Section L2: PROTECTION AND CONTROL REQUIREMENTS FOR LOAD ENTITIES AND TRANSMISSION ENTITIES

Purpose

This section specifies the protective and control requirements for interconnection requests from Load Entities (load-only) or Transmission Entities (transmission-only) to the PG&E Power System. If the interconnection also involves any kind of *generation*, then Section G2 of the PG&E Interconnection Handbooks shall also apply.

It is advised, if an interconnection starts as Load-only or Transmission-only with plans to add generation in the future, then consider Section G2 protection requirements up front.

Applicability

Refer to “Introduction”, section 1-2 for definitions of Load Entity, Transmission Entity and Generation Entity.

For all load entity or transmission entity interconnections: The applicable protective standards of this section apply to all Load and Transmission Entities interconnecting to any portion of the PG&E Power System. These standards, which govern the design, construction, inspection and testing of protective devices, have been developed by PG&E to assure consistency with applicable reliability criteria and includes appropriate ISO consultation.

Additional protective devices may be required for **load entities or transmission entities** based on the interconnection point and impacted parties.

Loads exceeding 1,000 kW must have telemetering. See Appendix F, “Telemetering and Transfer Trip”.

When interconnecting directly to the ISO Controlled Grid: The CAISO, in consultation with PG&E, may designate certain new or existing protective devices as CAISO Grid Critical Protective Systems. ISO controlled grid protective systems have special CAISO requirements, e.g., for installation and maintenance, as described in the CAISO Tariff and the TCA Section 8.

When interconnecting directly to the UDC: PG&E‘s UDC must coordinate with the CAISO, the PG&E TO and the Load Entity or Transmission Entity, as needed, to ensure that any CAISO Controlled Grid Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with the load’s and the PG&E Power System, in accordance with the CAISO Tariff Section 4 and the ISO-UDC Agreement, both available on the CAISO website.

When interconnecting to the Bulk Energy System: When connecting to the Bulk Energy System (BES), as defined by NERC then, all protective systems, including the station dc supply (e.g. batteries) associated with protective functions, must follow PRC-005-6, “Protective System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance and Testing”. There may be additional requirements as determined by

PG&E to ensure the integrity of the PG&E BES is maintained. **Note:** The “500kV class system” is operated at 525kV with a typical operating range of 525 – 540 kV.

Space Limitations: Certain substation locations have been fully built out and no longer have the physical space in the surrounding area to accommodate substation expansions. The substation locations shown in table L2-0 can no longer accommodate new connection requests.

Table L2-0

List of Substation Buses That Cannot Accept New Connections based on Space Limitations:

Gates 230kV	Newark 115 kV
Metcalf 115 kV	Newark 230 kV
Metcalf 230 kV	Pittsburg 115 kV
Metcalf 500kV	Pittsburg 230 kV
Midway 115 kV	Tesla 115 kV
Midway 230 kV	Tesla 230 kV
Midway 500 kV	Tesla 500 kV
Tranquillity 230kV	Gates 500kV
Pittsburg PP 230kV	

Rules on Tapping Transmission Lines - Effective January 1, 2016, tapping a transmission line, on PG&E owned lines, for new load and generation interconnections is not permitted on the PG&E system for 100 kV and above. The required method of interconnecting new load/generation is via a new or existing substation. If a new transition switching station is required in-lieu of a tap, on a PG&E owned line, then the new station must be owned, operated and maintained by PG&E. Effective January 1, 2019, tapping 3rd party transmission lines owned, operated and maintained by a 3rd party are restricted, and exceptions may or may not be allowed upon review of standby load agreements being served through non-PG&E facilities and installation of PG&E interconnection requirements required to safely and reliably interconnect the project. The Table L2-1 summarizes the rules for tapping transmission lines for load or generation.

Table L2-1

Rules For Tapping Transmission Lines

Above 100 kV	Below 100 kV
Tapping not permitted. All new connections for above 100 kV must be to a new or existing substation.	Interconnections are preferred to new or existing substations. Exceptions are allowed on a restricted basis with PG&E’s written approval as determined by PG&E standards.
Existing taps are “grandfathered” in	Existing taps are “grandfathered” in

L2.1. Protective Relay Requirements

The primary safety requirement is the ability to automatically disconnect immediately when a fault is detected, to minimize potential loss of life and property.

The protection equipment for a load or transmission entity must protect against faults within that facility and faults on the PG&E Power System. A load or transmission facility must also trip off-line (disconnect from the PG&E Power System automatically) when PG&E’s power is disconnected from the line into which the facility is generating.

PG&E line-protective equipment must perform one of the following;

1) Automatically clear a fault and restore power
2) Rapidly isolate only the faulted section so that the minimum number of customers is affected by any outage.

PG&E standardizes protection requirements as much as possible, however there are many system variables impacting protection requirements load size and type, number and size of existing generators, fault duties, line characteristics (e.g. voltage, impedance and ampacity) and pre-existing protection schemes. Identical load or transmission entity facilities at different locations may have widely varying protection requirements and costs. For example, high-speed fault clearing may or may not be required to minimize equipment damage and potential impact to system stability. Appendix R, “Protective Relay requirements and Approvals” provide more protection details.

PG&E's minimum protection requirements are designed and intended to protect the PG&E Power System only. As a general rule, neither party should depend on the other for the protection of its own equipment.

The Load Entity or Transmission Entity shall install at the Point of Interconnection, at a minimum, a disconnecting device or switch with load interrupting capability. Additional protective relays are typically needed to protect the Load Entity’s or Transmission Entity’s facilities adequately. It is the Load Entity’s or Transmission Entity’s responsibility to protect its own system and equipment from faults or interruptions originating on both PG&E's side and the Load Entity's or Transmission Entity's side of the Interconnection. The Load Entity's or Transmission Entity's facilities shall be designed to isolate any fault or abnormality that would adversely affect the PG&E Power System, or the Electric Systems of other entities connected to the PG&E Power System.

The protective relays used in the Load Entity's or Transmission Entity's System Protection Facilities must be:

1) PG&E approved devices
    a. Refer to Table G2-10 for approved overcurrent relay types
    b. Typical PG&E minimum requirements would consist of three single phase overcurrent relays

2) Set to coordinate with the protective relays at the PG&E line breaker terminals for the line to which the Load Entity or Transmission Entity is connected.

3) Set to trip the interrupting device closest to the point interconnection with PG&E.

4) Line protection schemes protecting PG&E owned transmission lines will be specified by PG&E.

5) The Load entity must notify PG&E when testing relays that tie into PG&E transmission lines.

6) Protective Relay testing by the Load entity shall be performed every 6 years, based on PG&E required testing standard. Load entity shall submit testing reports when requested by PG&E.

7) Switch racks with transmission line relays that connect to PG&E should have lamacoids as a reminder to notify PG&E when testing line relays. Lamacoids should state that "For line current differential relays, PG&E should be notified to verify Remote End relays are cut-out prior to commencement of testing. This also includes testing that could result in sending trip to the remote end PG&E terminal. Upon completion of testing, PG&E should be notified to Cut-In the remote relays."

For any given fault, applicable relay targets must be provided.

Do not change relay settings without PG&E's written approval.

Submittals: Table L2-2 shows the documents that must be submitted for review before any agreements are executed.

Table L2-2

Document Submittals

No.	Drawing or Document Required	Timing
1.	Single Line Diagram[1]	Mandatory (PG&E must approve prior to relay and major equipment purchase)
2.	Single Line Meter and Relay Diagrams[2]	Mandatory (PG&E must approve prior to relay and major equipment purchase)
3.	3-Line AC or schematic drawings	Mandatory prior to pre-parallel, (advise PG&E review prior to fabricating relay panels)
4.	DC schematics or tripping schemes for all PG&E required relays	Mandatory prior to pre-parallel, (advise PG&E review prior to fabricating relay panels)
5	Battery Form AT-1 from Appendix F	Mandatory prior to pre-parallel (PG&E must approve the station battery)
6	Modeling information (Aspen, PSCAD, RTDS)	Mandatory, equipment information is required to develop and run simulations. (RTDS models (PSCAD will not suffice) are required for all 500kV interconnections.

The Load Entity or Transmission Entity shall provide, install, own, and maintain such relays, circuit breakers and all other devices necessary[2] to promptly remove any fault contribution of the Load Entity's or Transmission Entity's facilities to any short circuit occurring on the electric system not otherwise isolated by PG&E equipment. Note: There may be additional protective equipment requirements, at the Load Entity's or Transmission Entity's cost, which PG&E will coordinate with the Load Entity (or Transmission Entity) or its representatives.

The Load Entity (or Transmission Entity) shall not modify or change any PG&E required protective equipment or settings without approval from PG&E.

PG&E assumes no liability for damage to Load Entity-owned or Transmission Entity-owned facilities resulting from mis-coordination between the Entity's protective device(s) and PG&E's protective devices. PG&E recommends that the Load Entity or Transmission Entity acquire the services of a qualified electrical engineer to review its plans. The Load Entity or Transmission Entity shall, at its expense, install, operate, and maintain System Protection Facilities in accordance with applicable ISO, WECC and NERC requirements and in accordance this Handbook.

[1] Refer to Appendix F for recommendations and requirements associated with pilot protection.
[2] These facilities in addition to other protection facilities are termed System Protection Facilities.

The protective devices shown in Table L2-1 may or may not be required for Load Entities as determined by PG&E on a case-by-case basis. Typically, a 500kV, 230 kV Ring or Breaker-and-a-Half (BAAH) substation bus service may require all relays listed, while a 60kV radial service may require only phase and ground overcurrent relays. Most line relaying depends on the existing system configuration, the existing protection, and line characteristics such as impedance, voltage, ampacity and available fault duty, at the location in question.

Fault-interrupting equipment should usually be located at the point of interconnection to PG&E, or as close to the interconnection point as practicable—typically within one span of overhead line or 200 feet of unspliced underground cable for transmission interconnection and 50 feet of overhead line or 100 feet of unspliced underground cable for distribution interconnections.

Refer to Section 6 of PG&E's Distribution Interconnection Handbook (DIH) for the detailed distribution primary service requirements.

For all relays required for the particular installation, a test report (see Form G2-2, Section G2) is mandatory, prior to energizing and every six years after that. **The Load Entity or Transmission Entity shall provide test reports to PG&E, from a qualified testing firm obtained by the entity, a minimum of thirty (30) working days prior to energizing.** Refer to Section L5 for information regarding the pre-parallel inspections.

On-site power (120 volts ac typically) is required for the test equipment. Circuit breakers must be tested every six years after the pre-parallel inspection. Once PG&E baseline established. Customer shall execute mechanism servicing, in conjunction with SF6 gas sampling, at a minimum every 12 years, taking corrective actions when deficiencies are identified. Scope, depth and frequency of testing/ maintenance may vary at each site due to equipment type, age, application, and manufacturer recommendations. Further maintenance considerations should be explored by customers on a case-by-case.

Facilities that fail to meet the above testing requirements are subject either to a delay in service or to being disconnected from the PG&E Power System.

L2.2. Reliability and Redundancy

The protection system must be designed with enough redundancy that failure of any one component still allows the facility to be isolated from the PG&E system under a fault condition.

L2.2.2 500kV Systems

The "500kV class system" is operated at 525kV.

- All interconnections must adhere to the existing operating modes of the 500kV system (examples are accommodating single pole tripping when required, avoiding single point of failure vulnerabilities on all five components of a NERC defined Protection System, including dual battery systems).
- For line protection, four concurrently independently operating protection relays are required to accommodate failure of one of dual telecom routes, CTs,

CCVTs tap, no DC single component for design (including raceways and DC panels) to meet requirement of 500kV Line remaining in service. The minimal requirements to stay energized are one line relay with high speed communications in service and one line relay with non-high speed communications assisted protection.

- Transposition of lines to create 3 sections will be reviewed to determine if required
- Series compensation to no more than 70%
- RTDS testing required to be placed in service performed by approved testing organization requiring approximately 1 week of testing for internal and external faults per line about 40,000 faults typically studied.
- Interconnection to the 500kV system requires dual vendor relays for all protection systems that are protecting PG&E owned 500kV system equipment (includes the 500kV lines, 500kV buses, and 500kV high side transformer protection relays as applicable).
- Breaker tripping must employ dual trip coils energized from all of the protection relays that are protecting the element, including the breaker failure protection.
- All relays protecting the 500kV system require a relay failure alarm contact (contact closed when relay de-energized) to be wired monitoring 24/7 by control center. Approved 500kV relays are not included in Table G2-10 in TIH G2. All 500kV line relays to match exact type, firmware, and special calibration settings specified by PG&E.
- For all interconnections to existing 500kV lines, relay cut out (RCO) switches or equivalent are required. All protection relays that trip 500kV breakers require separate RCO contact or equivalent (independent from the relay) that supervises the relay trip used for breaker tripping to both breaker trip coils and breaker failure initiation.
- Maintenance switches for breakers and lines are required for all RAS schemes which are independent of the relays being used to protect the element (ex. The breaker maintenance switch equivalent cannot be contained within the breaker failure relay).

Other Requirements:

The Load Entity must install a disconnect device or switch with load interrupting capability at the Point of Interconnection (POI).

Generally, fault-interrupting equipment should be located as close to the interconnection point as possible - typically within one span of overhead line or 200 feet of unspliced underground cable.

Breaker failure may be required in some instances. In those instances, PG&E will evaluate the breaker failure scheme and tripping modes. Breaker failure is always required on the 500kV system and must be operational and in service for the breaker to remained closed and energized.

L2.3. Relay Grades

All load facilities or transmission facilities interconnected to PG&E’s transmission system shall use utility grade relays, which are much more accurate and reliable than industrial grade relays. Utility grade relays also have targets to facilitate testing/troubleshooting and typically have draw-out cases. Current transformers must have a nominal 5A secondary current, and all relays must have a 5A nominal AC input current.

Utility grade auxiliary relays must be used in the tripping circuits of utility grade protection relays. All such relays must include manually resettable relay targets, which also identify the faulted phase. Their power supplies must be powered by station battery DC voltage and must include a DC under-voltage detection device and alarm. See Section G2.20 and Appendix T (Battery Requirements for Interconnection to PG&E System)

Microprocessor relays require a relay failure alarm contact (contact closed when relay de-energized) to be wired to alarm and monitoring similar to the DC battery undervoltage alarm.

NOTE

Monitoring of the DC battery voltage by a separate voltage relay or through a charger that provides a critical alarm to a 24/7/365 monitoring system is required. For installations that are too small to have th above monitoring, then an annunciated alarm with strobe light with audible alarm can be substituted. PG&E's written approval is required for any other alarm notification methods.

All proposed relay specifications and settings, for those relays which impact PG&E reliability and/or safety, shall be submitted to PG&E for approval **prior to ordering** (see Tables G2-3, G2-7, and G2-8 in Section G2). Load Entities or Transmission Entities who fail to submit relay specifications for approval shall risk the possibility of not being able to interconnect with PG&E (refer to Electric Rule 2). In some cases where PG&E may be unfamiliar with a specific proposed relay, PG&E may perform tests on relays provided by the Load Entity or Transmission Entity for approval, or request that test and supporting data from the manufacturer be supplied by the Load Entity or Transmission Entity. Such tests shall be performed at the Load Entity's or Transmission Entity's expense and prior to PG&E approval of the relay for interconnection use[3]. Approval of relays shall not indicate the quality or reliability of a product or service. No endorsements or warranties shall be implied.

L2.4. Line Protection

Line-protection relays must coordinate with the protective relays at the PG&E breakers for the line on which the facility is connected. The typical protective zone is a two-terminal line section with a breaker on each end. In the simplest case of a load on a radial line, current can flow in one direction only, so protective relays need to be coordinated in one direction and do not need directional elements. However, on the

[3] There are additional system tests associated with communication-assisted protection. These tests (also referred to as end-to-end satellite tests) require all terminals of a transmission line to be tested as a system and include the protection, communication equipment and medium between the interconnected terminals. Refer to Appendix F for more information.

typical transmission system, where current may flow in either direction depending on system conditions, relays must be directional. Also, the complexity and the required number of protective devices increase dramatically as the number of terminals increases in each protective zone. With two terminals in a protective zone, there are two paths of current flow. With three terminals there are six paths of current flow, and so on. For this reason, three terminals are discouraged and, in most cases, will not be allowed.

In coordinating a multi-terminal protective relay scheme, or short tie lines PG&E may require the installation of a communication aided transmission line relaying scheme. Common schemes of this type are Permissive Overreaching Transfer Trip (POTT) schemes or Line Current Differential (LCD) schemes. In these types of schemes, the transmission line protective relay at the Load Entity's or Transmission Entity's substation site will be required to be of the same manufacture and firmware as the PG&E relays for proper operation of the scheme. These line relays would be installed at the Load Entity's or Transmission Entity's expense as part of a Special Facilities Agreement according to applicable tariffs. Because this line relay is part of a scheme which is designed to protect the PG&E transmission system, PG&E must ensure the maintenance, testing and reliability of this type of relaying scheme[3].

In addition, the breaker's relays must be set to have overlapping zones of protection in case a breaker within any given zone fails to clear. The line protection schemes must be able to distinguish between load, inrush and fault currents. Multiple terminal lines become even more complex to protect. **Existing relay schemes may have to be reset, replaced, or augmented with additional relays at the Load Entity's or Transmission Entity's expense,** to coordinate with the Load Entity's or Transmission Entity's new facility.

The PG&E required relays must be located so that a fault on any phase of the PG&E line shall be detected. If transfer trip protection is required by PG&E, the Load Entity or Transmission Entity shall provide at its expense the required communications circuit. The communication circuit may be a leased line from the telephone company, a dedicated cable, microwave, or a fiber optic circuit and shall be designed with sufficient levels of monitoring of critical communication channels and associated equipment. PG&E will determine the appropriate communication medium to be used on a case-by-case basis. The leased line must have high-voltage protection equipment on the entrance cable so the transfer trip equipment will operate properly during fault conditions. (For detailed description of protection requirements of the transfer trip equipment, refer to Appendix F). Refer to Table G2-2 for communication repair time requirements.

Table L2-3 below lists the minimum protection that PG&E typically uses on its own installations. Higher voltage interconnections require additional protection due to the greater potential for adverse impact to system stability, and the greater number of customers who would be affected. Special cases such as distribution-level network interconnections, if acceptable, may have additional requirements. The acceptability and additional requirements of these interconnection proposals shall be determined by PG&E on a case-by-case basis.

L2.4.1. Fault-Interrupting Devices

The fault-interrupting device selected by the Load Entity or Transmission Entity must be reviewed and approved by PG&E for each application. There are two basic types of fault-interrupting devices:

- Circuit Breakers
- Circuit Switchers (by written exception only)

PG&E will determine the type of fault-interrupting device required for a load facility, based on the available fault duty at the interconnection point, size of load, the local circuit configuration and the existing PG&E protection equipment.

Fault interrupting devices utilizing gas as an interrupting medium shall have a low-pressure trip enabled tripping the interrupting device for the low-pressure block value is reached.

Vacuum fault interrupting devices shall have an overpressure trip enabled before the overpressure block value is reached.

Table L2-3

Basic Protective Devices[5]

Protection Device	**Device[3] Number**	**34.5 kV or less**	**44 kV 60 kV or 70 kV**	**115 kV**	**230 kV**	500kV[5]
Phase Overcurrent (Radial systems or load facility coordination)	50/51	X	X	X	X	X
Phase Directional Overcurrent	67		X[1]	X[1]		
Ground Directional Overcurrent			X[1]	X[1]	X[1]	X
Distance Relay Zone 1	21Z1			X[1]	X[1]	X
Distance Relay Zone 2	21Z2			X[1]	X[1]	X
Distance Relay Carrier	21Z2C			X[1]	X[1]	
Distance Relay Carrier Block	21Z3C			X[1]	X[1]	
-Current Differential	87L			X[1]	X1	X
Permissive Overreaching Transfer Trip (POTT) or Hybrid	21/67T			X[1]	X[1]	
Power Fail Trip[4]	27		X[1]	X[1]	X[1]	
Direct Transfer Trip	TT		X[2]	X[2]	X[2]	X- within line relays

Table L2-3 Notes:

1 May be required by PG&E depending on local circuit configurations.

2 Transfer Trip may be required on load transmission interconnections depending on PG&E circuit configuration and loading, as determined by PG&E. Typically, transfer trip is required on multi-terminal lines.

3 Refer to Table G2-9 (Section G2) for device number definitions and functions.

4 Power failure tripping may be required on load transmission interconnections to facilitate restoration of customer load after a transmission line or area outage.

5 500kV relays, protection philosophy, and logic settings will be reviewed and approved by PG&E. RTDS testing confirms the final protection settings.

L2.4.1.1. Circuit Breakers

A three-phase circuit breaker at the point of interconnection automatically separates the Load Entity's or Transmission Entity's equipment from the PG&E system upon detection of a circuit fault. Additional breakers may be installed in the Load Entity's or Transmission Entity's equipment to facilitate operating and protecting the facility, but they are not required by PG&E. The interconnection breaker must have enough capacity to interrupt the maximum available fault current at its location. It must be equipped with accessories to:

- Trip the breaker with an external trip signal supplied through a battery (shunt trip);
- Telemeter the breaker status when it is required;
- Automatic reclosing is not permitted, lockout if operated by protective relays required for interconnection. The lockout function can be accomplished by a dedicated hand reset relay or via a microprocessor relay in which the relay reset function resets the lockout function.

Generally, a three-phase circuit breaker is the recommended fault-interruption device at the point of interconnection. It is typically required due to its simultaneous three-phase operation and its ability to coordinate with PG&E line-side devices.

The required breakers must be trip tested (e.g. exercised) by the Generation Entity at least once a year.

500kV circuit breakers must meet or exceed PG&E breaker specifications. Breakers need to accommodate single pole tripping when required.

L2.4.1.2. Circuit Switchers

Circuit switchers should not be used because they do not have CT's and thereby increase exposure to the entire line section. Use of a circuit switcher must meet the following requirements:

- Applicant must obtain PG&E's written approval.
- The IC rating is within the fault duty at the POI.
- Stand-Alone CT's must be installed on the PG&E (Utility Side) of the circuit switcher to minimize the amount of 3rd party equipment within the PG&E relay zone of protection.
- CT's must be relaying class CT's with a nominal 5A secondary output.
- Stand-alone CT's will be insulation tested per TIH Section G5.1.1 "Proving Insulation."

L2.4.1.3. Relay Class Current Transformers (CT)

Metering class PT/CTs (including dual winding devices) shall not be used for relaying purposes in PG&E's system. Combination PT/CTs that are installed by PG&E for revenue metering purposes (including available taps) must not be connected to customer relays and used to provide protection of customer-owned equipment.

A combination PT/CT is a device that is installed at the customer's point of connection to facilitate revenue metering of the power flow to or from PG&E's grid.

A dual winding metering PT/CT is a particular type of combination PT/CT that is constructed with a separate second CT core winding. Dual winding units are non-standard devices that are not stocked by PG&E.

Prior to 2001, there may be grandfathered cases where the customer installed a circuit switcher rather than a circuit breaker as an interrupting device, and dual winding PT/CTs were installed to provide protection for the customer's equipment. This practice was discontinued because the CTs in the metering unit do not meet relaying accuracy class standards. Also, if the dual winding unit should fail, PG&E should not be liable for protecting the customer's equipment.

The CT's used for protective relay purposes must be a relaying class with a 5A nominal secondary output.

500kV breakers require C1200 CTs at 3000/5 tap for interface with lines to PG&E.

L2.5. Standby/Backup Source

Not applicable for 500kV interconnections.

L2.5.1. Standby Source

In cases where the Load Entity's load or a load served by the Transmission Entity requires a high level of reliability, the Load Entity can request both a transmission source and a back-up distribution or transmission source, at the Entity's expense. Normally, when the Entity's load is transferred from the primary source to the standby source or from the standby source to the primary source, a momentary outage (drop-and-pickup operation) is required.

When the Load Entity or the load supplied by the Transmission Entity is being fed from the back-up source and wants to transfer the load back to the primary source with a parallel operation (make-before-break), the following requirements must be met:

- Ratios and electrical connections of the transformers on both sources must be well matched to minimize circulating currents.
- Impedance of the transformers and the relative phase angles of the sources must be such that any "through load" (i.e. load flowing through the Load Entity's or Transmission Entity's electrical system to other customers) does not cause overloads.
- Protection must not be degraded during the parallel transfer operation, and neither PG&E's nor the Load Entity's or Transmission Entity's equipment must become over-stressed.
- The transfer switches, one on each side of the Load Entity's load (or the load served by the Transmission Entity), must be controlled by an automatic interlock scheme to minimize the time the parallel is in effect. Thus, transfer switches must be circuit breakers or other suitably rated, automatically controlled switches. Note that the available fault duty will be increased, and the Load Entity's or Transmission Entity's equipment may be overstressed while the two circuits are paralleled, so it is very important to make the parallel period as short as possible, typically one second or less.
  - Each parallel transfer operation can only proceed after specific approval has been given by PG&E. In some cases, additional protective devices and special operating procedures may be required to avoid endangering customers and/or PG&E facilities. PG&E's approval must be obtained prior to parallel transfer operation. PG&E may withhold approval if, in its sole judgment, the above requirements have not been met, or if a previously unforeseen factor or change in conditions is deemed to jeopardize operator or public safety or reliability to customers.
- The Load Entity or Transmission Entity must assume all liability for any problems or damage resulting from any parallel transfer operation.

L2.5.2. Backup Generators

Refer to Section G2 for a discussion of back-up/emergency generators.