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.	R.12-03-014 (Filed March 22, 2012)

OPENING BRIEF ON TRACK 4 OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

Barbara Barkovich
Barkovich & Yap, Inc.
PO Box 11031
Oakland, CA 94611
707.937.6203
barbara@barkovichandyap.com

Consultant to the California Large Energy Consumers Association

Nora Sheriff
Alcantar & Kahl LLP
33 New Montgomery Street
Suite 1850
San Francisco, CA 94105
415.421.4143 office
415.989.1263 fax
nes@a-klaw.com

Counsel to the California Large Energy Consumers Association

November 25, 2013

Table of Authorities

CPUC Decisions

D.10-02-032 9
D.10-06-034 11
D.11-11-008 9
D.13-03-031 9

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.	R.12-03-014 (Filed March 22, 2012)

OPENING BRIEF ON TRACK 4 OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

The California Large Energy Consumers Association (CLECA)[1] submits this opening brief pursuant to Rule 13.11 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure and the email instructions sent by Administrative Law Judge Gamson on November 4, 2013.

I. INTRODUCTION

The scope of this track is to determine if there is a local reliability need by 2018 and 2022 in the Los Angeles Basin area and in the San Diego sub-area due to the loss of the San Onofre Nuclear Generating Station (SONGS).[2] The Commission must consider the cost and other impacts of an additional 500 MW procured by SCE and over 1000 MW for SDG&E for a very low probability

---

1 The California Large Energy Consumers Association is an organization of large, high load factor industrial electric customers of Southern California Edison Company and Pacific Gas and Electric Company. CLECA has been an active participant in Commission regulatory proceedings since 1987.

2 Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge, issued May 31, 2013, at 4 ("Track 4 will consider the local reliability impacts of a potential long-term outage at the San Onofre Nuclear Power Station (SONGS) generators, which are currently not operational. The CAISO is developing a study to assess both the interim (2018) and long-term (2022) local reliability needs in the Los Angeles Basin local area and San Diego sub-area resulting from an extended SONGS outage.").

contingency. The Commission should thus consider the lawful use of controlled load shedding as an interim bridge solution. Pending the imminent completion of the ISO's Transmission Planning Process, anticipated rate design impacts on load shape, and development of characteristics for demand response to meet local needs, use of load shedding can avoid procurement costs. Based on the record in this track 4, the costs of any additional procurement would not be justified, nor would the resulting rates be just and reasonable.

II. THE CPUC SHOULD NOT AUTHORIZE SCE OR SDG&E TO NOW PROCURE ADDITIONAL LOCAL RELIABILITY RESOURCES

The timeframes for the local reliability need determination are 2018 and 2022. The record shows the following:

- The use of controlled load shedding is lawful and can meet local reliability requirements for certain low-probability contingencies while avoiding the cost of additional procurement – indeed additional procurement does not appear to be immediately needed;
- Special Protective Schemes using load shedding are in use now and can serve as an interim bridge to address the unlikely probability of a Category C N-1-1 event between now and 2018 and indeed until 2022;
- Meanwhile, the ISO's Transmission Planning Studies can be finalized, and the mitigating impacts on load shape from the Commission's rate design policies can develop, both of which will impact local reliability need;
- Finally, allowing additional procurement beyond what has been authorized in Track 1 could needlessly crowd out preferred resources, such as demand response.

CLECA accordingly recommends against authorization of procurement by SCE and SDG&E of additional resources; CLECA, therefore, does not address the remaining questions posed by Administrative Law Judge Gamson.[3]

A. Use of Load Shedding Is Lawful, Would Reduce Need And Avoid the Cost of Unnecessary Procurement

NERC and WECC regulations allow controlled load shedding in the form of a special protection scheme (SPS) for rare contingencies, such as a Category C N-1-1 event.[4] The probability of these events actually occurring is "extremely remote."[5] ISO Witness Sparks acknowledges that load shedding *is* permitted in response to a Category C N-1-1 event.[6]

SCE agrees that use of controlled load shedding as a mitigation strategy for a Category C contingency for SDG&E would reduce the need for additional generation in the LA Basin by 436 MW.[7, 8] SDG&E demonstrates that the use of

[3] The remaining questions are: "If so, what additional procurement amounts should be authorized at this time? Please specify any calculation that leads to this position? What additional resources, if any, should be authorized to fill procurement needs? Should there be any requirements or restrictions on procurement amounts for any specific resources or categories of resources? What process should the utilities use to fill any procurement amounts authorized at this time? Are there other determinations the CPUC should consider, or conditions the CPUC should impose, regarding Track 4 procurement?"

[4] 10 Tr. 1488 (ISO/Sparks)("NERC allows load shedding once you've considered the design of the system and the impacts of that load shedding."); *see also* 10 Tr. 1409 (ISO/Sparks); *see also id*. at 1488, 1505, and 1407.

[5] 13 Tr. 1955 (Sierra Club/Powers); *see also* 12 Tr. 1836-37 (ORA/Fagan)("what's probably more important is the relative likelihood that it might have to be used … it's not always invoked.").

[6] 10 Tr. 1470 (ISO/Sparks); *see also* Ex. ISO-2 (Sparks Rebuttal), at 5 (acknowledging the two load shedding schemes currently in place on an interim basis in urban areas of San Francisco and the San Joaquin Valley).

[7] 13 Tr. 2017 (SCE/Chinn); *see also* Ex. SCE-1 (Opening Testimony), at 6.

[8] "Shedding load in SDG&E's service area reduces the power flows through Orange County. As a result, there is no performance violation in SCE's system assuming the load shed in SDG&E for this critical C.3 contingency … Thus, the Mesa Loop-In demonstrates a much greater ability to reduce generation need (1,200 MW compared to 734 MW) in the LA Basin, if the critical SDG&E C.3 contingency is addressed by load shed in SDG&E's service area. … Load shed or additional generation in SDG&E would be more effective to address the critical C.3 contingency." Ex. SCE-1 (Opening Testimony), at 36-37.

controlled load shedding could reduce LCR requirements by 1000 MW.[9] The ISO says it does not consider controlled load shedding to be a viable strategy in this case. However, the ISO has no responsibility to consider the costs of contingency mitigation strategies. The costs associated with the additional 436 MW in the LA Basin (which SCE rounded up to 500 MW) and the additional 1000 MW in San Diego's service territory would not need to be incurred if an SPS were permitted. If load shedding were not used, the estimated, approximate additional net costs for SCE ratepayers "would be at least several hundred million dollars."[10] Estimates for added SCE capital costs are even greater, between $490 million to $1.26 billion.[11] The ISO admitted it did not quantitatively consider costs as part of its "thought process" on the use of controlled load shedding.[12] Cost and cost-benefit analysis is "not a focus" of the ISO.[13] The Commission, however, must consider cost in its exercise of its jurisdiction over utility procurement of local reliability resources.

The Commission should not spend ratepayer money to add yet another roughly 500-1500 MW in resources that **will rarely if ever be used** instead of using controlled load shedding by SDG&E in the case of an N-1-1 contingency

---

[9] "**Planning analyses performed by the CAISO supporting the Final 2013 LCR Technical Study indicate that adherence to the N-1-1 criteria without the possibility of load shedding increases the LCR requirements for the San Diego LCR area by over 1000 MW, the equivalent of two combined cycle units**." Ex. SDG&E-3 (Opening Testimony Jontry), at 7-8, (emphasis added.)

[10] *See* Ex. TURN-1, at 17-18 (Woodruff Opening Testimony); *see also Id,* at 21 ("the longer-term costs of meeting local need [without load shedding] ... may thus be higher than shown in Tables 4 and 5.)"

[11] *See* Ex. TURN-1, at 19-20 (Woodruff Opening Testimony). SDG&E's net additional costs are estimated to possibly reach $150 million and potential additional capital costs for SDG&E could reach up to $250 million. *Id*, at 22.

[12] 10 Tr. 1432 (ISO/Sparks)("we don't have any documentation of a quantitative cost/benefit analysis, but in going through and looking at the outage risks and the impact to load, on a certain level that is part of the thought process.").

[13] 11 Tr. 1630 (ISO/Millar).

under a 1-in-10 peak load condition. Neither SCE nor SDG&E modeled the probability of an N-1-1 event under a one-in-ten year peak load hour,[14] nor did the ISO.[15] The use of SPS is not a matter of failing to meet NERC and WECC requirements. The choice of additional new gas-fired generation is a matter of having ratepayers foot the significant bill for going beyond those requirements. Furthermore, new gas-fired generation would require emissions reduction credits and, as SCE witness Silsbee noted, emissions reductions credits can be expensive to obtain in the LA Basin.[16]

B. Load Shedding Is Used Now and Could Be A Bridge Solution

ISO Witness Sparks acknowledges that "the ISO has load shedding in small amounts for special protection schemes."[17] The ISO also has load shedding in "large" amounts for Special Protection Schemes.[18] In fact, "the ISO has actually 34 special protection schemes that drop load."[19] While the ISO raises concerns regarding the use of load shedding in the context of urban density in San Diego and LA, the record shows that Special Protection Schemes with load shedding are currently in use in similarly dense urban areas.

---

[14] 12 Tr. 1891 (SCE/Nelson)("Q: Has Edison performed any estimates of the probability of an N-1-1 contingency triggering a load shed absent additional resource development? A: Not that I'm aware of."); *see also* 12 Tr. 1735-36 (SDG&E/Jontry)("We didn't model any sort of probabilistic analysis. It was strictly a deterministic analysis.").

[15] 11 Tr. 1623-25 (ISO/Millar)(stating that the ISO has "deterministic planning criteria on a system wide basis … for transmission planning purposes" and acknowledging "our deterministic test is conservative in looking at high stressed load conditions which might not always be peak load.")

[16] 13 Tr. 2079 (SCE/Silsbee).

[17] 10 Tr. 1470 (ISO/Sparks); see also Ex. ISO-3 (Sparks Rebuttal), at 5 (acknowledging the two load shedding schemes currently in place on an interim basis in urban areas of San Francisco and the San Joaquin Valley).

[18] 11 Tr. 1583 (ISO/Sparks)(referring to three special protection schemes that "can drop large amounts of load.")

[19] 11 Tr. 1582 (ISO/Sparks).

Q: So this concentration on the coast is different in the LADWP service territory or in the San Francisco territory?

A: No. Those are also … [high] population density areas that are equally impacted by load shedding.[20]

The use of controlled load shedding proposed here is intended to be an interim or bridge solution, that is, to enable future transmission or potential preferred resources solutions.[21] ISO Witness Sparks explained, "using the transmission line as the example [of a permanent solution], sometimes it can take ten years to permit and engineering, construct the transmission line so that would be a good rule of thumb for short term."[22] Existing load shedding schemes are also interim, planned to be in place for up to 10 years to allow for the building of a transmission line.[23] As the record shows, the ISO recently relied on a Special Protection Scheme of load shedding in South Orange County for a period of two years to mitigate an N-2 outage.[24] Further, as ISO Witness Sparks acknowledged, historical practice permits reliance for an interim period of 10 years on load shedding of 500 MW in urban areas.[25] Finally, as ORA Witness Fagan explained,

> For most of the time the load is well below the 1-in-10 peak that's monitored here. You don't need to invoke load shedding … On the days when you do have load forecasted to be that high, to the

---

[20] 10 Tr. 1477 (ISO/Sparks); *see also Id.*, at 1409 (ISO/Sparks)(referring to the existing WECC-approved south-of-SONGS Special Protection Scheme with controlled load shedding.)

[21] Ex. ORA-3 (Fagan testimony), at 11; *see also* Tr. 1713-14 (SDG&E/Jontry); *see also* 13 Tr. 2022 (SCE/Chinn).

[22] 10 Tr. 1429 (ISO/Sparks); *see also id.*, at 1430 (ISO/Sparks)("any time beyond that [10 years] would be long term")

[23] 10 Tr. 1412 (ISO/Sparks) (defining interim as the time it can take to get a transmission line in place: "sometimes that can take 10 years").

[24] 10 Tr. 1413 (ISO/Sparks)(acknowledging use of controlled load drop for "a couple of years" before the completion of the Del Amo-Ellis loop-in in the summer of 2012).

[25] 10 Tr. 1411-12 (ISO/Sparks).

> extent that's coincident with the days where you might expect the contingency condition to happen, say there's fires in the immediate area, then you think about taking steps ahead of time such as second contingency DR, for example, to the extent that it's in place, so that you don't necessarily have to even invoke involuntary load shedding on that day… you just have to appreciate the different factors here that will likely minimize any actual need to use – to actually shed load during a period while you're waiting for the preferred resources and/or any new transmission line that might be built to be in place.[26]

C. Load Shedding as a Bridge Solution Would Enable Conclusion of the ISO's Transmission Planning Process and Achievement of Rate Design Policy Impacts on the Load Shape, Both of Which Will Impact Local Reliability Need

1. ISO Transmission Planning Studies

ISO Transmission Planning Study results will be issued in January 2014.[27] These should have key information on potential transmission line solutions.[28] Indeed, the outcome of the ISO's transmission planning process may minimize the need for new generation.[29] For example, the proposed Ellis Corridor, estimated to cost $20 million, could reduce the LA Basin local reliability need and is currently under consideration by the ISO.[30] New transmission connecting to

---

[26] 12 Tr. 1841-42 (ORA/Fagan).

[27] 10 Tr. 1423 (ISO/Sparks)("we're in the middle of the analysis … as soon as we have the analysis done, we'll share it. I think that will be in January.")

[28] 13 Tr. 2081 (SCE/Chinn); *see also id*. at 2043-44 (referring to the proposed Ellis Corridor project and the Mesa Loop-in project).

[29] 11 Tr. 1539 (ISO/Sparks)("we are looking at potential transmission mitigation in the transmission upgrades which could reduce the local capacity needs. We haven't completed the studies yet."); *see also* 13 Tr. 1964 (SCE/Cushnie)("The Cal ISO's transmission planning process is looking at other projects [than Mesa Loop-in] as well that might alleviated the need for additional generation.")

[30] 13 Tr. 2043-44 (SCE/Chinn); *see also* 11 Tr. 1628-29 (ISO/Millar)(acknowledging that a transmission project for a 65 mile 500 Kv line from Alberhill to Suncrest, with an estimated cost of $1-2 billion, could provide a local capacity reduction benefit of "approximately 1,000 MW").

San Diego could also address local reliability needs there.[31] SDG&E submitted at least ten transmission projects for the ISO's consideration.[32]

As SDG&E Witness Jontry explains, "as a short term operating sort of mitigation, we accept that load shedding is sometimes necessary."[33] Notably, the requested in-service date for one of SDG&E's proposed projects is before 2018; the Imperial Valley project could be in place in 8 to 10 years, and the Devers project "might happen more quickly because it's a much shorter route."[34] The Commission should not authorize additional procurement in Track 4, because load shedding can and should be used as an interim solution for up to 10 years to mitigate the unlikely occurrence of a Category C or D event; in that timeframe, the ISO's Transmission Planning Process can be expected to result in additional transmission that will reduce the need for local reliability. Similarly, impacts of the Commission's rate design policy on the load shape will also likely reduce the local reliability need in that timeframe.

2. Rate Design Policy Impacts

The Commission has been implementing a policy of changing non-residential rate designs for the last several years; the Commission's intent is to provide pricing signals to customers to encourage shifting load away from peak

---

31 13 Tr. 2018 (SCE/Chinn); *see also* 12 Tr. 1749 (SDG&E/Jontry)("The two 500 kV AC or DC projects, either the connection to the north to Edison or the connection to the east to Imperial Valley would reduce our generation need.").

32 12 Tr. 1748 (SDG&E/Jontry)(explaining that six of the projects were "full transmission project" and the remainder were subtransmission projects).

33 12 Tr. 1755 (SDG&E/Jontry)(agreeing that for an 8-year period, load shedding could be an interim solution).

34 12 Tr. 1785 (SDG&E/Jontry).

periods and away from dynamic pricing "event" periods.[35] The potential impact of transitioning small and medium business customers to new, mandatory, TOU rates and then to default CPP rates should not be ignored.[36] Small commercial customers do appear to respond to such rates.[37] Some load shape impact is expected from these new rates, which is why the Commission is proposing a pilot to study it. The Commission is also considering changes in residential rate design to provide similar pricing signals, and AB 327 permits the introduction of residential TOU rates starting in 2018, one of the years of interest in this proceeding. There is evidence on the record in R.13-09-011 that residential customers respond to TOU and dynamic rates.[38]

It makes no sense to ignore these potential changes in usage patterns by IOU customers in the demand forecasts used in the LTPP. While the California Energy Commission does not currently consider the impact of changes in rate design on load shape, it is interested in doing so going forward in the IEPR demand forecast, which is a starting point in the need determination in the LTPP proceedings. In the current Track 4, the years of interest are 2018, 2020, and

---

[35] *See, e.g.,* D. 10-02-032 and D. 11-11-008 for PG&E and D.13-03-031 for SCE.

[36] R. 13-09-011, Attachment A, p. 12 ("In separate decisions, the Commission has directed that PG&E, SDG&E and SCE transition all small and medium sized commercial customers (small commercial customers, or small businesses) to a new mandatory TOU rate. The Commission has also directed that after a period of adjustment on TOU that [sic] the utilities transition the same customers to a CPP rate, which the customer can choose to opt off of to return to the TOU rate. These rate transitions began in 2012 and will continue through 2016, and they will impact roughly 860,000 small and medium commercial accounts.").

[37] The SMUD small commercial Summer Solutions Study results warrant consideration here, particularly given the strong responses that are facilitated by technologies such as programmable communicating thermostats. *See* Small Business Demand Response with Communicating Thermostats, Herter et al. LBNL-2743E, September 2009. The SMUD small commercial Summer Solutions Study results warrant consideration here, particularly given the strong responses that are facilitated by technologies such as programmable communicating thermostats.

[38] *See* CLECA Comments, at 3-6(dated Sept. 30, 2013)(referring to evidence on residential customer response in comments in the residential rate design proceeding (R.12-06-013).

2022. These are years *after* TOU rates will have been implemented for all non-residential customers for several years or more, and 2020 and 2022 are after the permitted introduction in 2018 of default TOU rates for the residential class. There is a significant risk that not taking into account the ability of TOU and dynamic rates to change load shapes will result in over-procurement to meet the very infrequent 1-in-10 peaks associated with local reliability considerations; this would, in turn, raise rates unnecessarily.

The Commission should direct the utilities to perform statistically valid studies of the impact on loads of changing rate designs adopted pursuant to Commission orders and to make the data available to the CEC. The Commission should also request that the CEC reflect this information in its load forecasts and that these results be made available for the LTPP process and be used in future LTPP proceedings, like the new proceeding anticipated in 2014.

D. Authorization of Additional Local Resource Procurement Could Result in Crowding Out of Demand Response and Other Preferred Resources

SCE intends to fully procure the amounts already authorized in Track 1[39] and wants to roll any additional procurement authority from this Track 4 into its existing Track 1 authority.[40] This could possibly lead to procurement of larger or more conventional generation plants, e.g. a large combined cycle gas plant, instead of one or a few smaller combustion turbines:

[39] 13 Tr. 2001 (SCE/Cushnie).

[40] 13 Tr. 2002 (SCE/Cushnie) ("our proposal is to add the 500 MW to this existing procurement authorization thereby causing it to increase to 1900 MW to 2300 MW, and the 500 MW to be considered all-source procurement"); *see also* 13 Tr. 2004-2007.

Q: [O]ne idea was to give a more level playing field for gas-fired generation, correct?
A: Combined cycle specifically.[41]

Moreover, as SCE states, "it is conceivable that we may have met all of our gas fired generation requirements in the solicitation and have met potentially very little of the preferred resource procurement in the initial solicitation."[42] Indeed, when asked point blank, does SCE "realistically expect preferred resources to be able to compete in this all-source RFO", the ultimate answer was: "I'm really not in a position at this point in time to say … I just don't know."[43] This should give the CPUC pause in considering the requested additional procurement.

SCE did not consider the Commission's new storage targets when evaluating LCR need, beyond the 50 MW already included in Track 1 authorization.[44] SCE intends to rely on the DR and EE proceedings to conduct the Track 1 authorized procurement of DR and EE.[45]

Reliability-based DR can be used for the rare Category C and D contingencies, including transmission-related events, under consideration here.[46] But as SCE Witness Silsbee stated, "Currently, the CAISO does not plan to

---

[41] *Id*. Mr. Cushnie went on to express concern that "that 200 MW [all-source] block … is a very small block. And it's not something that gas-fired generation is going to fit neatly into… by expanding the block to 700 MW, it is conceivable that a combined cycle could be successful… and a combined cycle is the preferred gas-fired resource." 13 Tr. 1969-70 (SCE/Cushnie).

[42] 13 Tr. 2003 (SCE/Cushnie).

[43] 13 Tr, 1968-69 (SCE/Cushnie).

[44] 13 Tr. 2108-09 (SCE/Silsbee).

[45] 13 Tr. 1998 (SCE/Cushnie). SDG&E also intends to conduct procurement of DR in the DR proceeding. 12 Tr. 1866 (SDG&E/Anderson)(noting SDG&E's intent to "propose programs in the DR rulemaking").

[46] For example, the BIP and AP-I tariffs explicitly state that they can be used for "system contingencies". The Settlement adopted in D. 10-06-034 explicitly anticipates that reliability DR programs may have "*multiple reliability-only uses (system, transmission and local reliability) and may be triggered by IOUs for reasons other than CAISO needs, such as IOU-controlled distribution circuit operations*." D. 10-06-034, Appendix A, at 4 (emphasis added).

dispatch DR to meet LCR needs."[47] The ISO has expressed concern about the ability of existing DR to meet its needs[48] in connection with the short-time frame to respond to N-1-1 contingencies.[49] ISO Witness Sparks and CLECA have noted that DR programs can evolve to meet desired notice and response periods.[50] But this will take time, and the ISO explained that it is "working on identifying the necessary characteristics of preferred resources such as demand response such that it can meet local needs."[51] Indeed, Witness Sparks qualified his concerns with existing DR:

> that's not to say that we couldn't' find some other DR or modify that [existing] DR, but at this point in time we didn't want to cause confusion that that DR, as it exists today, could meet the need. And so it was not included in the residual calculation [in Table 13].[52]

As SCE Witness Nelson explained,

> once we have a better understanding of what it will take with the CAISO to meet LCR requirements, we could look at our existing programs and try to reshape them. So potentially that could have something to do with duration. It could have something to do with how quickly programs can go into effect. It may have something to do with time of day because load shape could be changing over time. So I think there's a number of different levers to pull there

---

[47] 13 Tr. 2089 (SCE/Silsbee).

[48] 10 Tr. 1456 (ISO/Sparks)("existing DR that doesn't have characteristics that meet the needs.")

[49] 10 Tr. 1504 (ISO/Sparks)(discussing N-1-1 contingencies: "given that the next contingency could result in voltage collapse or stability problems, you want to be able to do that [respond] quickly because you're exposed until you've readjusted the system. So within 30 minutes you readjust the system")

[50] 10 Tr. 1456 (ISO/Sparks); *see also* CLECA Comments, at 6-8.

[51] 11 Tr. 1553 (ISO/Sparks); *see also Id* at 1600 ("we also need the systems and infrastructure in place between ourselves and the utilities to make sure these resources can actually be used in real time").

[52] 10 Tr. 1456-57 (ISO/Sparks).

> that we could work. And since we have a fair amount of existing DR, it provides a good place to begin.[53]

The Commission should not short-circuit this opportunity for DR by authorizing procurement in this Track 4. Use of DR as a resource for local reliability is being addressed in other Commission dockets and venues, including on a preliminary basis at the ISO,[54] and the determinations of the needed characteristics for "local reliability" DR have not yet been made.[55] "There is still a lot of work to do as to defining what the characteristics of it will need to be, what the call provisions will need to be, how long it will need to be dispatched."[56] However, this process could be accelerated at the Commission and at the ISO, where the focus to date has been on the use of DR for flexibility rather than local reliability.[57] Further, SCE's "Living Pilot" is still in the development stages.[58] While the necessary characteristics for DR to be used for local needs are being developed over the next two years, use of a load shedding protocol would be appropriate.

> Q: So in other words, if you had a clear time frame that was likely to be met, just was going to take another year or another two years for some reason, whatever the planning reason might be, that might

---

[53] 12 Tr. 1897-98 (SCE/Nelson).

[54] CLECA Comments, at 7-8.

[55] 11 Tr. 1687 (ISO/Millar)(no local capacity requirements or criteria have been developed by ISO for DR yet); see also id at 1555; *see also* 12 Tr. 1902 (SCE/Neslon)(noting that the process of determining DR characteristics for meeting LCR need with the ISO is being developed.)

[56] 12 Tr. 1800-01 (SDG&E/Anderson).

[57] The ISO issued an initial draft document on September 4, 2013 entitled "Considerations of alternatives to transmission or conventional generation to address local reliability needs in the transmission planning process. However, nothing further has happened since that document was issued and discussed in one stakeholder call on September 18, 2013. At this rate, this effort will not be completed in time to affect the procurement, if any is authorized, for this Track 4 phase of the LTPP.

[58] SCE intends to consider incremental DR to meet LCR in Orange County near two key substations in its living pilot.

> be a circumstance where a load shedding protocol might be appropriate?
>
> A: Possibly. … We always want to make sure we have clear milestones … or making sure somebody is actively managing the process, so it's not indefinite.[59]

Both SCE's Living Pilot and the Commission's recently-initiated demand response rulemaking are being "actively managed" and the demand response rulemaking has clear milestones, as does the ISO's TPP. The use of controlled load shedding as an interim bridge is appropriate.

III. CONCLUSION

For all of the foregoing reasons, CLECA recommends against the authorization of additional resource procurement in this Track 4. Instead, controlled load shedding, permitted by NERC, should be used as an interim, bridge solution.

Respectfully submitted,

Nora Sheriff

Nora Sheriff

Counsel to the California Large Energy Consumers Association

November 25, 2013

---

59 11 Tr. 1578 (ISO/Sparks).