the flexibility attributes described by Mr. Rothleder: voltage support, frequency response, sustained energy supply, reliable responsiveness, no significant use limitations, and the ability to provide energy regulation, operating reserves and load following.[92] For the reasons set forth hereinabove, the modeling assumptions and preferred resource levels used by the ISO in the OTC study are reasonable for the purpose of determining the levels of local area resources for which procurement should be authorized.

However, both ISO witnesses Millar and Rothleder made it clear that the ISO is technology neutral and that should DR, EE, CHP or storage resources successfully meet the operational characteristics required by the ISO, they should be able to compete in an RFO or other procurement process. Responding to questions from Commissioner Florio, Mr.

[91] Ex. ISO-6, page 11.
[92] Ex. ISO-4, page 9.

Rothleder explained that each alternative technology would be analyzed in light of the particular attributes that could be provided:

> Q. (By Commissioner Florio)… Well, if electricity storage technologies were commercially feasible such as a battery storage or compressed air storage, could they provide similar flexibility?
>
> A. (By Mr. Rothleder) Potentially. We'd have to look to see how long the storage is and compare that to the length of time that we would need not just the movement capability but the sustained output of that resource, and I think some of those technologies potentially could. Although I -- except for compressed air and pumped storage hydro, my experience has been that the -- they're usually smaller type resources, very quick but not necessarily can sustain the energy output for a long period of time.
>
> Q. Okay. So you might be able to get the ramp rate, but the duration of the ramp might be an issue?
>
> A. That's correct.
>
> Q. So it's very technology specific?
>
> A. You'd have to really look at the characteristics of the technology and compare it to the operational … requirements of the system based on load changes and the supply changes.
>
> Q. Okay. And is the same generally true of demand response, that you have to look at the characteristics of the particular resource --
>
> A. Yes.
>
> Q. -- or the particular program?
>
> A. Maybe a different type of characteristic, how long the resource remains off, lead time to interrupt, is it a block of interruption or is it going to be ramped in.[93]

In his reply testimony, Mr. Millar provided a high level description of the non-generation resource characteristics needed to ensure that incremental resources can compete in the procurement process for local resources: [94]

- High net qualifying capacity (NQC) commitment[95]

[93] Tr. 326 line 21-328, line 1.
[94] Ex. ISO-6, pages 17-18.

- Substitutable for conventional generation and location specific
- Capable of reacting in the time frames necessary to address system issues

He also described more specific resource characteristics for each type of preferred resource:[96]

> Demand Response- while generally considered an alternative to generation resources in meeting system-wide load and supply balances, for local procurement purposes DR should be location-based and dispatchable (substitutable) and dependable over a significant period of time equivalent to the service provided by a generating facility (durable). In addition, in order to be able to quickly restore the system within 30 minutes following a contingency event, DR resources must be location and time specific, and able to provide prompt and dependable response to grid operators within the short time frames required by the planning standards.
>
> Energy Efficiency and (behind the meter) Combined Heat and Power- in addition to broad system benefits, these resources can meet local capacity requirements to the extent they can be reliably forecast to be in place at a specific point (committed) and included in load forecasts on a timely basis.
>
> Combined Heat and Power (Sales to Grid)- to the extent these generators can provide the level of service required in the local areas, they can compete with other generation to provide local requirements.

In response to questions from Commissioner Florio about how potential resource developers would know how to qualify to participate in an RFO, Mr. Millar explained:[97]

> … I would say that we at the ISO working with the utilities would have to help the utilities flesh out those requirements.
>
> Whether those requirements needed pre-approval before an actual RFO process was commenced or if it was addressed after the fact when people responded, I think that's an issue that we have to consider as an industry of what's the most effective way to initiate that process and to make sure that our criteria are clear in advance and don't get caught up, I'd say, in unnecessary challenges after the fact. If there's a risk of that the criteria need to be established beforehand.
>
> * *

[95] Subject to ISO review of effectiveness factors for particular locations. Tr. 346, lines 6-20.
[96] *Id.*, pages 12-13.
[97] Tr. 353, line 28-354, line 16.

Mr. Millar noted that the ISO would be willing to work with utilities in advance of a solicitation to provide guidance to potential developers, and that it is this process should move in parallel with the RFO to better reflect changes to the transmission and generation fleet being addressed at the ISO. [98] When asked whether the ISO's performance requirements are embodied in the tariff or other protocols, Mr. Millar noted:

> They're not laid out in a protocol or tariff. To my knowledge, the best collection of or discussion of these parameters is really now in our testimony in this proceeding, including the comments that were included as Exhibit 20 [ISO comments in the Commission demand response docket] as Mr. Rothleder's discussion and testimony and the parameters that I set out in my testimony.[99]

Thus, the record in this proceeding contains guidance for potential preferred resource developers to participate in an RFO or other form of procurement process, as well as the basic characteristics the ISO requires to meet ongoing grid reliability standards. The ISO looks forward to working with the Commission, the utilities and interested parties to work out in details as part of the procurement process proposed by SCE.

2. SCE's Procurement Proposal

In opening testimony, SCE generally agreed with the ISO's range of local area capacity needs in the LA Basin and Big/Ventura areas, and described the challenges associated with siting new generation resources in these heavily populated areas.[100] SCE also discussed the need for a new multi-year forward procurement mechanism to encourage market-based development of new generation resources, but recognizing the immediate need for resource procurement in the local areas, suggested that the Commission allow a more flexible procurement methodology in addition to, or in place of, a more standard

[98] Tr. 355, lines 3-14.
[99] Tr. 356, lines 2-9.
[100] Ex. SCE-1, pages 3-15.

competitive all-source solicitation.[101] This process would include bilateral contract negotiations, and the results of this LCR procurement process would be presented to the Commission for approval.

SCE provided additional details about its proposed LCR procurement process in reply testimony and on cross-examination during the hearing. Specifically, in response to intervener concerns that the loading order and statutory requirements for preferred resources was not correctly reflected in the ISO's studies, SCE noted:

> These parties claim that higher levels of preferred resources than forecasted by CAISO will reduce or eliminate the need for new LCR generation in SCE's service territory. This general concern is a key reason why SCE has requested flexibility in any LCR procurement authorization adopted for SCE. If preferred resources develop at a greater rate in SCE's local areas than forecasted by the CAISO, the need for new LCR generation should be reduced relative to current forecast levels. However, neither the Commission nor SCE can precisely control the amount and location of future preferred resource developments.[102]

During cross-examination, SCE witness Colin Cushnie provided additional details as to how preferred resources would be considered in the procurement process recommended by SCE. Recognizing that this solicitation for local area resources is a new effort and for this reason will be unique, Mr. Cushnie provided this explanation in response to questions by CEJA:

> Q. Is it possible that Edison might propose changes in order to make it more feasible for a preferred resource to win in an all-source RFO?
>
> A. Well, Edison is technology neutral in terms of what actually prevails in a solicitation. So what we're trying to do or what we will seek to do is to make sure that we appropriately consider all preferred resources. And how we go about doing that still requires some work.[103]

[101] *Id.* pages 21-25.
[102] Ex. SCE-2, page 4.
[103] Tr. 629, line 26- page 630, line 10.

Mr. Cushnie succinctly summarized the SCE procurement proposals in response to questions by Commissioner Florio:

> So I think there are two ways we can proceed in conducting a solicitation if we do do a solicitation. One is that we have finite requirements on what is and is not allowed to bid. And I think what happens there is that it pushes us up the scale of resources to basically those that are fully flexible, available all the time, fully controllable. Then we, obviously being technology neutral, any resource can compete.
>
> But very few outside of gas fired, if any, would probably show up to solicitation. The other approach we could take is Edison looks at all resources that exist in the marketplace. And to the exten[t] that there are certain resources that are probably not terribly effective but still arguably could meet the LCR need, we would do studies on those, as I indicated to some of the earlier questioners.
>
> If the economics of the resource and the viability of the resource could be ascertained to be positive, we would then move into a transmission planning study phase to see if in fact that preferred resource was effective in meeting the LCR need. But we would only do the transmission planning study if the economics and viability were first ascertained to be positive. There is probably hybrids of what I described, but conceptually those are sort of the two ways we can move forward with a solicitation.
>
> Finite requirements mean we are going to have very little in the way of resource types, they are going to be able to compete in these solicitations.[104]

The ISO believes that SCE's flexibility approach has for considering preferred resources in the LCR procurement process could work for an interim period. However a competitive approach based on objective criteria should be the long-term procurement approach. Clearly there is more work to do to implement either SCE approach and the ISO understand the "comparability" and competitive procurement challenges of resources, which on the surface appear to be apples and oranges. However, in the end, an objective criteria approach is the ultimate path forward since all energy resources must cost-effectively, efficiently, and reliably serve the energy needs of consumers. Reliably serving

[104] Tr. 664, line7-665, line 14.

consumers means resources supply energy in the right amount at the right time and in the right place. So even though non-traditional resources may be structurally different than traditional resources, non-traditional resources must provide consumers with reliable energy service just as traditional resources have done for years. Thus, to best advance the state's preferred loading order and to engender a spirit of competition and innovation, the ISO believes the Commission's policy should enable non-traditional resources, like DR and EE, to compete on level terms driven by service reliability needs and required operating characteristics, with firm in-service date commitments, contracted capacity amounts, performance obligations, and other relevant features to participate in competitive, long-term procurement processes.

B. Other Commission Policies and Consideration Affecting LCR Procurement

It goes without saying that the LCR procurement process must take into account GHG and AB 32 requirements, and these policies and statutory requirements have been addressed to a certain extent in SCE's testimony and during cross-examination.[105] The Commission also is considering issues related to non-generation resources in other dockets; for example, demand response and energy storage. To the extent that characteristics needed for participation as demand reduction or supply resources in capacity procurement processes are being considered in those dockets, they should be folded into this one.

Furthermore, the ISO provided testimony in the SDG&E application for approval of purchase power tolling agreements (R.11-03-025) describing the need for additional LCR procurement in the greater SDG&E local area above the capacity provided by the

[105] See, *e.g.* cross-examination of SCE witness Cushnie by counsel for CEJA Tr. 630, line 11- 634, line 2.

resources under contract, and the procurement process authorized in that proceeding should be consistent with the approach taken in this case.[106]

C. If A Need Is Determined, How The Commission Should Direct LCR Need To Be Met

As discussed in the first section, the ISO strongly urges the Commission to find a need for 2,370-3741 MW of new or replacement resources in the LA Basin and Ventura areas, and to direct SCE to begin procurement activities as quickly as possible. Given, as Mr. Cushnie noted, that this LCR procurement will be a new effort, the framework and structure should be developed as quickly as possible to allow implementation during 2013. The ISO is encouraged that the Commission has already held a workshop on these issues and recommends that the need determination and the procurement process design details move forward on parallel tracks.

D. Appropriate Method(s) of Procurement

See discussion above in Section A.

E. Timing Of Procurement

Procurement activities should begin as quickly as possible following the Track 1 decision. This is particularly important because, among other aspects of the procurement process, the ISO must conduct studies to evaluate the effectiveness of the proposed portfolio of resources. As repeatedly noted by the ISO throughout this proceeding, a minimum of five years lead time is required for new generation to come online, making the procurement timeline quite tight under the best of circumstances.

[106] Ex. ISO-8, page 3 (table).

V. INCORPORATION OF FLEXIBLE CAPACITY ATTRIBUTES IN LCR PROCUREMENT

A. If A Need Is Determined, Should Flexible Capacity Attributes Be Incorporated Into Procurement

Both Mr. Rothleder and Mr. Sparks testified that the resources procured to meet local area needs should have flexibility attributes. Based on the ISO's LCR contingency analysis, resources procured to meet local needs must include ramp rates and minimum output levels that allow the generation to be ramped-up quickly following the first transmission contingency in order to ensure reliable system operation following the next transmission contingency. The flexibility of the OTC generation allows efficient system dispatch when all transmission equipment is in-service, but still provides for reliable system operation following a transmission contingency.[107]

Mr. Rothleder provided a description of resource flexibility:

- Ability to be dispatched and respond to dispatches based on the registered ramp rate
- Provide dispatch flexibility between minimum and maximum operating level for the resource; the lower the minimum load relative to maximum, the more flexible the resource
- Quick response to changes in load and renewable resource intermittency
- Ability to provide ancillary services
- Inertia or governor control to respond to changes in frequency and provide system stability

[107] Ex. ISO-1, page 15, lines 1-9.

- Faster starting to respond to changes more quickly rather than having to be online prior to the change in condition[108]

As discussed above, it is possible that alternative preferred resources such as dispatchable DR might have some of these characteristics, although for study purposes the ISO was not aware of a viable alternative to conventional generation that meets these operational needs, nor did the other parties to this proceeding show that DR could satisfy these operational needs and ensure reliable grid operations in local areas.

Mr. Rothleder explained that, with respect to system needs for additional new generation, the ISO conducted a production simulation using the PLEXOS model but with the local area resource requirements identified in the OTC study. Specifically, 3,173 MW of local area capacity were added to the model as a combination of combined cycle gas turbine (CCGT) and gas turbine (GT) units. Based on the results of the simulation, and assuming this local area resource mix, the simulation results show a 1,051 MW residual system shortage of upward load following resources. Approximately 1200 MW of system resources are likely to be needed to cover this shortfall, which is consistent with the analysis conducted by the ISO in the prior LTPP proceeding, R.10-05-006, and described in Mr. Rothleder's testimony in that case.[109]

CEERT witness Caldwell questioned the study results provided by Mr. Rothleder, noting that the CCGT resources were running with very high capacity factors, at baseload or near baseload conditions, thus contradicting the need for local flexible resources.[110] In reply testimony, Mr. Rothleder explained that, as part of the ISO's work with the Air Resources Board (ARB), the study results have been updated to correctly reflect the forced

[108] Ex. ISO-4, page 8, lines 13-30.
[109] *Id.,* page 3, line 17 – page 5, line 2.
[110] Ex. CEERT-1, page 5.

outage and maintenance schedules for these resources. These updated results, presented in exhibit ISO-21, showed CCGT resource capacity factors in the range of 57%-66%. Mr. Rothleder also noted that, while energy from inflexible resources may be able to unload other flexible resources, further study is needed to determine to what degree this trade-off can occur or whether it is economic.[111]

Commissioner Florio posed several questions to Mr. Rothleder on this topic:

> Q. In your reply testimony ISO-5, page 4 of 5, the last paragraph you mention, while energy from inflexible resources may be able to unload other flexible resources, further study is needed to determine to what degree this trade can occur. Are you referring there to adding something like combined heat and power thatruns on a 24/7 baseload profile?
>
> A . Yeah, basically. Something that is more inflexible but gives you the ability to unload other flexible resources in the system and to make -- to use those when you need to ride through the variations in the system…
>
> Q. That would be kind of a portfolio specific phenomenon that if you have those flexible resources that are running above minimum load you can do this, but if they're running at minimum load you can't?
>
> A. There's two things you have to think about when doing that. Do those resources exacerbate potential issues with overgeneration. Okay. And the second thing that has to be considered is do you have enough embedded flexibility to meet your needs because if you don't have enough embedded flexibility you can't do that trade-off in the first place.[112]

A final question from Commissioner Florio very succinctly summarized the ISO's position on the flexibility issue:

> Q. …The overall takeaway I get from your testimony is -- tell me if this is a fair characterization -- is we're dealing here in this phase of the proceeding with replacing once-through cooling generation, but in doing that you're recommending that we keep an eye on the issue in the next phase of flexibility and, you know, potentially consider getting both elements at once rather than, say, pursuing a lot of inflexible resources here and then having to do more procurement of flexible resources later?

[111] Ex. ISO-5, page 4, lines 4-29.
[112] Tr. 329, line 26-330, line 26.

A. I think that's right. You have an opportunity here to address the local issues, and potentially how you address those and the characteristics of those resources that you use to do -- satisfy the local issues, it has effects on what may be the residual flexibility needs in the Track 2.[113]

B. Additional Rules, Not Already Covered By Resource Adequacy (RA) Rules, To Govern LCR Procurement

Except for the resource characteristics that the ISO will help develop for local (and system) procurement in this proceeding, as discussed in Section IV above, the ISO does not believe that additional rules are necessary to govern the Track 1 procurement.

VI. COST ALLOCATION MECHANISM (CAM)

A. Proposed Allocation Of Costs Of Needed LCR Resources

The ISO has no comment on this section, but reserves the right to respond in its Reply Brief.

B. Should CAM Be Modified At This Time?

The ISO has no comment on this section, but reserves the right to respond in its Reply Brief.

C. Should Load Serving Entities (LSEs) Be Able To Opt Out Of CAM?

The ISO has no comment on this section, but reserves the right to respond in its Reply Brief.

VII. OTHER ISSUES

A. SCE Capital Structure Proposal

The ISO has no comment on this section, but reserves the right to respond in its Reply Brief.

[113] Tr. 331, line 11-332, line 2.

B. Coordination of Overlapping Issues Between R.12-03-014 (LTPP), R.11-10-023 (RA), And A.11-05-023

Docket A.11-05-023, which involves an SDG&E request for approval of power purchase tolling agreements (PPTAs) with Pio Pico Energy Center, Quail Brush Power, and Escondido Energy Center, involves the same local area capacity need issues that are being considered in this proceeding. Mr. Sparks sponsored the LCR/OTC study results for the greater San Diego area, and Mr. Rothleder provided testimony regarding the "two for one" benefits of procuring flexible local resources for the system resource studies that are underway in Track II. The ISO understands that local area needs for San Diego will be determined in A.11-05-023, including the need to procure additional new local resources, above the 450 MWs provided by the PPTAs at issue. Based on the ISO's trajectory scenario, there is a need for LSEs to procure an additional 311 MW of resources in the greater San Diego local area.[114] Thus, there does not appear to be any "overlap" between the decisions that are going to be issued in A.11-05-023 and Track 1 in this LTPP although the issues under consideration with respect to local need are substantially the same.

However there is overlap between R.11-10-023, which is the two year resource adequacy proceeding (RA), and the Track 1 decision in this proceeding. The May 17 ACR and Scoping Memorandum recognized that the June 2012 decision in R.11-10-023 would inform the local area capacity need determination.[115] In the RA proceeding, the ISO proposed modifications to the Commission's RA programs recognizing the need to maintain operating flexibility in the existing resource fleet as increased amount of intermittent resources are added to the system, in order to maintain grid reliability and

[114] *See* Ex. ISO-8, page 3.
[115] Scoping Memorandum, page 3.

reduce reliance on the ISO's backstop mechanism. Among other things, the ISO proposed that the Commission adopt three categories of flexible capacity:

- Regulation
- Load following
- Maximum ramping

The ISO noted that these categories represent the operational attributes needed by the ISO and can be applied on a resource-by-resource basis to assess the flexibility that each resource can provide. The ISO then developed the amount of resources needed in each category, based on historical information, and suggested that, for the 2013 RA, the flexibility categories be adopted as advisory targets, and that mandatory flexibility requirements be developed for the 2014 RA year.[116] These categories are consistent with the description of flexibility for local resources provided by both Mr. Millar and Mr. Rothleder in this proceeding.[117] Energy Division staff also proposed modifications to the (MCC) to reflect flexibility characteristics.

On June 21, 2012, the Commission issued D.12-06-025. The Commission recognized the general agreement among the parties that there was no immediate need to impose flexibility requirements in 2013, but that mandatory flexibility requirements should be considered for adoption in the 2014 RA year. The Commission also recognized that these requirements would feed into both Track 1 and Track 11 procurement in this proceeding, and therefore that work on a flexibility framework must proceed expeditiously:

> We will immediately begin the effort to finalize a framework for filling flexible capacity needs in this proceeding. Our intent is to adopt a framework by or near the end of 2012, for implementation in the 2014 RA compliance year. We will also coordinate our efforts in this proceeding with those in the LTPP

[116] ISO March 2, 2012 supplemental information in R.11-10-023, page 5.
[117] Ex. ISO-5, page 8, line 13-page 9, line 9; Ex. ISO-6, page 17, line 17-page 18, line 3.

> proceeding. The Scoping Memo in the LTPP proceeding foresees a Commission decision by or near the end of 2012 potentially allowing or requiring utilities and/or other LSEs to procure for local reliability needs. The flexible needs framework we expect to adopt in this proceeding could potentially be used for subsequent Request for Offers to fulfill procurement determined in the LTPP proceeding.[118]

Consistent with this directive, on August 13, 2012, the Commission staff held a workshop on flexible capacity procurement in R.11-10-023. At that workshop, the ISO identified its two key objectives as instituting an interim RA solution with an explicit flexible capacity requirement beginning in the 2014 RA compliance year and collaborating with the CPUC and stakeholders to create a more durable and sustainable RA solution that takes us beyond 2020, beginning in the 2017 compliance year.

Thus, the overlap between these two proceedings will take place for the Track 1 phase of this LTPP proceeding. Assuming that the Commission issues an order by the end of 2012 directing SCE to initiate procurement activities, the flexibility framework being developed in R.11-10-023 can be implemented as part of long-term procurement for new resources, in addition to the RA annual showings. The ISO urges the Commission to include specific language in the Track 1 order referring to the flexibility framework and the Commission's intention to use it in long term procurement activities.

C. SCE Statewide Cost Allocation Proposal

> The ISO has no comment on this section, but reserves the right to respond in its Reply Brief.

[118] *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations* Docket R.11-10-023 (Order, page 20).

D. CAISO Backstop Procurement Authority To Avoid Violating Federal Reliability Requirements

SCE's initial testimony, at Sections VI, urges the Commission to work with the ISO to establish a new multi-year forward procurement mechanism for market-based development of new generation resources.[119] The ISO wholeheartedly agrees, and notes that on September 20 PG&E filed a motion in this docket and R.11-10-023 to move the consideration of this mechanism from Track III in LTPP to the RA proceeding. The ISO supports that proposal as well and urges the Commission to move quickly in this regard. However, recognizing that development of this new forward procurement mechanism may be under development in the RA proceeding during the time that procurement activities for Track 1 local resources should be initiated and undertaken (2013), the Commission, SCE, the ISO and interested parties should proceed to develop a framework for local procurement that takes the first step in the direction of providing guidance for non-generation resources with specific characteristics to participate along with new generation.

E. Energy Storage

The ISO has addressed energy storage issues in other sections of this brief.

VIII. CONCLUSION

For the reasons stated above, the Commission should find that there are local capacity needs in the LA Basin and Big Creek /Ventura areas for new generation resources based on the levels determined by the ISO using the trajectory renewable portfolio scenario. Without authorization for the procurement of new resources in these areas, grid reliability could be compromised. The ISO will work with SCE and other parties in

[119] Ex. SCE-1, pages 17-21.

determining the characteristics required for non-generation resources to compete in the procurement process.

Respectfully submitted,
By:*/s/Judith B. Sanders*
Nancy Saracino
General Counsel
Anthony Ivancovich
Assistant General Counsel
Judith B. Sanders
Senior Counsel
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel.: (916) 608-7143
Fax: (916) 608-7222
jsanders@caiso.com

Attorneys for the California Independent System Operator Corporation

September 24, 2012