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PROTECTION OF UTILITY/COGENERATION INTERCONNECTIONS

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PG&E'S EXPERIENCE WITH PROTECTION OF UTILITY/COGENERATION INTERCONNECTIONS

INTRODUCTION

PG&E currently has approximately 400 cogeneration facilities and independent power producers connected to the system at voltage levels ranging from 4 kV distribution up to the 230 kV transmission level. These generating facilities total about 4600 mW, or 20% of PG&E's summer peak load with generator sizes ranging from a few kilo-watts up to hundreds of mega-watts. PG&E engineers have more than ten years of experience specifying the protection requirements for these cogeneration facilities and refining the requirements based on actual operating performance. We continue to receive and review new applications for interconnection; many of these are at the transmission level.

This paper will present PG&E's basic relay requirements for interconnection of cogeneration facilities, describe some of the additional protection schemes devised to cover possible operating contingencies, and conclude with some operating experiences which illustrate the need for these schemes. In the paper we will refer primarily to cogeneration interconnection requirements, although the same general requirements may to any independent power producing generators connecting to our system.

THE ENVIRONMENT: INITIATION OF STANDARDS

In the late 1970's, PG&E protection engineers recognize the need to establish uniform interconnection requirements in order to handle the massive numbers of applicants requesting connection to the power system. PG&E's first interconnection guide, released in 1980, established standards for operating, metering, and relaying of cogeneration facilities. The requirements were generally developed based on the facilities' aggregate generation capacity, system voltage interconnection, and generation type. The guide was later expanded to supply technical coordination procedures and to provide guidance for the Qualifying Facility (QF) Project coordinator and technical reviewer in accordance with the California Public Utility Commission (CPUC) mandated QF Milestone Procedure. This guide is now published as the Power Producer's Interconnection Handbook and is available to customers upon request. The guide is updated and modified periodically to conform to changing operating constraints, laws, contractual agreements and new technologies encountered by PG&E.

BASIC INTERCONNECTION CONCERNS

A. SAFETY

PG&E is dedicated to supplying safe and reliable power to our customers. To protect the public from potential hazards to life and property, and to protect our own facilities, we impose certain design requirements and operating constraints on cogeneration facilities. Some examples of these are:

- The generating facilities must be equipped with protection devices which can detect electrical faults in the system and immediately trip the appropriate generator(s) off-line to eliminate their contribution of fault current into PG&E's system.

- Manual load break disconnect devices must be installed at the interconnection point to allow separation of the generating facilities from PG&E's system for maintenance of our line and substation equipment.

- The generator must separate from our system when our line is de-energized due to a line fault or for any other reason. This prevents the generator from carrying isolated load at other than normal system frequency and voltage, and allows PG&E's breakers to automatically test line and substation equipment without risk of damaging the customer's equipment.

B. IMPACT ON THE PG&E SYSTEM

PG&E's existing power system can be affected significantly by the addition of cogenerating units. For this reason, many studies are made to review the impact on protection, operational flexibility, service reliability, and power quality, and to estimate the expense to the applicant for resolving any problems created by the proposed interconnection. For example, the applicant may be required to connect to a transmission line rather than a distribution line because of the size of the generator. This connection would require more complex relays, a dedicated transformer and, perhaps, transfer trip. At times, the estimated expense of installing special interconnection facilities may make a proposed project uneconomical from the start.

C. IMPACT ON EXISTING PROTECTION SCHEMES

The addition of a cogenerator may significantly affect the performance of PG&E's existing protection schemes. Some preliminary studies are required to determine if the existing protection will work properly with the new generation source added to the system. At times the new source interconnection can affect the utility's protection in such a manner that it can desensitize or oversensitize existing relays significantly. This may require the installation of new relays and/or new relay schemes, at the customer's expense, or may only require setting changes to the existing relays. In either case, the amount of work required must be determined up front before a contract is signed with the cogenerator.

D. PROTECTION OF COGENERATOR'S EQUIPMENT

PG&E's protection interconnection requirements are designed and intended to ensure that the integrity of our existing protection schemes is maintained without compromise, and that appropriate coordination between our relays and the cogenerators' equipment exists. Design for adequate protection of cogenerator owned equipment, such as generator, bus, transformer, and power plant auxiliaries is the responsibility of the applicant.

GENERAL INTERCONNECTION REQUIREMENTS

Our protection requirements for a cogeneration facility are based on the following three factors which will be considered one at a time:

A. Generator capability.
B. Generator type.
C. Point of interconnection.

A. GENERATOR CAPABILITY

The interconnection requirements for generators are based on three categories of generator capability or size as shown in Table 1-1. These categories, supported by the CPUC, were adopted by PG&E and were based on the economic impact of interconnection requirements on the smaller projects and the system impact of the larger units.

Protection Devices	100 kW or Less	Between 100 kW and 1 mW	Greater than 1 mW
Overvoltage Protection	X	X	X
Undervoltage Protection	X	X	X
Over/Underfrequency Protection	X	X	X
Ground Fault Protection	X	X	X
Voltage Restraint/ Voltage Control Overcurrent or Impedance Relay		X	X
Manual/Automatic Synchronizing	Man or Auto	Man or Auto	Auto
Utility Grade Relays			X
3-Phase Fault Interrupting Device		X	X

Table 1-1
GENERATOR INTERCONNECTION REQUIREMENTS

In some cases, smaller divisions in generator size may be considered. For example:

- Generation greater than 40 kW may require ground protection.
- Single or aggregate generation exceeding 400 kW requires voltage restraint/voltage control or impedance relays to provide backup for system faults.

The Power Producer's Interconnection Handbook provides a list of relays, available from various manufacturers, which PG&E has approved for installation. Any relays selected by the applicants which are not on this list are subject to review and approval by PG&E.

B. TYPES OF GENERATORS

The next step in determining specific interconnection requirements is to consider the type of generator being installed. The characteristics of each type of generator will determine what protection is required in addition that shown in Table 1-1 and specific relay set points required such as for three set point underfrequency relays. The following are some interconnection considerations for the three categories of generators:

1. <u>Synchronous:</u>
   A synchronous machine is required to have a synchronism check relay to supervise manual paralleling with the system. Without it, a synchronous machine can parallel out of phase with the power system, possibly resulting in serious damage to the generator, and to mechanical couplings between the prime mover and the generator. Also, utility customers may be adversely affected if a distribution feeder trips because a generator is paralleled out of phase. PG&E requires generators greater than 1 mW to have an automatic synchronizing device.

2. <u>Induction:</u>
   An induction machine may self-excite due to VAR support equipment on the system, such as nearby shunt capacitor banks. This is usually a problem when the unit is islanded from the utility system, but still connected to local load. The protection requirements must address this potential problem.

3. <u>DC Inverter:</u>
   - In general, the fault current produced by an inverter is not much greater than the output load. This may not allow proper setting of phase overcurrent relays.
   - If the inverter fails, injection of DC current into the utility system may occur. The installation of an isolation transformer will prevent this problem.
   - The protection requirements must address possible islanding from the utility system. PG&E does permit some small cogenerator units connected to the power system through inverters to use industrial grade relays or microprocessor control devices to provide a combination of relay functions such as the sensing and tripping output for over/under frequency and over/under voltage conditions.
   - The inverter may output odd harmonics into the power system resulting in poor power quality for the utility customers.

C. POINT OF INTERCONNECTION

The final step in determining the interconnection requirements is to look at the point of interconnection to the system. If the generator is connecting to the system at a voltage higher than 21 kV, additional protective relays are usually required, and they are generally more sophisticated than those required for a distribution system connection. Whether or not additional relays are required depends on the interconnection voltage (such as distribution, sub-transmission or transmission), the existing relays in the system, and results of fault studies.

Each interconnection proposal must be studied carefully to determine the effects on the existing relays. For example, if the generation is being tapped in the middle of an existing transmission line, the applicant will be required to install relays which match those on the existing line. However, the existing relays may need to be replaced if they are desensitized by the tapped generating source to the extent that they no longer adequately protect the transmission line, or if the existing relays will not work properly on a three terminal line.

It is necessary to run system fault studies modeling the cogenerator on line to determine if the relays need to be replaced, and the specific type of relays required. The applicant must supply the generator and transformer impedance data before these studies can be completed. Fault studies required for the transmission system usually take more time and are more complex because the transmission circuit is more likely to be a part of a looped system with multiple generation sources, compared with a distribution circuit which is normally radial with a single generating source. Thus, there are more fault contingencies that must be considered for a transmission circuit due to the new generating sources and transformers which can desensitize the existing relays.

Table 1-2, below, summarizes the most common protection required, in addition to what is shown in Table 1-1, for units connecting to the subtransmission or transmission system.

		Line Voltages			
Protective Device	**Device Number**	**60 kV or 70 kV**	**115 kV**	**230 kV**	**Wind Farms: All Voltages With Two or More Machines**
Phase Directional Overcurrent	67	X	X		
Ground Directional Overcurrent	67N	X	X	X	X
Distance Relay Zone 1[1]	21Z1	X	X	X	X
Distance Relay Zone 2	21Z2	X	X	X	X
Distance Relay Carrier	21Z2C			X	
Ground Directional Overcurrent Carrier	67NC			X	
Distance Relay Carrier Block	21Z3C			X	
Direct Transfer Trip[1]	TT	X	X	X	X

1. May also be required on distribution interconnections.

Table 1-2
ADDITIONAL PROTECTIVE DEVICES

Besides additional relays, the interconnection requirements may include changes to the system required to address system stability or operating problems caused by the new generating source. Regardless of the connection voltage, these additional requirements can result in some major expenses which may affect the feasibility of the project.

ADDITIONAL INTERCONNECTION REQUIREMENTS FOR DISTRIBUTION AND TRANSMISSION CONNECTIONS:

In the following section, we will look at protection schemes, system reinforcements, and configuration changes that may be required for distribution and transmission interconnections in addition to those shown in Table 1-2

A. PROTECTION SCHEMES

1. Reclose blocking:

   A reclose blocking scheme is used to prevent PG&E's circuit breaker from automatically reclosing before the cogeneration goes off line. This scheme consists of a line side potential transformer and a low pickup voltage relay. An automatic line test is blocked by this voltage relay until the relay drops out at a low voltage, typically below 15 volts AC secondary.

   This circuit must be added to the automatic reclosing scheme for the typical distribution feeder since distribution circuits are normally radial and line-side potentials are not required as an input condition to the reclosing relay. Subtransmission and transmission line automatic reclosing already uses line-side potentials for time delay reclosing, so the only modification required is to add a low pickup undervoltage relay to supervise the line test feature.

2. Direct Transfer Trip:

   A direct transfer trip scheme is required to trip the cogenerator off-line for safety reasons. A leased phone line is the most common communication path for the transfer trip signal. PG&E requires the leased lines to meet the following specifications:

   - The lease line should be dedicated (cannot be switched or shared).
   - Indication of transfer trip received, breaker status, and channel fail alarm status should be available to the PG&E operating center upon the initiation of transfer trip.
   - The lease line circuit is required to hold the most reliable tariff and be free from potential interruption by the phone company.
   - The lease circuit shall be supplied with battery backup power to provide a non-interruptible service performance before, during and after a power fault condition.
   - The lease line circuit must be proven and in service prior to scheduled date of pre parallel inspection.

   The following are some system conditions which require direct transfer trip:

   a. The cogenerator's primary line relays or backup voltage-restraint generator overcurrent relay cannot detect an end-of-line fault on the utility system or operate in a reasonable time (less than 1.5 seconds) for the end-of-line fault.

b. There is a possibility of the cogenerator simultaneously islanding and carrying local load. Transfer trip is required to be installed at any three-phase interrupting device when the cogenerator rating is 50% or more of the area minimum load.

c. For wind farm applications with an aggregate of small generators regardless of size. With this type of dispersed generation, there is no guarantee that a sufficient number of generators will be on-line to provide a source to reliably operate the relay for a fault on the utility system.

d. For inverters greater than 400KW, due to possibility of islanding. Transfer trip is used when a voltage restraint overcurrent relay cannot be set to reliably detect faults on the line.

e. On transmission lines which have pilot relaying and high speed reclosing, transfer trip is required from both utility line terminals to the cogenerator site. This assures that the generator will be tripped off-line before the utility's circuit breakers high speed reclose, thereby preventing possible damage to the customer's equipment.

f. Special consideration should be given to generators interconnected on distribution circuits which are supplied by substation transformers protected by primary fuses. Faults on the transmission system may not be cleared immediately by the generator, which is a serious safety concern.

Figure 1 below illustrates this situation. A fault on the transmission line will be cleared by the circuit breaker at A. However, relays installed on the generator interconnection point on the distribution circuit may not be sensitive enough to detect faults on the transmission system. In addition, it may not be possible to install relays which are sensitive enough to detect all transmission line faults. In this case, a direct transfer trip circuit would be installed from the circuit breaker at A to the interconnection point or the generator breaker B.

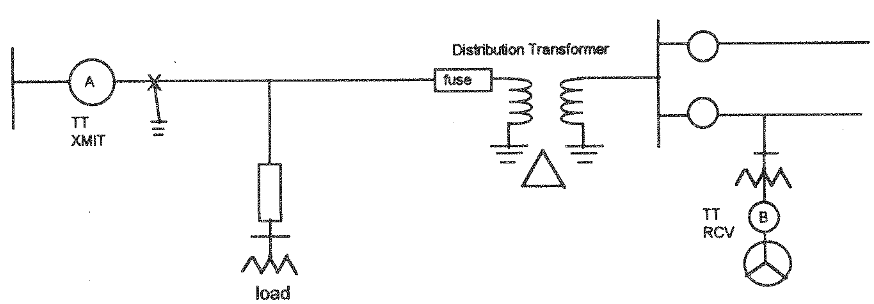

Figure 1. Transfer trip required to trip distribution generation for transmission line faults

g. Another example might be a generator connected to the sub-transmission system that impacts the transmission system through infeeds.

3. <u>Ground Fault Detection:</u>

Ground protection varies depending on the type of circuit and transformer connection. The following ground detection schemes are used in PG&E's distribution system:

a. Three-Wire Distribution Circuits:

Figures 2a and 2b illustrate the connections of three-wire distribution circuit ground detection schemes. Both of the schemes shown use a grounding transformer with a voltage relay to avoid introducing any additional zero sequence currents which could desensitize the existing feeder ground relays.

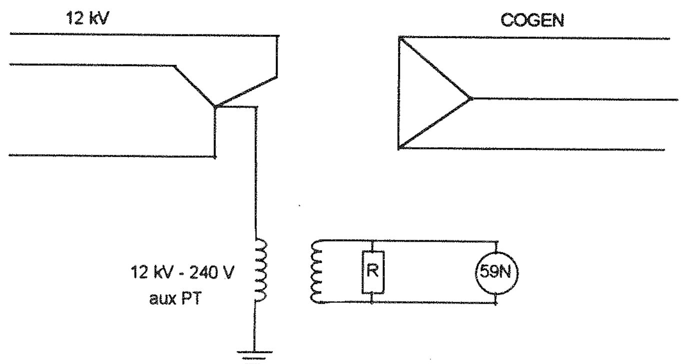

Figure 2a. Ground protection scheme for three-wire wye distribution circuit

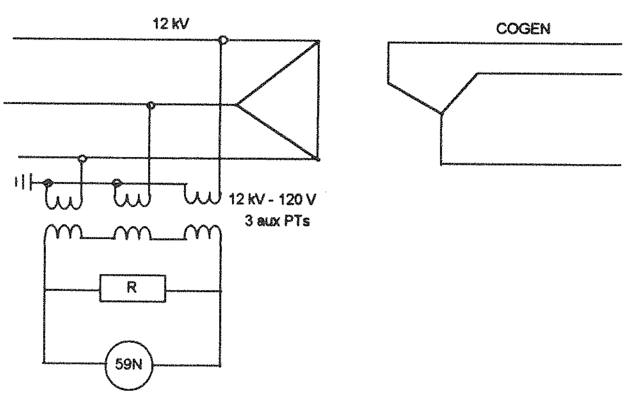

Figure 2b. Ground protection scheme for three-wire delta distribution circuit

b. Four-Wire Distribution Circuits:

Figures 3a and 3b illustrate the connections of four-wire distribution circuit ground detection schemes. Both schemes use a grounding transformer and a current relay since four-wire circuits normally have some load unbalance which could operate a sensitive voltage relay.

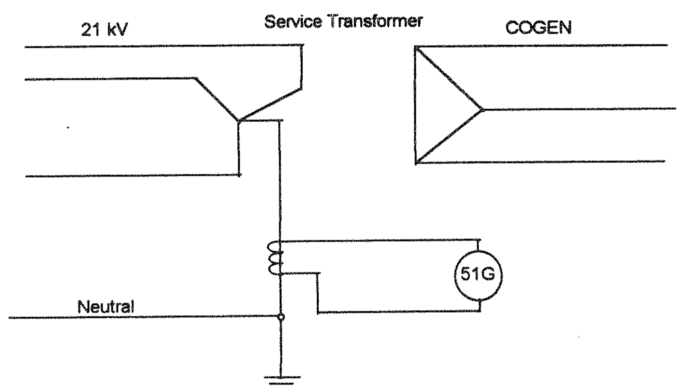

Figure 3a. Ground protection for 4-wire wye distribution circuit

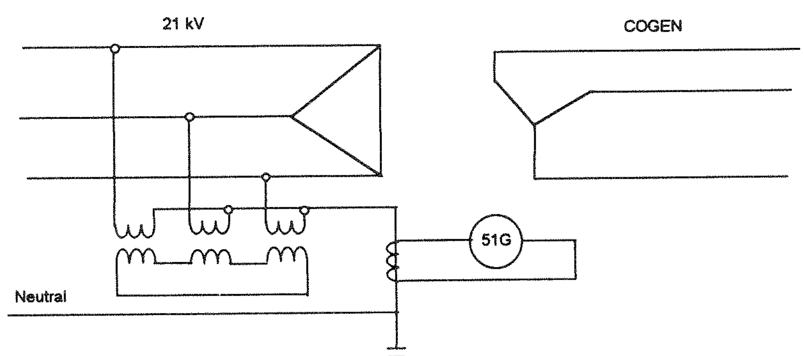

Figure 3b. Ground protection for 4-wire delta distribution circuit

c. **Transmission Circuits:**

Figures 4a and 4b illustrate the ground relay schemes for transmission interconnections. Usually the schemes consist of a ground overcurrent relay on the inter-tie breaker, or an overcurrent relay on the grounded neutral connection of the high-voltage side of the generator step-up transformer. Both schemes trip the three-phase interrupting device C.

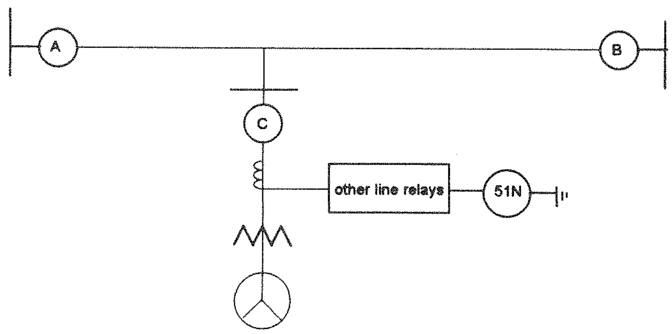

Figure 4a. Transmission ground relay scheme with connection on the inter-tie breaker.

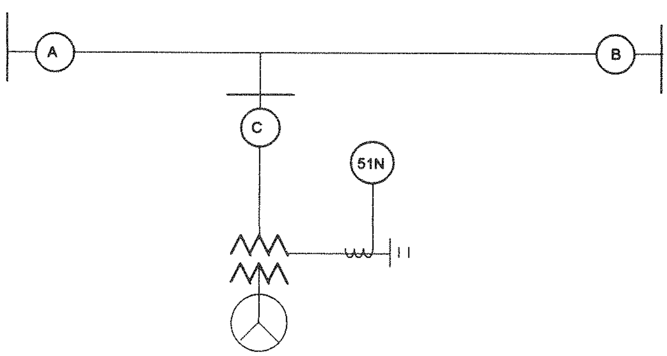

Figure 4b. Transmission ground protection scheme with relay connected on neutral of high-side winding transformer.

4. **Replace Single Phase Interrupting Devices:**

If the generator rating is greater than 1000 kW aggregated nameplate, all existing single-phase fault interrupting devices in series between the high voltage side of the generator transformer and the PG&E substation will be replaced with three phase interrupting devices. Single phase interrupting devices may not be replaced for units less than 1000 kW, however a blown fuse operation may cause single phasing conditions which will produce negative sequence currents in the generator. Negative sequence currents can cause damage to the generator and associated auxiliaries if left undetected. Protection of the generators and auxiliaries is the responsibility of the applicant as defined in the CPUC guideline.

5. Replace Utility Relays:
If existing PG&E relays are desensitized so they no longer provide adequate protection for the line because of the addition of a cogenerator, the relay settings will be changed or the relays will be replaced. Also, the relays will be replaced when the circuit configuration is altered, such as a change from a two terminal line to a three terminal line, so that use of the existing relays is no longer valid.

6. High-Speed Transmission Line Protection:
If the existing transmission line has high speed pilot protection, the cogenerator will be required to install relays which are compatible with the PG&E scheme. If the existing PG&E line relays will not function with a third tapped terminal, the relays will be replaced at the applicant's expense.

B. SYSTEM RECONFIGURATION AND REINFORCEMENT

1. Reconductor Transmission /Distribution Line:
Reconductoring may be required because of the following conditions caused by the addition of the generator:

   a. A voltage problem caused by increased loading on the line.

   b. An overload problem caused by the generator output exceeding the ampacity rating of the line conductor.

   c. An I^2T problem on a distribution circuit caused by increased fault currents or slower fault clearing times.

2. Replace overstressed or overloaded equipment:
If PG&E's equipment (such as circuit breakers, disconnects or transformers) become over stressed or over loaded due to the addition of a cogeneration facility, the over-stressed equipment will be replaced at the cogenerator's expense.

3. Loop the Line Through the Cogeneration Bus:
If tapping a cogenerator on the line results in one or more sections of line that cannot be protected by the existing relay schemes, the utility line may be looped through the generation station bus. One disadvantage of this solution is that the utility line may be interrupted for generating plant troubles.

4. Connect the Cogeneration Directly to the PG&E Substation Bus:
If the proposed interconnection is a tap very close to one end of a transmission line, it may not be possible to provide adequate protection for the transmission line using the existing relays. An existing power line carrier blocking scheme is an example of a relay scheme that would not operate properly for this type of interconnection. Rather than replace all of the utility line relays, it may be feasible for the applicant to build a short transmission line and connect directly to the nearby substation bus through a new circuit breaker. This solution has the added advantage that the cogenerator is not interrupted for transmission line faults.

5. Construct a New Transmission Line:
If a proposed connection to a distribution circuit would overload that circuit, and it is not practical to reconductor the circuit, an alternate solution may be for the applicant to construct a new transmission line.

- Three-terminal permissive transfer trip, or hybrid scheme with weak infeed option to protect the utility line.
- Direct transfer trip from the two remote utility circuit breakers at Station A and Station B to trip the tap breaker for utility line faults and allow high speed reclosing of the transmission line.

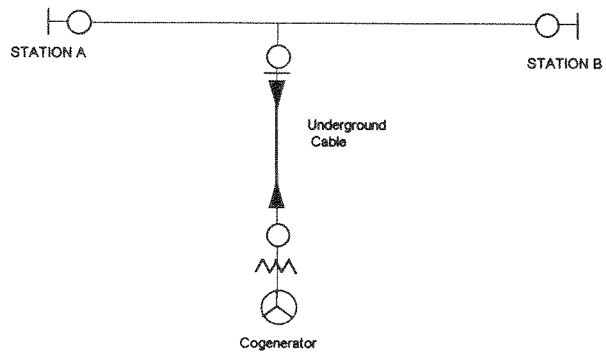

Figure 5. Cogeneration interconnected via underground cable

C. SPECIAL CONSIDERATIONS

1. **Stability Studies:**
Stability studies are generally required for proposed cogeneration facilities with aggregate generation of 10,000 kW or larger on the transmission system to determine the need for a high-speed protection scheme or direct transfer trip.

2. **Impacts on Other System Voltages:**
Cogenerating facilities that interconnect on lower voltages may adversely affect relaying on the high voltage (HV) transmission systems because of added infeeds. Additional costs for changes required to the HV protection systems should be identified before the utility enters into an agreement contract with the cogeneration applicant so that the costs can be born by the applicant. It is extremely difficult to obtain additional funding from the applicant if the additional relay work had not been identified at the beginning of the project.

Justifying the additional relaying can become a problem for the utility when the need for additional protection is not identified soon enough because different protection engineers are responsible for protection work at different voltage levels in an interconnected system. The problem can be compounded if there is lack of communication or lack of understanding of the impacts to the system of the added generation. These problems can occur within the same utility, or within interconnected utilities; therefore, it is extremely important to keep all parties informed when new generation is planned to be added to a utility system.

Figure 6 shows part of a 230 kV and a 60 kV network with a cogenerating facility interconnected on the 60 kV system which is large enough to serve the minimum 60 kV area load.

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Figure 6 shows part of a 230 kV and a 60 kV network with a cogenerating facility interconnected on the 60 kV system which is large enough to serve the minimum 60 kV area load.

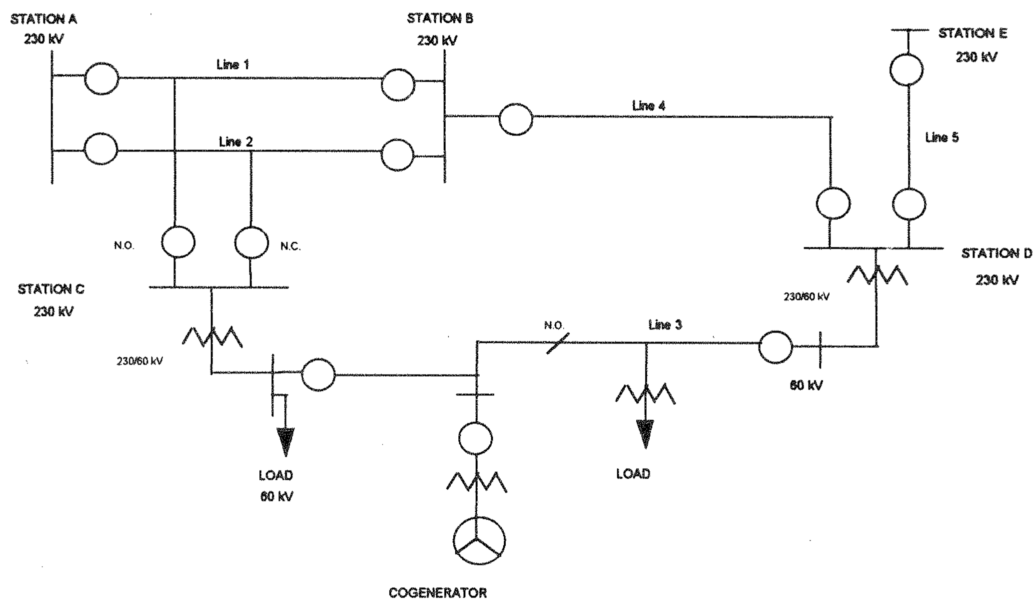

Figure 6. Example of typical subtransmission interconnection

The following examples illustrate potential problems that this cogenerating facility might present to the 230 kV system:

- Station C can be switched to either line 1 or line 2. Short circuit studies should be performed to verify if line-end faults on either of these two lines can be reliably detected from the 230 kV breaker at Station C. If line-end faults on these lines cannot be detected from Station C, the existing 230 kV relays may need to be replaced or direct transfer trip may need to be installed from Stations A and B to trip the high side breakers at Station C, and to permit high speed reclosing of the 230 kV of the breakers at Stations A and B.

- The ability to switch the 60 kV load to either station C or station D presents additional problems since the cogenerator will also be switched to station D by this switching action. Fault studies should be performed to determine if line-end faults on the 230 kV lines 4 and 5 can also be reliably detected. Additional considerations for this scenario would be to assume that one of the above lines is out of service due to circuit breaker maintenance at station D.

- Another very important consideration is high-speed reclose blocking in the event of a fault on line 5 which results in an incorrect operation of a pilot relay on line 4. For this scenario, both lines 4 and 5 will high speed reclose in 30 cycles and may cause significant damage to the generator if it is still on line.

  At PG&E we have devised protection schemes to solve this problem. For example, interlocking the two circuit breakers at Station D may be sufficient to prevent high speed reclosing against the generator as long as high speed reclosing is not permitted at Stations B and E. The use of a single phase undervoltage relay to block reclosing at Stations B and E may not be sufficient to prevent damage to generators on the 60 kV system. Therefore, we recommend that the line relays at stations B and E key direct transfer trip to the 230 kV breakers at Station D and that an open breaker at Station D should key a breaker status signal in the reverse direction (via the same transfer trip channel) to allow automatic reclosing of the 230 kV breakers at Stations B and E.

- A final consideration is breaker failure protection. If the 230 kV breakers at Station D have breaker failure protection, the 60 kV side of the transformer bank must also be tripped. The existing station design may not incorporate this feature because the 60 kV system had no source of generation. However, when a cogenerator is added to the 60 kV, this feature must be added at Station D.

INSTALLATION AND OPERATION

A. INSTALLATION

PG&E requires that the following procedures be followed prior to the energization of cogenerating unit(s) in order to assure proper operation and coordination of relays installed:

1. <u>Design Review:</u>
   All cogeneration relay settings and elementary design drawings are subject to review and approval by PG&E's protection engineers.

2. <u>Relay Tests:</u>
   The following functional tests are required to be performed and the test results copied to PG&E before a preparallel inspection is conducted.

   - Prove insulation of transformers, circuit breakers buses and cables to specifications.
   - Prove CT and PT ratios, connections and single grounding point. Supply CT saturation curves, and burden tests.
   - Prove circuit breaker tripping performance.
   - Conduct individual relay tests by applying the appropriate secondary currents, voltages and/or frequencies to the following tolerances:

Current, Voltage, Time	+/- 10%
Frequency	+/- 0.5 Hertz
Phase Angle	+/- 5.0 degrees
Impedance	+/- 5.0 %

3. **Preparallel Inspection:**

After the design review and relay tests have been completed, a preparallel inspection is required before the generator can parallel with the system. This inspection is performed by a certified technician and witnessed by PG&E's designated inspector. The following checks are performed during the preparallel inspection:

- Trip check each relay to assure the appropriate circuit breakers or switches will trip when the relay outputs a trip signal.
- Verify appropriate secondary current, and voltage inputs to relays.
- Check the synchronizing device for appropriate "in-phase" conditions.
- Check phasing and rotation.
- Check for load current on all relay current coils.
- Verify generator's operation at .9 PF lag and .95 PF lead at its rated output; and 95% and 105% from nominal voltage at its rated output.
- Load check all differential relays and voltage restraint overcurrent relays proving appropriate input connections.

B. OPERATING PROCEDURES

The cogenerator is under the jurisdiction and control of the PG&E system dispatcher while the generator is operating in parallel with the PG&E system. This operating arrangement is clarified by an operating agreement which has been signed by both the utility and the cogenerator before parallel operation begins.

OPERATING INCIDENTS

The following incidents are examples of problems that have occured when the generator protection requirements were ignored or not taken seriously:

A. PROTECTION PROBLEMS

1. **Need for Transfer Trip Caused Damage to the Generator:**

Situation:

A cogeneration project was installed at a single customer substation which was tapped on an existing transmission line creating a three terminal line. Line relays were installed at the single customer substation to trip the generating terminal for transmission line faults, but no transfer trip was installed from the utility line breakers. The generation capability roughly matched the load and it was designed to run as "islanded" following system disturbances so the generator was equipped with an asynchronous governor.

Problem:

A line fault occurred and was cleared quickly by the system breakers. The arc extinguished itself as a natural process while the cogeneration relays were timing to trip. The generator was able to run islanded carrying the line with almost no angular difference between systems. Forty five seconds after the fault was cleared, one of the system breakers made a "no slip" parallel with the cogenerator causing the separation of the turbine generator coupling.

Solution:

This problem could have been avoided if direct transfer trip had been installed at the two system breakers to trip the cogeneration plant main breaker when the utility breakers trip for a line fault. In addition, a synch check device, with ability to check slip, should have been installed to supervise automatic parallel of the system breakers.

2. Power Flow Between Two Voltages:

Situation:

The 60 kV low-side bank directional overcurrent relay at Station A was set sensitively to see high-side 230 kV bus faults. Cogeneration was added to the 60 kV system, see Figure 7 below.

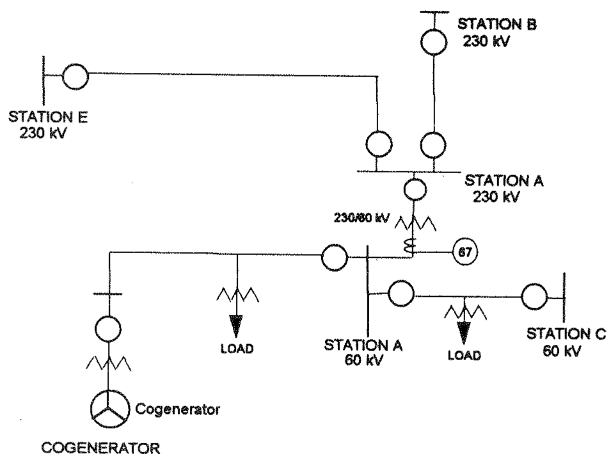

Figure 7 Power flow between two voltages

Problem:

Generation feeding into the 60 kV system exceeded the area load which forced power to flow into the 230 kV system through the 230/60 kV bank.

Solution:

The settings of the relays should be revisited whenever generation is added to the subtransmission system. If the settings cannot be raised above maximum expected reverse power flow, then sensitive reverse power relay should be installed to supervise the tripping of the low-side bank directional overcurrent relays.

B. FOUR-WIRE DISTRIBUTION CIRCUIT PROBLEM

1. Unbalanced Loading:

Situation:

A large cogeneration project was connected to a four-wire distribution circuit with a wye-grounded/delta generator step-up transformer. A neutral overcurrent relay was installed in the primary neutral of the step-up transformer to detect ground faults on the distribution circuit. The ground relay was set to detect end of line faults on the feeder and to provide backup for a line recloser in the event the recloser was bypassed.

Problem:

Unbalanced load currents flowed in the neutral of the four-wire circuit and were divided between the substation source breaker and the generator step-up transformer neutral. This caused undesirable operation of a neutral overcurrent ground relay during high load periods or when the distribution circuit was switched in the field.

Solution:

This problem can be solved by increasing the neutral overcurrent relay setting or applying negative sequence polarized directional ground relays. Disadvantages of installing the directional ground relay are that the relay requires three-phase potentials for a polarizing source (an extra expense), and there may be a standing negative sequence voltage due to the unbalanced loading. A disadvantage of increasing the neutral overcurrent relay setting is reduced protection for the distribution circuit.

2. Third Harmonic Loading:

Situation:

A large industrial customer (4 to 5 mW) was connected to the same distribution circuit as a nearby cogeneration facility. The industrial customer had a large percentage of connected load which used switching power supplies. The power supplies created a high level of harmonic currents on the distribution circuit, a major component being the third harmonic current.

Problem:

The third harmonic current circulated in the power system in the same manner as zero sequence current, so it was detected by the neutral overcurrent relay in the generator step-up transformer. This caused undesirable operation of ground relays which were set to operate for distribution system faults.

Solution:

This problem can be avoided by applying negative sequence polarized directional ground relays. The negative sequence element is not sensitive to third harmonic voltages, but it will operate for ground faults on the distribution circuit. However, this solution can be costly since three-phase high-side potentials are normally required.

C. OPERATING PROBLEMS WITH LARGE COGENERATION UNITS CONNECTED TO WEAK SYSTEMS:

1. Voltage Regulation:

Situation:

Large amounts of cogeneration was connected on the load side of a distribution line voltage regulator or the transmission substation transmission voltage regulator.

Problem:

During off-peak load conditions, the cogenerator produced reverse power flow through the utility substation regulator. This caused the substation load drop compensator to incorrectly regulate the voltage at load stations remote from the cogeneration site.

Solution:

Set the voltage regulator on flat voltage control since conventional load drop compensation cannot be used. However this can result in limited reactive support required to meet overall system needs if the voltage is regulated for nearby load stations. These problems can be avoided by connecting the cogeneration to higher voltage lines that are part of the bulk power system. However this is almost always a more costly solution.

2. Lack of Reactive Capability:

Situation:
Large cogeneration projects were located on the end-of-line remote from the utility system.

Problem:
Energizing one cogeneration facility step-up transformer caused the adjacent cogeneration facility to trip off-line by negative sequence relay. This was caused by transformer inrush currents being provided by the adjacent facility since it was a better reactive source than the remote utility substation.

Solution:
Review the relay setting and increase the relay minimum to trip or add more time delay if permitted by the unit ratings.

CONCLUSION

There is more to specifying cogenerator interconnection requirements than recommending the standard frequency, voltage and overcurrent relays. Each proposed interconnection must be carefully studied for impacts on the utility power system at all voltage levels. All costs for additional relay work and system reinforcements must be identified up front so the applicant can realistically evaluate the economic feasibility of the project and the utility is not left with an inoperable or compromised system. It is crucial that all parties take active responsibility for maintaining a two-way communication path, before, during and after project installation; to make known temporary operating changes to the system, proposed design changes, addition of cogeneration units and operating analyses so that appropriate actions are taken to maintain the integrity of protection.

Undoubtedly, the scenarios described in this paper just briefly touched on only a few of the protection problems and solutions related to our utility and interconnected facilities. We did not attempt to describe all factors which can influence the protection requirements, since they would be too numerous for one paper to cover. To speak on behalf of other utilities experiences would not be an easy task, since although the fault analysis is basic in nature, the solutions and approach are complex. It would require a library of manuals to properly describe all possible solutions, because the risks, probabilities, utilities' business economics, protection philosophies, preferences, and substation design would all have to be factored into the solutions. We can only hope, as protection engineers, that as more cogenerators are allowed on the line and continue to generate power into our system, the relaying technologies of the future will focus on improving and simplifying devices so that we can readily specify protection requirements to meet the operating needs of the system.

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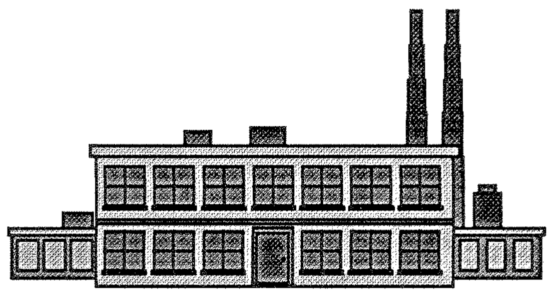

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