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)

COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

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The California Large Energy Consumers Association (CLECA)[1] submits these comments pursuant to the revised Scoping Memo of Assigned Commissioner Michel Peter Florio and Administrative Law Judge (ALJ) David Gamson issued September 16, 2013. The Scoping Memo allows for the submission of testimony in response to the Opening Testimony in Track 4 of this proceeding of the California Independent System Operator (CAISO), Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), and the City of Redondo Beach. In the alternative, the Scoping Memo permits comments on the seven questions raised by the ALJ at the September 4, 2013, Prehearing Conference (PHC). CLECA provides comments on two of the questions posed by ALJ Gamson and responds to one aspect of the testimony of Southern California Edison Company.

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1 The California Large Energy Consumers Association is an *ad hoc* 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.

I. INTRODUCTION

Of the questions posed by ALJ Gamson, CLECA responds only to the third question, i.e. are there "any other updates to assumptions that should be considered," and the seventh question, i.e. "If you are recommending preferred resources or storage to fill any need, it would be helpful to indicate how their attributes meet LCR need", later clarified as "not flexibility."

In response to the third question, we address the matter of an update to the load forecast. In response to the seventh question, we address the ability of demand response (DR) to meet local reliability needs.

CLECA also responds to the portions of the Opening Testimony of SCE and SDG&E on the issue of an additional need for supply-side resources due to CAISO's rejection of the use of controlled load shedding in case of a Category 3 contingency. In Track 1, CLECA briefed the extent to which the CAISO's reliability standards exceed the requirements of the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council (WECC); both NERC and WECC permit controlled load shedding for a Category 3 contingency. In these comments we briefly address the use of controlled load shedding as an alternative to additional incremental generation for such a contingency in the context of Track 4. The portion of our Track 1 brief that addresses the details of NERC and WECC regulations and CAISO policies as they relate to this point is attached.

II. COMMENTS

A. The Load Forecast Should Be Updated

ALJ Gamson's third question to parties was whether there were "any other updates to assumptions that should be considered?" There is at least one area where updated assumptions should be considered: the load forecast.

The load forecast should be updated in two ways. First, the 2013 IEPR load forecast, which is shortly to be adopted by the CEC, should be used. The IEPR load forecast takes into account the impact of price elasticity. For this reason, the most recent IEPR load forecast, that for 2013 and about to be adopted by the CEC, should be used, since it has the most up-to-date forecast of rate increases.

There is a second aspect to the use of an updated load forecast: the impact of rate design changes. Although the ALJ raised the question at the PHC as to whether rate design changes are relevant in this LTPP proceeding, CLECA submits that they are of key importance for resource planning and procurement because they affect the load forecast. The load forecast is the starting point of any need assessment.

The Commission has been implementing a policy of changing non-residential rate designs for the last several years; the Commission intent is to provide pricing signals to customers to encourage shifting load away from peak periods and away from dynamic pricing "event" periods.[2] Reliability contingency events can readily be times when such price signals are sent. This is similar to

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

the established policy of triggering BIP DR events for transmission "emergencies".

The Commission has also undertaken a proceeding to consider changes in residential rate design to provide similar pricing signals. Although significant statutory constraints and restrictions affect residential rate design, recently passed legislation on the Governor's desk, AB 327, would give the Commission more leeway to make changes here as well. This includes the introduction of residential TOU rates starting in 2018, one of the years of interest in this proceeding.

Furthermore, the new demand response rulemaking adopted on September 19 (R.13-09-011) explicitly discusses the potential impact of transitioning so many small and medium business customers to new, mandatory, TOU rates and then to default CPP rates.

> 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 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.[3]

The Commission expects there to be some load shape impact from these new rates, which is why it is proposing a pilot to study them. Furthermore, there is evidence that small commercial customers do respond to such rates, despite the long-held belief that they are the least responsive to pricing signals; the SMUD small commercial Summer Solutions Study results warrant consideration

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3 R. 13-09-011, Attachment A, p. 12.

here, particularly given the strong responses that are facilitated by technologies such as programmable communicating thermostats.[4] There is also ample evidence, incorporated into comments in the residential rate design proceeding (R.12-06-013), that residential customers respond to TOU and dynamic rates. It makes no sense to ignore these potential changes for IOU customers in the demand forecasts used in the LTPP.

CLECA has consulted with the CEC and determined that while it takes price elasticity into account in creating its load forecasts, the CEC does not at present take into account the impact of changes in rate design. The CEC, however, is interested in doing so going forward, as it is aware of Commission and publicly-owned utility (e.g. SMUD) policies that change rate designs to create more price signals. The Commission can facilitate this analysis as discussed below and thus improve the load forecasts.

Why is this important in this proceeding? The Commission and the CAISO use CEC IEPR load forecasts as a starting point in the need determination in the LTPP proceedings. In the current Track 4, the years of interest are 2018, 2020, and 2022. These are years *after* TOU rates will have been implemented for all non-residential customers for several years or more. A change in load shape as a result of these rates should have begun to occur. In addition, AB 327 allows the Commission to adopt default TOU rates for *residential* customers beginning in 2018. The impact of the extension of TOU rates to this class, which represents roughly 40% of demand on a 12-CP basis,

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[4] Small Business Demand Response with Communicating Thermostats, Herter et al. LBNL-2743E, September 2009.

should also have an effect on load shapes by 2020 and later. 1-in-10 peak loads are used to determine need for local reliability, and time-based and dynamic rate designs are intended to reduce peak loads, in addition to shifting load to lower load periods. There is a significant risk that not taking into account the ability of such rates to change load shapes will result in over-procurement to meet these very infrequent peaks; 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 make the data available to the CEC; the CEC could then incorporate these results in its future load forecasts. 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.

B. DR Could Meet LCR Need, But Its Consideration as a Resource Appears Precluded

The viability of demand response (DR) as a resource for local reliability is being addressed in other proceedings and venues but may not be resolved in time for a decision in Track 4 of this proceeding. SDG&E has not even considered DR in this proceeding as an alternative to address the closure of SONGS. Instead, it says that incremental DR can be addressed in the next DR proceeding addressing utility DR programs.[5] One major problem with that proposal is that the next DR proceeding will not begin until 2015, after the utilities file their program proposals in January of that year, and will not be decided until

[5] SDG&E Opening Testimony (Anderson), at 4.

the end of that year at the earliest. By then, the Commission will have long before issued a decision in Track 4 of this proceeding and procurement will be well under way. Thus, the SDG&E proposal effectively ignores DR.

SCE has proposed to consider incremental DR in Orange County near two critical substations to address DR's ability to meet LCR needs in its so-called "Living Pilots". It discusses expanded use of BIP and other DR Programs, but, while suggesting a stakeholder process, has proposed no time line in its testimony to assess the impact DR could have on local reliability.

The ISO had a stakeholder call on September 18 to discuss the possible role of DR and storage in transmission planning, which includes meeting local reliability needs.[6] However, the ISO's draft paper for that call focused on the so-called "duck curve", which has been developed to look at flexibility needs in meeting load less the output of intermittent renewable generation, and not local reliability. While the ISO proposed to develop categories for DR and storage, in terms of start time, duration, and frequency of use, the ISO's study process appears to be in the preliminary stages. It is not clear how the ISO will be able to provide results that will affect the procurement decision to result from this Track 4 phase of the LTPP.

This is unfortunate, because Track 4 focuses on reliability and possible transmission-related contingencies, especially Category C and D contingencies, which are rare but potentially severe. Reliability-based DR can already be used

[6] The initial draft document for this call was entitled "Considerations of alternatives to transmission or conventional generation to address local needs in the transmission planning process", dated September 4, 2013.

for such contingencies. 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*."[7] The ISO has expressed concern about the time to initiate these DR programs, but that discrete issue is resolvable by creating a subset of these programs to meet desired notice and response periods.

In addition, there are other DR opportunities. Customers can adjust their lighting and HVAC when called upon to do so through FlexAlerts or DR programs or pricing signals. These responses can be automated. Even customers who do not want to participate in DR on a regular basis by, for example, bidding their potential load drops or having them bid into ISO markets, have shown willingness to adjust loads downward during times of system stress. A transmission contingency is clearly such a time. While there is insufficient time in this proceeding to address the costs and benefits of such automation, it is expected to be an issue in the demand response rulemaking (R. 13-09-011). Again, the problem is that there will be a decision on need in this Track 4 proceeding before the anticipated preliminary decision in the DR rulemaking next summer. Thus, this proceeding effectively provides no opportunity for consideration of DR for LCR, despite its significant potential.

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7 D. 10-06-034, Appendix A, at 4 (emphasis added).

C. Options for Meeting Category C Contingency

In its Opening Testimony, SCE stated that the 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.[8, 9] SDG&E states that the use of controlled load shedding could reduce LCR

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[8] "Both SCE and the CAISO performed studies to determine the need for new local reliability resources in the LA Basin to replace retiring OTC plants and SONGS. Figure II-1 below reconciles SCE's results with the CAISO's results. **SCE developed its studies in collaboration with SDG&E which recommended using a load shedding scheme to plan for certain transmission contingencies arising in its service territory. When SCE incorporates this load-shedding scheme, it reduces SDG&E's dependence on imports from the LA Basin to meet its transmission contingency needs. The overall effect of the scheme reduces the need for new generation in the LA Basin by 436 MW.**" SCE Opening Testimony, at 6, (emphasis added.)

[9] "The LA Basin Generation Scenario and the LA Basin Transmission Scenario both assumed that SDG&E would load shed for the critical loss of the Ocotillo – Suncrest 500 kV line, ECO – Miguel 500 kV line and the automatic cross-trip of Otay Mesa – Tijuana 230 kV line (Category C.3 also known as a N-1-1). The Otay Mesa – Tijuana 230 kV line overloads after the loss of the first two lines and is removed from service automatically by relay equipment. This critical contingency reroutes all SDG&E imports, approximately 2,750 MW through SCE's transmission lines in Orange County. **However, SDG&E is assumed to load shed for this contingency. 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. The CAISO stated that it is not prudent to load shed for this critical SDG&E C.3 contingency.** So, SCE created two more cases to examine the impact of load shedding on the benefits of the Mesa Loop-In. Scenarios 1S and 2S are the same as Scenarios 1 & 2 (the LA Basin Generation Scenario and the LA Basin Transmission Scenario), respectively, except they do not assume SDG&E load shed for the critical Category C.3 contingency. SCE studies show additional generation needed in the LA Basin in Scenarios 1S & 2S relative to Scenarios 1 & 2 to address the critical SDG&E C.3 contingency. A comparison of Scenarios 1S and 2S shows that the Mesa Loop-In decreases need in LA Basin by only 734 MW (3,240 MW minus 2,506 MW). As previously discussed, the Mesa Loop-In shows a benefit of 1,200 MW if load shed in SDG&E is assumed. **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.**

Another way to address the critical SDG&E C.3 contingency is by increasing the amount of new generation inside SDG&E's service area and reducing its import level. The Mesa Loop-In is located closer to the LA Basin OTC units than SDG&E service area. It is, therefore, not highly effective in addressing SDG&E contingencies. **Load shed or additional generation in SDG&E would be more effective to address the critical C.3 contingency.**" SCE Opening Testimony, at 36-37 (emphasis added).

requirements by 1000 MW.[10]

The criteria used by the CAISO to determine the LCR need include an N-1-1 outage for a Category C contingency, in combination with a 1-in-10 peak load forecast. CLECA pointed out in its brief in Track 1 of this proceeding that NERC and WECC regulations allow controlled load shedding in the form of a special protective service (SPS) for such a contingency.[11] However, the CAISO, in contrast, apparently does not consider controlled load shedding to be a viable strategy in this case. 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.

The Commission is thus confronted with an explicit choice. Is it a good

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[10] "For the analysis that examined the N-1-1 of ECO-Miguel and Ocotillo Express-Suncrest 500 kV lines as the limiting contingency, a load-shedding Special Protection Scheme (SPS) was not assumed to be allowed. For the analysis that examined the worst G-1/N-1 contingency as the limiting contingency, a load-shedding SPS was assumed to be in place to mitigate the N-1-1 of the ECO-Miguel and Ocotillo Express-Suncrest 500 kV lines. SDG&E has a WECC-certified load shedding scheme in place to mitigate the N-1-1 of the Southwest Powerlink and the Sunrise Powerlink. Both approaches allow the transmission system to meet applicable North American Electric Reliability Corporation (NERC), WECC, and CAISO reliability criteria. The critical difference between the two criteria is that the N-1-1 is a NERC Category C contingency. The applicable NERC planning standard (TPL-003-0a) permits non-consequential loss of load (load shedding) for Category C contingencies. The G-1/N-1 is defined by the CAISO's Planning Standards as equivalent to a NERC Category B contingency, for which non-consequential load is not permitted. Therefore, load shedding is allowable for the N-1-1 but not the G-1/N-1. **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**. The large performance gap between the N-1-1 and G-1/N-1 in the CAISO's 2013 LCR analysis is caused by the loss of reactive support due to the SONGS generation retirement. As reactive resources are added back into the system (such as the synchronous condensers at Talega and the SONGS Mesa SVC, both projects approved by the CAISO), the performance gap will narrow. The performance difference between the N-1-1 and G-1/N-1 criteria in the Final 2013 LCR Technical Study analysis with SONGS generation in place was about 400 MW. Ultimately, the CAISO is the Transmission Planning Authority for the San Diego transmission system, and has the responsibility and authority to set and meet the planning criteria." Opening Testimony SDG&E Jontry, at 7-8, (emphasis added.)

[11] *See* R. 12-03-014, CLECA Opening Brief, September 24, 2012, at 8-20. Part of CLECA's Track 1 brief addressing this matter is included as an attachment to these comments; please note the footnote numbering in the attached does not match the filed version.

use of 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 under a 1-in-10 peak load condition? This is not a matter of failing to meet NERC and WECC requirements. This is a matter of having ratepayers foot the bill for going beyond those requirements. In Track 1, the CAISO provided no justification for this additional requirement other than a concern that the cost of a reduced level of reliability axiomatically fall below the cost of procuring additional resources. CLECA believes that this is not axiomatic and that the Commission, in the interest of its responsibility for just and reasonable rates, must address whether the cost of an additional 500 MW procured by SCE and over 1000 MW for SDG&E[12] for a very low probability contingency is appropriate.

III. CONCLUSION

For all of the foregoing reasons, CLECA urges the Commission to use the 2013 IEPR load forecast for its Track 4 need assessment and incorporate the potential role of demand response in providing local reliability. The Commission should also directly evaluate the need to incur additional costs for 500-1500 MW of generation to meet a CAISO policy for Category C contingencies that does not permit controlled load shedding; this evaluation must recognize that the CAISO policy is more stringent than NERC or WECC requirements. In addition, the Commission should direct the utilities to study the changes in load shapes that occur as a result of its rate design policies and to provide that information to the

[12] Opening Testimony SDG&E Jontry, p. 7.

CEC; this information could and should be used to further improve load forecasting, including that which is used in these LTPP proceedings.

Respectfully submitted,

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September 30, 2013

Attachment A – Excerpt from CLECA Opening Brief in Track 1 of R. 12-03-014

1. The Commission Must Consider the Cost of CAISO Standards that Exceed NERC Standards

NERC and WECC Reliability Standards enacted pursuant to the specific delegation of authority by Congress to FERC clearly have the force of law.[1] NERC Reliability Standards become "*mandatory and enforceable upon approval by the Commission*."[2] Violations of the NERC Reliability Standards adopted by FERC can result in assessments by NERC of monetary penalties.[3] Some CAISO standards, however, go beyond NERC and WECC regulations. There are several areas where the CAISO's exhibits show it has developed its own reliability standards which its tariff applies to LCR and the CAISO tariff makes it clear that these standards exceed the adopted NERC Reliability Standards.[4] The

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1 "*All users, owners, and operators of the bulk electric system shall comply with the reliability standards that take effect under this section [referring to §215(b) of the Federal Power Act, added by the Energy Policy Act of 2005].*" 16 USC §824(o)(b)(1). Order 693-A, 120 FERC ¶61,053 at ¶70 states, "*if a standard is approved by the Commission [FERC] under Section 215, compliance is mandatory ....*"

2 *See North American Electric Reliability Corp.*, 116 FERC ¶61,062 (July 20, 2006) (certifying NERC as the Electric Reliability Organization (ERO) pursuant to the Energy Policy Act of 2005); *see also* 119 FERC ¶61,060 (at 4) (approving WECC as a Regional Entity to which NERC may delegate enforcement authority pursuant to the Energy Policy Act of 2005).

3 *See Order on Review of Notice of Penalty*, 140 FERC ¶61,048 (July 19, 2012) (confirming NERC's authority to penalize Southwestern Power Administration for violation of NERC Reliability Standards under §215(e) of the Federal Power Act).

4 40.3.1.1 Local Capacity Technical Study Criteria

> The Local Capacity Technical Study will determine the minimum amount of Local Capacity Area Resources needed to address the Contingencies identified in Section 40.3.1.2. In performing the Local Capacity Technical Study, the CAISO will apply those methods for resolving Contingencies considered appropriate for the performance level that corresponds to a particular studied Contingency, as provided in NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0, **as augmented by CAISO Reliability Criteria** in accordance with the Transmission Control Agreement and Section 24.2.1. (Emphasis added).

Commission should recognize two key points here: First, CAISO's claim that violating its stricter standard would be equivalent to breaking the law is questionable. Second, and more importantly, this Commission, not CAISO (and indeed not FERC), bears responsibility for balancing the cost to ratepayers of potential LCR procurement with a determination on the need for LCR procurement.

(a) CAISO Standards vs. Adopted NERC Standards

CAISO standards that exceed FERC-approved NERC Reliability Standards do not appear to have the same force of law attributable to the FERC-approved NERC Reliability Standards. "*Only a Reliability Standard (including a regional Reliability Standard or variance) approved by the Commission is enforceable in the U.S. under section 215 of the FPA.*"[5] Accordingly, we question the accuracy of the CAISO's statements that it cannot violate its own reliability standard because this is "like" violating the law. This does not seem to be strictly correct.

Notably, while NERC Reliability Standards may be differentiated by region, they clearly state where they are differentiated by region.[6] For example, NERC's Reliability Standard TPL-003-0a (which has the force of law since it was adopted by FERC pursuant to §215 of the Federal Power Act) clearly states "*none identified*" under regional differences; similarly, adopted Reliability

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5 116 FERC ¶61,062, ¶277.

6 *See* Order 693, FERC Statutes and Regulations ¶31,242, Order or Rehearing Order 693-A, 120 FERC ¶61,053 (2007) (referencing six of eight regional differences and stating "*the Commission will continue to rely on NERC's definition of bulk electric system with the appropriate regional differences until Bulk Power System is better defined.*").

Standard TPL-004-0 and all the other TPL standards state "*none identified*" under regional differences.[7] If the CAISO's different reliability standard were adopted pursuant to §215(b) of the Federal Power Act like the NERC and WECC Reliability Standards, its difference would be noted in the NERC Reliability Standards. There is no mention of CAISO's regional difference in NERC's adopted Reliability Standard for transmission planning. It appears that WECC has not submitted, nor has NERC approved, nor FERC approved, any "*regional differences*" for any of the Transmission Planning standards (TPL).

Regional differences among the Reliability Standards can exist, "*if otherwise just and reasonable, not unduly burdensome and in the public interest,"* and if more stringent *AND* necessitated by a regional physical difference in the Bulk Power System.[8] They still must be approved, however, by NERC and then by FERC to become mandatory and enforceable and with violations subject to penalty. It is clear that the more stringent CAISO standards do not meet these criteria. Indeed, CLECA submits that, from the ratepayer perspective, the CAISO's focus on reliability regardless of cost is not reasonable, not in the public interest and is unduly burdensome. Moreover, as discussed further below, this Commission retains its jurisdiction over the determination of

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[7] *C.f.,* the different WECC Reliability Standard for operating limits, WECC Standard TOP-007-WECC-1 that appears to have been adopted by NERC and FERC; while substantively irrelevant, its existence demonstrates that where a Regional Entity (WECC) has an enforceable, mandatory Reliability Standard that is different from the NERC standard, it is clearly published within the NERC standards.

[8] 116 FERC ¶61,062, at ¶274. Moreover, Regional Entities (*e.g.*, WECC) are discouraged from adopting voluntary rules that detract from Commission-approved Reliability Standards. *Id.*, at ¶281. Arguably, the more restrictive CAISO standard that fails to permit the use of DR in certain instances detracts from the NERC inclusion of DR as a mitigation option in TPL standards.

reasonableness of the cost of utility procurement of reliability resources; this intersection of jurisdictional boundaries warrants careful consideration.

CAISO's Track 1 Exh. ISO-19 makes it clear that CAISO reliability rules exceed NERC Reliability Standards for combined line and generator unit outages. The standards state the following:

> *IV. Combined Line and Generator Unit Outage Standards Supporting Information Combined Line and Generator Outage Standard - A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002)*.

Track 1 ISO-19, p. 4. In providing further explanation, the CAISO states:

> *The ISO Planning Standards require that system performance for an over-lapping outage of a generator unit (G-1) and transmission line (L-1) must meet the same system performance level defined for the NERC standard TPL-002.* ***The ISO recognizes that this planning standard is more stringent than allowed by NERC,*** *but it is considered appropriate for assessing the reliability of the ISO's controlled grid as it remains consistent with the standard utilized by the PTOs prior to creation of the ISO.*

Track 1 ISO-19, p. 10, emphasis added.

The use of planning standards in excess of NERC Reliability Standards raises issues about the impact on ratepayers. Establishing a need for additional generation resources or requiring expenditure for additional transmission and distribution resources that are not required by law under adopted NERC Reliability Standards is not costless.

SCE confirmed in hearings that CAISO planning standards exceed NERC standards. In response to cross examination by the Sierra Club, SCE's witness

Cabbell stated:

> *Q Does CAISO have additional standards that they consider for LCR?*
>
> *A They have, yes, they have a set of planning standards that they have developed.*
>
> *Q Are those different than the NERC standards?*
>
> *A They are -- they are kind of on top of the NERC standards.*
>
> *Q Are they more stringent?*
>
> *A I think in some areas for the contingencies they look at they're more stringent.*
>
> *Q Can you explain how they're more stringent?*
>
> *A I think they're considering more of the, as we've been talking about, the Level D contingencies, and the way they actually take the N-1/N-2, one line out and a common load failure. So it's a little more stringent, which the NERC planning standards and NERC allow entities that have more stringent criteria depending on actually application to their system.*
>
> *Q What would NERC require absent the CAISO standards? They would look at -- what would their requirements be?*
>
> *A Well, they still look at, they have Level D performance standards, so, but those are typically in a loss of a substation, a loss of an entire corridor. So --*
>
> *Q They're looking -- sorry.*
>
> *A Oh, that's okay. Go ahead.*
>
> *Q So they're looking more at like Level Contingency B?*
>
> *A Well, yeah. They actually have a Level D, but it's typically, you want to look at the consequences and the risks. And you really -- sometimes you don't have to plan projects for Level D. There is a concern*

if there's cascading, but you don't have to plan projects for Level D. But for -- then you look at the Level C, which is an N-2, Level B, N-1, which we typically, that's when we plan our projects.

SCE-Cabbell, Track 1 Tr. pp. 813-814.

(b) Commission Consideration of LCR Criteria Must Weigh Costs

The CAISO's assessment of need for local reliability is based on Category C and D contingencies, involving two simultaneous outages or two outages with no restoration time in between. This is not explicitly covered by the CAISO's planning standard document, ISO-19. How does the CAISO determine what is needed for LCR?

> *Under the NERC reliability and planning standards, following an N-1 contingency, the ISO must take steps to ensure that the system can withstand a Category C common mode outage that would otherwise lead to voltage collapse. In the identified subareas, if generation redispatch were not an available option, then the ISO would need to interrupt electric supply to customers following a single contingency. Although this particular overlapping contingency is classified as Category D,* ***it is a resource planning requirement that has been included in the LCR criteria approved by the Commission in D.06-06-064 and in every other approved LCR study since that time****.*
>
> *Specifically, the system planning criteria can be found at page 17 of the 2013 Local Capacity Technical Analysis in Attachment 5 to Mr. Woodruff's testimony. [Footnote omitted.] In the bottom row, footnote 3 clarifies that for local capacity studies, this particular type of Category D contingency must be evaluated for risks and consequences, and in the case of voltage collapse or dynamic instability, a local requirement must be created.*

Track 1 Exh. ISO-3, Sparks Reply Testimony, at 7 (emphasis added).

The Commission should consider whether its adopted LCR criteria, incorporating the CAISO's more stringent reliability standards, are in the best interest of ratepayers. We note that footnote 3 of TPL-003 says that voltage collapse and dynamic instability are not allowed per NERC standards, but TPL-003 leaves it to the transmission planning entity to choose which extreme events to evaluate. ISO-13, p. 21 of 29, fn d. Notably, NERC's TPL-003 does allow for planned and/or controlled load shedding to remedy a multiple outage situation. *Id.*, fn c. TPL-004, covering extreme events, leaves it to the transmission planning entity to perform and evaluate studies "*only for those Category D contingencies that would produce the more severe system results or impacts*." ISO-13, p. 25 of 29. As we will show later, Category D contingencies do not require mitigation nor is it clear that the CAISO has an obligation to mitigate a Category C event following a Category B event. *Id.*, p. 20. Furthermore, the CAISO has discretion in determining which outage events it concludes must be mitigated in local reliability areas and subareas. The Commission should provide input to the CAISO's process in determining what mitigation is cost-effective for ratepayers.

We understand the CAISO's obligations with respect to grid reliability. However, the CAISO has neither an obligation nor the explicit authority to determine whether the costs of its proposals are just and reasonable from a ratepayer perspective. Indeed, as shown above, the CAISO does not even have the information to evaluate the costs of alternatives. This is the role of this Commission, *i.e.* to determine which resources its jurisdictional entities should procure in a cost-effective manner.

There are two key points to be made here. First: shedding load is a legitimate means of addressing a contingency that is acceptable to FERC and NERC. This matter is addressed in further detail below. Second: the CAISO has no responsibility for considering the cost or rate consequences of backstop procurement, which may lead to a decision to pursue a backstop option that would not be perceived as cost-beneficial from the ratepayer perspective.

How does the cost of meeting the need defined by the CAISO get factored into the analysis? The CAISO's transmission planning standards state that it performs a benefit-cost analysis of transmission system additions that reduce the risk of load drop exposure based on its own calculations. ISO-19, p. 14. There is no evidence that it considers all alternatives to such additions. Furthermore, the Commission has had no role in this cost-benefit analysis.

Why is this important in this proceeding? Because statements made by several CAISO witnesses strongly suggest that the CAISO perceives the risk of outages vastly exceeds the cost of additional system reinforcements.

> *A marginal shortage means the loss of firm load, which puts public safety and the economy in jeopardy, whereas a marginal surplus has only a marginal cost implication*.

Sparks Opening Testimony, pp. 5-6. Or, again:

> *In my testimony it asserts that the risk of coming up short and having to interrupt service to customers on a frequent basis is -- the impact of that far outweighs any additional cost that we might incur by perhaps procuring a little bit extra.*
>
> *Q Okay. However, if there is significant overprocurement for whatever reason, you know, there are negative implications of that as well, costs, environmental, whatever, right?*

A Yes. The degree of the error on both sides, the impact gets -- amplifies.

And so significant underprocurement, the impacts are even -- you know, can become political and end up, you know, getting the Governor impeached all the way to --

(Laughter)

THE WITNESS: -- overprocurement where there can be high rates.

Track 1 Tr. pp. 270-271.

It is appropriate for the Commission to consider here whether it or California ratepayers have the same view of risks compared to costs as the CAISO and whether acceptance of the CAISO's view of risk or proposed solution to the perceived risk is necessary. End-use customers face regular outages due to problems on the distribution system. The most stringent 1-in-10 or 100-year outage standard for generation will not change this. Customers, not the CAISO, pay the bills for additional generation and transmission to meet the CAISO's more stringent standards. The CAISO has not considered all the alternatives in its proposal nor has it considered the costs. In terms of its duty to set "just and reasonable rates," the Commission should be concerned by the CAISO's overly conservative position that LCR needs should be met solely through new gas-fired generation, regardless of cost. While the CAISO may see the downside here as simply "*backup insurance*" (Tr. p. 401) or early procurement,[9] ratepayers will pay more.

[9] CAISO indicated that if there were more distributed generation than it had forecast, resulting in excess generation when combined with its proposed conventional generation: "*Well, I would expect an increase in costs at least for a little while, but there still is load growth in these areas, and it might mean being a little early….*" Tr. p. 467.

2. Controlled Load Shed

The NERC Reliability Standards are clear in the case of a double contingency, and they explicitly allow the use of controlled interruption of load to meet a Category C contingency. NERC Standard TPL-003-0a – System Performance Following Loss of Two or More BES Elements (Category C) states:

> ***R1.*** *The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached).* ***The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard.***

Exh. ISO-13, p. 17 (emphasis added).

TPL-04-0, entitled System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements, addresses the Category D contingency discussed in the hearing room; TPL-04 discusses an annual evaluation of the risks of such contingencies, not a mitigation. The discussion of a Category D contingency in TPL-003-0a notes that such an event "*may involve the loss of substantial customer Demand and generation in a widespread area or areas*." ISO-13, p. 21 of 29. The point is that not every contingency can be prevented by adding resources and that the costs of attempting to do so may be greater than what customers are willing to pay for the extra insurance.