Issue Paper and Straw Proposal for Transmission Reliability Margin

Provided in Support of Stakeholder Process to Consider Refinement of ISO Market Requirements

December 21, 2011

Issue Paper and Straw Proposal for Transmission Reliability Margin

This Issue Paper and Straw Proposal initiates discussions with stakeholders, and presents the ISO's proposed refinement to its documentation of operational practices, to provide greater clarity in the ISO's management of transmission constraints in the real-time market.[1] Currently, the ISO implements certain adjustments to intertie schedules within operating hours, which can be disruptive to market participants' commercial transactions when bilateral trades are curtailed, as well as to the ISO's operations when reduced imports must be replaced from other sources. Using a mechanism known as "Transmission Reliability Margin" (TRM), the ISO will be able to anticipate these transmission constraints in advance and reduce these issues by reflecting them in market processes before schedules are awarded in the hour-ahead scheduling process (HASP).[2]

The ISO's proposed hourly TRM values will be limited to the current day, no earlier than 2 hours in advance of dispatch, due to the types of operating conditions that they reflect, as discussed in this document. For the day-ahead market and longer time horizons, the ISO will set its TRM values at zero MW. Whenever a TRM value greater than zero is established due to the existence of uncertainty, the hourly TRM values will be set for the duration during which the uncertainty is expected to occur.

NERC standards require transmission operators to publish a TRM Implementation Document (TRMID) if they maintain a TRM. The TRMID identifies each component of uncertainty that the transmission operator considers in establishing its TRM and describes how it is calculated. The ISO currently maintains TRM values of zero,[3] but has determined that it can improve the transparency of its operations to stakeholders by adopting the use of TRM values in certain narrow circumstances as defined in this initiative. This initiative will develop tariff revisions and the needed implementation documents.[4]

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1 Often, the ISO initiates a stakeholder process with an Issue Paper to develop the scope of its issue, and follows with a Straw Proposal. In this case, the ISO's intent is to limit the resulting tariff changes and implementation document to known, current operational issues, so the Issue Paper and Straw Proposal are combined.

2 NERC standards also allow for use of a Capacity Benefit Margin (CBM) in calculations of available transfer capability, which would be an amount of capacity reserved for load serving entities to ensure access to generation from interconnected systems. The ISO does not maintain CBM or include any of the components of CBM to establish its TRM values, and the CBM value is set at zero. The ISO is not proposing to change this practice.

3 ISO tariff Appendix L, section L.1.6, currently states in part: "The CAISO does not use TRMs. The TRM value is set at zero."

4 The proposed tariff amendment consists primarily of amending Appendix L of the ISO Tariff, which sets forth the ISO's methodology for calculating Total Transfer Capacity (TTC), Available Transfer

This Issue Paper and Straw Proposal describes the operational issues that will be addressed in the ISO's TRMID, and presents the ISO's draft TRMID and supporting tariff revision. Following stakeholder discussion and comments on this Issue Paper and Straw Proposal, the ISO will present any needed refinements in a Draft Final Proposal, which will then be the subject of additional stakeholder discussion and comments. The anticipated schedule for this stakeholder process is as follows, leading to implementation by June 2012:

December 21, 2011	Issue Paper and Straw Proposal published
January 10, 2012	Stakeholder conference call on Issue Paper and Straw Proposal
January 18, 2012	Stakeholder comments received on Issue Paper and Straw Proposal
February 7, 2012	Draft Final Proposal (including draft final tariff language) published
February 14, 2012	Stakeholder comments received on draft final tariff language
February 21, 2012	Stakeholder conference call on Draft Final Proposal and draft final tariff language
February 28, 2012	Stakeholder comments received on Draft Final Proposal and draft final tariff language
March 22-23, 2012	ISO Board of Governors meeting

This Issue Paper and Straw Proposal first presents a background explanation of the proposed use of a TRM, and then summarizes the specific factors that the ISO proposes to include. Two attachments present the ISO's draft TRMID and tariff revision.

Background

The development of the ISO's new TRMID and associated tariff amendment involves revising the portion of the tariff's Appendix L involving TRM to allow the ISO to designate a TRM under specified circumstances, including in situations involving high volumes of parallel loop flow, uncertainty in transmission topology, and simultaneous path interactions. The amendment also involves revising Appendix L's terminology so that it is better aligned with the terminology and methodology approved by NERC and FERC in the NERC MOD-001 and MOD-029 reliability standards that became effective on April 1, 2011. The impacts of these proposed changes would include: (1) changes to current OASIS posting practices for total transfer capability (TTC) and available transfer capability (ATC) values; (2) temporary reductions to permitted scheduling limits at certain intertie points in instances where a TRM is applied; (3) correspondingly, less frequent real-time schedule curtailments at those intertie points in periods when a TRM

Capacity (ATC), and the various components of ATC, including Transmission Reliability Margin (TRM), to update these terms for consistency with NERC standards, allow the TRM to be non-zero, and describe the associated calculations.

is in effect; and (4) better transparency for stakeholders concerning operator decision making in addressing intertie constraints.

These revisions respond to concerns raised by market participants. The existing authority allows the ISO to cut interties to manage unscheduled flow, topology issues and simultaneous path flows only within operating hours, and does not allow the ISO to proactively manage these issues. Thus, a scheduling coordinator can be awarded an energy schedule on the intertie in HASP, and the ISO must then cut the schedule in real-time to manage the identified issues, even if they can be anticipated before the start of the operating hour. This can be very frustrating to market participants as their awarded schedules are curtailed at times when they have little recourse in finding alternative sources or sinks of energy, and increases the manual work for the ISO's operators, including procurement of imbalance energy to replace the curtailed schedules. In addition, because the ATC calculations are established before the beginning of the operating hour, the ISO's OASIS data currently continues to show the availability of positive ATC values even when the occasional curtailments in real-time have affected market schedules.

NERC's reliability standards allow transmission operators to use TRM values in establishing the ATC value for any given period for an intertie interconnection point (called an "ATC Path" in NERC's terminology). TRM is an amount of transmission transfer capacity that is necessary to provide reasonable assurance that the interconnected transmission network will be secure when accounting for various types of inherent uncertainty in system conditions. NERC standard MOD-008-1 recognizes a number of components of uncertainty may be used in establishing TRM:

- Forecast uncertainty in transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages),
- Allowances for parallel path (loop flow) impacts,
- Allowances for simultaneous path interactions,
- Aggregate load forecast,
- Load distribution uncertainty,
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation),
- Short-term system operator response (operating reserve actions),
- Reserve sharing requirements, and
- Inertial response and frequency bias.

CAISO proposes to implement TRM for only the first three of these items.[5]

[5] It is common for ISOs to use only selected TRM components:

- Midwest ISO uses two TRM components: uncertainty and reserve sharing. The uncertainty component is used to account for parallel path flow, load forecast error, load distribution variability and variation of generation dispatch. The uncertainty component is set at 2% of flowgate capacity, but TRM can be released.

The ISO does not currently have tariff authority to establish and impose TRM values on ATC Paths under Appendix L of the Tariff. The proposed tariff amendment would revise Appendix L to allow the ISO to impose a TRM value in the real-time timeframe (shortly in advance of HASP) to account for three potential uncertainties: (1) unscheduled parallel loop flow; (2) uncertainties in transmission system topology (e.g., unplanned outages due to an encroaching fire or other circumstance); and (3) simultaneous path interactions. Each of these three elements of uncertainty is an expressly permitted use for TRM under applicable NERC reliability standards. The ISO would employ TRM only when these circumstances occur and only for the affected ATC Paths. While the use of TRM will reduce the capacity available for scheduling in the HASP by the amount of the TRM, it will have the benefit of reducing the frequency with which awarded schedules are curtailed in real time, within operating hours, as a result of these three elements of uncertainty.

The amendment will also improve the transparency of the ISO's processes through publication of the specific adjustments made by the ISO, rather than market participants simply being informed of schedule curtailments. In addition to providing advance notice of the expected capacity reductions, at a time that allows market participants to make final adjustments to their own schedules, the ISO will publish the values for each of the three components that contribute to the ISO's TRM calculation.

Related tariff changes result from NERC's revised MOD-001 and MOD-029 reliability standards, which establish certain requirements for how transmission operators (such as the ISO) are to calculate ATC for ATC Paths with other transmission operators. Among other requirements, NERC's standards require that the ATC calculation be made by subtracting specific identified elements from the TTC of the ATC Path. The ISO's current Appendix L contains an algorithm for calculating ATC, but relies upon a starting point that the ISO refers to as Operating Transfer Capability (OTC). Although the OTC starting point is effectively equivalent to TTC mathematically in NERC's terminology, Appendix L will be updated to remove the references to OTC and instead rely upon the TTC terminology approved by NERC. References elsewhere in the tariff to OTC will also be updated to refer to TTC.

Specific Factors to be Included in TRM

The following discussion further reviews the basis for the three TRM components that the ISO proposes to implement.

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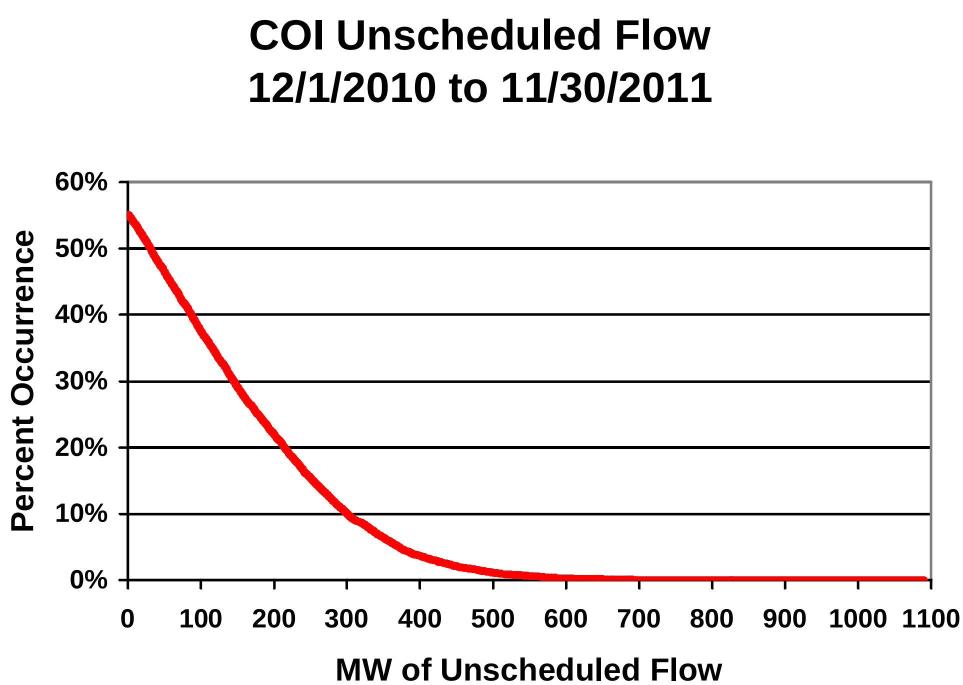
i New England ISO sets its TRM to account for inertial impact from loss of HVDC line imports.

i PJM's TRM has two components: load forecast error and allowance for parallel path flow (loop flow). To account for load forecast error as a TRM component, the percentage difference in flow on the flowgates with changes in load is applied to flowgates as a percentage of their rating. To account for loop flow as a TRM component, the percentage of difference in flow on the flowgates is applied to flowgates as a percentage of rating.

i SPP's TRM is utilized for reserve sharing.

Real-time curtailment of import schedules on COI after HASP awards are published, due to unscheduled flow

The position of the CAISO in the overall WECC transmission grid is such that the California-Oregon Intertie (COI) is susceptible to significant amounts of unscheduled loop flow between sources and sinks elsewhere in WECC. Unscheduled flow is the difference between the scheduled flow and the actual flow. The following graph illustrates the frequency of occurrence of unscheduled flow on COI, in the form of a duration curve showing that some amount of north-to-south unscheduled flow occurs 55% of the time, exceeds 200 MW 22% of the time, and exceeds 500 MW only 1% of the time.



The combination of scheduled and unscheduled flows on a transmission path may cause the path to overload. In some hours, the unscheduled flow on COI, combined with scheduled flow, results in schedule curtailments through WECC's Unscheduled Flow Mitigation Procedure (USFMP).

The details of the USFMP are stated in WECC's Unscheduled Flow Reduction Guideline, which is set forth as Appendix 3510A to the ISO's Operating Procedure 3510, which implements WECC's procedure.[6] Among the corridors for which WECC has formally established ratings, COI is Path 66 and consists of the two 500 kV lines from Malin to Round Mountain (in the ISO's balancing authority area) and one 500 kV line from Captain Jack to Olinda (in the Balancing Area of Northern California, which is

[6] ISO Operating Procedure 3510, its Appendix 3510A, and related documents are available at http://www.caiso.com/Documents/3510.pdf, http://www.caiso.com/Documents/3510A.pdf, and http://www.caiso.com/rules/Pages/OperatingProcedures/Default.aspx, repectively.

managed by SMUD). Path 66 is recognized as a “Qualified Path” under the USFMP, having met criteria of having at least 100 hours in the most recent 36 months with actual flow exceeding 97 percent of its TTC, and having energy schedules curtailed because of unscheduled flow. As path operator for Path 66 under the USFMP, the ISO’s responsibilities include monitoring scheduled and unscheduled flows on the path, keeping actual flows within its transfer capability using available tools including the USFMP when its implementation criteria are met, and coordinating accommodation of unscheduled flow on the qualified path.

Accommodation is a reduction made to schedules on a Qualified Path to allow for unscheduled flow across that path, or to keep its flow within operating limits. Effectively, accommodation is a reduction to the scheduling capacity of that Qualified Path, since actual schedules across the path are reduced below the established path capacity.

The nine steps of the USFMP state the sequence of the measures to be taken by the path operator of the Qualified Path, and four levels of contributing schedule curtailment as steps to be taken by other WECC member systems in response to notifications made by the path operator. When there is, or it is anticipated that there will be, a scheduling limitation due to unscheduled flow, the path operator and those scheduling across the path are required first to accommodate a minimum level of unscheduled flow. This accommodation is achieved by ensuring that the net schedules across the Qualified Path are reduced below the available TTC by the greater of 50 MW or 5 percent of the TTC. When the path operator has met this accommodation requirement, it may request additional relief under the USFMP, including the coordinated operation of certain controllable devices or curtailments by others who are scheduling across other transfer paths. In USFMP step 1 (as well as later steps), the ISO would ask the WECC reliability coordinator to request operation of phase shifters (located in Utah) for maximum relief of north-to-south flow on Path 66. In USFMP step 2, the path operator verifies that schedules on the Qualified Path do not exceed 95% of the path limit (including, for Path 66, that BANC’s schedules are below 95% of its 1/3 share of the Path 66 Limit). Additional steps of the USFMP are available if the path operator determines that the actual flow on the Qualified Path remains equal to or greater than 95% of the current TTC, as detailed in Operating Procedure 3510 and its appendices.

When the ISO needs to implement the UFMP in real-time, within the operating hour, the resulting curtailments to market schedules require market participants to adjust other schedules outside of their normal time horizons, and the ISO faces significant manual adjustments at a time when its operators are trying to restore the COI flow within its limits. Within its conformance with the USFMP, the ISO instead can adjust the COI limit as it issues market awards in HASP, through using the TRM. In the event that the ISO forecasts, based on currently observed parallel path (loop flow) conditions and projected scheduled flow for an upcoming operating hour, that parallel path (loop flow) impacts will occur in real-time over the qualified ATC Path in amounts sufficient to trigger Step 2 or higher of the USFMP for that path, the ISO may establish a TRM value for that path up to the amount that would be required to be curtailed in real-time under the applicable step of the USFMP.

The TRMID illustrates this using the following example. If:

- An ATC Path is rated at 1000 MW,
- The path is a qualified path for the USFMP,
- Unscheduled flow plus scheduled flow is forecasted to be above the path's TTC,
- Unscheduled flow is forecasted to exceed 5% of the path's applicable limit, and
- The ISO forecasts that it will need to invoke USFMP step 2 in real-time absent application of a TRM,

then the ISO may utilize up to 5% of path's TTC as the TRM value for the impacted path for the next available HASP run.

When the ISO forecasts that it will need to invoke USFMP step 6 or 7 in real-time, absent application of a TRM, the ISO would use up to 6% of the path's TTC as the TRM value for the next available HASP run. When the forecast is to invoke USFMP step 8 or 9, the ISO would use up to 7% of TTC as the TRM value.

The forecasting of unscheduled flow that is involved in USFMP can only be done close to real-time, so the applicability of this TRM component is in the values published for HASP.

<u>Uncertainty of transmission system availability due to threatened or actual fires</u>

Another source of uncertainty in the available capacity of interties is the movement of fires near transmission lines or other transmission system resources. In the event that there is uncertainty about the real-time availability of specific transmission resources due to potential forced outages, the ISO would manage risk and reliability by using a TRM value up to the amount of the expected reduction in the path limit for the impacted ATC Paths.

The TRMID illustrates this using the following example. If an ATC Path is rated at 1000 MW when the system is intact, but approaching fires mean that there is an uncertainty of its full availability due to a potential forced outage that may derate the ATC Path by 200 MW (i.e., to a new rating of 800 MW), then the ISO would utilize up to 200 MW of TRM values for the time period during which that uncertainty exists.

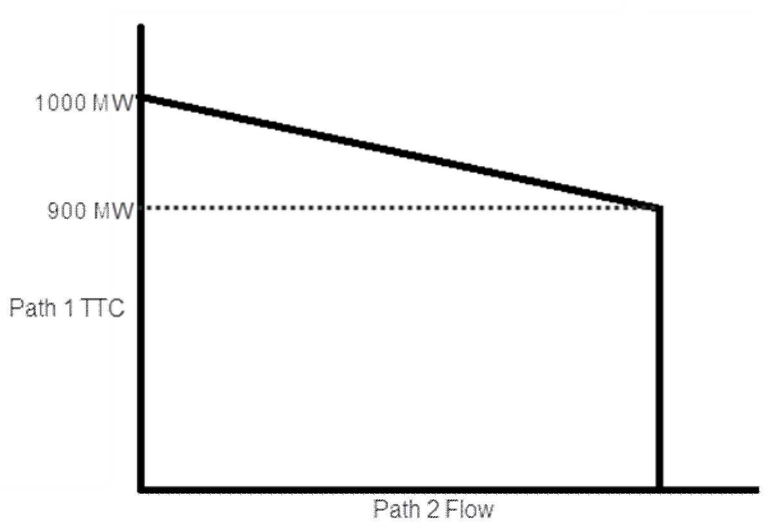
These expected conditions can only be known close to real-time, so the applicability of this TRM component is in the values published for HASP.

<u>Simultaneous interaction between different paths that may result in reduction of the TTC for the CAISO path</u>

In addition to transmission constraints that the ISO must enforce in the form of single-branch capacity limits and total flow on transmission corridors consisting of multiple parallel branches, the ISO must consider simultaneous interactions between transmission corridors, in the form of nomograms. When the actual flow from market schedules on the components of a nomogram is known with sufficient accuracy, such as within the ISO's balancing authority area, the ISO is able to enforce these nomograms in both the day-ahead and real-time markets. Because of uncertainty in the actual real-time flow on interties, which are affected by sources and sinks that are not scheduled in the ISO's markets, the ISO does not enforce nomogram constraints that affect interties in the day-ahead market. Rather, the impact of the interaction between multiple ATC Paths is currently accounted for with nomograms enforced in real-time, either in an automated manner through market systems or manually through monitoring by operations staff, to ensure there are no violations of the TTC.

There are, however, a number of ATC Paths that are managed by the ISO and have simultaneous interactions with non-ISO ATC Paths. In some cases, the real-time flow on non-ISO ATC Paths can be anticipated with reasonable certainty before the start of the operating hour. In the event that the ISO can project that one or more ISO ATC Paths will become constrained due to interactions with another non-ISO ATC Path, TRM may be utilized to ensure there are no violations of the TTC of the ISO's ATC Path. The amount of TRM value assigned will be set to be no greater than the impact of its interaction with the non ISO ATC Path.

The TRMID illustrates this using the following example. If an ATC Path within the ISO is found to be dependant with another non-ATC Path, shown below as Paths 1 and 2 respectively, and ISO can reasonably project the real-time flow on Path 2, the ISO would limit HASP schedules through a TRM applicable to Path 1. Limiting the schedules awarded in HASP would avoid curtailing the awarded schedules on Path 1 within the operating hour, to the extent that the ISO can anticipate the real-time operating conditions.



In this example, the ISO would limit the TRM value for Path 1 to 100 MW if the ISO forecasts that Path 2 flow would be at its maximum.

These expected conditions can only be known close to real-time, so the applicability of this TRM component is in the values published for HASP.

Attachment 1

Draft Transmission Reliability Margin Implementation Document

1.0 Purpose

The California Independent System Operator Corporation (ISO), as a registered Transmission Operator (TOP)[7] with the North American Electric Reliability Corporation (NERC), must comply with NERC reliability standards applicable to that function. MOD-008-1 requires each TOP that maintains Transmission Reliability Margin (TRM) to prepare and keep current a TRM Implementation Document (TRMID) that identifies each component of uncertainty the TOP considers in establishing TRM, describes how TRM is calculated and allocated for each component is used to establish a TRM value for each applicable time period. This TRM ID was developed to comply with NERC standard MOD-008-1.

This TRMID shall be available on the ISO OASIS at http://www.caiso.com/235f/235fcbd556310.html. (MOD-008-1 R2)

2.0 Identification of Components of Uncertainty in TRM (MOD-008-1 R1.1)

The ISO considers the following components of uncertainty in establishing for ATC Paths located at intertie points:

- Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.

3.0 Description of Method Used to Calculate and Allocate TRM for Each Component of Uncertainty (MOD-008-1 R1.2)

The ISO uses the following methods to calculate and allocate TRM values for each of the components of uncertainty identified in Section 2.0 of this TRMID.

3.1 Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).

[7] Unless otherwise noted, capitalized terms have the meaning set forth in the current NERC Glossary of Terms. This Glossary is located on NERC's website.

In the event that there is uncertainty about the availability in Real Time[8] of certain Transmission system resources due to potential Forced Outages, the ISO would utilize TRM to manage risk and reliability, using a TRM value up to the amount of the expected path limit reduction (the potential additional ATC Path derate) for the impacted ATC Paths.

Example: If an ATC Path is rated at 1000 MW during system intact, and, as a result of approaching fires, there is an uncertainty of full availability due to a potential Forced Outage that may derate the ATC path by 200 MW to a new rating of 800 MW, then the ISO would utilize up to 200 MW of TRM values for the time period during which that uncertainty exists.

3.2 Allowances for parallel path (loop flow) impacts.

In the event that the ISO forecasts, based on currently observed parallel path (loop flow) conditions and projected scheduled flow for an upcoming Operating Hour[9], that parallel path (loop flow) impacts will be realized in Real Time over a qualified ATC Path in amounts sufficient to trigger Step 2 or higher of the WECC Unscheduled Flow Mitigation Procedure (WECC USF Procedure)[10] for that Path, the ISO may establish for that Path a TRM value up to the amount that would be required to be curtailed in Real Time under the applicable Step of the WECC USF Procedure.

Example: An ATC Path has a TTC value of 1000 MW, the path is a qualified path for the WECC USF Procedure, and the following conditions exist:

- o Unscheduled flow + Real Time flow is forecasted to be above Path TTC, ***And***
- o Unscheduled flow is forecasted to be > 5% of the Path's Unscheduled flow applicable limit, ***And***
- o It is expected based on the forecast that WECC USF Procedure Step 2 will need to be invoked in Real Time absent application of a TRM.

i ***Then***

- o The ISO may utilize up to 5% of Path TTC as the TRM value for the impacted Path for the next available run of the ISO's Hour-Ahead Scheduling Process (HASP).[11]

When it is expected based on the forecast that WECC USF Procedure Step 6 or 7 will need to be invoked in Real Time absent application of a TRM, the ISO will

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[8] "Real Time" is defined in Appendix A of the ISO Tariff.

[9] "Operating Hour" is defined in Appendix A of the ISO Tariff.

[10] The WECC USF Procedure followed by the ISO is set forth in ISO Operating Procedure 3510, which is available on the ISO's public website. The ISO's WECC USF Procedure implements the WECC Unscheduled Flow Reduction Guideline, which is set forth as Appendix 3510A to Operating Procedure 3510.

[11] The "Hour Ahead Scheduling Process (HASP)" is defined in Appendix A of the ISO Tariff.

utilize up to 6% of Path TTC as the TRM value for the impacted Path for the next available HASP run.

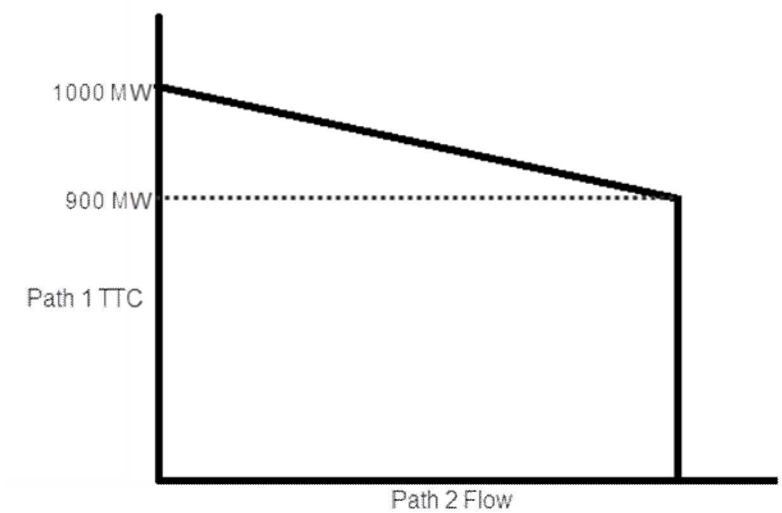
When it is expected based on the forecast that WECC USF Procedure Step 8 or 9 will need to be invoked in Real Time absent application of a TRM, the ISO will utilize up to 7% of Path TTC as the TRM value for the impacted Path for the next available HASP run.

3.3 Allowances for simultaneous path interactions.

The ISO generally does not limit the TTC of an ATC Path due to the simultaneous interaction with another path in the form of a nomogram that is enforced prior to Real Time. Rather, the impact of the interaction between multiple ATC Paths is accounted for with nomograms enforced in Real-Time, either in an automated manner through market systems or manually through monitoring by operations staff, to ensure there are no violations of the System Operating Limit.

There are, however, a number of ISO ATC Paths that have simulataneous interactions with non-ISO ATC Paths. In the event that one or more ISO ATC Paths become constrained due to interactions with another non-ISO ATC Path, TRM may be utilized to ensure there are no violations of the System Operating Limit in the ISO ATC Path. The amount of TRM value assigned will be set to be no greater than the impact of its interaction with the non ISO ATC Path.

Example: If an ATC Path within ISO is found to be dependant with other ATC Paths as seen in Figure Below:



In the example above, the ISO may utilize up to 100 MW of TRM value in Path 1 if the ISO forecasts that Path 2 flow would be at its maximum.

4.0 Identification of TRM Calculation for Different Time Periods and its calculation frequency (MOD-008-1 R1.3 and R4)

For the day-ahead and pre-schedule time period (as referenced in R.1.3.2 of NERC's MOD-008-1), the ISO sets its TRM values at 0 MW at all times.

For the beyond day-ahead and pre-schedule, up to thirteen months ahead, time period (as referenced in R.1.3.3 of NERC's MOD-008-1), the ISO also sets its TRM values at 0 MW at all times.

The hourly TRM values for Real Time and same day (as referenced in R.1.3.1 of NERC's MOD-008-1) are established on the day of dispatch, no earlier than 2 hours in advance of dispatch.. Whenever a TRM value greater than zero is established due to the existence of one or more of the components of uncertainty identified in Section 2.0 above, the hourly TRM values will be set for the duration of the periods during which the applicable component of uncertainty is expected to occur, in accordance with the methodology set forth in Section 3.1-3.3 above..

5.0 Using Components of Uncertainty (MOD-008-1 R2)

The ISO does not maintain Capacity Benefit Margin (CBM). Therefore, the ISO does not include any of the components of CBM establish its TRM values.

The only components of uncertainty included in TRM are those listed in Section 2.0 of this document.

6.0 TRM Reference Materials

i Additional ISO documentation associated with TRM can be found atISO Tariff, Appendix L. The ISO Tariff is available on the ISO's public website.

7.0 Posting TRM Values (MOD-008 R5)

The TRM values established by the ISO will be made public and posted in OASIS.

8.0 **Revisions to TRMID**

This document reflects the ISO's current TRMID. In the event that the ISO determines that it is necessary to revise any aspect of the process or methodology covered by this document, the ISO will issue a revised TRMID, which will be made publicly available and posted on OASIS.

Attachment 2

Blackline of Revisions to the Tariff

Appendix L: Method To Assess Available Transfer Capability

L.1 Description of Terms

The following descriptions augment existing definitions found in Appendix A "Master Definitions Supplement."

L.1.1 Available Transfer Capability (ATC) is a measure of the transfer capability in the physical transmission network resulting from system conditions and that remains available for further commercial activity over and above already committed uses.

ATC is defined as the Total Transfer Capability (TTC) less applicable operating Transmission Constraints due to system conditions and Outages (i.e., OTC), less the Transmission Reliability Margin (TRM) ~~(which value is set at zero),~~, less the sum of any unused existing transmission commitments (ETComm) (i.e., transmission rights capacity for ETC or TOR), less the Capacity Benefit Margin (CBM) (which value is set at zero), less the Scheduled Net Energy from Imports/Exports, less Ancillary Service capacity from Imports.

L.1.2 Total Transfer Capability (TTC) is defined as the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission system by way of all transmission lines (or paths) between those areas~~.~~ under specified system conditions. In collaboration with owners of rated paths and the WECC Operating Transfer Capability Policy Committee (OTCPC), the CAISO utilizes rated path methodology to establish the TTC of CAISO Transmission Interfaces.

~~**L.1.3 Operating Transfer Capability (OTC)** is the TTC reduced by any operational Transmission Constraints caused by seasonal derates or Outages. CAISO Regional Transmission Engineers (RTE) determine OTC through studies using computer modeling.~~
L.1.3 .

L.1.4 Existing Transmission Commitments (ETComm) include Existing Contracts and Transmission Ownership Rights (TOR). The CAISO reserves transmission capacity for each ETC and TOR based on TRTC Instructions the responsible Participating Transmission Owner or Non-Participating Transmission Owner submits to the CAISO as to the amount of firm transmission capacity that should be reserved on each Transmission Interface for each hour of the Trading Day in accordance with Sections 16 and 17 of the CAISO Tariff. The types of TRTC Instructions the CAISO receives generally fall into three basic categories:

- The ETC or TOR reservation is a fixed percentage of the TTC on a line, which decreases as the TTC is derated (ex. TTC = 300 MW, ETC fixed percentage = 2%, ETC = 6 MWs. TTC derated to 200 MWs, ETC = 4 MWs);

- The ETC or TOR reservation is a fixed amount of capacity, which decreases if the line's TTC is derated below the reservation level (ex. ETC = 80 MWs, TTC declines to 60 MW, ETC = ~~OTC~~TTC or 60 MWs; or

- The ETC or TOR reservation is determined by an algorithm that changes at various levels of TTC for the line (ex. Intertie TTC = 3,000 MWs, when line is operating greater than 2,000 MWs to full capacity ETC = 400 MWs, when capacity is below 2000 MWs ETC = ~~OTC~~TTC/2000* ETC).

Existing Contract capacity reservations remain reserved during the Day-Ahead Market and Hour-Ahead Scheduling Process (HASP). To the extent that the reservations are unused, they are released in real-time operations for use in the Real-Time Market.

Transmissions Ownership Rights capacity reservations remain reserved during the Day-Ahead Market and HASP, as well as through real-time operations. This capacity is under the control of the Non-Participating Transmission Owner and is not released to the CAISO for use in the markets.

L.1.5 ETC Reservations Calculator (ETCC). The ETCC calculates the amount of firm transmission capacity reserved (in MW) for each ETC or TOR on each Transmission Interface for each hour of the Trading Day.

- **CAISO Updates to ETCC Reservations Table.** The CAISO updates the ETC and TOR reservations table (if required) prior to running the Day-Ahead Market and HASP. The amount of transmission capacity reservation for ETC and TOR rights is determined based on the ~~OTC~~TTC of each Transmission Interface and in accordance with the curtailment procedures stipulated in the existing agreements and provided to the CAISO by the responsible Participating Transmission Owner or Non-Participating Transmission Owner.

- **Market Notification.** ETC and TOR allocation (MW) information is published for all Scheduling Coordinators which have ETC or TOR scheduling responsibility in advance of the Day-Ahead Market and HASP. This information is posted on the Open Access Same-Time Information System (OASIS).

- For further information, see CAISO Operating Procedure M-423, Scheduling of Existing Transmission Contract and Transmission Ownership Rights, which is publicly available on the CAISO Website.

~~**L.1.6 Transmission Reliability Margin (TRM)** is that amount of transmission transfer capability necessary reserved in the Day-Ahead Market (DAM) to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. This DAM implementation avoids Real-Time Schedule curtailments that would otherwise be necessary due to:~~

- ~~Demand Forecast error~~
- ~~Anticipated uncertainty in transmission system topology~~
- ~~Unscheduled flow~~
- ~~Simultaneous path interactions~~
- ~~Variations in Generation Dispatch~~
- ~~Operating Reserve actions~~

~~The level of TRM for each Transmission Interface will be determined by CAISO Regional Transmission Engineers (RTE).~~

~~The CAISO does not use TRMs. The TRM value is set at zero.~~

L.1.6 Transmission Reliability Margin (TRM) is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

The CAISO uses TRM to account for the following NERC-approved components of uncertainty:

- Forecast uncertainty in transmission system topology, including forced or unplanned outages or maintenance outages.
- Allowances for parallel path (loop flow) impacts, including unscheduled loop flow.
- Allowances for simultaneous path interactions.

The CAISO establishes hourly TRM values for each of the applicable components of uncertainty prior to the Market Close of the HASP. The CAISO does not use TRM (i.e., TRM values are set at zero) during the beyond day-ahead and pre-schedule (i.e., planning) time frame indentified in R.1.3.3 of NERC Reliability Standard MOD-008-1. A positive TRM value for a given hour is set only if one or more of the conditions set forth below exists. Where none of these conditions exist, the TRM value for a given hour is set at zero.

The methodology the CAISO uses to establish each component of uncertainty is as follows:

The CAISO uses the transmission system topology component of uncertainty to address a potential ATC path limit reduction at an Intertie resulting from an emerging event, such as an approaching wildfire, that is expected to cause a derate of one or more transmission facilities comprising the ATC path. When the CAISO, based on existing circumstances, forecasts that such a derate is expected to occur, the CAISO may establish a TRM value for the affected ATC path in an amount up to, but no greater than, the amount of the expected derate.

The CAISO uses the parallel path component of uncertainty to address the impact of unscheduled flow (USF) over an ATC path that is expected, in the absence of the TRM, to result in curtailment of Intertie Schedules in Real Time as a result of the requirements established in WECC's applicable USF mitigation policies and procedures (WECC USF Policy). When the CAISO forecasts, based on currently observed USF conditions and projected scheduled flow for an upcoming Operating Hour(s), that in the absence of a TRM, scheduled flow will need to be curtailed in Real Time under the applicable WECC USF Policy, the CAISO may establish a TRM for the ATC path for the applicable hour(s) in an amount up to, but no greater than, the forecasted amount that is expected to be curtailed in Real Time pursuant to the WECC USF Policy. The CAISO uses snapshots of USF data from its EMS in establishing TRM values for this component of uncertainty.

The CAISO uses the simultaneous path interactions component of uncertainty to address the impact that transmission flows on an ATC path located outside the CAISO's Balancing Authority Area may have on the transmission transfer capability of an ATC path located at an Intertie. In the event of such path interactions, the CAISO uses a TRM value to prevent the risk of a system operating limit violation in Real Time for the CAISO ATC path. The amount of the TRM value may be set at a level up to, but not greater than, the forecasted impact on the CAISO ATC path's capacity imposed by expected flow on the non-CAISO ATC path.

The CAISO uses the following databases or information systems, or their successors, in connection with establishing TRM values: SLIC, Existing Transmission Contract Calculator (ETCC), PI, EMS, and CAS.

L.1.7 **Capacity Benefit Margin (CBM)** is that amount of transmission transfer capability reserved for Load Serving Entities (LSEs) to ensure access to Generation from interconnected systems to meet generation reliability requirements. In the Day-Ahead Market, CBM may be used to provide reliable delivery of Energy to CAISO Balancing Authority Area Loads and to meet CAISO responsibility for resource reliability requirements in Real-Time. The purpose of this DAM implementation is to avoid Real-Time Schedule curtailments and firm Load interruptions that would otherwise be necessary. CBM may be used to reestablish Operating Reserves. CBM is not available for non-firm transmission in the CAISO Balancing Authority Area. CBM may be used only after:

- all non-firm sales have been terminated,
- direct-control Load management has been implemented,

- customer interruptible Demands have been interrupted,
- if the LSE calling for its use is experiencing a Generation deficiency and its transmission service provider is also experiencing transmission Constraints relative to imports of Energy on its transmission system.

The level of CBM for each Transmission Interface is determined by the amount of estimated capacity needed to serve firm Load and provide Operating Reserves based on historical, scheduled, and/or forecast data using the following equation to set the maximum CBM:

CBM = (Demand + Reserves) - Resources

Where:

- Demand = forecasted area Demand
- Reserves = reserve requirements
- Resources = internal area resources plus resources available on other Transmission Interfaces

The CAISO does not use CBMs. The CBM value is set at zero.

L.2 ATC Algorithm

The ATC algorithm is a calculation used to determine the transfer capability remaining in the physical transmission network and available for further commercial activity over and above already committed uses. The CAISO posts the ATC values in megawatts (MW) to OASIS in conjunction with the closing events for the Day-Ahead Market and HASP Real-Time Market process.

The following OASIS ATC algorithms are used to implement the CAISO ATC calculation for the ATC rated path (Transmission Interface):

~~OTC = TTC – CBM – TRM - Operating Constraints~~

ATC Calculation For Imports:
ATC = ~~OTC~~TTC – CBM – TRM – AS from Imports- Net Energy Flow - Hourly Unused TR Capacity.

ATC Calculation For Exports:
ATC = ~~OTC~~TTC – CBM – TRM – Net Energy Flow - Hourly Unused TR Capacity.

ATC Calculation For Internal Paths 15 and 26:
ATC = ~~OTC~~TTC – CBM – TRM – Net Energy Flow

The specific data points used in the ATC calculation are each described in the following table.

ATC	ATC MW	Available Transfer Capability, in MW, per Transmission Interface and path direction.
Hourly Unused TR Capacity	USAGE_MW	The sum of any unscheduled existing transmission commitments (scheduled transmission rights capacity for ETC or TOR), in MW, per path direction.
Scheduled Net Energy from Imports/Exports (Net Energy Flow)	ENE IMPORT MW	Total hourly net Energy flow for a specified Transmission Interface.
AS from Imports	AS IMPORT MW	Ancillary Services scheduled, in MW, as imports over a specified Transmission Interface.
~~OTC~~TTC	~~OTC~~TTC MW	Hourly ~~Operating~~Total Transfer Capability of a specified Transmission Interface, per path direction, with consideration given to known Constraints and operating limitations.
~~Transmission Constraint~~	~~Constraint MW~~	~~Hourly Transmission Constraints, in MW, for a specific Transmission Interface and path direction.~~
CBM	CBM MW	Hourly Capacity Benefit Margin, in MW, for a specified Transmission Interface, per Path Direction.
TRM	TRM MW	Hourly Transmission Reliability Margin, in MW, for a specified Transmission Interface, per path direction.
~~TTC~~	~~TTC MW~~	~~Hourly Total Transfer Capability, in MW, of a specified Transmission Interface, per path direction.~~.

~~The links to the CAISO Website where the actual~~Actual ATC mathematical algorithms and other ATC calculational information are located ~~are as follows:~~

~~Operating Procedures – Transmission~~
~~http://www.caiso.com/thegrid/operations/opsdoc/transmon/index.html~~

~~Operating Procedure - Total Transfer Capability Methodology~~
~~http://www.caiso.com/1bfe/1bfe98134fa0.pdf~~

~~Operating Procedure - System Operating Methodology~~
~~http://www.caiso.com/1c13/1c1390d420810.pdf~~

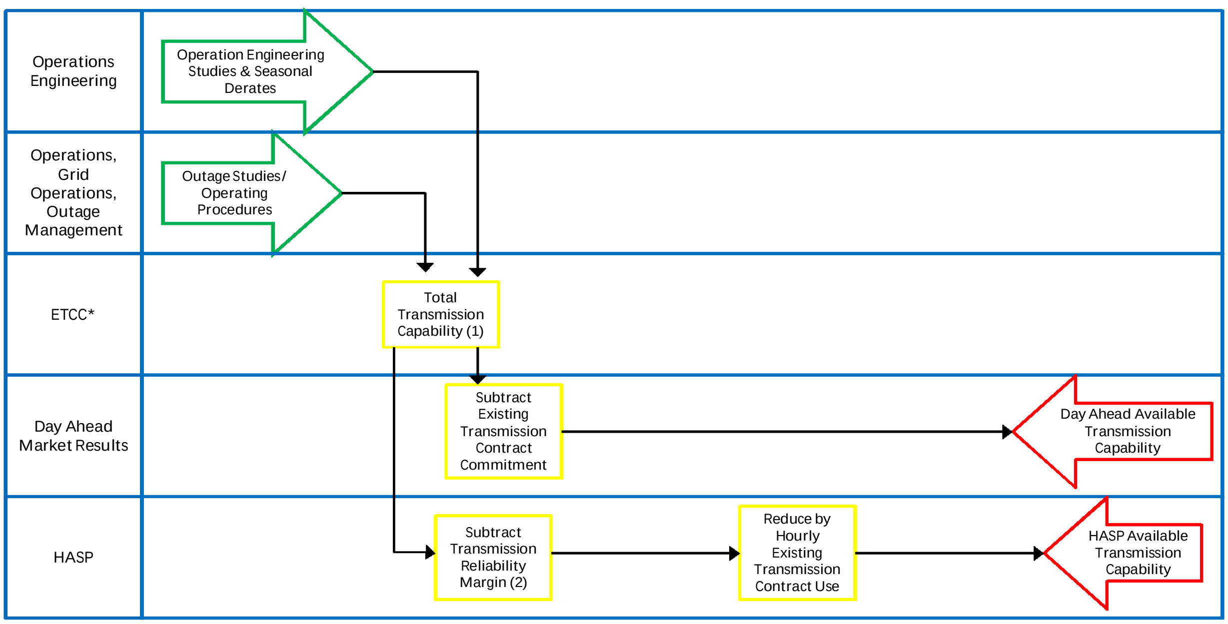
~~Business Practice Manual for Market Operations~~
~~https://bpm.caiso.com/bpm/bpm/version/000000000000005~~

in the CAISO's ATC Implementation Document (ATCID) posted on OASIS ~~– Transmission Information~~.
~~http://oasis.caiso.com/mrtu-oasis~~

L.3 ATC Process Flowchart

[Note to Stakeholders: This is a revised version of the ATC Process Flowchart that appears in Section L.3 of the ISO's current Appendix L. We are unable to show the changes in redline format.]

Available Transmission Capability



*ETCC – Existing Transmission Contract Calculator
(1) – WECC rated path methodology
(2) - See TRMID posted on OASIS

L.4 TTC~~ – OTC~~ Determination

All transfer capabilities are developed to ensure that power flows are within their respective operating limits, both pre-Contingency and post-Contingency. Operating limits are developed based on thermal, voltage and stability concerns according to industry reliability criteria (WECC/NERC) for transmission paths. The process for developing TTC ~~or OTC is the same with the exception of~~also requires i the inclusion or exclusion of operating Constraints based on system conditions being studied. ~~Accordingly, further description of the process to determine either OTC or TTC will refer only to TTC~~ .

L.4.1 Transfer capabilities for studied configurations may be used as a maximum transfer capability for similar conditions without conducting additional studies.

Increased transfer capability for similar conditions must be supported by conducting appropriate studies.

L.4.1.2 At the CAISO, studies for all major inter-area ~~paths~~paths' (mostly 500 kV) ~~OTC~~TTC are governed by the California Operating Studies Subcommittee (OSS) as one of four sub-regional study groups of the WECC OTCPC (i.e., for California sub-region), which provides detailed criteria and methodology. For transmission system elements below 500 kV the methodology for calculating these flow limits is detailed in Section L.4.3 and is applicable to the operating horizon.

L.4.2 Transfer capability may be limited by the physical and electrical characteristics of the systems including any one or more of the following:

- **Thermal Limits** – Thermal limits establish the maximum amount of electric current that a transmission line or electrical facility can conduct over a specified time-period as established by the Transmission Owner.

- **Voltage Limits** – System voltages and changes in voltages must be maintained within the range of acceptable minimum and maximum limits to avoid a widespread collapse of system voltage.

- **Stability Limits** – The transmission network must be capable of surviving disturbances through the transient and dynamic time-periods (from milliseconds to several minutes, respectively) following the disturbance so as to avoid generator instability or uncontrolled, widespread interruption of electric supply to customers.

L.4.3 **Determination of transfer capability** is based on computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. Each simulation represents a single "snapshot" of the operation of the interconnected network based on the projections of many factors. As such, they are viewed as reasonable indicators of network performance and may ultimately be used to determine Available Transfer Capability. The study is meant to capture the worst operating scenario based on the RTE experience and good engineering judgment.

L.4.3.1 **System Limits** – The transfer capability of the transmission network may be limited by the physical and electrical characteristics of the systems including thermal, voltage, and stability consideration. Once the critical Contingencies are identified, their impact on the network must be evaluated to determine the most restrictive of those limitations. Therefore, the ~~TTC1~~TTC becomes:

~~TTC_1~~TTC = lesser of {Thermal Limit, Voltage Limit, Stability Limit} following $N\text{-}1_{worst}$

L.4.3.2 ~~Parallel path flows will be considered in determining transfer capability and must be sufficient in scope to ensure that limits throughout the interconnected network are addressed. In some cases, the parallel path flows may result in transmission limitations in systems other than the transacting systems, which can limit the TTC between two transacting areas. This will be labeled TTC₂. Combined with **Section L**.4.3.1 above TTC becomes:}~~

~~TTC = lesser of {TTC_1 or TTC_2}~~

L.5 Developing a Power Flow Base-Case

L.5.1 **Base-cases** will be selected ~~used~~ to model reality to the greatest extent possible including attributes like area Generation, area Load, Intertie flows, etc. At other times (e.g., studying longer range horizons), it is prudent to stress a base-case by making one or more attributes (Load, Generation, line flows, path flows, etc.) of that base-case more extreme than would otherwise be expected.

L.5.2 Power Flow Base-Cases Separated By Geographic Region

The standard RTE base-cases are split into ~~five~~ geographical regions ~~in~~within the CAISO Controlled Grid ~~including the Bay Area, Fresno Area, North Area, SDG&E Area, and SCE Area~~.

L.5.3 Power Flow Base-Cases Selection Methodology

The RTE determines the studied geographical area of the procedure. This determines the study base-cases from the Bay Area, Fresno Area, North Area, SCE Area, or SDG&E Area.

The transfer capability studies may require studying a series of base-cases including both peak and off-peak operation conditions.

L.5.4 Update a Power Flow Base-Case

After the RTE has obtained one or more base-case studies, the base-case will be updated to represent the current grid conditions during the applicable season. The following will be considered to update the base-cases:

- Recent transmission network changes and updates
- Overlapping scheduled and Forced Outages
- Area Load level
- Major path flows
- Generation level
- Voltage levels
- Operating requirements

L.5.4.1 Outage Consideration

Unless detailed otherwise, the RTE considers modeling Outages of:

- Transmission lines, 500 kV
- Transformers, 500/230 kV
- Large Generating Units
- Generating Units within the studied area
- Transmission elements within the studied area

At the judgment of the RTE, only the necessary Outages will be modeled to avoid an unnecessarily burdensome and large number of base-cases.

L.5.4.2 Area Load Level

Base-case Demand levels should be appropriate to the current studied system conditions and customer Demand levels under study and may be representative of peak, off-peak or shoulder, or light Demand conditions. The RTE estimates the area Load levels to be utilized in the peak, partial-peak and/or off-peak base-cases. The RTE will utilize the current CAISO Load forecasting program (e.g., ALFS), ProcessBook (PI) or other competent method to estimate Load level for the studied area. Once the RTE has determined the correct Load levels to be utilized, the RTE may scale the scale the base-case Loads to the area studied, as appropriate.

L.5.4.3 Modify Path Flows

The scheduled electric power transfers considered representative of the base system conditions under analysis and agreed upon by the parties involved will be used for modeling. As needed, the RTE may estimate select path flows depending on the studied area. In the event that it is not possible to estimate path flows, the RTE will make safe assumptions about the path flows. A safe assumption is more extreme or less extreme (as conservative to the situation) than would otherwise be expected. If path flow forecasting is necessary, if possible the RTE will trend path flows on previous similar days.

L.5.4.4 Generation Level

Utility and non-utility Generating Units will be updated to keep the swing Generating Unit at a reasonable level. The actual unit-by-unit Dispatch in the studied area is more vital than in the un-studied areas. The RTE will examine past performance of select Generating Units to estimate the Generation levels, focusing on the Generating Units within the studied area. In the judgment of the RTE, large Generating Units outside the studied area will also be considered.

L.5.4.5 Voltage Levels

Studies will maintain appropriate voltage levels, based on operation procedures for critical buses for the studied base-cases. The RTE will verify that bus voltage for critical busses in within tolerance. If a bus voltage is outside the tolerance band, the RTE will model the use of voltage control devices (e.g., synchronous condensers, shunt capacitors, shunt reactors, series capacitors, generators).

L.6 Contingency Analysis

The RTE will perform Contingency analysis studies in an effort to determine the limiting conditions, especially for scheduled Outages, including pre- and post-Contingency power flow analysis modeling pre- and post-Contingency conditions and measuring the respective line flows, and bus voltages.

Other studies like reactive margin and stability may be performed as deemed appropriate.

L.6.1 Operating Criteria and Study Standards

Using standards derived from NERC and WECC Reliability Standards and historical operating experience, the RTE will perform Contingency analysis with the following operating criteria:

Pre-Contingency

- All pre-Contingency line flows shall be at or below their normal ratings.
- All pre-Contingency bus voltages shall be within a pre-determined operating range.

Post-Contingency

- All post-Contingency line flows shall be at or below their emergency ratings.
- All post-Contingency bus voltages shall be within a pre-determined operating range.

The RTE models the following Contingencies:

- Generating Unit Outages (including combined cycle Generating Unit Outages which are considered single Contingencies).
- Line Outages
- Line Outages combined with one Generating Unit Outage
- Transformer Outages
- Synchronous condenser Outages
- Shunt capacitor or capacitor bank Outages
- Series capacitor Outages
- Static VAR compensator Outages
- Bus Outages – bus Outages can be considered for the following ongoing Outage conditions.
    - o For a circuit breaker bypass-and-clear Outage, bus Contingencies shall be taken on both bus segments that the bypassed circuit breaker connects to.

- o For a bus segment Outage, the remaining parallel bus segment shall be considered as a single Contingency.
- o Credible overlapping Contingencies – Overlapping Contingencies typically include transmission lines connected to a common tower or close proximity in the same right-of-way.

L.6.2 Manual Contingency Analysis

If manual Contingency analysis is used, the RTE will perform pre-Contingency steady-state power flow analysis and determines if pre-Contingency operating criteria is violated. If pre-Contingency operating criteria cannot be preserved, the RTE records the lines and buses that are not adhering to the criteria. If manual post-Contingency analysis is used the RTE obtains one or more Contingencies in each of the base cases. For each Contingency resulting in a violation or potential violation in the operating criteria above, the RTE records the critical post-Contingency facility loadings and bus voltages.

L.6.3 Contingency Analysis Utilizing a Contingency Processor

For a large area, the RTE may utilize a Contingency processor.

L.6.4 Determination of Crucial Limitations

After performing Contingency analysis studies, the RTE analyzes the recorded information to determine limitations. The limitations are conditions where the pre-Contingency and/or post-Contingency operating criteria cannot be conserved and may include a manageable overload on the facilities, low post-Contingency bus voltage, etc. If no crucial limitations are determined, the RTE determines if additional studies are necessary.

L.7 Traditional Planning Methodology to Protect Against Violating Operating Limits

After performing Contingency analysis studies, the RTE next develops the transfer capability and develops procedures, Nomograms, RMR Generation requirements, or other Constraints to ensure that transfer capabilities respect operating limits.

L.8 Limits for Contingency Limitations

Transfer limits are developed when the post-Contingency loading on a transmission element may breach the element's emergency rating. The type of limit utilized is dependent on the application and includes one of the following limits:

- Simple Flow Limit - best utilized when the derived limit is repeatable or where parallel transmission elements feed radial Load.
- RAS or SPS – existing Remedial Action Schemes (RAS) or special protection systems (SPS) may impact the derivation of simple flow limits. When developing the limit, the RTE determines if the RAS or SPS will be in-service during the Outage and factors the interrelationship between the RAS or SPS and the derived flow

limit. RTE will update the transfer limits in recognition of the changing status and/or availability of the RAS or SPS.

Blackline of Revisions to Affected Sections of the Main Tariff

6.5.2.1 Communications Regarding the State of the CAISO Controlled Grid

The CAISO shall use OASIS to provide public information to Market Participants regarding the CAISO Controlled Grid or facilities that affect the CAISO Controlled Grid. Such information may include but is not limited to:

(a) Future planned Outages of transmission facilities;

(b) ~~Operating~~Total Transfer Capability (~~OTC~~TTC); and

(c) Available Transfer Capability (ATC) for WECC paths and Transmission Interfaces with external Balancing Authority Areas.

* * *

6.5.2.3.2 Network and System Conditions

By 6:00 p.m. the day prior to the target Day-Ahead Market, the CAISO will publish known network and system conditions, including but not limited to ~~OTC~~TTC and ATC, the total capacity of inter-Balancing Authority Area Transmission Interfaces, and the available capacity.

* * *

23. Categories Of Transmission Capacity

References to new firm uses shall mean any use of CAISO transmission service, except for uses associated with Existing Rights or TORs. Prior to the start of the Day-Ahead Market, for each Balancing Authority Area Transmission Interface, the CAISO will allocate the forecasted Total Transfer Capability of the Transmission Interface to four categories. This allocation will represent the CAISO's best estimates at the time, and is not intended to affect any rights provided under Existing Contracts or TORs. The CAISO's forecast of Total Transfer Capability for each Balancing Authority Area Transmission Interface will depend on prevailing conditions for the relevant Trading Day, including~~, but not limited to, the effects of parallel path (unscheduled) flows and/or other~~ limiting operational conditions. This information will be posted on OASIS in accordance with this CAISO Tariff. The four categories are as follows:

(a) transmission capacity that must be reserved for firm Existing Rights;

(b) transmission capacity that may be allocated for use as CAISO transmission service (i.e., "new firm uses");

(c) transmission capacity that may be allocated by the CAISO for conditional firm Existing Rights; and

(d) transmission capacity that may remain for any other uses, such as non-firm Existing Rights for which the Responsible PTO has no discretion over whether or not to provide such non-firm service.

* * *

30.8 Bids On Out-Of-Service Paths At Scheduling Points Prohibited

Scheduling Coordinators shall not submit any Bids or ETC Self-Schedules at Scheduling Points using a transmission path for any Settlement Period for which the ~~Operating~~Total Transfer Capability for that path is zero (0) MW. The CAISO shall reject

Bids or ETC Self-Schedules submitted at Scheduling Points where the ~~Operating~~Total Transfer Capability on the transmission path is zero (0) MW. If the ~~Operating~~Total Transfer Capability of a transmission path at the relevant Scheduling Point is reduced to zero (0) after Day-Ahead Schedules have been issued, then, if time permits, the CAISO shall direct the responsible Scheduling Coordinators to reduce all MWh associated with the Bids on such zero-rated transmission paths to zero (0) in the HASP. As necessary to comply with Applicable Reliability Criteria, the CAISO shall reduce any non-zero (0) HASP Bids across zero-rated transmission paths to zero after the Market Close for the HASP.

* * *

36.4 FNM For CRR Allocation And CRR Auction

When the CAISO conducts its CRR Allocation and CRR Auction, the CAISO shall use the most up-to-date DC FNM which is based on the AC FNM used in the Day-Ahead Market. The Seasonal Available CRR Capacity shall be based on the DC FNM, taking into consideration the following, all of which are discussed in the applicable Business Practice Manual: (i) any long-term scheduled transmission Outages, (ii) ~~OTC~~TTC adjusted for any long-term scheduled derates, (iii) a downward adjustment due to TOR or ETC as determined by the CAISO, and (iv) the impact on transmission elements used in the annual CRR Allocation and Auction of (a) transmission Outage or derates that are not scheduled at the time the CAISO conducts the Seasonal CRR Allocation or Auction determined through a methodology that calculates the breakeven point for revenue adequacy based on historical Outages and derates, and (b) known system topology changes, both as further defined in the Business Practice Manuals. The Monthly Available CRR Capacity shall be based on the DC FNM, taking into consideration: (i) any scheduled transmission Outages known at least thirty (30) days in advance of the start of that month as submitted for approval consistent with the criteria specified in Section 36.4.3, (ii) adjustments to compensate for the expected impact of Outages that are not required to be scheduled thirty (30) days in advance, including unplanned transmission Outages, (iii) adjustments to restore Outages or derates that were applied for use in calculating Seasonal Available CRR Capacity but are not applicable for the current month, (iv) any new transmission facilities added to the CAISO Controlled Grid that were not part of the DC FNM used to determine the prior Seasonal Available CRR Capacity and that have already been placed in-service and energized at the time the CAISO starts the applicable monthly process, (v) ~~OTC~~TTC adjusted for any scheduled derates or Outages for that month, and (vi) a downward adjustment due to TOR or ETC as determined by the CAISO. For the first monthly CRR Allocation and CRR Auction for CRR Year One, to account for any planned or unplanned Outages that may occur for the first month of CRR Year One, the CAISO will derate all flow limits, including Transmission Interface limits and normal thermal limits, based on statistical factors determined as provided in the Business Practice Manuals.

* * *

Blackline of Revisions to the Appendix A

Master Definitions Supplement

Available Transfer Capability (ATC)
The available capacity of a given transmission path, in MW, after subtraction from that path's Total Transfer Capability of capacity associated with Existing Contracts and Transmission Ownership Rights ~~from that path's Operating Transfer Capability~~ and any Transmission Reliability Margin, as established consistent with CAISO and WECC transmission capacity rating guidelines, as further described in Appendix L.

* * *

Monthly Available CRR Capacity
The upper limit of network capacity that will be used in the monthly CRR Allocation and monthly CRR Auctions calculated by using ~~OTC~~TTC adjusted for Outages, derates, and Transmission Ownership Rights for the relevant month in accordance with Section 36.4.

* * *

~~**Operating Transfer Capability (OTC)**~~
~~The maximum capability of a transmission path to transmit real power, expressed in MW, at a given point in time, as further defined in Appendix L.~~

* * *

Seasonal Available CRR Capacity
The upper limit of network capacity that will be used in the annual CRR Allocation and annual CRR Auction calculated by effectively reducing ~~OTC~~TTC for Transmission Ownership Rights as if all lines will be in service for the relevant year in accordance with Section 36.4.

* * *

Total Transfer Capability (TTC)
The amount of electric power that can be moved or transferred ~~over an~~reliably from one area to another area of the interconnected transmission ~~network in a reliable manner while meeting~~ systems by way of all ~~of a specific set of defined pre-Contingency and post-Contingency~~transmission lines (or paths) between those areas under specified system conditions.