UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of PACIFIC GAS AND ELECTRIC COMPANY	Docket No. 50-275 Facility Operating License No. DPR-80
Diablo Canyon Power Plant Units 1 and 2	Docket No. 50-323 Facility Operating License No. DPR-82

License Amendment Request
No. 98-01

Pursuant to 10 CFR 50.90, Pacific Gas and Electric Company hereby applies to amend its Diablo Canyon Power Plant (DCPP) Facility Operating License Nos. DPR-80 and DPR-82 (Licenses), and requests review and approval of the replacement of the startup transformers (SUTs) with transformers having automatic load tap changers (LTCs), installation of shunt capacitor banks at the DCPP switchyard and at the Mesa Substation in the Los Padres Region of PG&Es service territory, and manual operation of the Unit 2 SUT LTC until the automatic voltage control feature on the Unit 2 SUT is functional.

Information on the proposed changes is provided in Attachment A. The changes have been reviewed and do not involve a significant hazards consideration as defined in 10 CFR 50.92 or an unreviewed environmental question. Further, there is reasonable assurance that the proposed changes will not adversely affect the health and safety of the public.

Sincerely,

Robert P. Powers

Subscribed and sworn to before me
this 14th day of January, 1998.
County of San Luis Obispo
State of California

Notary Public

Attorneys for Pacific Gas
and Electric Company
Roger J. Peters
Richard F. Locke

Richard F. Locke

IMPLEMENTATION OF 230 KV SYSTEM IMPROVEMENTS

A. DESCRIPTION OF AMENDMENT REQUEST

This license amendment request (LAR) requests NRC review and approval, in accordance with 10 CFR 50.90, of the replacement of the Diablo Canyon Power Plant (DCPP) startup transformers (SUTs) with transformers having automatic load tap changers (LTCs), installation of shunt capacitor banks at the DCPP switchyard and at the Mesa Substation in the Los Padres Region of PG&Es service territory, and manual operation of the Unit 2 SUT LTC until the automatic voltage control feature on the Unit 2 SUT is functional.

The improvements are being made to resolve voltage issues reported in Licensee Event Report (LER) 1-95-007, which required operation of the Morro Bay Power Plant (MBPP) during peak system loading. Implementation of the 230 kV improvements will make operation of MBPP to support DCPP operation unnecessary. PG&E is selling MBPP as a result of the restructuring of the electric industry in the State of California. Transfer of ownership of MBPP is expected to occur on or about March 31, 1998.

B. BACKGROUND

Offsite power (see Figure 1) for startup and standby service is provided from the 230 kV transmission system. The two incoming 230 kV transmission lines, one from the nearby MBPP switchyard, approximately 10 miles away, and the other from the Mesa Substation, feed a 230 kV switchyard having three 230 kV circuit breakers, one for each line and one for the standby startup transformers. Offsite power to the plant auxiliary systems and engineered safety feature (ESF) buses can also be provided from the 500 kV system when the main generator is not in operation. The 500 kV line is a backup for the 230 kV plant power supply via the main transformer to the unit auxiliary transformers.

LER 1-95-007

On August 8, 1995, PG&E determined that the 230 kV system may not be able to meet its design requirements for all system loading conditions. Studies conducted at that time indicated that during peak system loading, all 230 kV lines and MBPP Units 3 or 4 needed to be in service to ensure DCPP minimum 230 kV voltage requirements are met. Prior to that time there was no requirement that a unit of MBPP be operated to support DCPP operation.

The Final Safety Analysis Report (FSAR) when DCPP was licensed stated that the MBPP 230 kV switchyard is a reliable source of power with four generating units (MBPP) and two 230 kV double circuit tower lines from Midway and Gates Substations connected to the 230 kV switchyard buses. The safety evaluation report prepared by the Directorate of Licensing, U. S. Atomic Energy Commission (now U. S. Nuclear Regulatory Commission), in evaluating the adequacy of the offsite power system, concluded that a combination of either 230 kV circuit and one of the three 500 kV circuits provides sufficient assurance that redundant and independent sources of offsite power are provided, and that the design of the offsite power system was acceptable. Operation of MBPP to support DCPP operation was not specifically discussed.

LER 1-95-007 stated that "system modifications were under evaluation for the next refueling outage for each unit to address future maintenance, growth, or changes on the 230 kV system."

California Electric Industry Restructuring

California is in the process of restructuring its electric industry. Legislation passed by the California legislature and signed into law describes requirements associated with restructuring of the electric industry. This legislation, in part, requires the establishment of an Independent System Operator that will be responsible for directing operation of the transmission system and controlling power flow and availability. These functions are currently performed by PG&E within its service territory. PG&E will, however, continue to own and maintain its transmission system, and will man and operate some major switchyards including the DCPP switchyard.

Various decisions of the California Public Utilities Commission which preceded the enactment of the restructuring legislation also require that PG&E and Southern California Edison submit plans to voluntarily divest at least half of their fossil-fueled generation facilities to assure that the utilities do not exercise market power in California due to their generation capability. In complying with this requirement, PG&E has agreed to sell the MBPP. MBPP is an approximately 1000 MWe power plant consisting of four natural gas fired units, and is described in the DCPP FSAR as part of the 230 kV preferred power source since the DCPP 230 kV switchyard is supplied, in part, by the MBPP switchyard. As noted above, the relevant transmission facilities will continue to be owned by PG&E. These facilities include: (1) the MBPP switchyard, (2) the four 230 kV incoming lines from the 500 kV Midway and Gates Substations, and (3) the three 230 kV lines between the following switchyards/substations: MBPP-DCPP, MBPP-Mesa, and Mesa-DCPP

230 kV Improvements

To resolve the issues reported in LER 1-95-007, and in preparation for electric industry restructuring, specifically the sale of MBPP, PG&E initiated an upgrade of the 230 kV transmission system in the Los Padres Region (of which DCPP is part). The goal of the upgrades is to provide DCPP with adequate 230 kV power assuming operation of the grid in accordance with industry emergency and normal guidelines, and to ensure that DCPP is no longer dependent on MBPP operation. The 230 kV system is the immediate access offsite power source for DCPP.

The 230 kV system improvements include installation of shunt capacitor banks at the DCPP switchyard and at PG&E's Mesa Substation and installation of new 230/12 kV SUTs at DCPP with LTCs. The shunt capacitors will assure adequate VAR support previously provided by MBPP for present peak load and future peak load growth under worst case line outage conditions. Installation of the automatic LTC 230/12 kV SUTs will allow the voltage on the plant 12 kV and 4 kV buses to be maintained within limits acceptable for plant equipment operation given the emergency voltage operating criteria for the transmission system of +5 percent/-10 percent. The normal Western System Coordinating Council (WSCC) voltage criteria for the transmission system of +5 percent/-5 percent is less severe.

PG&E has installed the LTC 230/12 kV SUTs in both Units 1 and 2, although the automatic voltage control feature on the Unit 2 transformer will not be functional until the Unit 2 eighth refueling outage scheduled to begin mid-February 1998. Until the automatic voltage control feature is functional on the Unit 2 SUT, PG&E will manually adjust the tap as necessary to accommodate voltage schedules on the 230 kV system. Tap changes to the new transformer with the LTC can be made on-line without deenergizing the transformer.

The shunt capacitors have not yet been installed on the Los Padres Region 230 kV system. The VAR support is needed during peak summer loads and during the worst case line outage condition to stabilize voltage. The capacitors are scheduled to be installed in April 1998, prior to their need in summer, 1998.

C. JUSTIFICATION

The equipment improvements and changes in operation of DCPP are required to resolve voltage issues reported in LER 1-95-007, which required operation of the MBPP during peak system loading. Implementation of the 230 kV improvements will make operation of MBPP to support DCPP operation unnecessary. PG&E is

selling MBPP as a result of the restructuring of the electric industry in the State of California. Transfer of ownership of MBPP is scheduled to occur on or about March 31, 1998. Starting January 1, 1998, PG&E may economically dispatch the MBPP units until ownership is transferred.

D. SAFETY EVALUATION

Replacement of SUTs With Transformers With LTCs/Installation of Shunt Capacitor Banks

1971 GDC 17, Regulatory Guide (RG) 1.6, RG 1.32, and IEEE 308, "Criteria for Class 1E Electric Systems for Nuclear Power Stations," constitute the design basis requirements for offsite power availability at DCPP. DCPP utilizes PG&E's 230 kV transmission system to meet the requirements for an immediately available offsite power source and PG&E's 500 kV transmission system to meet the requirements for a delayed offsite power source. The offsite power sources are also referred to as the preferred power sources. Operability of the immediately available offsite power source (230 kV) minimizes challenges to the onsite power source (diesel generators).

The design of DCPP as described in the FSAR requires that the two 230 kV transmission lines feeding the DCPP switchyard, one directly from MBPP switchyard, and the other from MBPP through the Mesa Substation, each be independently able to support the transfer of plant auxiliary loads for a design basis accident on one unit and loads required for concurrent orderly safe shutdown on the remaining unit when either 230 kV source is available. The voltage available at the DCPP 4 kV and 480 V vital buses when supplied from the 230 kV startup source is not adequate under certain design basis operating scenarios to support the operation of required safety-related equipment. Presently, several compensatory measures, such as operating MBPP and using a reduced load transfer, are utilized to ensure 230 kV offsite power is operable. Due to the design characteristics of the DCPP power distribution system and PG&E's 230 kV transmission system, it has been determined that for all weekdays and some weekends during extreme hot or cold weather, it is necessary to operate MBPP in anticipation of a unit trip or accident, to ensure that sufficient voltage is available to successfully transfer the plant auxiliary loads on one unit and the safe shutdown loads on the other unit to the startup source.

To provide adequate voltage with either 230 kV line in service and to eliminate the need to operate MBPP in support of DCPP, the DCPP SUTs have been replaced with transformers with LTCs. To assure the 230 kV system remains

within emergency voltage limits, shunt capacitor banks will be installed at the DCPP switchyard and at the Mesa Substation in the Los Padres Region of PG&Es service territory. Installation of the automatic LTC 230/12 kV startup transformers will allow the voltage on the plant 12 kV and 4 kV buses to be maintained within limits acceptable for plant equipment operation given the emergency voltage operating criteria for the transmission system of +5 percent/ -10 percent. The normal WSCC voltage criteria for the transmission system of +5 percent/-5 percent is less severe. The shunt capacitors will assure adequate VAR support that was previously provided by MBPP in the Los Padres Region for present peak summer load and future peak load growth under worst case line outage conditions.

The replacement of a fixed ratio transformer with an automatic load tap changing transformer will enhance the capability of the 12 kV and 4 kV electrical distribution systems.

The automatic LTC feature eliminates the potential for "double sequencing" of the 4 kV vital loads during an accident, and therefore, enhances the margin of safety. Double sequencing means the ESF loads would be started, stopped, and restarted. This could occur during a design basis accident or unit trip if the ESF loads were immediately transferred to the 230 kV source, and then 30 seconds later the remaining balance of plant loads were to transfer. With a 230 kV line out-of-service, this sequence could cause a 230 kV degraded voltage condition for DCPP and actuate the emergency diesel generator (EDG) second level undervoltage relays (SLURs). Actuation of the SLURs would cause the ESF loads to stop and be restarted on the EDGs, i.e., double sequencing.

LTCs have been used extensively in electrical transmission systems throughout the country. Many nuclear power stations, i.e., Limerick, Peach Bottom, Salem, Hope Creek, and others, have used LTC transformers as a part of their original design. LTC retrofits have been done for several plants under 10 CFR 50.59; some of the recent (1994) installations include the Sequoyah and Browns Ferry plants. The advanced BWR design by GE (ABWR) and advanced PWR design by Westinghouse (AP600) also use LTC transformers for the station auxiliaries. Both ABWR and AP600 designs have gone through NRC review, and the ABWR design has been licensed by the NRC.

LTCs are extremely reliable. The type of LTC (Reinhausen Type M) selected for DCPP application is considered the best in the industry in performance and reliability, with a failure rate of 1 in 1667 years. In comparison, a large power transformer has a failure rate of 1 in 300 years. From an failure modes effects analysis perspective, LTC failure is bounded by the failure of the transformer. The failure of the transformer is accommodated in the existing accident analysis

by considering it within the realm of the loss of offsite power. The credible failure mechanism of the LTC is a malfunction of the voltage control relay. To guard against this malfunction, a backup voltage relay is supplied with the LTC equipment. The backup relay prevents the LTC from running to the full voltage raise or full voltage lower position. If the voltage fluctuates to the outside of the bandwith setting of the voltage control relay, the backup relay blocks the automatic control in that direction. Since the backup relay setpoint is approximately 3 percent higher than the primary voltage control relay setpoint, the LTC voltage control would be blocked from further control and will be frozen at the backup relay voltage setpoint. This potential malfunction of the LTC is monitored in the control room through indication and annunciator action. The control room operator would take action under this condition which could include taking manual control of the LTC or removing the transformer from service and aligning to the other unit's SUT while maintenance is performed.

Finally, a malfunction of the LTC coincident with a grid disturbance has been evaluated from the perspective of damage to the transformer or creating a failure mode that would affect both trains of vital equipment needed for safe shutdown of the unit, and determined to be not credible. Even for the worst case scenario of grid voltage increasing, with the LTC stuck at the worst tap position, the transformer and other equipment fed from the transformer would be able to sustain an overvoltage condition without any damage for a minimum period of 2 hours. Any overvoltage is expected to be in close proximity to the voltage level normally experienced by operating equipment during an outage with either 230 kV at the maximum value of 240 kV or 500 kV at a maximum value of 550 kV. Operation of affected equipment during outages with a high voltage condition has been evaluated and found acceptable. Grid disturbances causing decreasing voltage with the LTC stuck would be detected by the SLUR, and the 4 kV vital buses would be separated from the offsite power source and transferred to the EDGs as per the original design. Malfunction of both the primary voltage control relay and the backup voltage control relay causing the LTC to run away to either the extreme high and low tap positions is not credible since the probability of both the primary and the backup voltage control relays to fail simultaneously is 7.4E-8/year. Periodic maintenance of the LTC components will ensure the reliability of the LTC.

A failure of the LTC does not invalidate the assumptions used in the station blackout (SBO) methodology. The SBO analysis assumes the loss of all power including the loss of offsite power.

Also, the new transformers have a higher short circuit and seismic withstand capability. A study of the DCPP transformers as a result of the failure of a Unit 1 auxiliary transformer in 1995 indicated that the SUTs were among those with the

least capability for withstanding a through-fault short circuit current. The study indicated that the short circuit withstand capability of these transformers was approximately 40 percent of what is needed. The replacement transformer has a higher short circuit withstand rating than the original and is designed to withstand full short circuit current. Accordingly, transformer failure due to inadequate through-fault capability is no longer a concern.

The replacement SUTs have been seismically qualified for higher acceleration levels than the original transformers, and satisfy the review requirements of PG&E's Long Term Seismic Program. Spare transformer bushings are stocked at DCPP to facilitate repairs should they suffer any damage during an earthquake.

The installation of shunt capacitor banks at the DCPP switchyard and at the Mesa Substation in the Los Padres Region of the PG&E service territory will replace the needed VAR support in the Los Padres area presently provided by MBPP for present peak load (next expected to occur during the summer 1998) and future peak load growth under worst case line outage conditions, assuming no generation from the MBPP. The shunt capacitors are static devices and are more reliable than generators. Further, each capacitor bank consists of two stacks and each stack is independently controlled, thereby providing redundancy in operation. Failure of one capacitor stack would not significantly affect the VAR support since the sizing of the capacitor bank includes adequate margin. From a failure mode perspective, the failure of a capacitor stack is less likely than the failure of a generator. Furthermore, the effect of failure of a capacitor stack only results in a partial loss of VAR support compared to a total loss of VAR support from a generator failure. The shunt capacitors are scheduled to be installed on the 230 kV system by April of 1998. These shunt capacitors are required for the 1998 peak summer loads.

Manual Operation of the Unit 2 SUT LTC

The Unit 1 SUT was replaced in May 1997 with a new LTC transformer with an automatic voltage control feature. The Unit 2 SUT was replaced with DCPP on-line in November 1997 with a new LTC transformer with manual voltage control. The automatic voltage control feature is planned to be installed on the Unit 2 SUT during the Unit 2 eighth refueling outage, which is scheduled to begin mid February 1998. During the interim time period the Unit 2 transformer LTC will be manually adjusted to accommodate the voltage schedules on the 230 kV system.

Presently, the DCPP switchyard voltage is maintained within a range of 232 kV to 234 kV during day time with the help of MBPP generation. The minimum

acceptable voltage ranges are specified in system operating procedures. The minimum for all lines in service with MBPP 3 or 4 in operation is 231 kV. Without MBPP generation, the voltage at the DCPP 230 kV switchyard may not be maintained at the present voltage range of 232 kV to 234 kV. Based on the studies performed by PG&E transmission planning, the daily voltage range during the months of January through April 1998 is expected to be in the range of 225 kV to 240 kV. A nominal voltage range of 225 kV to 235 kV is expected to be maintained during the hours of 7:00 a.m. and 10:00 p.m. on week days, and normally between 230 kV to 240 kV during the hours of 10:00 p.m. and 7:00 a.m. weekdays and all hours during weekends. The LTCs have sufficient range to compensate for the anticipated 230 kV voltage variation without the installation of shunt capacitors. The Unit 1 SUT with automatic LTC would maintain a constant preset voltage at the 12 kV buses. The Unit 2 startup transformer LTC will be adjusted as necessary for the optimum tap position corresponding to the anticipated 230 kV voltage range during that period to assure adequate voltage for proper equipment operation. The optimum tap positions are specified in system operating procedures for several expected voltage ranges which cover all possible line outage configurations; the procedures also include the necessary compensatory measures to maintain operability. This operation will continue through approximately mid-February 1998 until Unit 2 is shut down for refueling. By the end of the Unit 2 outage, scheduled for approximately late March 1998, the automatic LTC feature for the Unit 2 startup transformer will be operational and manual adjustment will no longer be required.

Based on projected system load during this interim period (until the peak summer Los Padres system loads), shunt capacitors are not required to be installed because 230 kV system voltage can be maintained within an acceptable range without the MBPP generation for all single line outage conditions as required by the WSCC for grid reliability.

Manual operation of the LTC is acceptable based on the guidance provided in NRC Information Notice IN 97-78. The adjustment of the LTC will be done per written plant procedure, and recovery from an incorrect adjustment can be made immediately with no effect on plant operation. The adjustments are made in advance to assure adequate voltage is available for an accident or unit trip. The adjustments of the LTC are not made in response to a plant transient nor are they made to mitigate the effects of a plant accident. The control room operator will monitor the transformer voltage, and any undesirable response will be immediately detected. Further, the manual operation of the LTC does not affect the margin of safety for the vital 4 kV and 480V buses since the pretransfer voltage levels at the vital 4 kV buses are to be maintained at the same values considered in the original design.

Conclusion

The changes described above will allow the 230 kV system voltage to be maintained within limits acceptable for plant equipment operation without MBPP operation. Therefore, PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the changes.

E. NO SIGNIFICANT HAZARDS EVALUATION

PG&E has evaluated the no significant hazards considerations (NSHC) involved with the proposed amendment, focusing on the three standards set forth in 10 CFR 50.92(c) as set forth below:

> *"The commission may make a final determination, pursuant to the procedures in paragraph 50.91, that a proposed amendment to an operating license for a facility licensed under paragraph 50.21(b) or paragraph 50.22 or for a testing facility involves no significant hazards considerations, if operation of the facility in accordance with the proposed amendment would not:*
>
> *(1) Involve a significant increase in the probability or consequences of an accident previously evaluated; or*
>
> *(2) Create the possibility of a new or different kind of accident from any accident previously evaluated; or*
>
> *(3) Involve a significant reduction in a margin of safety.*

The following evaluation is provided for the NSHCs.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   The replacement of the startup transformers (SUTs) with new transformers equipped with load tap changers (LTCs) for voltage control does not alter the original configuration of the electrical distribution system and hence, will not increase the probability of occurrence of an accident previously evaluated.

   The replacement of the SUTs with new transformers equipped with LTCs will enhance the capability of the 12 kV and 4 kV electrical distribution systems to maintain sufficient voltage for successful transfer of the plant

auxiliary loads to the startup source following a unit trip. This change eliminates the potential for "double sequencing" (starting loads from the 230 kV system, subsequent voltage degradation causes load shedding and restarting from the diesel generators) of the 4 kV vital loads during an accident by providing adequate voltage to the 4 kV vital buses from the 230 kV source. The maintenance of adequate voltage at the 4 kV vital buses prevents the second level undervoltage relay (SLUR) action. The LTC will automatically maintain adequate voltage at the terminals of the vital equipment under design basis accident conditions. Therefore, engineered safety feature equipment will function as previously evaluated.

The manual operation of the Unit 2 LTC while in a standby mode will not increase the probability of an accident since normally none of the plant loads are energized from the 230 kV system. Plant loads are only powered from the 230 kV system during short periods of unit startup and shutdown. Loss of the 230 kV system while the operating plant loads are fed from the 25/500 kV system cannot initiate an accident since the system is not connected to plant equipment if the loads are supplied by the 25/500 kV system. Therefore, the proposed modifications will not increase the probability of an accident previously evaluated. The manual operation of the Unit 2 LTC assures adequate voltage is supplied to Unit 2 safety equipment in the event of an accident. Therefore, the proposed modification will not increase the consequences of an accident.

The installation of the shunt capacitors at the Diablo Canyon Power Plant switchyard and Mesa Substation to replace the VAR support from Morro Bay Power Plant (MBPP), assuming no MBPP generation, does not alter the capability or availability of the offsite power source. Since shunt capacitors are considered more reliable than generators, it adds to the reliability of the 230 kV system and will not increase the probability of an accident previously evaluated.

Even if 230 kV voltage were lost or became degraded, the first or second level undervoltage relays will initiate transfer to the diesel generators should there be a loss or degraded 230 kV system while feeding the vital loads from the 230 kV system. This scenario is evaluated in Final Safety Analysis Report (FSAR) Update Section 15.2.9.1 "Loss of Offsite Power to the Station Auxiliaries."

Therefore, the changes will not increase the consequences of an accident previously evaluated since the safety-related loads will function as required.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

The change does not result in a change in operation, maintenance, physical change, or procedural change that could create the possibility of an accident that is of a new or different type than previously evaluated.

The replacement SUTs and the installation of the shunt capacitors to replace MBPP serves the same function as the original design and do not create the possibility of a new or different type of accident. Should there be a loss of offsite power, the onsite power source (diesel generators) will provide power to the loads. The FSAR already includes an evaluation for station blackout if there is a total loss of both onsite and offsite power.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

The replacement transformers and the installation of the shunt capacitors will not cause a reduction in the margin of safety as defined in the basis for any Technical Specification (TS). The minimum voltage required for safe shutdown is defined in TS Table 3.3.4, Functional Unit 7.b, "Second Level Undervoltage Relay (SLUR) setting." By replacing the existing SUTs with automatic LTC transformers, the vital 4 kV bus voltage will be automatically maintained at a sufficiently higher value during normal operation such that during an accident, the minimum 4 kV vital bus voltages after the bus transfer will be adequate to prevent SLUR actuation. The installation of the shunt capacitors will assure adequate VAR support that was previously provided by operation of the MBPP in the Los Padres Region of PG&E's service territory for present peak load and future peak load growth under worse case line outage conditions.

During the interim period between January and February 1998, when manual control of the Unit 2 SUT LTC will be utilized to maintain adequate voltage at the 12 kV and 4 kV buses, the margin of safety is not reduced since the adjustment of the LTC will assure stable voltage for the vital buses.

Therefore, there is no reduction in a margin of safety as defined in the basis for any TS.

F. NO SIGNIFICANT HAZARDS DETERMINATION

Based on the above safety evaluation, PG&E concludes that the changes proposed by this LAR satisfy the no significant hazards consideration standards of 10 CFR 50.92(c), and accordingly a no significant hazards finding is justified.

G. ENVIRONMENTAL EVALUATION

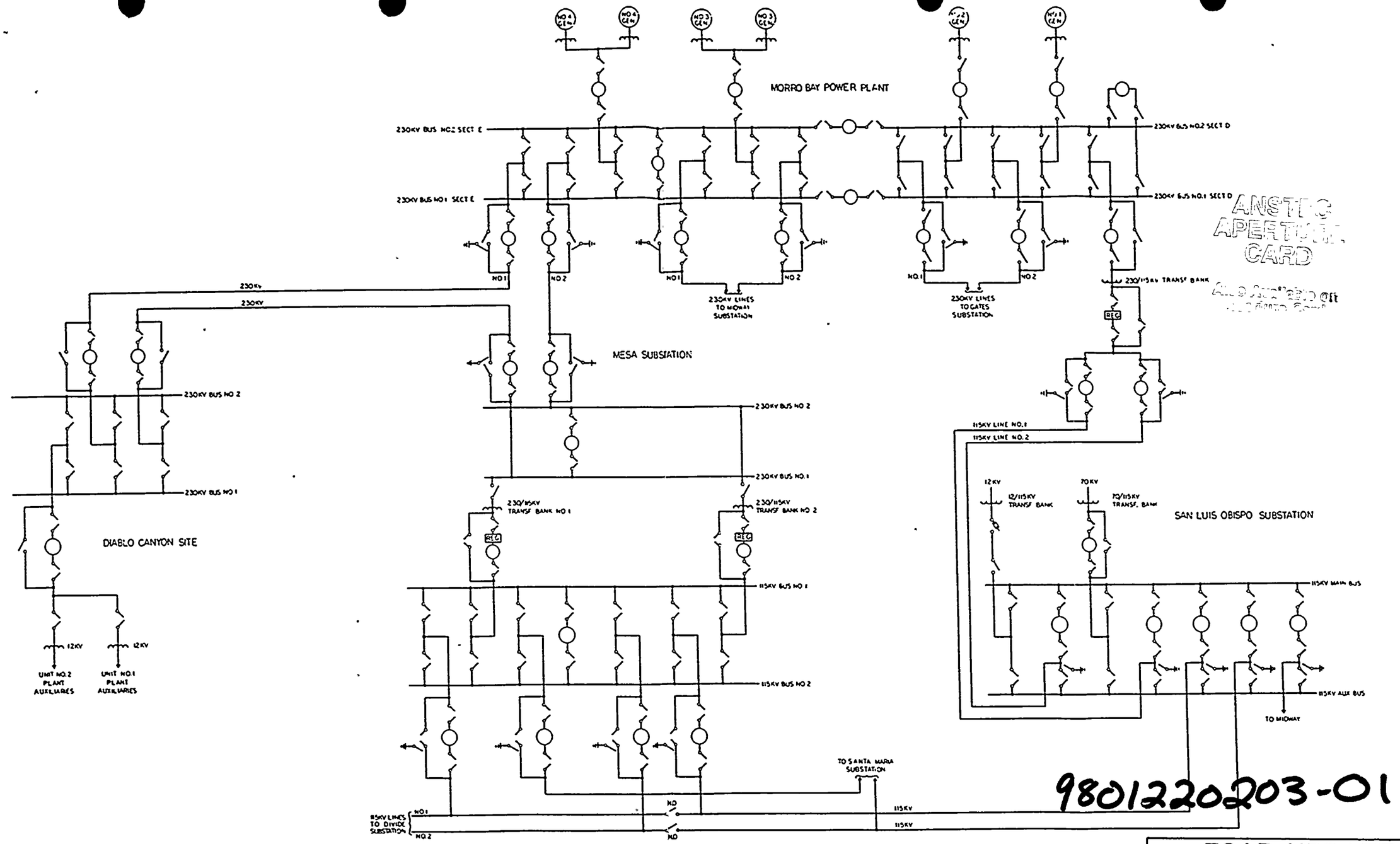
PG&E has evaluated the proposed changes and determined the changes do not involve: (I) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed changes meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), an environmental assessment of the proposed change is not required.

FIGURE 1

OFFSITE SINGLE LINE DIAGRAM

FSAR FIGURE 8.2-1

(Attached)



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FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 8.2-1
OFFSITE SINGLE LINE DIAGRAM

10-80S0S8168P