2023 Local Capacity Area Technical Study

Final

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2023 Local Capacity Area Technical Study Manual
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Introduction

The Local Capacity Technical Study ("Technical Study" or "LCT Study") is intended to determine the minimum capacity needed in each identified transmission constrained "load pocket" or Local Capacity Area to ensure compliance with all mandatory reliability standards. The existence of Local Capacity Requirements (LCR) precedes restructuring of the California electric system in 1998. Prior to restructuring, the investor-owned utilities operated integrated systems where deliberate trade-offs were made between investing in transmission and generation. As a result, some areas were planned in a manner that consciously relied on local generation to supplement transmission capacity into the local area to satisfy demand and reliability requirements. Electric restructuring itself did not change the topology of the electric system and the physical need for local generation. Rather, it changed the means of access to such resources. The investor-owned utilities no longer owned much of the local generation, and consequently, prior to ISO start-up, it was determined that the ISO needed to have certain resources available to meet local reliability needs, and thus directly contracted with Reliability Must-Run or "RMR" generation for such purposes.

The adoption by the State of Resource Adequacy (RA) requirements facilitates resources being procured by Load Serving Entities (LSEs) rather than by the ISO through RMR contracts. The Technical Study is intended to work in conjunction with resource adequacy requirements to ensure that the ISO has access to sufficient local generation to ensure reliability standards are satisfied.

There are several components of the reliability standards underlying the Technical Study. Consistent with the mandatory nature of the NERC Planning Standards, the ISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards.[1] The ISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the NERC Planning Standards as well as Local Reliability Criteria, which reflect Reliability Criteria unique to the transmission systems of each Participating Transmission Owners ("PTOs"). Pursuant to its tariff authority, the ISO, in consultation with the PTOs and other stakeholders, has adopted ISO Grid Planning Standards intended to, among other things, interpret NERC Planning Standards and identify circumstances in which the ISO should apply standards more stringent than those adopted by NERC. Together, these pre-established criteria form Reliability Criteria to be followed in order to maintain desired performance of the ISO Controlled Grid under Contingency and steady state conditions. The NERC Planning Standards define reliability on interconnected bulk electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

The study process includes a number of opportunities for stakeholder input. This input is incorporated into the next phase of studies.

[1] Pub. Utilities Code § 345

Study Objectives

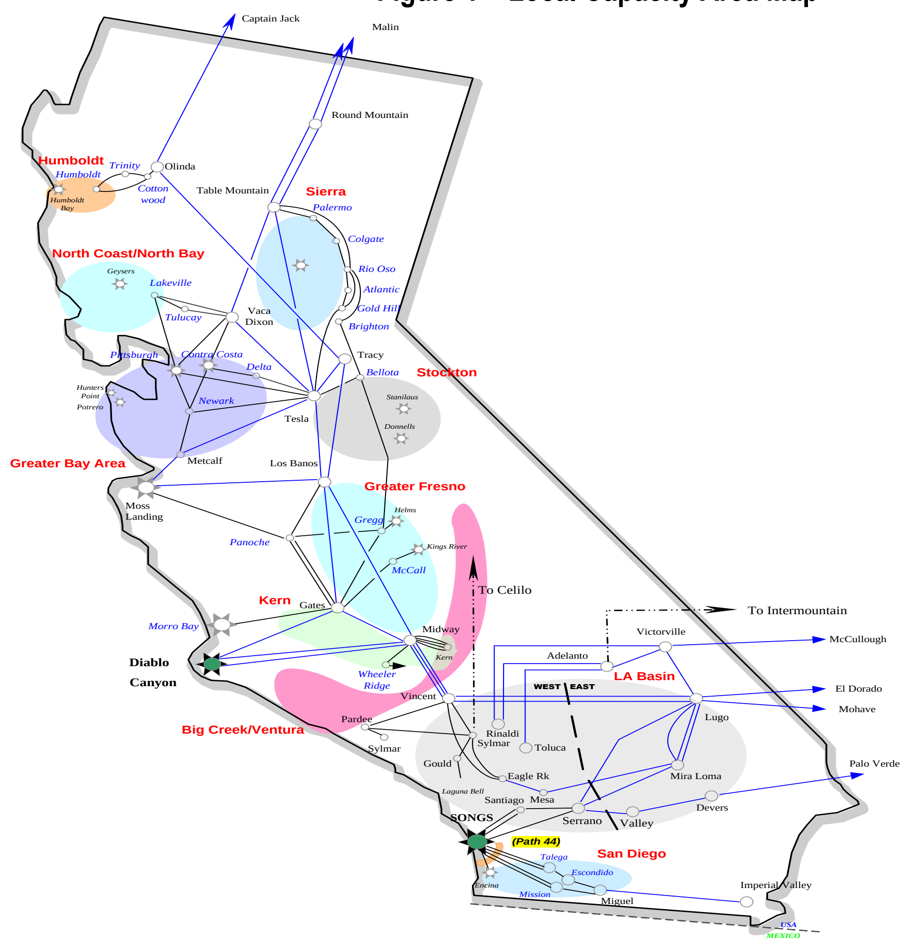
Similar to studies performed for 2006-2022, the purpose of the 2023 Local Capacity Technical Study ("Technical Study" or "LCT Study") is to identify specific areas within the ISO Controlled Grid that have local reliability needs and to determine the minimum generation capacity (MW) that would be required to satisfy these local reliability requirements, while enforcing generation deliverability status and Maximum Import Capability for all common mode contingencies (Category P0, P1, P7).

Technical Study Assessment and Required Capacity Summary

Preface

The technical analysis the ISO performed for the 2022 calendar year to determine the local reliability requirements evaluated ten local areas within the ISO Controlled Grid where operational history has shown that local reliability issues exist. Seven of these areas (Humboldt, North Coast/North Bay, Greater Bay, Sierra, Stockton, Fresno and Kern) are in PG&E's service area; two (LA Basin and Big Creek/Ventura) are in SCE service area and one (San Diego) in SDG&E service area. A number of these areas are further subdivided as needed into sub-areas. A map of the areas is shown in Figure 1 below.

Figure 1 – Local Capacity Area Map



Base Case Input Assumptions

Transmission System Configuration:

The existing transmission system shall be modeled, including all projects operational on or before June 1, 2023 and all other feasible operational solutions brought forth by the PTOs and as agreed to by the ISO.

The majority of local areas peak in the summer time. In order to be consistent with past practices for base case development the ISO will model all transmission projects operational on or before June 1. Exemption: Humboldt area peaks in the winter and therefore only projects up to January 1, 2023 are included.

Generation Modeled:

All existing generation resources shall be modeled (less announced retirements) and shall include all new generation projects that will be on-line and commercial on or before June 1, 2023. For new generation data should be available from the CEC web site: http://www.energy.ca.gov/sitingcases/all_projects.html or through the ISO interconnection process if no CEC license is required. Generation resources shall be dispatch up to the latest available net qualifying capacity not to exceed historical (projected for new resources) output values at the time of the managed peak load in the local area for purposes of the 2023 Technical Study.

Solar resources will be dispatched at their actual output at the time of the net local area or sub-area peak by using actual resource data from within the local area or sub-area or from a neighboring area or sub-area if none exists at the time of the study.

The majority of local areas peak in the summer time. In order to be consistent with past practices for base case development, the ISO will model all generation projects operational on or before June 1, 2023. One exemption is the Humboldt area, that peaks in the winter and therefore only new generation up to January 1, 2023 should be included in that area.

If the new generation resources account for a significant portion of the LCR needs, then the possibility exists that the ISO cannot manage the transmission system in the first few months of the year without additional (existing) generation (beyond the minimum contracted amount – required after June 1) being made available to the ISO. As such, the ISO may be required to augment the quantity of capacity available in the first few months.

Load Forecast:

Consistent with the ISO transmission planning process, the ISO will utilize the latest information available from the California Energy Commission for the Technical Study. As per the ISO Transmission Planning Standards for local area assessments, the 1-in-10 summer managed peak load will be used in the analysis for each of the local capacity areas with the exception of the Humboldt area where the winter peak will be used.

Methodology

Maximize Import Capability into the Local Area:

Import capability into the local area shall be maximized, thus minimizing the generation required in the local area to meet reliability requirements. In other words, after the most stringent contingencies have been taken, the limiting element should be loaded at 100% of its applicable rating for constraints driven by equipment loading limits. Also, the voltage and/or reactive margin should be at their respective minimum allowable levels, after the most restrictive contingencies have been taken, for voltage and/or reactive margin driven constraints.

It is possible that the LSEs will comply in purchasing the minimum capacity requirement from units that are less effective (or that do not solve all the area constraints). If this should happen, the ISO would be forced to augment the local capacity available to it to satisfy the reliability criteria. The ISO will seek to minimize this exposure by publishing data to facilitate more effective LSE procurement, such as single or multiple effectiveness factors for resources in local areas or sub-areas where excess capacity exists.

Consideration of Storage Charging Requirements:

In addition to effectiveness factors, additional consideration is needed for storage being considered in meeting local capacity requirements. For all requirements and contingencies other than extreme event considerations, the ISO expects that for batteries that qualify as local capacity resource adequacy resources, the transmission and the other local capacity resources must be sufficient to recharge the batteries in anticipation of the outage continuing into the next day’s peak load period. The ISO will only maintain charge capability, under category P1 system adjustment followed by P7 resulting in voltage collapse or dynamic instability for areas with peak load at or above 250 MW or if the voltage collapse and dynamic instability propagates beyond the area directly affected by the outage, for batteries that have acquired firm charging services from the grid (similar to firm load).

Maintaining Path Flows:

Path flows shall be maintained below all established path ratings into the local areas, including 500 kV elements. For clarification, given the existing transmission system configuration, the only 500 kV paths that flows directly into a local area and, therefore, considered in the LCT Study is the South of Lugo transfer path flowing into the LA Basin.

Paths that do not directly flow into a local area, but influence the local area LCR need, should be set at or below the established path rating such that it assures the path operator that it can sustain any flow on this path at peak time for this local area. Currently the only known path that influences but does not flow directly into a local area is Path 15. Based on previous LCT studies the maximum flow of 2500 MW S-N yields the highest amount of LCR needs for the Greater Fresno and this assumption assures that at Fresno peak time the ISO can support any Path 15 flow.

QF/Nuclear/State/Federal Units:

Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources shall be modeled on-line and shall be dispatch up to the latest available Net Qualifying Capacity (“NQC”) not to exceed historical (projected for new resources) output values at the time of the managed peak load in the local area for purposes of the 2023 Technical Study.

Units Owned or Under Long-term Contracts with LSEs:

Units owned or under long-term contracts with LSEs shall be modeled on-line and shall be dispatch up to the latest available NQC not to exceed historical (projected for new resources) output values at the time of the managed peak load in the local area for purposes of the 2023 LCR Study. This information may be provided by LSEs.

Maintaining Deliverability of Generation as well as Import Allocations Relied upon by RA:

Generation and import capability, relied upon in the RA program, deliverability status shall be maintained for all common mode contingencies (including all single contingencies as well as double circuit tower line and same right-of-way contingencies). The import capability utilized shall be the Maximum Import Capability calculated by the ISO for import assignment purposes. This value reflects the maximum deliverable quantity across each branch group.

The Maximum Import Capability has been demonstrated to be deliverable during high peak load conditions, while complying with reliability criteria. Also, all generators been demonstrated to be fully deliverable to the aggregate of load and therefore have established NQCs. For the Technical Study, the Maximum Import Capability and generation deliverability must be maintained to avoid the need to reduce the import flows across branch groups and deliverability of certain generators. The last approach is to be avoided because, in addition to market participant equitability issues, for the most part there will be rather large decreases in import allocations and generation deliverability for rather small decreases in local area LCR needs. After a single contingency during the “System Readjustment” all generating units as well as imports can be reduced (up to a limit – see system readjustment) in order to protect for the next most limiting contingency.

Load Pocket Boundary:

The 2023 Technical Study shall be produced based on load pockets defined by a fixed boundary.

It is preferred that the requirement for the Technical Study should be reasonably stable over time to encourage longer-term contracting by LSEs. Transmission configurations as well as unit and load effectiveness factors change every year due to new transmission projects added to the grid. As such, the only way to have a stable area is to define it as a fix boundary based on experience of known constraints into any one area. The area definition is subject to change only if new major transmission and/or generation projects significantly change the local area constraints.

There may be some units or loads located outside the local area boundary that may help reduce one or more of the constraints within the local area, but nevertheless not qualify as a Local Capacity Area Resource. However, in the great majority of cases, units and load outside the defined local area are less valuable in that they either do not mitigate the binding constraint or do not help to reduce flows on the majority of other potential constraints resulting from other less severe contingencies when compared to resources located within the local area. During the validation of local procurement, the ISO will use all units procured by all LSEs, regardless of location, in order to see if any further procurement is needed to satisfy Reliability Criteria.

ISO Statutory Obligation Regarding Safe Operation:

The ISO must maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times. For example, during normal operating conditions (8760 hours per year), the ISO must protect for all single contingencies (P1, P2) and multiple contingencies (P4, P5) as well as common mode double line outages (P7). As a further example, after a single contingency, the ISO must readjust the system in order to be able to support the loss of the next most stringent contingency (P3 , P6 and P1+P7 resulting in potential voltage collapse or dynamic instability).

Local Capacity Criteria to be studied

The following tables provides a comparison of system planning criteria, based on the NERC performance standards, used in the study:

Table 1: Criteria Comparison for Bulk Electric System contingencies

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	Current Local Capacity Criteria
P0 – No Contingencies	X	X	X
P1 – Single Contingency			
1. Generator (G-1)	X	X[1]	X[1]
2. Transmission Circuit (L-1)	X	X[1]	X[1]
3. Transformer (T-1)	X	X[1,2]	X[1]
4. Shunt Device	X		X[1]
5. Single Pole (dc) Line	X	X[1]	X[1]
P2 – Single contingency			
1. Opening a line section w/o a fault	X		X
2. Bus Section fault	X		X
3. Internal Breaker fault (non-Bus-tie Breaker)	X		X
4. Internal Breaker fault (Bus-tie Breaker)	X		X
P3 – Multiple Contingency – G-1 + system adjustment and:			
1. Generator (G-1)	X	X	X
2. Transmission Circuit (L-1)	X	X	X
3. Transformer (T-1)	X	X[2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X	X
P4 – Multiple Contingency - Fault plus stuck breaker			
1. Generator (G-1)	X		X
2. Transmission Circuit (L-1)	X		X
3. Transformer (T-1)	X		X
4. Shunt Device	X		X
5. Bus section	X		X
6. Bus-tie breaker	X		X

P5 – Multiple Contingency – Relay failure (delayed clearing)			
1. Generator (G-1)	X		X
2. Transmission Circuit (L-1)	X		X
3. Transformer (T-1)	X		X
4. Shunt Device	X		X
5. Bus section	X		X
P6 – Multiple Contingency – P1.2-P1.5 system adjustment and:			
1. Transmission Circuit (L-1)	X	x	X
2. Transformer (T-1)	X	x	X
3. Shunt Device	X		X
4. Bus section	X		X
P7 – Multiple Contingency - Fault plus stuck breaker			
1. Two circuits on common structure (L-2)	X	X	X
2. Bipolar DC line	X	X	X
Extreme event – loss of two or more elements			
Two generators (Common Mode) G-2	X[4]	X	X[4]
Any P1.1-P1.3 & P1.5 system readjusted (Common Mode) L-2	X[4]	X[3]	X[5]
All other extreme combinations.	X[4]		X[4]

1 System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.
2 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.
3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.
4 Evaluate for risks and consequence, per NERC standards.
5 Expanded to include any P1 system readjustment followed by any P7 without stuck breaker. For voltage collapse or dynamic instability situations mitigation is required "if there is a risk of cascading" beyond a relatively small predetermined area – less than 250 MW - directly affected by the outage.

Table 2: Criteria Comparison for non-Bulk Electric System contingencies

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	Current Local Capacity Criteria
P0 – No Contingencies	X	X	X
P1 – Single Contingency			
1. Generator (G-1)	X	X[1]	X
2. Transmission Circuit (L-1)	X	X[1]	X
3. Transformer (T-1)	X	X[1,2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X[1]	X

P2 – Single contingency 1. Opening a line section w/o a fault 2. Bus Section fault 3. Internal Breaker fault (non-Bus-tie Breaker) 4. Internal Breaker fault (Bus-tie Breaker)			
P3 – Multiple Contingency – G-1 + system adjustment and: 1. Generator (G-1) 2. Transmission Circuit (L-1) 3. Transformer (T-1) 4. Shunt Device 5. Single Pole (dc) Line	 X X X X X	 X X X[2] X	 X X X X X
P4 – Multiple Contingency - Fault plus stuck breaker 1. Generator (G-1) 2. Transmission Circuit (L-1) 3. Transformer (T-1) 4. Shunt Device 5. Bus section 6. Bus-tie breaker			
P5 – Multiple Contingency – Relay failure (delayed clearing) 1. Generator (G-1) 2. Transmission Circuit (L-1) 3. Transformer (T-1) 4. Shunt Device 5. Bus section			
P6 – Multiple Contingency – P1.2-P1.5 system adjustment and: 1. Transmission Circuit (L-1) 2. Transformer (T-1) 3. Shunt Device 4. Bus section		 x x	
P7 – Multiple Contingency - Fault plus stuck breaker 1. Two circuits on common structure (L-2) 2. Bipolar DC line		 X X	
Extreme event – loss of two or more elements Two generators (Common Mode) G-2 Any P1.1-P1.3 & P1.5 system readjusted (Common Mode) L-2 All other extreme combinations.		 X X[3]	

[1] System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.

[2] A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

[3] Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.

A significant number of simulations were run to determine the most critical contingencies within each local area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all tested contingencies were measured against the system performance requirements defined by the criteria shown in Tables 1 and 2. Where the specific system performance requirements were not met, generation was adjusted until performance requirements were met for the local area. The adjusted generation constitutes the minimum generation needed in the local area. The following describes how the criteria were tested for the specific type of analysis performed.

1. *Power Flow Assessment:*

Contingencies	Thermal Criteria[1]	Voltage Criteria[2]
P0	Applicable Rating	Applicable Rating
P1 [3]	Applicable Rating	Applicable Rating
P2	Applicable Rating	Applicable Rating
P3	Applicable Rating	Applicable Rating
P4	Applicable Rating	Applicable Rating
P5	Applicable Rating	Applicable Rating
P6 [4]	Applicable Rating	Applicable Rating
P7	Applicable Rating	Applicable Rating
P1 + P7 [4]	-	No voltage collapse

[1] Applicable Rating – Based on ISO Transmission Register or facility upgrade plans including all established path ratings.

[2] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

[3] Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions and be able to safely prepare for the loss of the next most stringent element and be within Applicable Rating after the loss of the second element.

[4] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. *Post Transient Flow Assessment:*

Contingencies	Reactive Margin Criteria [2]
Selected [1]	Applicable Rating

[1] If power flow results indicate significant low voltages for a given power flow contingency, simulate that outage using the post transient load flow program. The post-transient assessment will develop appropriate Q/V and/or P/V curves.

[2] Applicable Rating – positive margin based on the higher of imports or load increase by 5% for N-1 contingencies, and 2.5% for N-2 contingencies.

3. *Stability Assessment:*

Contingencies Selected [1]	Stability Criteria [2] Applicable Rating

[1] Base on historical information, engineering judgment and/or if power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency.
[2] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

Definition of Terms

Applicable Rating:

This represents the equipment rating that will be used under certain contingency conditions.

Normal rating is to be used under normal conditions.

Long-term emergency ratings, if available, will be used in all emergency conditions as long as "system readjustment" is provided in the amount of time given (specific to each element) to reduce the flow to within the normal ratings. If not available normal rating is to be used.

Short-term emergency ratings, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.

Temperature-adjusted ratings shall not be used because this is a year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.

ISO Transmission Register is the only official keeper of all existing ratings mentioned above.

Ratings for future projects provided by PTO and agree upon by the ISO shall be used.

Other short-term ratings not included in the ISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

Path Ratings need to be maintained in order for these studies to comply with the Operating Reliability Criteria and assure that proper capacity is available in order to operate the system in real-time.

System Readjustment:

This represents the actions taken by operators in order to bring the system within a safe operating zone after any given contingency in the system.

Actions that can be taken as system readjustment after a Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency:

1. System configuration change – based on validated and approved operating procedures
2. Generation re-dispatch

a. Decrease generation (up to 1150 MW) – limit given by single contingency SPS as part of the ISO Grid Planning standards (ISO SPS3)
b. Increase generation – this generation will become part of the LCR need

Actions, which shall not be taken as system readjustment after a Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency:

1. Load drop – based on the intent of the ISO/WECC and NERC criteria for category P1 contingencies.

An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. NERC and ISO Planning standards mandate that no load shedding should be done immediately after a Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency. The system should be planned with no load shedding regardless of when it may occur (immediately or within 15-30 minutes after the first contingency). It follows that load shedding may not be utilized as part of the system readjustment period – in order to protect for the next most limiting contingency. Therefore, if there are available resources in the local area, such resources should be used during the manual adjustment period (and included in the LCR need) before resorting to shedding firm load.

Firm load shedding is allowed in a planned and controlled manner after the first contingency in P2.2(HV), P2.3(HV), P2.4, P4.1-5(HV), P4.6, P5.1-5(HV) and after the second contingency in P6(non-high density area), P7(non-high density area) & P1 system adjusted followed by P7 category events.

This interpretation tends to guarantee that firm load shedding is used to address Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) conditions only under the limited circumstances where no other resource or validated operational measure is available. A contrary interpretation would constitute a departure from existing practice and degrade current service expectations by increasing load's exposure to service interruptions.

Time allowed for manual readjustment:

The time allowed for manual readjustment is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. The time should not be more than thirty (30) minutes.

The CAISO Planning Standards also impose this manual readjustment requirement. As a parameter of the Local Capacity Technical Study, the CAISO must assume that as the system operator the CAISO will have sufficient time to:

(1) make an informed assessment of system conditions after a contingency has occurred;

(2) identify available resources and make prudent decisions about the most effective system redispatch;

(3) manually readjust the system within safe operating limits after a first contingency to be prepared for the next contingency; and

(4) allow sufficient time for resources to ramp and respond according to the operator's redispatch instructions. This all must be accomplished within 30 minutes.

Local capacity resources can meet this requirement by either (1) responding with sufficient speed, allowing the operator the necessary time to assess and redispatch resources to effectively reposition the system within 30 minutes after the first contingency, or (2) have sufficient energy available for frequent dispatch on a pre-contingency basis to ensure the operator can meet minimum online commitment constraints or reposition the system within 30 minutes after the first contingency occurs. Accordingly, when evaluating resources that satisfy the requirements of the CAISO Local Capacity Technical Study, the CAISO assumes that local capacity resources need to be available in no longer than 20 minutes so the CAISO and demand response providers have a reasonable opportunity to perform their respective and necessary tasks and enable the CAISO to reposition the system within the 30 minutes in accordance with applicable reliability criteria.

The Executive Appeals Committee (Committee) of the CAISO convened on April 22, 2016 to consider the appeals to Proposed Revision Request (PRR) 854 to the CAISO's business practice manual for reliability requirements. The decision by the Committee defers implementation of PRR 854. As a result, the proposed amendment to the business practice manual was not implemented. The Committee reserved the right to adopt the PRR, with any necessary modifications, at the conclusion of the stakeholder process to address pre-contingency dispatch requirements for slower responding resources. While this stakeholder process is underway, the Committee's decision was that the CAISO will continue to conduct its Local Capacity Technical Study as required by Section 40.3.1.1 of its tariff, but the CAISO will use its discretion not to exercise its Capacity Procurement Mechanism authority to address annual resource deficiencies that are directly attributable to a discrepancy between a local regulatory authority's resource adequacy counting rules for demand response resources and CAISO's Local Capacity Technical Study. Instead, prior to the conclusion of the stakeholder process addressing pre-Contingency dispatch resources, the ISO will rely upon existing slower acting resources in the Local Capacity Technical Study assuming these resources have sufficient availability to provide pre-Contingency dispatch necessary to resolve Contingencies in the applicable 30-minute timeframe.

Special Protection Schemes:

All known SPS shall be used. New SPS must be verified and approved by the ISO and comply with the new SPS guideline described in the ISO Grid Planning Standards.

Effectiveness Factor:

Effectiveness factors are determined relative to the limiting equipment after applying the contingency(s). The ISO methodology for establishing the effectiveness factor of an individual unit increases the output of the tested unit and decreases (same amount) from all the other on-line units in the ISO Control Area (except the designated system swing). The amount of the "other" units' decreases is based on their Pgen multiplied by the ratio of the total P increase versus total Pgen for all on-line units in the control area.

Pump model:

During the Technical Study, pumps should be modeled as firm loads up to the maximum of CEC coincident peak load forecast for these pumps or the firm transmission service (if available).

Due to weather and environmental changes, it is somewhat unpredictable, in the year ahead timeframe, how much pump is needed and at what level a year ahead of time, as such the pump owner should have its firm transmission right service (where it exists), reserved even if this would exceed CEC load forecast. Coordinate with pump owner for further details.

Iterative process for interdependent areas and sub-area:

The LCR needs of the areas and sub-area that are electrically interdependent (for example LA Basin and San Diego-Imperial Valley or North Coast/North Bay and Bay Area) have been considered through a coordinated study process to ensure that the resource needs for each LCR area or sub-area not only satisfy its own reliability need but also provide support to the other area or sub-area since resource needs in one area or sub-area are dependent on the amount of resources that are dispatched for the adjacent area and sub-area or vice versa. Under most circumstances, the smaller area or sub-area is evaluated first for its LCR needs. The next bigger area and/or sub-area are evaluated next and so on. The biggest area and/or sub-area is generally evaluated last. The LCR needs in the smallest and intermediate areas and sub-area are then re-checked to ensure that the initial determination is still adequate. This iterative process may need to be cycled back a few times until a stable set of results are achieved that address all LCR needs in the interdependent areas and/or sub-areas.

Studies by Performance Level

Performance Level P0 – Normal conditions:

1. Set the base case based on the existing input assumptions.
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the level of Maximum Import Capability for the particular branch groups plus any increase due to new capability that may be related to new transmission projects. This step is done in order to protect the deliverability of imports to the aggregate of load.
3. Screen the local area for highest flows due to normal flow pattern. Find one or more elements (or approved path ratings) that could be normally overloaded if not enough generation is maintained in the local area.
4. For the most stringent element (s), find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last). Make sure all these units are on-line at their deliverable output – check deliverability studies for consistency. This is done in order to maintain the deliverability of units (otherwise if they sign contracts with LSE they could become undeliverable).
5. Go back to the units within the local area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of normal rating:
    a. QF/Nuclear/State/Federal units
    b. Units under known existing long-term contracts with LSEs
    c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This is the Category P0 requirement. Keep this so that it can be compared with category P1&P2&P3 and P4&P5&P6&P7&P1+P7 requirements. It will only be used if higher than Category P1&P2&P3 or P4&P5&P6&P7&P1+P7 requirements.
7. Repeat this for any sub area if required.

<u>Performance Level P1&P2&P3 – Single and generator out followed by another contingency conditions:</u>

1. Set the base case based on the existing input assumptions. (You can start with the base case used for category P0 study).
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the Maximum Import Capability for the particular branch groups with influence plus any increase due to new allocations that may be related to new transmission projects. – This step is done in order to protect the deliverability of imports to the aggregate of load.
3. Screen the area for highest emergency flows due to P1&P2&P3 contingency conditions. Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under these contingency conditions) if not enough generation is maintained in the area.
4. For the most stringent element(s), find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last). Make sure all these units are on-line at their deliverable output – check deliverability studies for consistency. This is done in order to maintain the deliverability of all units deemed so (otherwise if they sign contracts with LSE they could become undeliverable).
5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of emergency rating:
   a. QF/Nuclear/State/Federal units
   b. Units under known existing long-term contracts with LSEs
   c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This is the Category P1&P2&P3 requirement. Keep this so that it can be compared with category P0 and P4&P5&P6&P7&P1+P7 requirements. It will only be used if higher than Category P0 or P4&P5&P6&P7&P1+P7 requirements.
7. Repeat this for any sub area if required.

<u>Performance Level P4 – Loss of multiple elements caused by a stuck breaker (non-bus-tie breaker) conditions:</u>

1. Set the base case based on the existing input assumptions. (You can start with the base case used for category P0 study).
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the Maximum Import Capability for the particular branch groups plus any increase due to new allocations that may be related to new transmission projects. – This step is done in order to protect the deliverability of imports to the aggregate of load.
3. Screen the area for highest emergency flows due to P4 contingency conditions. Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under double contingency conditions) if not enough generation is maintained in the area. (Use all known automatic [including firm load shedding special protection schemes] or manual operating procedures that help reduce the flow on the most limiting element.)
4. For the most stringent element(s), find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last).
5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to

the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of emergency rating:

   a. QF/Nuclear/State/Federal units
   b. Units under known existing long-term contracts with LSEs
   c. Other market units without long-term contracts

6. Add the output of all units that reduce the flow. This will be the Category P4 requirement. Keep this so that it can be compared with category P5, P6, P7 & P1+P7 requirements. It will only be used if higher than other category P5, P6, P7 & P1+P7 requirements.
7. Repeat this for any sub area if required.

Performance Level P5 – Delayed fault clearing due to failure of a non-redundant relay conditions:

1. Set the base case based on the existing input assumptions. (You can start with the base case used for category P0 study).
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the Maximum Import Capability for the particular branch groups plus any increase due to new allocations that may be related to new transmission projects. – This step is done in order to protect the deliverability of imports to the aggregate of load.
3. Screen the area for highest emergency flows due to P7 common mode double contingency conditions. Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under double contingency conditions) if not enough generation is maintained in the area. (Use all known automatic [including firm load shedding special protection schemes] or manual operating procedures that help reduce the flow on the most limiting element.)
4. For the most stringent element(s), find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last).
5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of emergency rating:
   a. QF/Nuclear/State/Federal units
   b. Units under known existing long-term contracts with LSEs
   c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This will be the Category P5 requirement. Keep this so that it can be compared with category P4, P6, P7 & P1+P7 requirements. It will only be used if higher than other category P4, P6, P7 & P1+P7 requirements.
7. Repeat this for any sub area if required.

Performance Level P7 – Any two adjacent circuits on common structure conditions:

1. Set the base case based on the existing input assumptions. (You can start with the base case used for category P0 study).
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the Maximum Import Capability for the particular branch groups plus any increase due to new allocations that may be related to new transmission projects. – This step is done in order to protect the deliverability of imports to the aggregate of load.

3. Screen the area for highest emergency flows due to P7 common mode double contingency conditions. Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under double contingency conditions) if not enough generation is maintained in the area. (Use all known automatic [including firm load shedding special protection schemes] or manual operating procedures that help reduce the flow on the most limiting element.)
4. For the most stringent element(s), find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last). Make sure all these units are on-line at their deliverable output – check deliverability studies for consistency. This is done in order to maintain the deliverability of all units deemed so (otherwise if they sign contracts with LSE they could become undeliverable).
5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of emergency rating:
    a. QF/Nuclear/State/Federal units
    b. Units under known existing long-term contracts with LSEs
    c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This will be the Category P7 common mode requirement. Keep this so that it can be compared with category P4, P5, P6 & P1+P7 requirements. It will only be used if higher than other category P4, P5, P6 & P1+P7 requirements.
7. Repeat this for any sub area if required.

Performance Level P6 – Any two single contingencies (non-P3) with system readjustment conditions:

1. Start with the base cases set for category P1 study.
2. Screen the area for highest emergency flows due to all applicable double contingency conditions. Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under double contingency conditions) if not enough generation is maintained in the area. (Use all known automatic [including firm load shedding special protection schemes] or manual operating procedures that help reduce the flow on the most limiting element.)
3. For the most stringent element (s) find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last).
4. After the first contingency, do the following system readjustment before taking the next worst contingency:
    a. System configuration change – based on validated and approved operating procedures
    b. Decrease generation from units in the ISO BAA that aggravate the constraint (deliverability is not protected for this P6 category)[2].
    c. Stop decreasing a certain generator when:
        i. Another flow limit in the system has been reached.
        ii. Resources are required by any subsequent P1 contingency or P7 contingency resulting in voltage collapse or dynamic instability.

[2] Maximum Import Capability on an intertie (branch group) that aggravates the constraint may also be reduced per existing operating procedure agreed upon by both neighboring control areas.

iii. Total net generation decrease reaches 1150 MW – limit given by single contingency SPS as part of the ISO Grid Planning standards (ISO SPS3).

d. Increase generation from units that help reduce the flow on the most stringent element – this generation will become part of the LCR need (read next bullet).

5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of emergency rating:
   a. QF/Nuclear/State/Federal units
   b. Units under known existing long-term contracts with LSEs
   c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This will be the Category P6 requirement. Keep this so that it can be compared with category P4, P5, P7 & P1+P7 requirements. It will only be used if higher than other Category P4, P5, P7 & P1+P7 requirements.
7. Repeat this for any sub area if required.

<u>Protect against voltage collapse for performance level P1 followed by P7 conditions:</u>

1. Start with the base cases set for category P1 study.
2. Screen the area for voltage collapse only based on applicable single contingencies followed by P7 (double circuit tower line outages) contingency conditions if not enough generation is maintained in the area. (Use all known automatic [including firm load shedding] special protection schemes and/or operating procedures that help avoid voltage collapse.)
3. For the most stringent element (s) find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last).
4. After the first contingency, do the following system readjustment before taking the next worst P7 contingency:
   a. System configuration change – based on validated and approved operating procedures
   b. Decrease generation from units in the ISO BAA that aggravate the constraint only[3]. Stop decreasing a certain generator when:
      i. Another flow limit in the system has been reached.
      ii. Resources are required by any subsequent P1 contingency or P7 contingency resulting in voltage collapse or dynamic instability.
      iii. Total generation decrease reaches 1150 MW – limit given by single contingency SPS as part of the ISO Grid Planning standards (ISO SPS3).
   c. Increase generation from units that help maintain voltage stability – this generation will become part of the LCR need (read next bullet).
5. Go back to the units within the area that help eliminate the voltage collapse situation. Turn on these units up to their NQC (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the voltage collapse situation has been eliminated:

[3] Maximum Import Capability on an intertie (branch group) that aggravates the constraint may also be reduced per existing operating procedure agreed upon by both neighboring control areas.

   a. QF/Nuclear/State/Federal units
   b. Units under known existing long-term contracts with LSEs
   c. Other market units without long-term contracts
6. Add the output of all units that help maintain the voltage stability in the local area. This will be the Category P1 + P7 requirement. Keep this so that it can be compared with category P4, P5, P6 & P7 requirements. It will only be used if higher than Category P4, P5, P6 & P7 requirements.
7. Repeat this for any sub area if required.

Total Area LCR Requirement:

For any given area or sub area compare the requirement for Category P0, P1&P2&P3 and P4&P5&P6&P7&P1+P7. The most stringent one will dictate that area LCR need.

General helpful tips:

If the area of study has one or more sub areas, then start with the smallest and/or most easy (radial) sub areas. All the units required in order to meet the sub area requirements should be turned on and accounted as part of the bigger sub area or entire area requirements (if they help reduce the flow on the most stringent element.)

If these units (those needed in a sub area) aggravate other sub area requirements, then be very careful during system re-dispatch so that the decrease of this generation does not cause problems in the previous sub area.

Service Reliability

This is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (involving customer load interruption) developed and approved by the ISO, in consultation with the PTOs. Under this option, there is no expected load interruption to end-use customers as the ISO operators prepare for the second contingency. However, the customer load may be interrupted after the second contingency occurs.