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Introduction

This document captures the criteria, as adapted by the CAISO, to calculate the **Total Transfer Capability (TTC)**. Transfer capability is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). In this context, “area” may be an individual electric system, pocket (as defined by a cut plane), power pool, control area, subregion, or NERC Region, or a portion of any of these. A Transmission Path can be an individual transmission element or for a combination of elements. Transfer capability is also directional in nature. That is, the transfer capability from Area A to Area B is not generally equal to the transfer capability from Area B to Area A.

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 Western Electricity Coordinating Council (WECC) refers to Transfer Capability across an inter-area path as the Operating Transfer Capability (OTC). At CAISO, an intra-area operating constraint is described as a flow limit, a simultaneous flow limit, or a nomogram constraint by way of an outage distribution factor.

At CAISO, studies for all major inter-area paths (mostly 500 kV) OTC are governed by the OSS Handbook for California Sub-regional Study Group, which provides detailed criteria and methodology. For transmission system elements below 500 kV, most of the flow limits are constrained by thermal limitations. This procedure documents the methodology for calculating these flow limits and is applicable to the operating horizon.

NERC Definition[1]

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments[2] (which includes retail customer service) and the Capacity Benefit Margin (CBM).

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

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[1] “ATC Definition and Determination”, NERC, June 1996

[2] CAISO Commitment is defined as:

Prior to MRTU → TTC – ETC = ATC
After MRTU DA → TTC- (Used & Unused ETC) – TOR = ATC
After MRTU HASP → TTC - Unused ETC –TOR = ATC

transmission system by way of all transmission lines (or paths) between those areas under specific system conditions.

Transmission Reliability Margin (TRM) is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Capacity Benefit Margin (CBM) is defined as that amount of transmission transfer capability reserved by load-serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Transfer Capability versus Transmission Capacity

NERC standards address the use of common terminology to calculate and report transmission transfer limits to maintain the reliability of the interconnected transmission networks. These transfer values are called “capabilities” (differentiating them from “capacities”) because they are highly dependent on the generation, customer demand, and transmission system conditions assumed during the analyzed time-period. The electric industry generally uses the term “capacity” as a specific limit or rating of power system equipment. In transmission, capacity usually refers to the thermal limit or rating of a particular transmission element or component. The ability of a single transmission line to transfer electric power, when operated as part of the interconnected network, is a function of the physical relationship of that line to the other elements of the transmission network.

Individual transmission line capacities or ratings cannot be added to determine the transfer capability of a transmission path or interface (transmission circuits between two or more areas within an electric system or between two or more systems). Such aggregated capacity values may be vastly different from the transmission transfer capability of the network. Often, the aggregated capacity of the individual circuits of a specific transmission interface between two areas of the network is greater than the actual transfer capability of that interface. In summary, the aggregated transmission line capabilities of a path or interface do not represent the transfer capabilities between two areas.

Limits to Transfer Capability

The ability of interconnected transmission networks to reliably transfer electric power 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 before it sustains permanent damage by overheating or before it violates public safety requirements.
- **Voltage Limits** – System voltages and changes in voltages must be maintained within the range of acceptable minimum and maximum limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread

collapse of system voltage can result in a partial or complete blackout of the interconnected network.

- **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. All generators connected to the AC interconnected transmission systems operate in synchronism with each other at the same frequency (nominally 60Hz). Immediately following a system disturbance, generators begin to oscillate relative to each other, causing fluctuations in system frequency, line loadings and system voltages. For the system to be stable, the oscillations must diminish as the electric systems attain a new, stable operating point. If a new, stable operating point is not quickly established, the generators will likely lose synchronism with one another, and all or a portion of the interconnected electric system may become unstable. Generator instability may damage equipment and cause uncontrolled, widespread interruption of electric supply to customers.

Determination of Transfer Capability

The calculation of transfer capability is generally 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 available transfer capability.

The conditions on the interconnected network continuously vary in real time. Therefore, the transfer capability of the network will also vary from one instant to the next. For this reason, transfer capability calculations may need periodic updates for application in the operation of the network. In addition, depending on actual network conditions, transfer capabilities can often be higher or lower than those determined in the off-line studies. The farther into the future that simulations are projected, the greater is the uncertainty in actual conditions that will be present during real-time operations. However, transfer capabilities determined from simulation studies are generally viewed as reasonable indicators of actual network capability. The snapshot is meant to capture the worst operating scenario based on the RTE experience and good engineering judgment.

- 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 Total Transfer Capability (TTC) becomes:

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

- Parallel Path Flows – When electric power is transferred across the network, parallel path flow occurs proportional to the relative impedance of the parallel paths. This complex electric transmission network phenomenon can affect all systems of an interconnected network, especially those systems electrically near the transacting systems. As a result, transfer capability determination 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 transfer capability between the two contracting areas.

Procedure

1. Developing a Power Flow Base-Case

1.1. General

The first step in calculating Transfer Capabilities for local area procedures is for the RTE to obtain one or more base-cases. A base-case should model reality to the greatest extent possible including attributes like area generation, area load, intertie flows, outage conditions, 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.

1.2. Power Flow Base-Cases Separated By Geographic Region

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

- For the Bay Area, one summer off-peak and eight summer-peak base-cases are typically available. The summer-peak base-cases each have different Bay Area load levels, which range from 5500 MW to 9000 MW in 500 MW increments.
- For the North Area, two standard base-cases are available. The first base-case models the winter operation conditions of the North Area grid, and the second base-case models the summer operation conditions of the North Area grid.
- For the Fresno Area two base-cases are available: Helms Generation (Peak) and Helms Pumping (off-peak). Each base-case has different permutations of Fresno Generation, Fresno Load, and Path 15 Flow.
- For the SCE and SDG&E Areas, three standard base-cases are available. The first base-case models the winter operation conditions of the SCE and SDG&E grids, the second base-case models the summer operation conditions of the SCE and SDG&E grids, and the third base-case models the spring operation conditions of the SCE and SDG&E grids.

1.3. 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.

2. Update a Power Flow Base-Case

2.1. General

After the RTE has obtained one or more base-case studies, the next step in calculating Transfer Capabilities for local area procedures is for the RTE to update each base-case to represent the current grid conditions during the applicable season. To update the base-cases, consider the following:

A) Incorporate Recent Transmission Network Changes and Updates
B) Model the Overlapping Scheduled and Forced Outages
C) Update Area Load Level
D) Modify Major Path Flows
E) Update Generation level
F) Maintain Voltage Levels
G) Uphold Procedure Operating Requirements

Updating base-cases is an iterative process. Often times a base-case will not solve if significant changes are made between one solution and the next. The RTE may need to go through the steps outlined above multiple times to finally get the base-case updated and tuned. The RTE should note that any incremental updates, which force large changes in the swing unit’s generation, might cause base-case solution problems.

2.2. Incorporate Recent Transmission Network Updates

The base-case configuration of the interconnected systems should represent the simulated conditions, including any expected facility outages. The activation of any operating procedure actions, such as RAS/SPS normally expected to be in effect, should also be included in the base-case simulations.

2.3. Model Ongoing Scheduled Outages

The RTE models the ongoing scheduled outages, which clearly impact the study results of the Transfer Capability for the local area procedure being reviewed. A significant number of generation and transmission system contingencies should be screened, considering individual electric system, pockets (as defined by a cut plane), and subregional areas, to ensure that the facility outage most restrictive to the transfer being studied is identified and analyzed. The contingencies evaluated may in some instances include multiple contingencies where deemed to be appropriate.

At a minimum, the RTE considers modeling the following ongoing scheduled outages:

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

The above list is not absolute. In some cases, the RTE should model ongoing outages from other areas. In other cases, the RTE may not need to model any of the ongoing outages at all. An RTE's area experience is crucial for determining the influence of ongoing outages on the Transfer Capability for a local area procedure under review.

An ongoing outage may not necessarily overlap 100% of the time with the procedure season under review. As a result, the RTE creates and updates separate base-cases with each permutation of ongoing outages to capture all the applicable outage conditions. It is essential for the RTE to model only the necessary outages (not all the outages); otherwise, there could be a large number of base-cases placing an unrealistic demand on the RTE.

2.4. Update the 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.

Even though the RTE may have selected a base-case based on area loads, the area load levels in the base-case will need to be refined further. For the most part, the RTE primarily is concerned with scaling the load of the area being studied (e.g. Fresno). In some cases, it might be important to scale loads in neighboring areas also.

The RTE estimates the area load levels to be utilized in the peak, partial-peak and/or off-peak base-cases. As indicated above, the RTE utilizes the ISO's load forecasting program (ALFs), ProcessBook (PI) or any 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 employs various EPCL programs within PSLF to scale the base-case loads.

2.5. Modify Path Flows

Use the scheduled electric power transfers considered representative of the base system conditions under analysis and agreed upon by the parties involved for modeling.

On the other hand, it may be necessary for an RTE to estimate select path flows depending on the studied area. In some instances, it may not be possible to estimate Path flows with any level of certainty. If this is the case, the RTE makes some assumptions about the Path flows. It may be a safe assumption to make the Path flows more extreme or less extreme than would otherwise be expected.

If path flow forecasting is necessary the RTE should utilize PI to trend the Path flows indicated above on previous similar days. Based on those similar days and the outage parameters, the RTE estimates the Path flows and may seek the advice of CAISO Bulk RTEs regarding estimated Path flows.

2.6. Update Generation Level

Realistically dispatch utility and non-utility generators for the simulated system conditions.

After updating the load level and modifying Path flows, the RTE updates the generation level in one or more areas to keep the swing generator at a reasonable level. The actual unit-by-unit dispatch in the studied area is more vital than the un-studied areas.

The RTE examines the past performance of select generators in PI to estimate the generation levels, focusing on the generators within the studied area. Also, consider large generating units outside the studied area. The farther the scheduled outage is in the future the more erroneous this method becomes.

2.7. Maintain Voltage Levels

Maintain appropriate voltage levels, based on operation procedures, on critical buses for the studied base-cases. If a bus voltage is outside the tolerance band, the RTE utilizes the voltage control devices including, but not limited to, Synchronous Condensers, Shunt Capacitors, Shunt Reactors, Series Capacitors, Generators, etc. Additionally, the RTE verifies the PSLF scheduled bus voltage for the select buses to ensure the voltage for the critical buses are within the tolerance band.

3. Contingency Analysis

3.1. General

After the RTE has updated one or more base-cases, the next step in determining Transfer Capability for local area procedures is for the RTE to perform contingency analysis studies in an effort to determine the limiting conditions for the outage.

- Pre-contingency load flow analysis involves modeling pre-contingency steady state conditions and measuring the respective line flows, bus voltages, etc.
- Post-contingency load flow analysis involves modeling post-contingency conditions and measuring the respective line flows, bus voltages, etc.

Other studies like reactive margin, stability, etc. are complex studies not typically performed for local area procedure revisions. In some instances, these studies may be necessary, and the methodology can be found in the OSS manual.

3.2. Operating Criteria and Study Standards

To perform contingency analysis in a consistent manner, the RTE adheres to the standards below. These standards are derived from NERC and WECC Reliability Standards, and historical operating experience.

Pre-Contingency Operating Criteria

- 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 Operating Criteria

- 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.

Contingency Analysis

The RTE models the contingencies when performing contingency analysis, including:

- Generator Outages (G-1) (including Combined Cycle Generating Plant Outages which are considered single contingencies).
- Line Outages (L-1)
- Line Outages combined with one generator outage (L-1+G-1)
- Transformer Outages (T-1)

- 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.
  - For a circuit breaker bypass-and-clear outage, bus contingencies shall be taken on both bus segments that the bypassed circuit breaker connects to.
  - For a bus segment outage, the remaining parallel bus segment shall be considered as a single contingency.
- Credible Overlapping Contingencies – Overlapping Contingencies typically include transmission lines connected to a common tower or close proximity in the same right-of-way.

3.3. Manual Contingency Analysis

Pre-Contingency Steady State Load Flow Analysis

Within PSLF, the RTE performs pre-contingency steady state load flow analysis and determines if the pre-contingency operating criteria is not violated. If the pre-contingency operating criteria cannot be preserved, the RTE records the lines and buses that are not adhering to the criteria. And then does what with that?

Post-Contingency Steady State Load Flow Analysis

Within PSLF, the RTE manually 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. Refer to 3.5

3.4. Contingency Analysis Utilizing a Contingency Processor

For a large area, manually performing contingency studies for all contingencies study in the area is arduous and would be inefficient. To perform these studies in a more efficient fashion, the RTE utilizes a contingency processor. The “Pflopro12-2.p” EPCL is the CAISO adopted contingency processor.

Among other functions, “Pflopro12-2.p” automatically performs contingency analysis similar to the description of the manual process above. Refer to 3.5

3.5. Determination of Crucial Limitations

After performing contingency analysis studies, the RTE analyzes the recorded information (contingencies, facility loadings, and bus voltages) in an effort to determine the crucial 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. The RTE must analyze the data to determine the limitations relevant to the studied outage and then utilize these limitations to develop procedure requirements.

If no crucial limitations are determined, the RTE determines if additional studies are necessary. If additional studies are necessary, the RTE may need to select, update and/or study additional base-cases to determine the crucial limitations.

4. Employ Traditional Methods to Protect Against Violating Operating Limits

4.1. General

After performing contingency analysis studies, the RTE next develops the Transfer Capability for local area procedures to develop limits, nomograms, RMR requirements, and other constraints to ensure that Transfer Capabilities respect operating limits.

4.2. Identify Operating Limits

The RTE identifies operating limits which may be threatened pre-contingency.

To protect against exceeding the limitation, the RTE identifies the line(s) and/or bus(es) to monitor during the outage, and may provide tools, such as building a PI screen.

4.3. Limits for Contingency Limitations

Develop limits for a procedure 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 indicated below.

- Simple Flow Limit - Simple Flow Limits are best utilized when the derived limit is repeatable. Often times derived Simple Flow Limits are not repeatable at different load levels and/or generation patterns. Simple Flow Limits work best in applications where parallel transmission elements feed radial load. If a transmission element is lost, 100% the pre-contingency power shifts over to the remaining elements feeding the load after the contingency.

- Accounting for RAS or SPS – In some cases, existing RAS or SPS systems 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 understands the interrelationship between the RAS or SPS and the derived Flow Limit.

4.4. Simple Flow Limit Derivation Process

Flow Chart 1 (Diagram 1) indicates the Simple Flow Limit Derivation Process. The process should be reliable for most Simple Flow Limit Derivations.

Flow Chart 1 - Simple Flow Limit Derivation Process

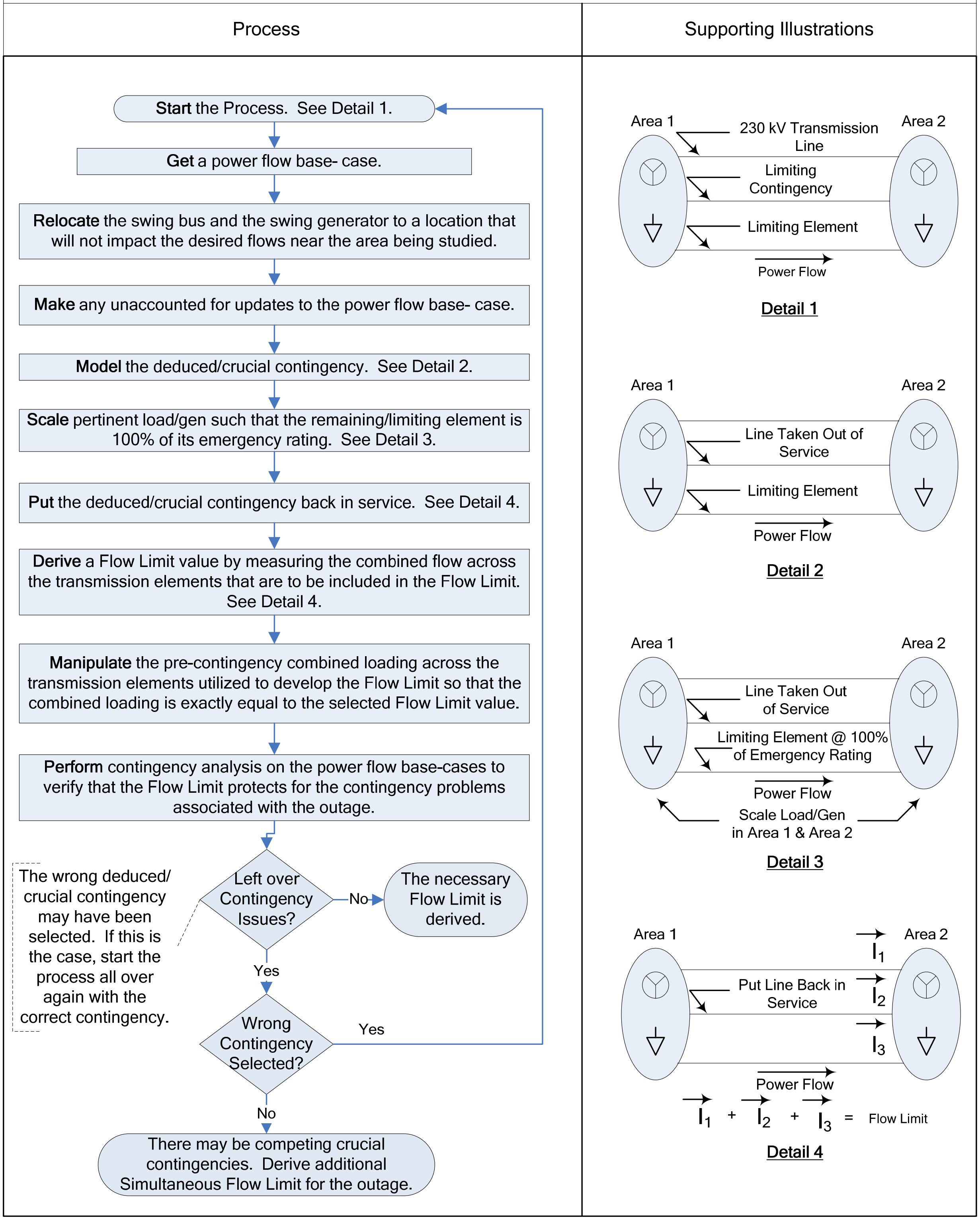


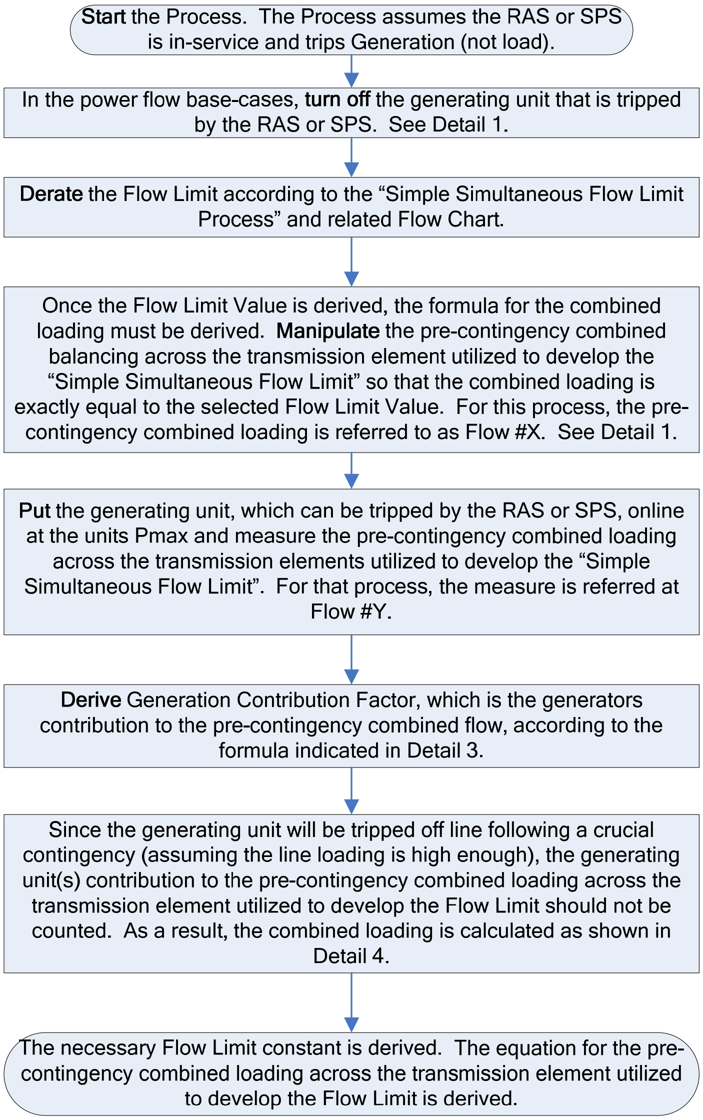
Diagram 1

4.5. Simple Flow Limit with a RAS or SPS Derivation Process

1) Flow Chart 2, (Diagram 2) indicates the Simple Flow Limit with a RAS or SPS Derivation Process. A process description is also given below.

Flow Chart 2 - Simple Flow Limit with a RAS or SPS Derivation Process

Process	Supporting Illustrations



Start the Process. The Process assumes the RAS or SPS is in-service and trips Generation (not load).

In the power flow base-cases, **turn off** the generating unit that is tripped by the RAS or SPS. See Detail 1.

Derate the Flow Limit according to the “Simple Simultaneous Flow Limit Process” and related Flow Chart.

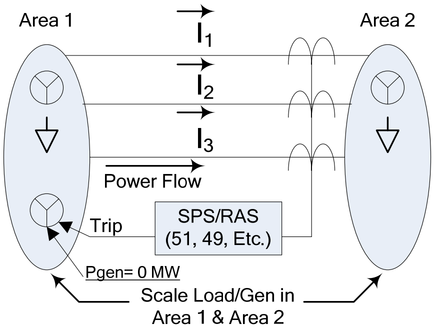
Once the Flow Limit Value is derived, the formula for the combined loading must be derived. **Manipulate** the pre-contingency combined balancing across the transmission element utilized to develop the “Simple Simultaneous Flow Limit” so that the combined loading is exactly equal to the selected Flow Limit Value. For this process, the pre-contingency combined loading is referred to as Flow #X. See Detail 1.

Put the generating unit, which can be tripped by the RAS or SPS, online at the units Pmax and measure the pre-contingency combined loading across the transmission elements utilized to develop the “Simple Simultaneous Flow Limit”. For that process, the measure is referred at Flow #Y.

Derive Generation Contribution Factor, which is the generators contribution to the pre-contingency combined flow, according to the formula indicated in Detail 3.

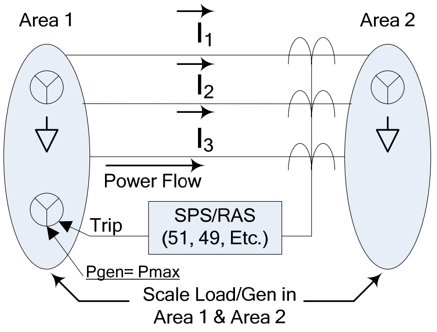
Since the generating unit will be tripped off line following a crucial contingency (assuming the line loading is high enough), the generating unit(s) contribution to the pre-contingency combined loading across the transmission element utilized to develop the Flow Limit should not be counted. As a result, the combined loading is calculated as shown in Detail 4.

The necessary Flow Limit constant is derived. The equation for the pre-contingency combined loading across the transmission element utilized to develop the Flow Limit is derived.



$$\vec{I}_1 + \vec{I}_2 + \vec{I}_3 = \text{Flow \#X}$$

Detail 1



$$\vec{I}_1 + \vec{I}_2 + \vec{I}_3 = \text{Flow \#Y}$$

Detail 2

$$\text{Factor \#Z} = \frac{(\text{Flow \#Y} - \text{Flow X})}{\text{Pmax}}$$

Where Factor #Z - Contribution Factor

Detail 3

$$\text{Combined Loading} = \vec{I}_1 + \vec{I}_2 + \vec{I}_3 - (\text{Flow \#Z} \times \text{Pgen})$$

Factor #Z = previous derived constant
Pgen = Generating Units Actual Generation

Detail 4

Diagram 2

Supporting Information

RESPONSIBILITIES

RTE	Regional Transmission Engineer

REFERENCES

FAC-012	Transfer Capability Methodology

DEFINITIONS

Unless the context otherwise indicates, any word or expression defined in the Master Definitions Supplement to the CAISO Tariff shall have that meaning when capitalized in this Operating Procedure.

VERSION HISTORY

Version	Change	By	Date
1.0	1st Draft.		6/8/07

Technical Review

Reviewed By Content Expert	Signature	Date
Operations Support		6/12/07
Regional Transmission		6/12/07
Grid Ops		6/13/07
Market Ops		6/16/07
Outage Management		6/12/07
Scheduling		6/14/07

Approval

Approved By	Signature	Date
Director of Regional Transmission		6/12/07
Director of Grid Operations		-