



Revision to ISO Transmission Planning Standards

Market and Infrastructure Policy
Straw Proposal

REVISED DRAFT

May 28, 2014

Straw Proposal

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Attachment 1 ISO Planning Standards – Redline Draft of Proposed Changes

1 Introduction

The ISO is proposing to modify the ISO Planning Standards to clarify and codify existing policy applications in the standards as well as updates due to changes within the NERC Transmission Planning (TPL) standards. The three areas that the ISO is planning on making the specific changes to Planning Standards are as follows:

- Non-consequential load shedding for Category C contingencies
- Extreme Event mitigation for San Francisco Peninsula area
- Changes to NERC Transmission Planning Standards (TPL)

This discussion paper is the first step in initiating the stakeholder process to make the proposed changes to the ISO Transmission Planning Standards. The ISO intends to take the revised planning standards to the ISO Board of Governors for approval in September 2014. The schedule for the stakeholder process and revisions to the planning standards is provided below.

2 Overview

The ISO is required through its tariff to adhere to planning standards established by the North American Electric Reliability Corporation (NERC), as well as regional standards, criteria and business practices established by the Western Electricity Coordinating Council (WECC). In addition, ISO's FERC-approved tariff provides for the approval of Planning Standards by the ISO's Board of Governors, which provides the necessary vehicle for needs specific to the ISO controlled grid to be properly addressed in ensuring acceptable system reliability. The ISO has identified such specific requirements necessary for reliable system operation that are referred to and documented as the ISO Planning Standards.

All of these planning standards are critical to providing reliable service to customers. They also form the foundation or basis for all planning activities. Transmission projects are developed and advanced as necessary to ensure compliance with these standards, and when transmission projects are advanced for other reasons, such as meeting economic or policy considerations, those projects must also remain compliant with approved planning standards.

As such, the planning standards set the direction for planning activities, and the basis for many of the transmission projects approved by the ISO.

The ISO has identified three areas in which further clarity in the Planning Standards would be beneficial, or which need to be updated to avoid inconsistencies with NERC mandatory standards. The three areas that have been identified are:

- Non-consequential load shedding for Category C contingencies (needed to codify and provide further clarity of existing and historical planning practices regarding these multiple contingency events)

- Extreme Event mitigation for San Francisco Peninsula area (needed to address the growing concerns for this particularly unique area)
- Changes necessary to maintain consistency with NERC Transmission Planning Standards (TPL)

2.1 Schedule

The ISO plans to complete this stakeholder process by August 2014 so that the Grid Planning Standards can be taken to the ISO Board for approval at the September Board meeting. As such, the ISO offers the following updated schedule for this stakeholder process:

Date	Action
March 26	Post issue paper/straw proposal
April 11	Stakeholder meeting (in person)
April 25	Stakeholder comments due by 5:00 p.m.
May 28	Post revised straw proposal
June 4	Stakeholder web conference
June 18	Stakeholder comments due by 5:00 p.m.
July 16	Post Draft Final Proposal
July 30	Stakeholder web conference
August 13	Stakeholder comments due by 5:00 p.m.
September 18-19	ISO Board meeting

3 Non-consequential load dropping: Category C Contingencies

Category C contingencies are more precisely defined in the NERC TPL standards, but can be summarized as the more probable multiple contingency events; less probable than the single contingency Category B events, but more probable than the Category D “extreme” events defined in the NERC TPL standards. The ISO is intending to provide further clarity in the ISO Planning Standards regarding when load shedding through Special Protection Systems is considered an acceptable means to address planning needs for Category C contingencies. The Planning Standards currently provide guidelines regarding system implications of SPS operation and SPS design considerations that need to be taken into account, but do not currently address the current and historical practices regarding considerations of non-consequential load shedding for Category C contingencies.

The ISO’s current practice in local area planning, which is consistent with historical practices prior to and since the creation of the ISO, is to not rely upon high density urban load shedding as a long term planning solution for Category C contingencies. This practice has not previously been codified in the ISO Planning Standards, however. Also, further clarification of the considerations in the viability of load shedding as a short term measure, or in lower density areas is also being considered.

3.1 NERC Standard TPL 003

NERC Standard TPL 003 Requirement R1 states the following:

“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.”¹

In Table I of TPL003 the following footnote is applied to all Category C contingencies listed.

“Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.”

The key points from these two TPL 003 excerpts, in the context of this study, are the following:

1. The ISO must demonstrate that it can operate the transmission system to supply peak load during a Category C outage.
2. The ISO must review the system design and expected system impacts when considering load shedding as a mitigation measure for a Category C outage.

¹ [http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-003-0b&title=System Performance Following Loss of Two or More Bulk Electric System Elements \(Category C\)&jurisdiction=United States](http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-003-0b&title=System%20Performance%20Following%20Loss%20of%20Two%20or%20More%20Bulk%20Electric%20System%20Elements%20(Category%20C)&jurisdiction=United%20States)

3.2 Local Area Long-Term Planning

A local area is characterized by relatively small geographical size, with limited transmission import capability and most often with scarce resources that usually can be procured at somewhat higher prices than system resources. These areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local generation and transmission capacity. The need for system reinforcement in a number of local areas is expected to climb due to projected resource retirements, with Category C contingencies playing a material role in driving the need for reinforcement. The ISO believes that these needs have already largely been identified through recent transmission planning cycles, and the 2013-2014 Transmission Plan in particular. Relying on load shedding on a broad basis to meet these emerging needs would run counter to historical and current practices, resulting in general deterioration of service levels. Further, one of the fundamental ISO Tariff requirements is to maintain service reliability at pre-ISO levels, and this further drives the need to codify the circumstances in which load shedding is not an acceptable long term solution.

The ISO system has approximately 14 special protection schemes that drop load for category C contingencies on the 100 kV system and above. Two of these SPS will be removed once transmission upgrades that are under development are in-place. The remaining SPS are not relied upon in order to serve load in high population density areas from the high voltage transmission system. In addition, the ISO ensures that new special protection systems adopted in the long-term transmission plan for local areas do not rely on load shedding in high population density areas for outages on the 100 kV and above transmission system. This current practice, which has considerable historical support, is based on not planning to shed large blocks of high density urban load for category C contingencies as a long term solution.

The ISO has explored the practices of other ISOs and RTOs regarding load shedding for category C contingencies and found that four of the nine ISO-RTO have identified various degrees of differences in planning criteria between their overall footprints and some of the large urban centers within those footprints. The differences relate mainly to locational capacity requirements, assumptions on the availability of generation resources (due to environmental restrictions), respecting more stringent contingencies than for the rest of the system, or lower ability to adjust the system following contingencies. The purpose of these criteria for large urban centres is in part to not rely on interruption of firm customer demand in lieu of planned transmission or generation to meet TPL 003 and for other credible contingency events. Out of the remaining five ISO-RTO that we talked to four of them do not rely on, or limit the amount of, interruption of firm customer Demand in lieu of planned transmission or generation to meet TPL 003 throughout their footprint. The fifth remaining ISO-RTO defers to the Transmission Owners discretion regarding the use of load shedding to address a Category C violation as long as the NERC TPL standards are not violated.

The need for more stringent planning criteria for large urban centres seems to be in part driven by the population density and potential (economic and safety) impact that loss of electricity supply would have

on such highly populated areas such as New York City, and in part by objective and legacy constraints the various systems have, such as Dallas/Fort Worth area where environmental restrictions are likely to lead at times the loss of fossil generation.

The ISO's approach of avoiding urban load shedding in high density areas is therefore consistent directly or indirectly with the general approaches of the other ISOs and RTOs.

3.2.1 Population density

In general the electric utility industry avoids dropping load in high population density areas due to, among other reasons, high impacts to the community from loss of service to hospitals and elevators to traffic lights and potential crime. Further, the challenge of accessing alternative services becomes progressively more challenging in urban areas as the area of supply interruption grows. Consistent with that broader industry practice and current ISO practices, for local area long-term planning, the ISO intends to not allow load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate Category C contingencies and impacts on the 115 kV or higher voltage systems.

The diagram below shows the Urbanized Areas² in California.

Urbanized Areas as defined by the US Census Bureau with populations over one million would be considered high density urban load areas for purposes of the ISO Planning Standard.

² *Urbanized Area (UA)*: A statistical geographic entity consisting of a densely settled core created from census tracts or blocks and contiguous qualifying territory that together have a minimum population of at least 50,000 persons.

Figure 1: Urbanized Areas in California



3.2.2 Risk of outage

In considering if load shedding is a viable mitigation in either the short term, or the long term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

Use of Benefit to Cost Ratio calculations

Benefit to Cost Ratio analysis can provide meaningful input into transmission reinforcement decisions, particularly in the case of radial systems and the need to loop or otherwise provide back-up service to radially-served loads. The ISO Planning Standards includes a chapter addressing “Planning for New Transmission versus Involuntary Load Interruption Standard” to address these circumstances, and BCR analysis is discussed in that context.

However, these BCR type calculations do not necessarily give correct values or magnitude of impacts for large and complex networked transmission systems. This is because several factor including duration of interruption, number of interruptions per year, and the time of occurrence of interruption are generally beyond existing modeling capabilities to properly quantify within looped transmission systems considering multiple possible contingency combinations and availability of multiple local resources.

The ISO considers that BCR type calculations may be provided as additional information when planning for non-consequential load loss in these type of events however this data may not be the main driver or sole justifier for decisions to move forwards with either SPS or transmission upgrades.

3.3 System Wide Long-Term Planning

System planning is characterized by much broader geographical size, with greater transmission import capability and most often with plentiful resources that usually can be procured at somewhat lower prices than local area resources. Due to this fact more resources are available and are easier to find, procure and dispatch. Reliance on non-consequential load drop for double contingencies is mostly used to increase the transfer capability of major transmission paths across California and the West to the benefit of all and with rather rare occurrences of real outages. The operators have a greater availability of resources at their disposal and take active steps to reduce reliance on these load dropping schemes any time there active fires in the areas of concern or other known actions or phenomenon that could hinder the flow of electricity across these transmission paths.

For the reasons described above, the ISO is not proposing to eliminate existing system wide SPS schemes that include some non-consequential load dropping for common corridor double contingency events. However, prudent system design should include separating the distance between transmission circuits 300 kV and above more than 250 ft centerline to centerline, so that they are not categorized as a category C simultaneous contingency.

3.4 Short-Term Planning

In the near term any SPS, may be used to bridge the gap between real-time operations and the time when system reinforcements could potentially be built and/or otherwise made available. The ISO intends to add this clarification to the ISO Planning Standards.

3.5 Proposed changes to ISO Planning Standard

The following is the language that the ISO is intending to add to the Transmission Planning Standards:

The local areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local generation and transmission capacity. Increased reliance on load shedding to meet these needs would run counter to historical and current practices, resulting in general deterioration of service levels.

For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

- In the near term during short-term planning, SPS which drops load, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.
- In considering if load shedding is a viable mitigation in either the short-term, or the long-term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

There will also a *Background behind Planning for High Density Urban Load Area Standard* section that compiles the reasons for the new standard as described throughout this entire chapter.

Under the *Interpretations of terms from NERC Reliability Standard and WECC Regional Criteria* section the following definition will be entered:

High Density Urban Load Area: Is an Urbanized Area³, as defined by the US Census Bureau, with a population over one million persons.

4 San Francisco-Peninsula Extreme Event Reliability Standard

The ISO is required as a part of the NERC Reliability Standard TPL-004 to study the effects of Extreme Events (Category D) on the system, however the standard does not require that the mitigations be put in place for the Extreme Events. The ISO assessment conducted as a part of its 2013-2014 transmission planning process has determined that there are unique circumstances affecting the San Francisco area that form a credible basis for considering mitigations of risk of outages and of restoration times that are beyond the reliability standards applied to the rest of the ISO footprint. The unique characteristics of the San Francisco Peninsula are illustrated throughout Appendix D of the ISO 2013-2014 Transmission Plan. The ISO has summarized these unique characteristics in a separate document titled *San Francisco Peninsula Area - Unique Characteristics and Risk of Extreme Events*. Due to the details provided on the critical infrastructure within the area, the material has been posted on the ISO Market Participant Portal and subject to a ISO Transmission NDA to access.

As outlined in Appendix D, the characteristics that makes it apparent that the San Francisco-Peninsula is uniquely situated and requiring consideration of mitigation are the following:

- high density urban load area,
- geographic and system configuration,
- potential risks of outages including seismic, third party action and collocating facilities; and
- challenging restoration times.

Within the western interconnection the characteristics of the Peninsula area are also unique. A similar area within the United States for comparison would be the New York City area which has established specific requirements for operation of the system in the area as a part of the New York State Reliability Council Reliability Rules.⁴

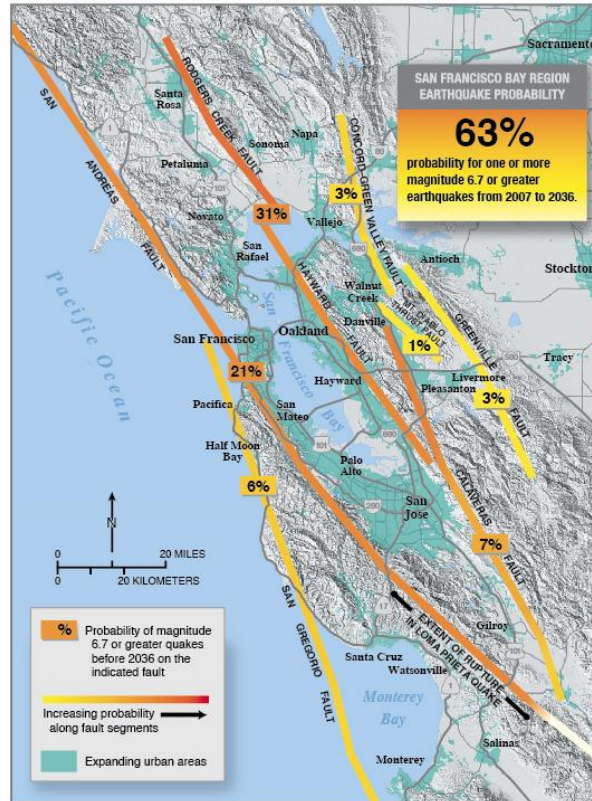
The probability of earthquakes occurring in the Greater Bay Area has been forecasted as illustrated in Figure 3 from the USGS website⁵. The figure illustrates the probability of earthquakes of magnitudes 6.7 or greater occurring in the Bay area in the next 30 years. With this, the issue is not so much related to if a seismic event is to occur in the area, but where exactly and to what extent the impact of such event will be.

³ Urbanized Area (UA): A statistical geographic entity consisting of a densely settled core created from census tracts or blocks and contiguous qualifying territory that together have a minimum population of at least 50,000 persons.

⁴ <http://www.nysrc.org/pdf/Reliability%20Rules%20Manuals/RR%20Manual%20V32%20Final%201-11-13%20.pdf>

⁵ <http://earthquake.usgs.gov/regional/nca/ucurf/>

Figure 3 – Bay Area Earth Quake Probabilities



At one time, the ISO Planning Standards did provide the San Francisco-Bay Area a special standard that had to do with resource unavailability at peak conditions and treatment of system normal conditions with certain resources out of service. This standard was eliminated after all old and less reliable resources in the San Francisco-Peninsula retired and transmission facilities were brought into service. These facilities include the Jefferson-Martin 230 kV cable and the TransBay Cable HVDC, that primarily dealt with addressing Category C type contingencies in the area with the retiring of generation in the peninsula area.

The ISO is therefore proposing to add to the Planning Standards specific recognition of the unique characteristics of supply to the San Francisco Peninsula and acknowledgment that planning for extreme events – including the approval of transmission solutions to improve the reliability of supply - is an appropriate action for the ISO Board to consider and approve.

The following is the language that the ISO is intending to add to the Transmission Planning Standards:

The ISO has determined through its Extreme Event assessments, conducted as a part of the annual transmission planning process, that there are unique characteristics of the San Francisco Peninsula area requiring consideration for mitigation as follows.

- high density urban load area,
- geographic and system configuration,
- potential risks of outages including seismic, third party action and collocating facilities; and
- challenging restoration times.

The requirements of NERC TPL-004-0a (to be superseded by TPL-001-4) requires Extreme Event contingencies to be assessed; however the standard does not require mitigation plans to be developed for these Extreme Events. The unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages that are beyond the application of mitigation of extreme events in the reliability standards to the rest of the ISO controlled grid. The ISO will consider the overall impact of the mitigation on the identified risk and the associated benefits that the mitigation provides to the San Francisco Peninsula area.

5 Changes to NERC Transmission Planning Standards

The current ISO Planning Standard is based upon the current NERC reliability standards TPL-001, TPL-002, TPL-003 and TPL-004. NERC has been developing over the last number of years an update to the transmission planning standards, which among other changes consolidates the four existing TPL standards into one standard. The NERC standard TPL-001-4 has been approved by FERC. TPL-001-4 will replace the transmission planning standards TPL-001, TPL-002, TPL-003 and TPL-004. The effective date for TPL-001-004 is spread over two years, with the effective dates of the requirements in the standard to be:

- Requirements R1 and R7 – January 1, 2015
- Requirements R2 through R6 – January 1, 2016

With the sequenced in-service date of the standard, the ISO will be conducting the studies for the 2014-2015 Transmission Planning Process applying the NERC Reliability Standards TPL-001, TPL-002, TPL-003 and TPL-004. The ISO will ensure compliance to Requirements R1 and R7 as a part of the assessment. The ISO will be applying the NERC Reliability Standard TPL-001-04 for the 2015-2016 Transmission Planning Process.

The new standard, TPL-001-4, is similar in principle and application as the current TPL-001 through 004 with some elevation of the requirements in the standard. In addition, the new standard provides a complete recategorization of system contingencies, and replacing the current Category A, B, C and D

contingency definitions. Within TPL-001-4 the contingencies will be categorized as P0 through P7 as set out in Table 1 of the new standard. The following reflects in general how the current categories correlate to the new contingency categorization.

- Category A will become contingency P0
- Category B and C will become contingencies P1 through P7
- Category D will be considered Extreme Events

The ISO is proposing to change the ISO Planning Standards (effective April 1, 2015) to reflect the requirements of TPL-001-4 for use in the 2015-2016 Transmission Planning Process.

The following is the language that the ISO is intending on adding, deleting or changing to the Transmission Planning Standards:

The **Combined Line and Generator Outage Standard** and the **Combined Line and Generator Unit Outage Standard Supporting Information** chapter will be removed.

The links to the WECC and NERC standards as well as the ISO transmission control agreement (TCA) will be updated. A new link to the WECC Regional Business Practice TPL-001-WECC-RBP-2.1 will be provided.

Numerous references from old NERC standards will be replaced with reference to the new NERC standard TPL-001-4 and the new nomenclature for categories of contingencies will be used.

The following language found under **Planing for New Transmission versus Involuntary Load Interruption Standard** bullet 1) will be removed since it contradict new TPL-001-4 footnote 9⁶.

“This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to protect for the next worst single contingency.” **To be deleted.**

Under the **Interpretations of terms from NERC Reliability Standard and WECC Regional Criteria** section the following Interpretation will be entered:

⁶ TPL-001-4 Footnote 9 states: “Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled ‘Initial Condition’) and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss.”

Footnote 12 of TPL-001-4 Interpretation and Applicable Timeline⁷:

The shedding of Non-Consequential load following the single contingencies of P1, P2-1 and P3 on the Bulk Electric System of the ISO Controlled Grid is not considered appropriate in meeting the performance requirements. In the Near-term planning horizon the requirements of Footnote 12 may be applied until the longer-term mitigation plans are in-service. In the near-term transmission planning horizon, the non-consequential load loss will be limited to 75 MW and has to meet the conditions specified in Attachment 1 of TPL-001-4.

6 Next Steps

The ISO will host a stakeholder web conference on June 4, 2014 to discuss the contents of this revised straw proposal. Stakeholder comments on this revised straw proposal will be due June 18, 2014. The ISO anticipates seeking ISO Board approval at the September 2014 Board Meeting.

⁷ TPL-001-4 has an 84 month effective date for some of the requirements. With this, after Jan 1, 2021 the Corrective Action Plans may no longer include curtailment of firm transmission service or non-consequential load loss in excess of 75 MW or non-consequential load loss that does not meet the conditions specified in Attachment 1 of TPL-001-4 for the following categories of contingencies: P1-2 and P1-3 (for controlled interruption of electric supply to local networks customers connected to or supplied by the faulted element), P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV) as well as P5 (above 300 kV).



Attachment 1 – Redline of Proposed Changes

California ISO Planning Standards

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I. Introduction

The California ISO (ISO) tariff provides for the establishment of planning guidelines and standards above those established by NERC and WECC to ensure the secure and reliable operation of the ISO controlled grid. The primary guiding principle of these Planning Standards is to develop consistent reliability standards for the ISO grid that will maintain or improve transmission system reliability to a level appropriate for the California system.

These ISO Planning Standards are not intended to duplicate the NERC and WECC reliability standards, but to complement them where it is in the best interests of the security and reliability of the ISO controlled grid. The ISO planning standards will be revised from time to time to ensure they are consistent with the current state of the electrical industry and in conformance with NERC Reliability Standards and WECC Regional Criteria. In particular, the ISO planning standards:

- Address specifics not covered in the NERC Reliability Standards and WECC Regional Criteria;
- Provide interpretations of the NERC Reliability Standards and WECC Regional Criteria specific to the ISO Grid;
- Identify whether specific criteria should be adopted that are more stringent than the NERC Reliability Standards and WECC Regional Criteria where it is in the best interest of ensuring the ISO controlled grid remains secure and reliable.

NERC Reliability Standards and WECC Regional Criteria:

The following links provide the minimum standards that ISO needs to follow in its planning process unless NERC or WECC formally grants an exemption or deference to the ISO. They are the NERC Transmission Planning (TPL) standards, other applicable NERC standards (i.e., NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant and San Onofre Nuclear Generating Station), and the WECC Regional Criteria:

<http://www.nerc.com/page.php?cid=2|20>

<http://www.wecc.biz/library/Documentation%20Categorization%20Files/Forms/AllItems.aspx?RootFolder=%2flibrary%2fDocumentation%20Categorization%20Files%2fRegional%20Criteria&FolderCTID=&View=%7bAD6002B2%2d0E39%2d48DD%2dB4B5%2d9AFC9F8A8DB3%7d>

<http://www.wecc.biz/Standards/WECC%20Criteria/Forms/AllItems.aspx>

Section II of this document provides additional details about the ISO Planning Standards. Guidelines are provided in subsequent sections to address certain ISO planning standards, such as the use of new Special Protection Systems, which are not specifically addressed at the regional level of NERC and WECC. Where appropriate, background information behind the development of these standards and references

(web links) to subjects associated with reliable transmission planning and operation are provided.

II. ISO Planning Standards

The ISO Planning Standards are:

1. **Applicability of NERC Reliability Standards to Low Voltage Facilities under ISO Operational Control**

The ISO will apply NERC Transmission Planning (TPL) standards, the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant and San Onofre Nuclear Generating Station, and the approved WECC Regional Criteria to facilities with voltages levels less than 100 kV or otherwise not covered under the NERC Bulk Electric System definition that have been turned over to the ISO operational control.

~~2. 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). Supporting information is located within Section IV of this document.~~

~~3. Voltage Standard~~

~~Standardization of low and high voltage levels as well as voltage deviations across the TPL-001, ~~TPL-002, and TPL-003~~ standards is required across all transmission elements in the ISO controlled grid. The low voltage and voltage deviation guideline applies only to load and generating buses within the ISO controlled grid (including generator auxiliary load) since they are impacted by the magnitude of low voltage and voltage deviations. The high voltage standard applies to all buses since unacceptable high voltages can damage station and transmission equipment. These voltage standards are shown in Table 1.~~

~~All buses within the ISO controlled grid that cannot meet the requirements specified in Table 1 will require further investigation. Exceptions to this voltage standard may be granted by the ISO based on documented evidence vetted through an open stakeholder process. The ISO will make public all exceptions through its website.~~

Table 1
(Voltages are relative to the nominal voltage of the system studied)

Voltage level	Normal Conditions (TPL-001P0)		Contingency Conditions (TPL-002 & TPL-003P1-P7)		Voltage Deviation	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	TPL-002P1-P3	TPL-003P4-P7
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05	0.90	1.1	≤5%	≤10%

The maximum total voltage deviation for standard TPL-001-4 category P3 is ≤5% measured from the voltage that exists after the initial condition (loss of generator unit followed by system adjustments) and therefore takes in consideration only voltage deviation due to the second event.

Voltage and system performance must also meet WECC Regional Business Practice TPL-001-WECC-RBP-2.1:
<http://www.wecc.biz/library/Documentation%20Categorization%20Files/Regional%20Business%20Practices/TPL-001-WECC-RBP-2%201.pdf>

43. Specific Nuclear Unit Standards

The criteria pertaining to the Diablo Canyon Power Plant (DCPP) and San Onofre Nuclear Generating Station (SONGS), as specified in the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for DCPP and SONGS, and Appendix E of the Transmission Control Agreement located on the ISO web site at:

<http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=3972DF1A-2A18-4104-825C-E24350BA838F>
<http://www.caiso.com/docs/09003a6080/25/a3/09003a608025a3bd.pdf>

54. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

A single module of a combined cycle power plant is considered a single contingency (G-1) and shall meet the performance requirements of the NERC TPL-001-4 standards for single contingencies (TPL002P1). Supporting information is located in Section ~~V-IV~~ of this document. Furthermore any reference to the loss of a “generator unit” in the NERC multiple contingency standards (P3-P5) shall be similar to the loss of a “single module of a combined cycle power plant”. ~~a single transmission circuit outage with one combined cycle module already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TLP002) as established in item 1 above.~~

A re-categorization of any combined cycle facility that falls under this standard to a less stringent requirement is allowed if the operating performance of the combined

cycle facility demonstrates a re-categorization is warranted. The ISO will assess re-categorization on a case by case based on the following:

- a) Due to high historical outage rates in the first few years of operation no exceptions will be given for the first two years of operation of a new combined cycle module.
- b) After two years, an exception can be given upon request if historical data proves that no outage of the combined cycle module was encountered since start-up.
- c) After three years, an exception can be given upon request if historical data proves that outage frequency is less than once in three years.

The ISO may withdraw the re-categorization if the operating performance of the combined cycle facility demonstrates that the combined cycle module exceeds a failure rate of once in three year. The ISO will make public all exceptions through its website.

65. Planning for New Transmission versus Involuntary Load Interruption Standard

This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements. It does not address all circumstances under which load dropping is permitted under NERC and WECC planning standards.

1. No single contingency (TPL-002-001-4 P1 and ISO standard [G-1][L-1]) should result in loss of more than 250 MW of load. ~~This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to position the electric system for reliable operation in anticipation of the next worst contingency.~~
2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines “closed in” during normal operation.
3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more constraining.
4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure, through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

To better understand the potential impact of the updated “planning for new transmission versus involuntary load interruption” standard, this standard will

be considered a guideline for the first year that it is in effect in order to get an inventory of stations and transmission elements not in compliance and a cost impact of bringing them into compliance.

6. Planning for High Density Urban Load Area Standard

The local areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local generation and transmission capacity. Increased reliance on load shedding to meet these needs would run counter to historical and current practices, resulting in general deterioration of service levels.

For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

- In the near term during short-term planning, SPS which drops load, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.
- In considering if load shedding is a viable mitigation in either the short-term, or the long-term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

7. San Francisco-Peninsula Extreme Event Reliability Standard

The ISO has determined through its Extreme Event assessments, conducted as a part of the annual transmission planning process, that there are unique characteristics of the San Francisco Peninsula area requiring consideration for mitigation as follows.

- high density urban load area,
- geographic and system configuration,
- potential risks of outages including seismic, third party action and collocating facilities; and
- challenging restoration times.

The requirements of NERC TPL-004-0a (to be superseded by TPL-001-4) requires Extreme Event contingencies to be assessed; however the standard does not require mitigation plans to be developed for these Extreme Events. The unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages that are beyond the application of mitigation of extreme events in the reliability standards to the rest of the ISO controlled grid. The ISO will consider the overall impact of the mitigation on the identified risk and the associated benefits that the mitigation provides to the San Francisco Peninsula area.

III. ISO Planning Guidelines

The ISO Planning Guidelines include the following:

1. New Special Protection Systems

As stated in the NERC glossary, a Special Protection System (SPS) is “an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition of faulted components to maintain system reliability.” In the context of new projects, the possible action of an SPS would be to detect a transmission outage (either a single contingency or credible multiple contingencies) or an overloaded transmission facility and then curtail generation output and/or load in order to avoid potentially overloading facilities or prevent the situation of not meeting other system performance criteria. A SPS can also have different functions such as executing plant generation reduction requested by other SPS; detecting unit outages and transmitting commands to other locations for specific action to be taken; forced excitation pulsing; capacitor and reactor switching; out-of-step tripping; and load dropping among other things.

The primary reasons why SPS might be selected over building new transmission facilities are that SPS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, SPS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, SPS is a commonly considered alternative to building new infrastructure in an effort to keep costs down when integrating new generation into the grid and/or addressing reliability concerns under multiple contingency conditions. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability. These reliability concerns necessarily dictate that guidelines be established to ensure that performance of all SPSs are consistent across the ISO controlled grid. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of existing transmission facilities while maintaining system reliability and optimizing operability of the ISO controlled grid. Needless to say, with the large number of generator interconnections that are occurring on the ISO controlled grid, the need for these guidelines has become more critical.

It needs to be emphasized that these are guidelines rather than standards. In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies). This is to emphasize that best engineering practice and

judgement will need to be exercised by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of SPS in all potential applications.

ISO SPS1

The overall reliability of the system should not be degraded after the combined addition of the SPS.

ISO SPS2

The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. In situations where the design of the SPS requires WECC approval, the WECC Remedial Action Scheme Design Guide will be followed.

ISO SPS3

The total net amount of generation tripped by a SPS for a single contingency cannot exceed the ISO's largest single generation contingency (currently one Diablo Canyon unit at 1150 MW). The total net amount of generation tripped by a SPS for a double contingency cannot exceed 1400 MW. This amount is related to the minimum amount of spinning reserves that the ISO has historically been required to carry. The quantities of generation specified in this standard represent the current upper limits for generation tripping. These quantities will be reviewed periodically and revised as needed. In addition, the actual amount of generation that can be tripped is project specific and may depend on specific system performance issues to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts provided in this guide. The net amount of generation is the gross plant output less the plant's and other auxiliary load tripped by the same SPS.

ISO SPS4

For SPSs, the following consequences are unacceptable should the SPS fail to operate correctly:

- A) Cascading outages beyond the outage of the facility that the SPS is intended to protect: For example, if a SPS were to fail to operate as designed for a single contingency and the transmission line that the SPS was intended to protect were to trip on overload protection, then the subsequent loss of additional facilities due to overloads or system stability would not be an acceptable consequence.
- B) Voltage instability, transient instability, or small signal instability: While these are rare concerns associated with the addition of new generation, the consequences can be so severe that they are deemed to be unacceptable results following SPS failure.

ISO SPS5

Close coordination of SPS is required to eliminate cascading events. All SPS in a local area (such as SDG&E, Fresno, etc.) and grid-wide need to be evaluated as a whole and studied as such.

ISO SPS6

The SPS must be simple and manageable. As a general guideline:

- A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS.
- B) The SPS should not be monitoring more than 4 system elements or variables. A variable can be a combination of related elements, such as a path flow, if it is used as a single variable in the logic equation. Exceptions include:
 - i. The number of elements or variables being monitored may be increased if it results in the elimination of unnecessary actions, for example: generation tripping, line sectionalizing or load shedding.
 - ii. If the new SPS is part of an existing SPS that is triggered by more than 4 local contingencies or that monitors more than 4 system elements or variables, then the new generation cannot materially increase the complexity of the existing SPS scheme. However, additions to an existing SPS using a modular design should be considered as preferable to the addition of a new SPS that deals with the same contingencies covered by an existing SPS.
- C) Generally, the SPS should only monitor facilities that are connected to the plant or to the first point of interconnection with the grid. Monitoring remote facilities may add substantial complexity to system operation and should be avoided.
- D) An SPS should not require real-time operator actions to arm or disarm the SPS or change its set points.

ISO SPS7

If the SPS is designed for new generation interconnection, the SPS may not include the involuntary interruption of load. Voluntary interruption of load paid for by the generator is acceptable. The exception is that the new generator can be added to an existing SPS that includes involuntary load tripping. However, the amount of involuntary load tripped by the combined SPS may not be increased as a result of the addition of the generator.

ISO SPS8

Action of the SPS shall limit the post-disturbance loadings and voltages on the system to be within all applicable ratings and shall ultimately bring the system to within the long-term (4 hour or longer) emergency ratings of the transmission equipment. For example, the operation of SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back additional generation (or trip load if not already addressed under ISO SPS7 above) to bring the line loading within the line's four-hour or longer rating. This is intended to minimize real-time operator intervention.

ISO SPS9

The SPS needs to be agreed upon by the ISO and may need to be approved by the WECC Remedial Action Scheme Reliability Task Force.

ISO SPS10

The ISO, in coordination with affected parties, may relax SPS requirements as a temporary “bridge” to system reinforcements. Normally this “bridging” period would be limited to the time it takes to implement a specified alternative solution. An example of a relaxation of SPS requirement would be to allow 8 initiating events rather than limiting the SPS to 6 initiating events until the identified system reinforcements are placed into service.

ISO SPS11

The ISO will consider the expected frequency of operation in its review of SPS proposals.

ISO SPS12

The actual performance of existing and new SPS schemes will be documented by the transmission owners and periodically reviewed by the ISO and other interested parties so that poorly performing schemes may be identified and revised.

ISO SPS13

All SPS schemes will be documented by the owner of the transmission system where the SPS exists. The generation owner, the transmission owner, and the ISO shall retain copies of this documentation.

ISO SPS14

To ensure that the ISO’s transmission planning process consistently reflects the utilization of SPS in its annual plan, the ISO will maintain documentation of all SPS utilized to meet its reliability obligations under the NERC reliability standards, WECC regional criteria, and ISO planning standards.

ISO SPS15

The transmission owner in whose territory the SPS is installed will, in coordination with affected parties, be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO SPS16 Generally, the SPS should trip load and/or resources that have the highest effectiveness factors to the constraints that need mitigation such that the magnitude of load and/or resources to be tripped is minimized. As a matter of principle, voluntary load tripping and other pre-determined mitigations should be implemented before involuntary load tripping is utilized.

ISO SPS17

Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO is required unless otherwise deemed unnecessary by the ISO. Specific telemetry requirements will be determined by the Transmission Owner and the ISO on a project specific basis.

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).~~

~~The ISO Planning Standards require that system performance for an overlapping 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.~~

VIV. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard Supporting Information

Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard - A single module of a combined cycle power plant is considered a single (G-1) contingency and shall meet the performance requirements of the NERC TPL-001-4 standards for single contingencies (TPL002P1).

The purpose of this standard is to require that an outage of any turbine element of a combustion turbine be considered as a single outage of the entire plant and therefore must meet the same performance level as the NERC TPL-001-4 standard TPL-002P1.

The ISO has determined that, a combined cycle module should be treated as a single contingency. In making this determination, the ISO reviewed the actual operating experience to date with similar (but not identical) combined cycle units currently in operation in California. The ISO's determination is based in large part on the performance history of new combined cycle units and experience to date with these units. The number of combined cycle facility forced outages that have taken place does not support a double contingency categorization for combined cycle module units in general. It should be noted that all of the combined cycle units that are online today are treated as single contingencies.

Immediately after the first few combined cycle modules became operational, the ISO undertook a review of their performance. In defining the appropriate categorization for combined cycle modules, the ISO reviewed the forced outage history for the following three combined cycle facilities in California: Los Medanos Energy Center (Los Medanos), Delta Energy Center (Delta), and Sutter Energy Center (Sutter)¹. Los Medanos and Sutter have been in service since the summer of 2001, Delta has only been operational since early summer 2002.

Table 2 below sets forth the facility forced outages for each of these facilities after they went into operation (i.e. forced outages² that resulted in an output of zero MWs.) The table demonstrates that facility forced outages have significantly exceeded once every 3 to 30 years. Moreover, the ISO considers that the level of facility forced outages is significantly above the once every 3 to 30 years even accounting for the fact that new combined cycle facilities tend to be less reliable during start-up periods and during the initial weeks of operation. For example, four of the forced outages that caused all the three units at Los Medanos to go off-line took place more than nine months after the facility went into operation.

Facility	Date	# units lost
Sutter ³	08/17/01	No visibility
Sutter	10/08/01	1 CT
Sutter	12/29/01	All 3
Sutter	04/15/02	1 CT + ST
Sutter	05/28/02	1 CT
Sutter	09/06/02	All 3
Los Medanos ⁴	10/04/01	All 3
Los Medanos	06/05/02	All 3
Los Medanos	06/17/02	All 3
Los Medanos	06/23/02	1CT+ST
Los Medanos	07/19/02	All 3
Los Medanos	07/23/02	1CT+ST
Los Medanos	09/12/02	All 3
Delta ⁵	06/23/02	All 4
Delta	06/29/02	2 CT's + ST
Delta	08/07/02	2 CT's + ST

¹ Los Medanos and Sutter have two combustion turbines (CT's) and one steam turbine (ST) each in a 2x1 configuration. Delta has three combustion turbines (CT's) and one steam turbine (ST) in a 3x1 configuration. All three are owned by the Calpine Corporation.

² Only forced outages due to failure at the power plant itself are reported, forced outages due to failure on the transmission system/switchyard are excluded. The fact that a facility experienced a forced outage on a particular day is public information. In fact, information on unavailable generating units has been posted daily on the ISO website since January 1, 2001. However, the ISO treats information regarding the cause of an outage as confidential information.

³ Data for Sutter is recorded from 07/03/01 to 08/10/02

⁴ Data for Los Medanos is recorded from 08/23/01 to 08/10/02

⁵ Data for Delta is recorded from 06/17/02 to 08/10/02

Table 2: Forced outages that have resulted in 0 MW output from Sutter, Los Medanos and Delta after they became operational

The ISO realizes that this data is very limited. Nevertheless, the data adequately justifies the current classification of each module of these three power plants as a single contingency.

VI. Background behind Planning for New Transmission versus Involuntary Load Interruption Standard

For practical and economic reasons, all electric transmission systems are planned to allow for some involuntary loss of firm load under certain contingency conditions. For some systems, such a loss of load may require several contingencies to occur while for other systems, loss of load may occur in the event of a specific single contingency. Historically, a wide variation among the PTOs has existed predominantly due to slightly differing planning and design philosophies. This standard is intended to provide a consistent framework upon which involuntary load interruption decisions can be made by the ISO when planning infrastructure needs for the ISO controlled grid.

The overarching requirement is that implementation of these standards should not result in lower levels of reliability to end-use customers than existed prior to restructuring. As such, the following is required:

1. No single contingency (TPL-001-4002 P1 and ISO standard [G-1][L-1]) may result in loss of more than 250 MW of load. ~~This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to protect for the next worst single contingency.~~

This standard is intended to coordinate ISO planning standards with the WECC requirement that all transmission outages with at least 300 MW or more be directly reported to WECC. It is the ISO's intent that no single contingency (TPL-001-4 P1002 and ISO standard [G-1][L-1]) should trigger loss of 300 MW or more of load. The 250 MW level is chosen in order to allow for differences between the load forecast and actual real time load that can be higher in some instances than the forecast and to also allow time for transmission projects to become operational since some require 5-6 years of planning and permitting with inherent delays. It is also ISO's intent to put a cap on the ~~radial and/or consequential loss of load allowed under footnote to the NERC standard TPL-001-4-002 that may allow radial and/or non-consequential loss of load for~~ single contingencies (P1).

2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines "closed in" during normal operation.

This standard is intended to bring consistency between the PTOs' substation designs. It is not the ISO's intention to disallow substations with load below 100 MW from having looped connections; however it is ISO's intention that all substations with peak load above 100 MW must be connected through a looped configuration to the grid.

3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more stringent.

This standard is intended to insure that the system is maintained at the level that existed prior to restructuring. It is obvious that as load grows, existing back-ties for radial loads (or remaining feed after a single contingency for looped substations) may not be able to pick up the entire load; therefore the reliability to customers connected to this system may deteriorate over time. It is the ISO's intention to establish a minimum level of back-up tie capability that needs to be maintained.

4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

It is ISO's intention to allow the build-up of transmission projects that are proven to have a positive benefit to ratepayers by reducing load drop exposure.

Information Required for BCR calculation: For each of the outages that required involuntary interruption of load, the following should be estimated:

- The maximum amount of load that would need to be interrupted.
- The duration of the interruption.
- The annual energy that would not be served or delivered.
- The number of interruptions per year.
- The time of occurrence of the interruption (e.g., week day summer afternoon).
- The number of customers that would be interrupted.
- The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural).
- Value of service or performance-based ratemaking assumptions concerning the dollar impact of a load interruption.

The above information will be documented in the ISO Transmission Plan for areas where additional transmission reinforcement is needed or justified through benefit to cost ratio determination.

VI. Background behind Planning for High Density Urban Load Area Standard

A local area is characterized by relatively small geographical size, with limited transmission import capability and most often with scarce resources that usually can be procured at somewhat higher prices than system resources. These areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local resource and transmission capacity. The need for system reinforcement in a number of local areas is expected to climb due to projected resource retirements, with single and double contingency conditions playing a material role in driving the need for reinforcement. Relying on load shedding on a broad basis to meet these emerging needs would run counter to historical and current practices, resulting in general deterioration of service levels. One of the fundamental ISO Tariff requirements is to maintain service reliability at pre-ISO levels, and it drives the need to codify the circumstances in which load shedding is not an acceptable long-term solution:

1. For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

This standard is intended to continue avoiding the need to drop load in high density urban load areas due to, among other reasons, high impacts to the community from hospitals and elevators to traffic lights and potential crime.

2. In the near term during short-term planning, SPS which drops load, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.

This standard is intended to insure that a reliable transition exists between the time when problems could arise until long-term transmission upgrades are placed in service.

3. In considering if load shedding is a viable mitigation in either the short-term, or the long-term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

It is ISO's intention to thoroughly evaluate the risk of outages and their consequences any time a load shedding SPS is proposed regardless of population density.

VII. Interpretations of terms from NERC Reliability Standard and WECC Regional Criteria

Listed below are several ISO interpretations of the terms that are used in the NERC standards that are not already addressed by NERC.

Combined Cycle Power Plant Module: A **combined cycle** is an assembly of heat engines that work in tandem off the same source of heat, converting it into mechanical energy, which in turn usually drives electrical generators. In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, one or more gas turbine generator(s) generates electricity and heat in the exhaust is used to make steam, which in turn drives a steam turbine to generate additional electricity.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTO and the ISO subject to appropriate coordination and review with the relevant local, state, regional and federal regulatory authorities.

Entity Required to Develop Load Models: The PTOs, in coordination with the utility distribution companies (UDCs) and others, develop load models.

Entity Required to Develop Load Forecast: The California Energy Commission (CEC) has the main responsibility for providing load forecast. If load forecast is not provided by the CEC or is not detailed and/or specific enough for a certain study then the ISO, at its sole discretion, may use load forecasts developed by the PTOs in coordination with the UDCs and others.

Footnote 12 of TPL-001-4 Interpretation and Applicable Timeline⁶: The shedding of Non-Consequential load following the single contingencies of P1, P2-1 and P3 on the Bulk Electric System of the ISO Controlled Grid is not considered appropriate in meeting the performance requirements. In the Near-term planning horizon the requirements of Footnote 12 may be applied until the longer-term mitigation plans are in-service. In the near-term transmission planning horizon, the

⁶ TPL-001-4 has an 84 month effective date for some of the requirements. With this, after Jan 1, 2021 the Corrective Action Plans may no longer include curtailment of firm transmission service or non-consequential load loss in excess of 75 MW or non-consequential load loss that does not meet the conditions specified in Attachment 1 of TPL-001-4 for the following categories of contingencies: P1-2 and P1-3 (for controlled interruption of electric supply to local networks customers connected to or supplied by the faulted element), P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV) as well as P5 (above 300 kV).

non-consequential load loss will be limited to 75 MW and has to meet the conditions specified in Attachment 1 of TPL-001-4.

High Density Urban Load Area: Is an Urbanized Area, As defined by the US Census Bureau⁷ ~~a high density urban load area is an area with a populations over one million persons.~~

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. For studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level. The more stringent 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 more certainty in a regional load forecast than in the local area load forecast. Having a more stringent standard for local areas will help minimize the potential for interruption of end-use customers.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified and corresponding operating procedures are in place when required.

Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

⁷ Urbanized Area (UA): A statistical geographic entity consisting of a densely settled core created from census tracts or blocks and contiguous qualifying territory that together have a minimum population of at least 50,000 persons.