California ISO Planning Standards

Effective February 2, 2023

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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 the WECC Regional Criteria:

http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States

https://www.wecc.biz/Standards/Pages/Default.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 Remedial Action Schemes, 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 Reliability Standards to non-Bulk Electric System Facilities under ISO Operational Control

In planning for identified non-BES facilities, according to NERC Bulk Electric System definition and WECC BES Inclusion and Exclusion Guidelines, that have been turned over to the ISO operational control, the ISO will apply the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant, the approved WECC Regional Criteria and NERC Transmission Planning (TPL) standard TPL-001-4 categories P0, P1 and P3 contingencies taken on the non-BES equipment. All other NERC Transmission Planning (TPL) standard TPL-001-4 categories of contingencies taken on non-BES equipment may be evaluated for risk and consequences and may be used for project justification in conjunction with reduction in load outage exposure, through a benefit to cost ratio (BCR) under standard 5 section 4 herein.

2. Voltage Standard

Voltage and system performance must meet WECC Regional Criteria TPL-001-WECC-CRT-3 https://www.wecc.biz/Reliability/TPL-001-WECC-CRT-3.1.pdf.

In accordance with Requirements WR2 and WR3 of WECC Regional Criteria TPL-001-WECC-CRT-3 the following standards and limits are to be used within the ISO controlled grid.

Table 1: ISO steady state voltage standard.

Voltage level	Normal Conditions (P0)		Contingency Conditions (P1-P7)		Voltage Deviation
	Vmax (pu)	Vmin (pu)	Vmax (pu)	Vmin (pu)	P1&P3
≤ 200 kV	1.05	0.95	1.10	0.90	≤8%
≥ 200 kV	1.05	0.95	1.10	0.90	≤8%
≥ 500 kV	1.05	1.00	1.10	0.90	≤8%

The voltage deviation applies only to load and generating buses within the ISO controlled grid (including generator auxiliary load). The maximum total voltage deviation for standard TPL-001-4 category P3 is ≤8% measured from the voltage that exists after the initial condition (loss of generator unit followed by system adjustments) and therefore takes into consideration only voltage deviation due to the second event.

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 and will be documented through stakeholder process. The ISO will make public all exceptions through its website.

Exceptions and clarifications by PTO area:

Table 2: System Voltage Limits in SCE Area

Facility	Nominal Voltage	Steady State Pre-Contingency		Steady State Post-Contingency	
		High (kV/p.u.)	Low (kV/p.u.)	High (kV/p.u.)	Low (kV/p.u.)
All buses	525 kV	540/1.029	520/0.990	550/1.048[2]	498.8/0.950
Alamitos, Arcogen, Huntington Beach, Mandalay, Redondo	230 kV	230/1.000[1]	220/0.957	230/1.000[2]	207/0.900
Bailey, Chevmain, Cima, Colorado River, Cool Water, Eagle Mt., Eagle Rock, El Casco, Gene, Harborgen, Highwind, Iron Mt., Inyo, Ivanpah, Johanna, Lewis, Primm, Rancho Vista, Red Bluff, Sandlot, Santiago, Serrano, Whirlwind, Windhub	230 kV	241.5/1.050	218.5/0.95	245/1.065[2]	207/0.900
All other buses	230 kV	241.5/1.050	218.5/0.95	242/1.052[2]	207/0.900
Eagle Mtn, Blythe	161 kV	169/1.050[2]	152.95/0.950	169/1.050[2]	144.9/0.900
Cool Water, Inyokern, Kramer, Victor	115 kV	120.75/1.050	109.25/0.950	121/1.052[2]	103.5/0.900
Control, Inyo	115 kV	120.75/1.05	117/1.026	121/1.052[2]	114.5/0.996
All other buses	115 kV	120.75/1.050	109.25/0.950	123/1.070[2]	103.5/0.900
All buses	66 kV	69.3/1.050	62.7/0.950	72.5/1.090[2]	59.4/0.900

[1] Due to equipment (circuit breaker) voltage limit.

Table 3: System Voltage Limits in PG&E Area

Facility	Nominal Voltage	Steady State Pre-Contingency		Steady State Post-Contingency	
		High (kV/p.u.)	Low (kV/p.u.)	High (kV/p.u.)	Low (kV/p.u.)
DCPP bus	500 kV	545/1.090	512/1.024	550/1.100	512/1.024
All other buses	500 kV	550/1.100	518/1.036	550/1.100	473/0.946
DCPP bus	230 kV	242/1.052	218/0.948	242/1.052	207/0.900
All other buses	230 kV	242/1.052	219/0.952	242/1.052	207/0.900
All buses	115 kV	121/1.052[2]	109/0.948	121/1.052[1]	104/0.904
All buses	70 kV	72.5/1.036	66.5/0.950	72.5/1.036	63.0/0.900
All buses	60 kV	63.0/1.050	57.0/0.950	66.0/1.100	54.0/0.900

Maximum voltage deviation: DCPP 230 kV bus at 11 kV or 4.78%.

Table 4: System Voltage Limits in SDG&E Area

Facility	Nominal Voltage	Steady State Pre-Contingency		Steady State Post-Contingency	
		High Limit (kV)	Low Limit (kV)	High Limit (kV)	Low Limit (kV)
All buses	525 kV	550/1.048	498.75/0.950	550/1.048	472.5/0.900
All buses	230 kV	241.5/1.050	218.5/0.950	241.5/1.050	207/0.900
All buses	138 kV	144.9/1.050	131.1/0.950	144.9/1.050	124.2/0.900
All buses	69 kV	72.45/1.050	65.55/0.950	72.45/1.050	62.1/0.900

Table 5: System Voltage Limits in VEA Area

System	Facility	Steady State Pre-Contingency		Steady State Post-Contingency	
		High (kV/p.u.)	Low (kV/p.u.)	High (kV/p.u.)	Low (kV/p.u.)
All buses	230 kV	248.4/1.080	218.5/0.950	253/1.100	207/0.900
All buses	138 kV	149.0/1.080	131.1/0.950	151.8/1.100	124.2/0.900

Table 6: System Voltage Limits for Trans Bay Cable

System	Facility	Steady State Pre-Contingency		Steady State Post-Contingency	
		High Limit (kV/p.u.)	Low Limit (kV/p.u.)	High Limit (kV/p.u.)	Low Limit (kV/p.u.)
All buses	230 kV	241.5/1.050	218.5/0.950	253/1.100	207/0.900
All buses	115 kV	120.75/1.050	109.25/0.950	126.5/1.100	103.5/0.900

[2] PG&E Utility Standard TD1036S allows 115 kV voltages to operate as high as 126 kV until capital projects can be placed into service to achieve a desired operating limit of 121 kV.

3. Specific Nuclear Unit Standards

The criteria pertaining to the Diablo Canyon Power Plant (DCPP), as specified in the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for DCPP, 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

4. 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 standard for single contingencies (P1). Supporting information is located in Section 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 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.

5. 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-001-4 P1) should result in loss of more than 250 MW of load.
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.

6. Planning for High Density Urban Load Area Standard

6.1 Local Area 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.[3] 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 planning, where allowed by NERC standards, load dropping, 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, where allowed by NERC standards, is a viable mitigation in either the near-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 RAS including common right of way, common structures, history of fires, history of lightning, common substations,

[3] A “local area” for purposes of this Planning Standard is not necessarily the same as a Local Capacity Area as defined in the CAISO Tariff.

restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, number of customers impacted by the outage, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

6.2 System Wide 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. Provided it is allowed under NERC reliability standards, the ISO will allow non-consequential load dropping system-wide RAS schemes that include some non-consequential load dropping to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

7. Extreme Event Reliability Standard

The requirements of NERC TPL-001-4 require Extreme Event contingencies to be assessed; however the standard does not require mitigation plans to be developed for these Extreme Events. The ISO has identified in Section 7.1 below that the San Francisco Peninsula area has unique characteristics requiring consideration of corrective action plans to mitigate the risk of extreme events. Other areas of the system may also be considered on a case-by-case basis as a part of the transmission planning assessments.

7.1 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 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.

8. Other Planning Standards

8.1 Local Capacity Area Technical Criteria

A Local Capacity Area, as defined in the ISO Tariff, is planned to meet the minimum performance established in mandatory standards as well as local capacity technical study criteria as defined in ISO Tariff section 40.3.1.1.

8.2 Scheduled Outage Planning Standard

Scheduled outages are necessary to support reliable grid operations. During scheduled outages the P0 and P1 performance requirements in NERC TPL-001-4 for either BES or non-BES facilities must be maintained. A Corrective Action Plan action(s) must be implemented when it is established through a combination of real-time data and technical studies that there is no window to accommodate necessary scheduled outages.

III. ISO Planning Standards and Guidelines for Remedial Action Schemes (RAS)

The ISO Planning Standards and Guidelines include the following:

Remedial Action Scheme (RAS)

As stated in the NERC glossary, a Remedial Action Scheme (RAS) is ” a scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s)”.

RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

In the context of new projects, the possible action of an RAS would be to detect a transmission outage 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 RAS can also have different functions such as executing plant generation reduction requested by other RAS; 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 RAS might be selected over building new transmission facilities are that RAS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, RAS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, RAS 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 RAS have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of RAS, there can be increased exposure to not meeting system performance criteria if the RAS 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 RAS. If there are a large number of RAS, it may become difficult to assess the interdependency of these various schemes on system reliability. In addition, as RAS has become progressively increasing in complexity, it is necessary to consider the level of logic complexity through combining multiple features that were acceptable individually but that could compound to a level that cannot be integrated into market operation.

These reliability concerns necessarily dictate that guidelines and standards be established to ensure that performance of all RASs are consistent across the ISO controlled grid. It is the intent of these guidelines and standards to allow the use of RASs 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 and standards has become more critical.

In the following, the RAS standards are noted as “ISO S-RAS#” and the RAS guidelines as “ISO G-RAS#”.

RAS Standards

ISO S-RAS1

New RAS implementation should meet the NERC PRC-012-2 (or subsequent version) requirements.

ISO S-RAS2

The RAS should not be proposed for mitigating reliability concerns under normal conditions (i.e., Category P0).

ISO S-RAS3

If the RAS is designed for new generation interconnection, the RAS should not include the involuntary interruption of firm customer load. Voluntary interruption of load paid for by the generator is acceptable.

RAS Guidelines

ISO G-RAS1

The following are guidelines for optimizing resources to participate in the RAS design and implementation so that generation deliverability benefit is maximized:

A. The RAS should be designed for simple operation to trip a fixed set of generation under specific contingencies[4].

    i. It should not be implemented with complex design whose operation is predicated on different flow levels on monitored transmission facilities to dynamically trip variable amounts of generation.

    ii. A RAS should not include logics to dynamically arm and trip various generation levels to achieve transmission facility flow objectives. Modeling of RAS dynamic arming and tripping of generation is not feasible in the ISO market.

B. The RAS should trip load and/or resources that have the effectiveness factors greater than 10% on the constraints that need mitigation such that the magnitude of load and/or resources to be tripped is minimized.

    i. As a matter of principle, voluntary load tripping and other pre-determined mitigations should be implemented before involuntary load tripping is utilized. Involuntary load tripping should not be included in the RAS in the high density load area(s).

    ii. In addition, the RAS should avoid tripping the station service and generator auxiliary load as tripping these loads could affect generator tripping mechanism.

ISO G-RAS2

The RAS must be simple and manageable:

A. There should be no more than 6 contingencies (P1 – P7) that would trigger the operation of a RAS.

B. The RAS 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.

[4] The generating facilities selected to participate in a generation dropping RAS should be optimized, so that generation deliverability and feasible congestion mitigation benefits are maximized.

C. Overlapping RAS (i.e., two different RAS monitoring one or more of the same elements or contingencies) is not allowed.

D. A RAS that includes storage facilities and is implemented to operate when there is an excess of generation should not also be implemented to operate when there is an excess of charging. Similarly, a RAS that includes storage facilities and is implemented to operate when there is an excess of charging should not also be implemented to operate when there is an excess of generation. This set up will help make the RAS simpler for design, implementation, and modeling.

The following are examples that illustrate the above guideline:

1. **Example 1** – total resource with excess of generation output level that triggers reliability concerns

   For this example, let's assume that we have a combined hybrid resource that consists of 200 MW solar generation and 105 MW of battery energy storage system (BESS). The reliability issue is identified with total aggregated generation output of or exceeding 100 MW under contingency condition. With BESS at 105 MW discharging, the total generation output for the hybrid facility is 305 MW. With BESS at 90 MW charging, the total generation output for the hybrid facility is 110 MW. The RAS will then need to trip both the solar generation and the BESS regardless of the BESS' operating mode.

   On the other hand, if the total hybrid facility aggregated output is -105 MW (i.e., BESS in maximum charging mode and solar generation is unavailable due to nighttime hours), the same RAS should not be designed to operate. This would simplify the RAS design, implementation and modeling in the ISO market.

2. **Example 2** – total resource with excess of charging output level that triggers reliability concerns

   For this example, let's assume that we have a 100 MW of solar generation and 205 MW of BESS. The reliability issue is identified with total aggregated charging load of 100 MW or more under contingency condition. The RAS would then be operated if solar generation is at 100 MW and BESS charging at 205 MW (for a total aggregated charging load of 105 MW), or if solar generation is at 0 MW (i.e., unavailable in nighttime hours), and the BESS is charging at 205 MW (which could occur in early hours of the day) resulting in a total charging load of 205 MW.

   On the other hand, if the total hybrid facility aggregated output is 0 – 100 MW due to solar generation output and BESS is at 0 MW output, the same RAS should not be designed to operate. Similarly to the above example, this setup would simplify the RAS design, implementation and modeling.

E. The RAS should only monitor overloading facilities no more than 1 substation beyond the first point of interconnection for generating facility, or bulk transmission substation where loading concerns are identified. The impact of generation or load dropping on a remote facility tends to be ineffective due to the electrical distance within the network between the generation or load to be dropped and the remote facility. Remote monitoring of facilities may also add substantial complexity to system operation and should be avoided. Exception to this guideline may include facility that is found to provide effective system loading relief and if it does not add substantial complexity to RAS implementation and system operation.

F. A RAS should not require real-time operator actions to arm or disarm the RAS or change its set points.

ISO –G-RAS3

The total net amount of generation tripped by a RAS for a single contingency (P1 or P2) should not 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 RAS for multiple contingencies (P3 – P7) cannot exceed 1400 MW. These amounts should be based on the maximum interconnection service capacity of the generating facilities that are to be tripped rather than their current MW production. This amount is related to the minimum amount of contingency 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 guideline.

ISO G-RAS4

The ISO, in coordination with affected parties, may relax RAS requirements, including exceptions to complex RAS, as a temporary “bridge” to long-term system reinforcements that are being developed for ISO management and Board approval. Normally this “bridging” period would be limited to the time it takes to implement the specified transmission solution. In addition, for multiple element contingencies that are not in the ISO market model these guidelines and standards may be more flexible.

An example of a relaxation of RAS guidelines and standard requirements would be to allow 8 initiating events rather than limiting the RAS to 6 initiating events until the identified system reinforcements are placed into service.

IV. 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 standard for single contingencies (P1).

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 P1.

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)[5]. 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 outages [6]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.

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[5] 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.

[6] 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.

Facility	Date	# units lost
Sutter[7]	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[8]	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[9]	06/23/02	All 4
Delta	06/29/02	2 CT's + ST
Delta	08/07/02	2 CT's + ST

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.

V. 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:

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[7] Data for Sutter is recorded from 07/03/01 to 08/10/02
[8] Data for Los Medanos is recorded from 08/23/01 to 08/10/02
[9] Data for Delta is recorded from 06/17/02 to 08/10/02

1. No single contingency (TPL-001-4 P1) may result in loss of more than 250 MW of load.

   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 P1) 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 NERC standard TPL-001-4 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 for Local Areas

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.

   The following is a link to the 2010 Census Urban Area Reference Maps:

   http://www.census.gov/geo/maps-data/maps/2010ua.html

This site has diagrams of the following urbanized areas which contain over one million persons.

Los Angeles--Long Beach--Anaheim, CA
San Francisco--Oakland, CA
San Diego, CA
Riverside--San Bernardino, CA
San Jose, CA

2. In the near-term planning, where allowed by NERC standards, load dropping, 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, where allowed by NERC standards, is a viable mitigation in either the near-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 RAS 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 RAS 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 Timeline[10]: The shedding of Non-Consequential load following P1, P2-1 and P3 contingencies 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 long-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.

High Density Urban Load Area: Is an Urbanized Area, as defined by the US Census Bureau[11] with a population 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.

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[10]Implementation and applicable timeline will remain the same as the "Effective Date:"(s) described in the NERC TPL-001-4 standard.

[11] 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.

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.