## Diablo Canyon Power Plant ER Changes Reflected in the Environmental Report Update Amendment 2

| Attachment | ER Section | Subject |
|---|---|---|
| 1 | Chapter 7<br>Table 8-1<br>Table 8-2<br>Section 9.2 | Updated to address more recent data on energy alternatives in California and a combination alternative. |
| 2 | Section 4.20<br>Appendix F | Updated the Severe Accident Mitigation Alternatives (SAMA) Analysis using an updated Probabilistic Risk Assessment (PRA) model, more recent population, economic, and evacuation information, and updated seismic hazard curves. |

# Attachment 1 – Environmental Report, Amendment 2

## Chapter 7
## Table 8-1
## Table 8-2
## Section 9.2

# CHAPTER 7 - ALTERNATIVES TO THE PROPOSED ACTION

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NRC

The environmental report shall discuss "Alternatives to the proposed action...." 10 CFR 51.45(b)(3), as adopted by reference at 10 CFR 51.53(c)(2)

"...The report is not required to include discussion of need for power or economic costs and benefits of ... alternatives to the proposed action except insofar as such costs and benefits are either essential for a determination regarding the inclusion of an alternative in the range of alternatives considered or relevant to mitigation...."
10 CFR 51.53(c)(2)

"While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable..." (NRC 1996)

"...The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant's service area...." (NRC 1996)

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Chapter 7 evaluates alternatives to Diablo Canyon Power Plant (DCPP) license renewal. In this chapter, Pacific Gas and Electric Company (PG&E) identifies reasonable alternatives to renewal of the operating licenses for DCPP Units 1 and 2, and describes the environmental impacts of these reasonable alternatives. This chapter also includes descriptions of alternatives that were considered by PG&E, but determined to be unreasonable, as well as the supporting rationale for those determinations.

PG&E divided its alternatives discussion into two categories: "no-action" and "alternatives that meet system generating needs." In considering the level of detail and analysis that it should provide for each category, PG&E relied on the NRC decision-making standard for license renewal:

> "...the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decision makers would be unreasonable." [10 CFR 51.95(c)(4)]

The environmental impact evaluations of alternatives presented in this chapter are not intended to be exhaustive. Rather, PG&E generally structured the analysis to focus on comparative impacts, specifically whether an alternative's impacts would be greater, smaller, or similar to the proposed action.

Providing additional detail or analysis was not considered beneficial or necessary if it only brings to light additional adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which provide that the consideration of alternatives (including the proposed action) should enable reviewers to evaluate their comparative merits (40 CFR 1500-1508). This chapter establishes the basis for necessary comparisons to the Chapter 4 discussion of impacts from the proposed action.

In characterizing environmental impacts from alternatives, PG&E has used the same definitions of "small," "moderate," and "large" that are presented in the introduction to Chapter 4 and used by the NRC in its Generic Environmental Impact Statement (GEIS) (Reference 21).

## 7.1 NO-ACTION ALTERNATIVE

PG&E uses "no-action alternative" to refer to a scenario in which the NRC does not renew the DCPP operating licenses for Units 1 and 2. Under the no-action alternative, operation of Units 1 and 2 would cease upon expiration of the current operating licenses in 2024 and 2025. Components of this alternative include decommissioning the facility and replacing the generating capacity of DCPP.

DCPP provides approximately 2,285 megawatts (Reference 4) of baseload, low carbon electricity to PG&E's customers. Because Units 1 and 2 constitute a significant block of long-term baseload capacity, *this evaluation* ~~it is reasonable to~~ assume*s* that a decision not to renew the operating licenses for both Units would necessitate the replacement of its approximately 2,285 MWe capacity *and electricity generation* with other sources of generation. Replacement could be accomplished by (1) building new generating capacity, (2) purchasing power from the wholesale market, or (3) reducing power requirements through demand reduction. Section 7.2.1 identifies and describes alternative generating technologies as potential candidate technologies to replace the DCPP baseload *generation (i.e., capacity and energy)*~~capacity~~. PG&E considered any alternative that could not replace the *baseload* ~~capacity~~ *generation* of DCPP an unreasonable alternative. Conversely, if an alternative technology could replace the *baseload* capacity of DCPP, PG&E considered that a reasonable alternative. Section 7.2.2 describes environmental impacts of reasonable alternatives, including purchased power. ~~In addition, w~~*W*ith respect to demand reduction, PG&E ~~will need to pursue all feasible energy efficiency and renewable energy options in order to~~*already must* meet California's aggressive renewable power requirements and Greenhouse Gas *(GHG)* Emissions Performance Standards. ~~It is unlikely that there will be enough renewable generation or demand reduction to both meet these requirements and also replace 2,285 MW of DCPP baseload generation with renewable power or energy efficiency. Therefore, the "no action" alternative could undermine efforts to meet those standards.~~ *It is uncertain whether an additional 2,285 MW of energy efficiency or demand side reduction can be identified beyond that already planned by the State. Depending on the source of replacement power, PG&E might also need to mitigate GHG emission increases.*

Under the no-action alternative, PG&E would continue operating DCPP until the existing licenses expire, then initiate decommissioning activities in accordance with NRC requirements. The Generic Environmental Impact Statement (GEIS) (Reference 21) defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. NRC-evaluated decommissioning options include immediate decontamination and dismantlement (DECON option) and safe storage of the stabilized and defueled facility for a period of time, followed by additional decontamination and dismantlement (SAFSTOR option). Regardless of the option chosen, decommissioning must be completed within a 60-year period after expiration of the operating licenses. The GEIS describes decommissioning activities based on an evaluation of the "reference" pressurized-water reactor (the 1,175-megawatt-electric [MWe] Trojan Nuclear Plant). This description is applicable to decommissioning activities that PG&E would conduct at DCPP.

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include impacts of occupational and public radiation dose; impacts of waste management; impacts to air and water quality; and ecological, economic, and socioeconomic impacts. NRC indicated in the "Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities; Supplement 1" (Reference 23) that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations. PG&E adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

PG&E notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. PG&E will have to decommission DCPP regardless of the NRC decision on license renewal; license renewal would only postpone decommissioning for another 20 years. NRC has established in the GEIS that the timing of decommissioning operations does not substantially influence the environmental impacts of decommissioning. PG&E adopts by reference the NRC findings (10 CFR 51, Appendix B, Table B-1, Decommissioning) to the effect that delaying decommissioning until after the renewal term would have small environmental impacts.

PG&E also notes that the no-action alternative could have an impact on area real estate values following DCPP shutdown and decommissioning. PG&E employs approximately ~~1,350~~*1,440* employees at DCPP and more than 95 percent of these employees reside in San Luis Obispo and Santa Barbara Counties. Since DCPP is noted to be one of the largest employers in San Luis Obispo County (Reference 16), the reduction in overall long-term site workforce (1) could force employees to relocate to another area with similar job-types available, (2) could result in a lower median County income, and (3) could thus, impact area real estate values.

PG&E concludes that the decommissioning impacts would not be substantially different from those occurring following license renewal, as identified in the GEIS (Reference 21) and in the decommissioning generic environmental impact statement (Reference 23). These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

The discriminators between the proposed action and the no-action alternative are to be found within the choice of generation replacement options. Section 7.2.2 analyzes the environmental impacts from these options.

## 7.2 ALTERNATIVES

DCPP has a net capacity of 2,285 MWe and in ~~2007~~ *2012* generated approximately ~~18.6~~*18.5* terawatt-hours of electricity (Reference 17). If the DCPP operating licenses were not renewed, the *baseload* power produced by DCPP, which represents a significant portion of the energy that PG&E supplies to customers in its service territory, would not be available. PG&E would need to build new generating capacity, purchase power, or reduce power requirements through demand reduction to meet the electric power requirements of its customers.

The current mix of power generation options in California is one indicator of what PG&E considers to be *potentially* feasible alternatives. *In 2012, generating capacity in California was 71,329 MW (Reference 19, Table 4). This capacity includes units fueled by natural gas (58 percent), hydroelectric (14.2 percent), other renewables (11.1 percent), nuclear (6.2 percent), pumped storage (5.4 percent), geothermal (2.9 percent), petroleum (0.6 percent), coal (0.5 percent), and other gases (0.3 percent).* In ~~2007~~*2012*, electric generators in California had a gross power output of ~~210,847~~*199,519* Gigawatt Hours (GWh). This ~~capacity~~ *generation* includes units fueled by natural gas (~~60.4~~*60.0* percent), hydroelectric (*13.5*~~15.7~~ percent), ~~other renewables (9.0 percent),~~ nuclear (~~6.9~~*9.3* percent), *other renewables (8.7 percent), geothermal (6.3 percent),* pumped storage (~~5.8~~*0.3* percent), petroleum (~~1.2~~*0.1* percent), coal (~~0.6~~*0.7* percent), and other gases (~~0.4~~*0.7* percent). ~~Actual utilization of energy consists of natural gas (54.9 percent), hydroelectric (13 percent), nuclear (17 percent), other renewables (11.8 percent), petroleum (1.1 percent), coal (1.1 percent), other gases (0.9 percent), and pumped storage (0.1 percent).~~ Figures 7.2-1 and 7.2-2 show California's electric generating capacity and actual utilization (Reference 19*, Table 5*).

Comparison of actual utilization of generation capacity in California indicates that nuclear, natural gas, and hydroelectric are used by electric generators in the State more than other methods of generation. This condition reflects the relatively low fuel cost for nuclear, natural gas, and hydroelectric power plants for baseload, and the relatively higher use of oil and gas-fired units to meet peak loads. In addition, the utilization reflects the availability of nuclear and hydroelectric power relative to other sources with intermittent availability (e.g., renewables).

In ~~2008~~*2014*, California *planning* reserve margins were ~~approximately~~ *projected to be* ~~22~~ *34* percent (Reference 8). The California Energy Commission defines planning reserve margin as the minimum level of electricity supplies needed to cover a range of unexpected contingencies, such as increased air conditioning demand on a hotter than average day, or an unplanned maintenance outage at a power plant. California energy demand is projected to increase from ~~277,479~~*266,754* GWh in ~~2008~~ *2014* to ~~313,671~~*279,632* GWh in ~~2018~~ *2024* (Reference 5, Form 1.~~1b~~*1c*). Of these statewide energy demand projections, PG&E would comprise approximately ~~37~~ *38* percent of the energy (Reference 5, Form 1.1c).

## 7.2.1 ALTERNATIVES CONSIDERED

For purposes of this environmental report, PG&E conducted evaluations of alternative generating technologies to identify candidate technologies that would be capable of replacing the net baseload capacity of the two nuclear units at DCPP. Alternatives considered included the following:

- natural gas
- purchased power
- demand side management
- nuclear
- coal
- oil
- wind
- solar thermal
- photovoltaics
- *distributed generation*
- hydropower
- geothermal
- wood energy
- municipal solid waste
- other biomass-derived fuels
- fuel cells
- *ocean wave and current energy*
- delayed retirement

Based on these evaluations, PG&E determined that the only viable *discrete energy* alternative generation technology to replace DCPP *baseload generation*~~power~~ is natural gas-fired generation. California laws and regulations preclude building and operating new nuclear, coal and oil-fired power plants in California *and* ~~. Additionally, California~~*already require PG&E to meet* ~~'s~~ aggressive renewable power and energy efficiency requirements ~~require PG&E to pursue all available and technologically feasible renewable power and energy efficiency; it is unlikely that there will be enough renewable generation or demand reduction to both meet these requirements and also replace 2,285 MW of DCPP baseload generation with renewable power or energy efficiency~~. Moreover, it would be imprudent to forego the opportunity to continue operating DCPP after 2025 based on an assumption that renewable technology*,* ~~and~~ energy efficiency*, and operational capabilities* will have advanced sufficiently and be available to replace 2,285 MW of DCPP baseload generation.

Finally, overlaying these concerns about the alternative generation technologies are federal and state greenhouse gas emissions reduction goals. According to EPRI, even while adding renewable capacity equal to 4 times ~~today's~~ wind and solar capacity *in 2008*, the United States ~~must~~ *would need to* maintain all of its current nuclear capacity, and add 45 more nuclear facilities, to meet greenhouse gas emissions reduction goals.

*Mixture*
The NRC indicated in the GEIS that, while many methods are available for generating electricity and numerous combinations or mixes can be assimilated to meet system needs, it would be impractical to analyze all the combinations. Therefore, NRC determined that the alternatives evaluation should be limited to analysis of single discrete electrical generation sources and only those electric generation technologies that are technically feasible and commercially viable (Reference 21).

*Although several of these discrete alternatives could be considered in combination for replacement power generation at multiple sites, they do not generally provide baseload capacity and would entail greater environmental impacts compared to renewing the DCPP licenses. Nevertheless, in order to provide insights regarding the impacts associated with a combination of energy sources, PG&E has considered a combination alternative that includes a contribution of natural gas, wind, solar, geothermal, and demand-side management to replace the baseload generation capacity of DCPP. PG&E has considered the environmental impacts of an assumed combination of one Concentrated Solar Power (CSP) facility constructed somewhere in California within the PG&E service area with a 400 MWe nameplate capacity and equipped with thermal storage capabilities; 830 MW of wind energy (alternate site) with energy storage, 1160 MW from solar photovoltaic (alternate site) with energy storage, 100 MW of geothermal, a demand side management (DSM) equivalent to a peak load reduction of 100 MWe, annually, and an NGCC power plant located on the DCPP site with 1,105 MWe capacity.*

*Demand Side Management and Energy Efficiency*
*The concept of demand side management (DSM) and energy efficiency (EE) as a resource does not meet the primary NRC criterion "that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable." DSM/EE is neither single, nor discrete, nor is it a source of generation. However, because of substantial efforts made by the State of California and PG&E, PG&E examines DSM/EE in this environmental report as an alternative to replace at least part of the output of DCPP.*

### 7.2.1.1 Alternatives that Meet System Generating Needs

*Natural-Gas-Fired Generation*
Natural gas provides the fuel for most new power generation facilities in the State. Lawrence Berkeley National Laboratory estimated that the demand for natural gas-fired generation could drop about 1 percent per year from 2011 to 2020, reaching about 9 percent below 2010 levels (Reference 10).

As described in PG&E's January 2004 Proponent's Environmental Assessment (Reference 25), PG&E would need to design, permit, and construct several combined-cycle gas turbine power plants somewhere in California, most-likely in the southern Central Valley region, to replace the output of DCPP. If DCPP output were replaced exclusively with combined-cycle gas turbine power plants, four plants would need to be constructed (2,250 MW at 562.5 MW per plant). These combined-cycle gas turbine power plants are typically configured in a two-on-one design (two gas turbines and one steam turbine with associated heat recovery steam generators and duct burners). Considering auxiliary power requirements for the plant, the nominal net capacity output for General Electric Frame 7F Technology combustion turbines would be 562.5 MW. ~~The~~ *As of 2009, the* capital cost for constructing this hypothetical 562.5 MW power plant ~~is~~ *was* assumed to be approximately $725 to $~~850~~ *821* million[1].

*Combination Alternative*

*As noted above, PG&E already must pursue wind, solar, and geothermal generation opportunities in order to meet California's aggressive renewable power requirements. There may be insufficient operational flexibilities to both meet those renewable power requirements and replace DCPP baseload capacity with wind, solar, and geothermal generation. Nevertheless, in order to provide insights regarding the impacts associated with a combination of energy sources, PG&E has considered a combination alternative that includes a contribution of natural gas, wind, solar, geothermal, and demand-side management.*

*Myriad combinations are possible. However, the combination that PG&E selected for evaluation represents what PG&E believes to be a technically feasible and practicable technology combination alternative to continuing the operation of DCPP reactors. This combination will include one CSP facility constructed somewhere in California within the PG&E service area with a 400 MWe nameplate capacity and equipped with thermal storage capabilities; 830 MW of wind energy (alternate site), 1,160 MW from solar photovoltaic (alternate site), 100 MW of geothermal, demand side management (DSM) equivalent to a peak load reduction of 100 MW, annually, and an NGCC power plant located on the DCPP site with 1105 MW capacity.*

*Most utility-scale CSP facilities have nameplate ratings of no more than 400 MW, so PG&E has considered one facility of that size in the combination alternative, together with thermal storage. In order to overcome their intermittent nature and the daily ramp impacts on the system, wind and solar PV power must be combined with energy storage mechanisms. Under California Assembly Bill (AB) 2514, California's largest utilities must develop energy storage systems. Based on the California Public Utility Commission's (CPUC) storage decision, issued in 2013, storage targets were adopted. As a result, PG&E anticipates procuring 580 MW of energy storage by 2020 that could be used to overcome the intermittency of wind and solar PV generation. Assuming a 35 percent capacity factor, the installed wind capacity necessary to generate 290 MW is approximately 830 MW. Assuming a 25 percent capacity factor, the installed solar PV capacity necessary to generate 290 MW is approximately 1,160 MW. Geothermal generation in 2025 is expected to be approximately one-third that of wind or solar PV.*

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[1] This estimate is based on ~~recent~~ *two* PG&E gas-fired projects: Colusa Generating Station (1.29 million per MW) *and*~~,~~ Humboldt Bay Generating Station (1.46 million per MW)~~, and Tesla Generating Station (1.52 million per MW)~~.

*PG&E therefore considered a hypothetical geothermal contribution of 100 MW to the combination alternative. An additional 100 MW of demand reduction is assumed for the combination alternative. The NGCC component would represent the remaining 1105 MW of the combination alternative's net baseload capacity of 2,285 MW.*

| *Generation* | *Installed Capacity* | *Capacity Factor (if applicable)* | *"Baseload" Equivalent* |
|---|---|---|---|
| *CSP* | *400 MW* | | *400 MW* |
| *Wind* | *830 MW* | *35%* | *290 MW* |
| *Solar PV* | *1,160 MW* | *25%* | *290 MW* |
| *Geothermal* | *100 MW* | | *100 MW* |
| *DSM* | *100 MW* | | *100 MW* |
| *NGCC* | *1105 MW* | | *1105 MW* |
| ***Total*** | | | ***2285 MW*** |

*To meet Southern California local area requirements following closure of the San Onofre Nuclear Generation Station (SONGS), the CPUC authorized Southern California Edison (SCE) to procure 550 MW of preferred resources, in addition to 1,000 MW of gas-fired generation (Reference 32). The CPUC also authorized SCE to procure up to 400 MW of additional preferred resources and 300-500 MW from any source. The CPUC authorized San Diego Gas & Electric (SDG&E) to procure 175 MW from preferred sources and 300 MW from a gas-fired project. SDG&E may procure an additional 300-600 MW from any source. In total, the CPUC authorized 950 MW from preferred resources, 1,300 MW of new gas-fired generation, up to 400 MW more from preferred resources, and 600-1,100 MW from any source, with at least 75 MW of energy storage. Of the minimum of 2,700 MW authorized by CPUC, approximately half (1,300 MW) will come from gas-fired generation. Of the maximum of 3,600 MW authorized by the CPUC, up to 2,400 MW could be gas-fired generation. Therefore, the actual combination of resources used to meet local area requirements after the SONGS closure will have about the same or greater contribution from gas-fired resources than the hypothetical combination alternative considered in the ER. The maximum contribution from preferred resources (2,300 MW) is slightly less than the total contribution from preferred resources in PG&E's hypothetical combination alternative (2,590 MW).*

*Purchased Power*
"Purchased power" is power purchased and transmitted from electric generation plants that the applicant does not own and that are located elsewhere within the region, nation, Canada, or Mexico. If available, purchased power from other sources could potentially obviate the need to renew the DCPP license.

Purchased power is ~~a feasible~~*considered as an* alternative to DCPP license renewal *but presents several challenges. First, t*~~T~~here is no assurance~~, however,~~ that sufficient capacity or energy would be available during the entire time frame of 2025 through 2045 to replace the approximately 2,285 MWe of baseload generation. ~~This is supported by~~

~~the Energy Information Administration (EIA) projection that total gross U.S. imports of electricity will increase from 28.7 quadrillion Btu in 2008 to 31.45 quadrillion Btu in the year 2030 (Reference 18).~~ *Second, purchased power would also require GHG emissions offsets associated with incremental generation either within or outside of California.* ~~It appears unlikely that electricity imported from Canada or Mexico would be able to replace the DCPP generating capacity.~~

*Finally, i*~~I~~f power to replace DCPP capacity were to be purchased from sources outside California, the generating technology would likely be one of those described in the GEIS and would require the construction of new transmission facilities*, whether new transmission to existing transmission system or to support an increase in imports from existing resources,* with their associated environmental impacts and costs. The description of the environmental impacts of other technologies in Chapter 8 of the GEIS is representative of the purchased power alternative to renewal of the DCPP operating licenses. Thus, the environmental impacts of purchased power would still occur but would be located elsewhere within the region, nation, or another country.

*Demand Side Management and Energy Efficiency*
*Demand-side management programs generally are designed to reduce customer energy consumption and overall electricity use. Some programs also attempt to shift energy use to off-peak periods (Reference 11). The demand side management alternative considered here includes energy efficiency and demand reduction, and distributed generation as an alternative is considered below.*

*The CPUC oversees various demand-side management programs administered by the regulated utilities (including PG&E's Integrated Demand-Side Management Program, Reference 26), and many municipal electric utilities have their own demand-side management programs. The combination of these programs constitutes the most ambitious overall approach to reducing electricity demand administered by any state in the nation (Reference 11). To further coordinate and integrate demand-side management options for consumers, in 2008, the CPUC implemented a California Long-Term Energy Efficiency Strategic Plan (Reference 13).*

*Committed efficiency savings reflect savings from initiatives that have been approved, finalized, and funded, whether already implemented or not. There are also likely additional savings from initiatives that are neither finalized nor funded but are reasonably expected to occur, including impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2014 (program measures). These savings are referred to as achievable. According to the California Energy Commission's 2014-2024 Final Forecast (Reference 33, Table 32), Additional Achievable Energy Efficiency (AAEE) savings for California reach nearly 5,000 MW in 2024 with 2,141 MW in PG&E's service territory.*

### 7.2.1.2 Alternatives ~~that Do Not Meet System Generating Needs~~*Not Considered Reasonable*

This section identifies *standalone* alternatives that PG&E deemed unreasonable, and the bases for these determinations. PG&E accounted for the fact that DCPP provides baseload generation and that any feasible alternative to DCPP would also need to be able to provide baseload power. In performing this evaluation, PG&E relied heavily upon NRC's GEIS (Reference*s* 21 *and 29*).

~~*Demand Side Management and Energy Efficiency*~~
~~Demand-side management programs are designed to reduce customer energy consumption and overall electricity use. Because there would be no construction, there would be no new environmental impacts created from this alternative. Some programs also attempt to shift energy use to off-peak periods (Reference 11).~~

~~The CPUC supervises various demand-side management programs administered by the regulated utilities (including PG&E's Integrated Demand-Side Management Program, Reference 26), and many municipal electric utilities have their own demand-side management programs. The combination of these programs constitutes the most ambitious overall approach to reducing electricity demand administered by any state in the nation (Reference 11). To further coordinate and integrate demand-side management options for consumers, in 2008, the CPUC implemented a California Long-Term Energy Efficiency Strategic Plan (Reference 13).~~

~~Thus far, California's building efficiency standards (along with those for energy efficient appliances) have saved more than $56 billion in electricity and natural gas costs since 1978. It is estimated the standards will save an additional $23 billion by 2013 (Reference 14).~~

~~Reducing demand is an essential part of PG&E's operations. However, the available energy savings from these programs are insufficient to maintain service reliability to PG&E customers in the face of population and employment growth. Energy conservation would offset only a small fraction of the baseload energy supply lost by the shutdown of DCPP (Reference 11).~~

*New Nuclear Reactor*
California law prohibits the construction of any new nuclear power plants in California until the Energy Commission finds the federal government has approved and there exists a demonstrated technology for the permanent disposal of spent fuel from nuclear power facilities (Reference 9).

*Coal-Fired Generation*
In January 2007, the CPUC adopted an interim Greenhouse Gas (GHG) Emissions Performance Standard in an effort to help mitigate climate change. The Emissions Performance Standard is a facility-based emissions standard requiring that all new long-term commitments for baseload generation serve California consumers with power

plants that have emissions no greater than a combined-cycle gas turbine plant (1,100 pounds of $CO_2$ per megawatt-hour). "New long-term commitment" refers to new plant investments (new construction), new or renewal contracts with a term of 5 years or more, or major investments by the utility in its existing baseload power plants (Reference 12). With these standards in place, new coal-fired power generation technology is not an option in California. If and when carbon capture/sequestration technology becomes commercially viable, it may be appropriate to revisit the possibility of constructing and operating a coal-fired power plant in California.

*Oil-Fired Generation*

~~The Energy Information Administration (EIA) projects that oil-fired plants will account for very little of the new generating capacity in the U.S. during the 2008 to 2030 time frame because of continually rising fuel costs (Reference 17). In addition, t~~*T*he environmental impacts of operating current generation oil-fired power plants are similar to those from comparably sized coal-fired plants and are therefore not an option in California at this time. Thus, an oil-fired replacement for the capacity that would be lost if DCPP were to cease operations is not considered further in this discussion.

*Wind*

Wind turbines capture kinetic energy from the wind and use it to turn electric generators. Wind farms currently account for ~~1.3~~*7.9* percent of California's electrical capacity *(Reference 30)*. Capacities of a single wind turbine range from 400 W up to 3.6 MW. Approximately 150,000 to 180,000 acres are required to produce 1,000 MW at a wind farm (Reference 27). This corresponds to a minimum site size of 342,000 to 411,000 acres for 2,285 MW of generation (Reference 27). Wind turbine "footprints" however, utilize only about 5 percent of the land on which the system is built. This allows for dual use of a site, such as for agriculture or ranching. A significant barrier to wind power development is the lack of available transmission access in areas with wind resources. Other challenges to siting wind farms are the bird mortality resulting from collisions with turbine blades, the noise of the rotors, and visual aesthetics. Because the power output can only be intermittently generated during the day or during certain seasons, depending on the location, wind turbines are unsuitable for baseload applications (Reference 11). *Wind generation* ~~and,~~ therefore~~, wind generation~~ cannot be considered an adequate replacement of DCPP generation *absent sufficient energy storage to overcome wind's intermittency. Besides pumped-storage hydroelectricity, Compressed Air Energy Storage (CAES) is the technology most suited for storage of large amounts of energy; however, no combination of wind and CAES has yet been proposed at the scale necessary to replace DCPP generation*. ~~Moreover, as stated above, PG&E will need to pursue all feasible wind generation opportunities in order to meet California's aggressive renewable power requirements. It is unlikely that sufficient wind generation will be available to both meet those renewable power requirements and replace DCPP capacity with wind generation.~~

*Solar Thermal (Concentrated Solar Power [CSP])*

"Solar thermal power plants transform heat from the sun into mechanical energy, which is then used to generate electricity. The shape and structure of the solar collectors/reflectors varies depending on the technology employed. Parabolic trough collectors use long parabolic mirrors that focus the sunlight on a central tube containing a heat transfer fluid, which is circulated back to a central power plant that houses a generator. Similarly, solar tower projects use a field of tracking mirrors that focus the sun on a central tower, where the heat transfer fluid is heated and then used to power electrical generation. A third technology, which is not fluid-based, uses a field of independently tracking parabolic mirrors, each of which focuses the sunlight on its own Stirling-cycle engine, which drives a small attached generator. Some of these facilities use conventional gas-fired steam boilers to generate supplemental electricity. The use of water for evaporative cooling can place a significant strain on limited water resources in arid areas and could potentially impact sensitive biological resources." (Reference 6)

The amount of acreage (habitat) required for each type of solar thermal technology varies. Assuming a parabolic trough system was located in a maximum solar exposure area, such as in a desert region, 500 acres per 100 MW (Reference 11) would be required. This corresponds to a site size of 11,425 acres for 2,285 MW of generation. While the plants do not generate problematic air emissions and have relatively low water requirements, construction of solar thermal plants leads to potential habitat destruction and substantial aesthetic changes. Solar thermal can be a good peak power source because it collects the sun's radiation during daylight hours and generates power during peak usage periods. Because solar thermal power is not available 24 hours per day, it is typically not acceptable for baseload applications *absent sufficient energy storage to overcome solar's intermittency* (Reference 11). *As noted above, besides pumped-storage hydroelectricity, CAES is the technology most suited for storage of large amounts of energy; however, no combination of CSP and CAES has yet been proposed at the scale necessary to replace DCPP generation.*~~Moreover, as stated above, PG&E will need to pursue all feasible solar generation opportunities in order to meet California's aggressive renewable power requirements. It is unlikely that sufficient solar generation will be available to both meet those renewable power requirements and replace DCPP capacity with solar generation.~~

*Photovoltaics*
Photovoltaic PV) power generation uses special semiconductor panels to directly convert sunlight into electricity. Arrays built from the panels can be mounted on the ground or on buildings where they can also serve as roofing material. *California state e*~~E~~lectricity generation *capacity* from solar technologies, including both photovoltaic and solar thermal systems, currently totals about ~~0.3~~*3.9* percent of the state's electricity production *(Reference 30)*. PV systems can have negative visual impacts, especially if ground mounted. Unless they are constructed as integral parts of buildings, PV systems require about four acres of ground area per MW of generation. Assuming that a PV system was located in a maximum solar exposure area, generation of 1,000 MW would require 54,000 acres. This corresponds to a site size of 123,390 acres for 2,285 MW of generation (Reference 27). PV installations are highly capital intensive and manufacturing of the panels generates hazardous wastes. Additionally, natural variation in sunlight intensity in a given location, and the limits of existing battery and

capacitor technology, hinders the use of photovoltaics as a primary source of power in large industrial applications. *Moreover, PV output does not fully match California's peak electrical demand periods. PV produces more energy than customers need during the day which means PG&E must store or dispose of excess generation during the day and supply additional energy in the late afternoon to meet the residual peak when there is little or no solar generation.*~~Despite these limitations, the daytime power output of PV systems generally match California's peak electrical demand periods.~~ *Regardless,* ~~T~~*t*he intermittent nature of the power~~, however,~~ makes PV systems unsuitable for baseload applications *absent sufficient energy storage to overcome solar's intermittency* (Reference 11). *As noted above, besides pumped-storage hydroelectricity, CAES is the technology most suited for storage of large amounts of energy; however, no combination of solar PV and CAES has yet been proposed at the scale necessary to replace DCPP generation.*~~Moreover, as stated above, PG&E will need to pursue all feasible PV generation opportunities in order to meet California's aggressive renewable power requirements. It is unlikely that sufficient PV generation will be available to both meet those renewable power requirements and replace DCPP capacity with PV generation.~~

*Distributed Generation*
According to the California Energy Commission, distributed generation is the widespread generation of electricity from facilities that are smaller than 50 MW in net generating capacity. ~~Distributed generation units owned by PG&E or by industrial, commercial, institutional, or residential energy consumers would reduce the need for replacement generation. While distributed generation technologies are recognized as important resources to the region's ability to meet its long-term energy needs, distributed generation does not provide a means for PG&E to offset a substantial portion of the baseload energy lost by shutdown of DCPP.~~ *Distributed generation generally refers to the production of electricity at or close to the point of use. Distributed generation units owned by PG&E or by industrial, commercial, institutional, or residential energy consumers could reduce the need for replacement generation. Distributed generation technologies include fuel cells, small gas turbine, internal combustion engines, micro-turbines, solar PV, and wind (Reference 18).*

*Potential limitations on the extent of distributed generation development include the willingness of building owners to install PV systems or allow such systems to be installed on their rooftops; energy costs of these systems; impacts on grid reliability with a higher penetration of intermittent DG; effectiveness of the pending utility programs focused on this size; and the capacity of the equipment and labor supply chains, from manufacturing through installation (Reference 18). Moreover, the impacts of DG facilities on grid reliability or the transmission and distribution system increase with increased DG penetration (Reference 18). In addition, because distributed generation does not reduce overall generation, and instead merely disperses that generation over a greater area, the impacts of distributed generation reflect the sum of the impacts of individual DG units.*

*The California Energy Commission recognizes (Reference 34) that the peak demand forecast could be reduced by the projected impacts of distributed PV, solar thermal, and combined heat and power (CHP) systems, including the effects of the Self-Generation Incentive Program (SGIP), California Solar Initiative (CSI), and other programs. The California Energy Commission estimates (Reference 34, Table 2) that PG&E Planning Area Self-Generation Peak Impacts could reach 2079.3 MW by 2024. However, there is substantial uncertainty as to the level of DG penetration that will occur. According to the California Energy Commission (Reference 34), more than 1,000 MW of the distributed generation in the PG&E service territory is expected to be photovoltaic (PV) systems.*

*As noted above, PV systems used in DG can have negative visual impacts, especially if ground mounted. Unless they are constructed as integral parts of buildings, PV systems require about four acres of ground area per MW of generation. PV installations are highly capital intensive and manufacturing of the panels generates hazardous wastes. Additionally, natural variation in sunlight intensity in a given location, and the limits of existing battery and capacitor technology, hinders the use of photovoltaics as a primary source of power in large industrial applications. Moreover, PV output does not fully match California's peak electrical demand periods. PV produces more energy than customers need during the day which means PG&E must store or dispose of excess generation during the day and supply additional energy in the late afternoon to meet the residual peak when there is little or no solar generation. As a result, the intermittent nature of PV power as the primary source of DG makes DG systems unsuitable for baseload applications absent sufficient energy storage to overcome solar's intermittency (Reference 11). While development of battery storage options is ongoing, none are currently available in quantities or capacities that would provide baseload amounts of power. In light of the large contribution of solar PV to potential DG in PG&E service area and limitations on its use as baseload capacity, DG cannot serve as a reasonable alternative to the baseload generation of DCPP.*

*Hydroelectric Power*

Hydroelectric power uses the energy of falling water to turn turbines and generate electricity. Power production increases with both greater water flow and greater fall. California hydropower plants range in size from less than 0.1 MW to over 1,200 MW (Reference 11). Hydropower currently provides ~~13~~ *17.8* percent of the state's electricity ~~production~~*capacity*~~, generally in baseload applications~~ *(Reference 30)*. Hydropower facilities typically require 14 acres per MW of generation (Reference 11). Production of 100 MW would require inundation of about 1,400 acres. This corresponds to a site size of 31,990 acres for 2,285 MW of generation. Hydropower generates no emissions or hazardous effluents and requires no fuel. However, development of new hydropower facilities is limited due to the severe environmental concerns and the lack of appropriate sites (Reference 11). Accordingly, hydroelectric power is not a reasonable alternative to renewal of the operating licenses for DCPP.

*Geothermal*

Geothermal power plants employ high pressure steam and hot water from naturally occurring subsurface geothermal reservoirs to drive turbines and generate electricity. Condensed steam and used water are injected back into the geothermal reservoir to sustain production. Geothermal plants account for approximately 3.5 percent of California's power and range in size from under 1 MW to 110 MW *(Reference 30)*. Geothermal plants typically operate as baseload facilities and require 1 to 8 acres per MW (Reference 15). Generation of 100 MW would require at least 20 acres and many miles of new transmission facilities to deliver the power. This corresponds to an average of 9,140 acres for 2,285 MW of generation. Geothermal plants must be built near geothermal reservoir sites, because steam and hot water cannot be transported long distances without significant thermal energy loss. "The large amount of land needed to construct a geothermal plant implies altering current land uses of farming, ranching, forest, or natural habitat. Clearing this land would damage or destroy much of the existing habitat for wildlife, as well as pose potential adverse consequences for cultural resources. Some of the land originally cleared for construction of the geothermal facilities could probably be returned to previous uses, since it would not all be utilized by geothermal facilities. Much acreage would still be lost for the life of the plant, however, and this loss could be complicated by subsidence caused by withdrawal of the geothermal fluid." (Reference 21) Newer geothermal technology uses reinjection of the geothermal fluid to maintain production, thereby reducing subsidence. Future geothermal development in California could occur in Imperial County, Lake County, and the northeastern and north-central portions of California (Reference 6). *The USGS estimates that California has the potential for additional geothermal power development on private and public lands of 9,282 MWe (Reference 29).* Geothermal plants offer baseload capacity similar to DCPP, but it is unlikely to be available *within PG&E's service area* on the scale required to replace the capacity of DCPP. *New geothermal capacity would also require construction of new transmission lines.*~~Moreover, as stated earlier, PG&E will need to pursue all feasible geothermal opportunities in order to meet California's aggressive renewable power requirements. It is unlikely that sufficient geothermal generation will be available to both meet those renewable power requirements and replace DCPP capacity with geothermal generation.~~

*Wood Energy*

As discussed in the GEIS (Reference 21), the use of wood waste to generate electricity is largely limited to those states with significant wood resources. The pulp, paper, and paperboard industries in states with adequate wood resources generate electric power by consuming wood and wood waste for energy, benefiting from the use of waste materials that could otherwise represent a disposal problem.

Further, as discussed in Section 8.3.6 of the GEIS (Reference 21), construction of a wood-fired plant would have an environmental impact that would be similar to that for a coal-fired plant, although facilities using wood waste for fuel would be built on a smaller scale. Like coal-fired plants, wood-waste plants require large areas for fuel storage, processing, and waste (i.e., ash) disposal. Additionally, operation of wood-fired plants has environmental impacts, including impacts on the aquatic environment and air.

Wood has a low heat content that makes it unattractive for baseload applications. It is also difficult to handle and has high transportation costs. Transportation of wood or wood wastes during the accumulation and delivery phases is generally dependent on the use of trucking on public roads. Reliance on vehicle transport for fuel supply can result in negative impacts to traffic and congestion near a generation facility, as well as the inherent additional air quality concerns resulting from truck fuel combustion emissions. Fuel transportation impacts are an added concern for most biomass related generation projects.

PG&E has concluded that, due to the lack of an environmental advantage, low heat content, handling difficulties, and high transportation costs, wood energy is not a reasonable alternative to DCPP license renewal.

*Municipal Solid Waste*
As discussed in Section 8.3.7 of the GEIS (Reference 21), the initial capital costs for municipal solid waste plants are greater than for comparable steam turbine technology at wood-waste facilities. This is due to the need for specialized waste separation and handling equipment.

The decision to burn municipal solid waste to generate energy is usually driven by the need for an alternative to landfills, rather than by energy considerations. The use of landfills as a waste disposal option is likely to increase in the near term. However, it is unlikely that many landfills will begin converting waste to energy because of unfavorable economics.

Estimates in the GEIS suggest that the overall level of construction impacts from a waste-fired plant should be approximately the same as that for a coal-fired plant. Additionally, waste-fired plants have the same or greater operational impacts (including impacts on the aquatic environment, air, and waste disposal). Some of these impacts would be moderate, but still larger than the environmental effects of DCPP license renewal.

PG&E has concluded that, due to the high costs and lack of environmental advantages, burning municipal solid waste to generate electricity is not a reasonable alternative to DCPP license renewal.

*Other Biomass-Derived Fuels*
In addition to wood and municipal solid waste fuels, there are several other concepts for fueling electric generators, including burning energy crops, converting crops to a liquid fuel such as ethanol (ethanol is primarily used as a gasoline additive), and gasifying energy crops (including wood waste and manure). As discussed in the GEIS, none of these technologies has progressed to the point of being competitive on a large scale or of being reliable enough to replace a baseload plant such as DCPP.

PG&E has concluded that, due to the high costs and lack of environmental advantage, burning other biomass-derived fuels is not a reasonable alternative to DCPP license renewal.

*Fuel Cells*

Fuel cells convert the energy from a chemical reaction between a fuel (such as hydrogen) and an oxidizer (such as oxygen) into electricity. Fuel cells have ultra-low air emissions, and operate similar to batteries but do not run down or require recharging. They run as long as fuel and oxidizer are supplied to them, and can operate using fuel gases from biomass conversion. Even small fuel cells can perform at high efficiencies. Fuel cell power plants from 10 kW to 3 MW have been field demonstrated in California.

Many fuel cell power plants require a fossil fuel such as natural gas to operate and thus must be located where the fuel can be delivered. In general, fuel cell plants require more land than combined-cycle power plants, but emit about the same amount of carbon dioxide. No water-cooled systems are required by fuel cells. Thus, water use and thermal discharges are avoided. Fuel cells generate some hazardous waste, including periodic removal and disposal of absorption beds. The elevated pressures (3 to 7 atmospheres) and explosion hazards of fuels such as hydrogen or natural gas present some public safety issues (Reference 11). *Currently, fuel cells are not economically or technologically competitive with other alternatives for electricity generation.* Even if fuel cell technology matures over the next 10-15 years to the point where it can be used on an industrial scale, it would not be a reasonable replacement for DCPP capacity.

*Ocean Wave and Current Energy*

*Ocean waves, currents, and tides represent kinetic and potential energies. Waves, currents, and tides are often predictable and reliable; ocean currents flow consistently, while tides can be predicted months and years in advance with well-known behavior in most coastal areas. The total annual average wave energy off the U.S. coastlines at a water depth of 60 m (197 ft) is estimated at 2,100 terawatt-hours (TWh) (2,100,000,000 MWh) (Reference 31). In general, technologies that harness ocean wave energy are in their infancy and have not been used at a utility scale, though these technologies may become commercially available in the near future as more feasibility studies and prototype tests are conducted.*

*Ocean current energy technology is similarly in its infancy. In relatively constant currents, ocean turbines can produce sufficient capacity factors for baseload demand (Reference 31). Only a small number of prototypes and demonstration units have been deployed to date.*

*PG&E is not currently aware of any plans to develop or deploy ocean wave and ocean current generation technologies on a scale similar to that of DCPP. Consequently, due to relatively high costs and limited planned implementation, PG&E concludes that ocean energy technologies are not feasible substitutes for DCPP.*

*Delayed Retirement*

As the NRC noted in the GEIS (Reference 21), extending the lives of existing non-nuclear generating plants beyond the time they were originally scheduled to be retired represents another potential alternative to license renewal. Fossil plants slated for retirement tend to be ones that are old enough to have difficulty in meeting today's restrictions on air contaminant emissions. Additionally, these older units are likely relatively inefficient, having high fossil fuel consumption profiles, which do not optimize energy recovery from combustion in comparison to newer technologies. In the face of increasingly stringent environmental restrictions, and likely increasing fossil fuel scarcity and costs, delaying retirement in order to compensate for a plant the size of DCPP would be unreasonable without major construction to upgrade or replace plant components. PG&E currently has no plans for retiring any of its fleet of power plants and expects to need additional fuel efficient generating capacity in the near future.

### 7.2.2 ENVIRONMENTAL IMPACTS OF ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

This section evaluates the environmental impacts of alternatives that PG&E has determined to be reasonable alternatives to DCPP license renewal: natural gas-fired generation*, a combination of energy sources,* ~~and~~ purchased power*, and demand-side management and energy efficiency*.

#### 7.2.2.1 Natural Gas-Fired Generation

NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants. Section 7.2.1.1 presents PG&E's reasons for defining the gas-fired generation alternative as a combined-cycle plant on the DCPP site or at another location within PG&E's service region. Reduced land requirements, due to a smaller facility footprint, would reduce impacts to ecological, aesthetic, and cultural resources. A smaller workforce could have socioeconomic impacts in the surrounding communities. Human health effects associated with air emissions would be of concern. Aquatic biota losses due to cooling water withdrawals would be reduced by the concurrent shutdown of the DCPP nuclear Units. This assumes that new mechanical-draft cooling towers would need to be constructed to support the new closed cycle cooling system.

In the GEIS Supplement for Donald C. Cook Nuclear Plant (Reference 24), NRC evaluated the environmental impacts of constructing and operating four 468-MWe combined-cycle gas-fired units as an alternative to a nuclear power plant license renewal. PG&E has reviewed the NRC analysis, believes it to be sound, but notes that it analyzed less generating capacity than the 2,285 MWe of net power discussed in this analysis. In defining the DCPP gas-fired alternative, PG&E has used site and California-specific input and has scaled from the NRC analysis, where appropriate. In order to adequately replace the entire net generation of DCPP, four 562.5-MWe combined-cycle plants would be required (total net generation capacity of 2,250 MWe). The conceptual replacement units are comparable to the type of combined-cycle nonduct fired fossil fuel generation units recently constructed in California (Moss Landing Power Plant – 530 MWe [Reference 1], Contra Costa Power Plant – 530 MWe [Reference 2], and Colusa Power Plant – 660 MWe [Reference 7]).

*Air Quality*

Natural gas is a relatively clean-burning fossil fuel that primarily emits nitrogen oxides ($NO_x$), a regulated pollutant, during combustion. A natural gas-fired plant would also emit small quantities of sulfur oxides ($SO_x$), particulate matter, and carbon monoxide, all of which are regulated pollutants. Control technology for gas-fired turbines focuses on $NO_x$ emissions. More significant would be the emission of ~~green house gases (~~GHG~~)~~, primarily carbon dioxide ($CO_2$). PG&E estimates the gas-fired alternative emissions to be as follows:

$SO_x$ = 199 tons per year

$NO_x$ = 638 tons per year

Carbon Monoxide = 134 tons per year

Particulates = 111 tons per year

Carbon Dioxide = 8,780,805 tons per year

Table 7.2-1 shows how PG&E calculated these emissions.

$NO_x$ effects on ozone levels, $SO_2$ allowances, and $NO_x$ emission offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, and regulatory requirements are less stringent, the emissions are still substantial. PG&E concludes that emissions from the gas-fired alternative at DCPP or an alternative site would noticeably alter local air quality, but would not destabilize regional resources (i.e., air quality). Air quality impacts would therefore be moderate.

However, the substantial GHG emissions from new fossil generation would be counterproductive to the State plan for reduction of global warming emissions from both industrial and non-industrial activities. California Assembly Bill 32, “The California Global Warming Solutions Act of 2006,” requires the State to reduce GHG emissions to 1990 levels by 2020. Moreover, by Executive Order S-20-06, dated October 18, 2006, California must reduce GHG emissions 80 percent below 1990 levels by 2050. The power generation industry is currently a major component of existing GHG sources. Approval for construction and operation of new industrial sources could be significantly hindered by these adopted environmental requirements.

*Waste Management*

The solid waste generated from this type of facility would be minimal. There will be spent selective catalytic reduction catalyst used from $NO_x$ control and small amounts of solid-waste products (i.e. ash) from burning natural gas fuel. In the GEIS, the NRC staff concluded that waste generation from gas-fired plants would be minimal (Reference 21). Gas-fired plants produce very few combustion by-products because of the clean nature of the fuel. Waste-generation impacts would be so minor that they would not noticeably alter any important resource attribute. Construction-related debris would be generated during construction activities. Overall, the waste impacts at the DCPP site or an alternative site would be small for a natural gas-fired plant (Reference 24).

*Land Use*

Approximately 25 to 30 acres of land would be needed to construct and operate a typical 500 MW combined-cycle power plant (Reference 3). PG&E owns sufficient land at the DCPP site if needed for this purpose. However, the topography of the site would require significant excavation and grading that would substantially increase the costs of such a project in comparison to implementation at more flat, accommodating, locations. Multiple units would likely have to be placed at tiered elevations. PG&E assumed that this alternative would use the existing switchyard, offices, and transmission line ROWs. However, new mechanical-draft cooling towers would need to be constructed to support closed cycle cooling systems for the essentially new generation facilities. Additionally, existing plant structures occupy much of the available buildable land, therefore, any replacement would require decommissioning and removal of existing structures, further complicating such an effort. The existing DCPP footprint would not be available for replacement of the DCPP baseload without a significant time lag.

The environmental impacts of locating the gas-fired generation facility at an alternate location would depend on the past use of the location. If the site is a previously undisturbed site the impacts would be more significant than if the site was a previously developed site. Construction and operation of the gas-fired facility at an undeveloped site would require construction of a new cooling system, switchyard, offices, gas transmission pipelines, and transmission line ROWs. A previously industrial site may have closer access to existing infrastructure, which would help to minimize environmental impacts. A gas-fired alternative constructed at the DCPP site would have direct access to a transmission system and offices.

*Other Impacts*

As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized using best management practices. PG&E estimates a peak construction workforce of approximately 650 per plant, therefore socioeconomic impacts of construction would be minimal. However, since PG&E estimates a workforce of 31 per plant for gas operations (Reference 7), the reduction in overall long-term site workforce would result in adverse socioeconomic impacts. PG&E believes these impacts would be small to moderate.

Combined-cycle power plants using evaporative cooling consume about 6 acre-feet of either fresh or recycled/reclaimed water per year per MW based on expected capacity factors. In addition, a new high efficiency combined-cycle power plant would burn approximately 3.25 million cubic feet of natural gas per hour. The natural gas would need to be delivered through a pipeline system that can support the level of natural gas needed for a baseload power plant. See Figure 7.2-3 for an illustration of the natural gas pipeline infrastructure in California, which may facilitate the delivery of natural gas to a replacement baseload~~ed~~ power plant in the absence of the power normally distributed by DCPP (Reference 11). Regardless of where the natural gas-fired plant is built, additional land would be required for natural gas wells and collection stations. Approximately 7,578 acres would be needed for wells and stations (Reference 21).

Any large scale replacement generation facilities would need to connect to the PG&E transmission grid, which is currently configured to receive a large proportion of power from DCPP. This network would need to be rerouted to reflect the changed generation locations. ~~Alternatively, new transmission facilities could be used as a substitute for some in-State generation by improving access to generation in the Pacific Northwest and Southwestern states (Reference 11).~~ Major 500 kV transmission components connect DCPP to the Gates Substation in Fresno County and the Midway Substation in Kern County. Shutdown of DCPP would result in significant changes in load flow and likely result in reduced utilization of the existing interconnecting lines, which would necessitate significant reconfiguration of the transmission grid in those areas.

Developing new transmission facilities requires roughly ten years of advance planning. Demonstrating need, securing environmental approvals, permits, and rights-of-way, and construction activities contribute to the long lead-time needed for transmission planning. Because of the difficulty of securing new rights-of-way, replacement transmission facilities would likely, in part, follow existing major paths (Reference 11).

Impacts to aquatic resources and water quality at the DCPP site would be smaller than the impacts of DCPP operations, due to the projected necessary use of mechanical-draft cooling towers that would be constructed to support the closed cycle cooling systems. However, the additional stacks and boilers would increase the visual impact of the existing site. Impacts to cultural and ecological resources would be likely due to construction of a new natural gas pipeline on previously disturbed land. Additionally, use of closed cycle cooling systems with saltwater makeup would result in substantial air emissions from cooling towers.

PG&E estimates that other construction and operation impacts of combined-cycle plants would be small. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved.

#### *7.2.2.2 Combination Alternative*

*As noted above, the combination alternative will include one CSP facility constructed somewhere in California within the PG&E service area with a 400 MWe nameplate capacity and equipped with thermal storage capabilities; 830 MW of wind energy (alternate site) with energy storage, 1160 MW from solar photovoltaic (alternate site) with energy storage, 100 MW of geothermal, a demand side management (DSM)* *equivalent to a peak load reduction of 100 MWe, annually, and an NGCC power plant located on the DCPP site with 1,105 MWe capacity.*

*The wind and solar components of the combination alternative would be located in one or more areas of California with the appropriate wind or solar profile, but not on the existing DCPP site. Likewise, the geothermal generation would be located elsewhere in PG&E service territory.*

*Because the power output from wind and solar PV are intermittent, they would need to be combined with an energy storage mechanism in order to approximate baseload generation. Technologies currently available or under consideration for deployment as potential energy storage alternatives include battery storage, flow batteries, flywheel, superconducting magnetic energy storage, supercapacitor, and CAES. PG&E has chosen CAES as being representative of the energy storage technologies because of the potential for supplying adequate amounts of backup power of a longer duration. CAES uses pressurized air as the energy storage medium. An electric motor-driven compressor is used to pressurize the storage reservoir using off-peak energy, and air is released from the reservoir through a turbine during on-peak hours to produce energy. The turbine is essentially a modified turbine that can also be fired with natural gas or distillate fuel. The theory behind the combination of intermittent generation with energy storage is that when the generation capacity is available, the amount of power produced could, at times, exceed the demand for power at that time. CAES facilities are currently operated as peaking plants with energy placed into storage during the less expensive, non-peak demand hours and generated from the storage units during the higher priced, peak demand hours. CAES systems with the potential for supplying 580 MWe might be expected to be dependent upon the availability and capacities of a suitable underground cavern or multiple caverns. It should also be noted that one or more CAES facilities may be required, with distributed impacts.*

*Currently, no large-scale, base-load CAES facilities are in operation anywhere in the world, nor are any existing CAES facilities combined with either wind or solar power. A 200- to 300-MW CAES facility integrated with a 75- to 150-MW wind farm, referred to as the Iowa Stored Energy Park, was proposed in Iowa but was terminated in July 2011 due to geology limitations. Two CAES facilities combined with natural gas power plants, a 110-MW facility in Alabama and a 290-MW plant in Germany, have been built and are in operation. PG&E is currently exploring a utility-scale CAES project (approximately 300 MW) near Bakersfield, California. If found to be feasible, a commercial plant could come on-line in the 2020-2021 timeframe. For the purposes of PG&E's analysis, it has been conservatively assumed that a single CAES facility could be identified to support 580 MW of base-load power generation in the PG&E service area.*

*Air Quality*
*The air quality impacts from the natural gas will be less than those considered in Section 7.2.1.1, but in proportion to the amount of natural gas generation. PG&E estimates the gas-fired contribution to the combination alternative emissions to be as follows:*

*$SO_x$ = 96 tons per year*

*$NO_x$ = 309 tons per year*

*Carbon Monoxide = 65 tons per year*

*Particulates = 54 tons per year*

*Carbon Dioxide = 4,246,297 tons per year*

*The natural gas component of the combination alternative is expected to be the primary driver of air quality impacts.*

*Waste Management*

*The solid waste generated from the natural gas component of the combination alternative would be minimal. There will be spent selective catalytic reduction catalyst used from NOx control and small amounts of solid-waste products (i.e. ash) from burning natural gas fuel. PV installations are highly capital intensive and manufacturing of the panels generates hazardous wastes.*

*Land Use*

*Approximately 50 to 60 acres of land would be needed to construct and operate two typical 500 MW combined-cycle power plants (Reference 3). PG&E owns sufficient land at the DCPP site if needed for this purpose, but construction would likely require significant excavation and grading that would substantially increase the costs of such a project in comparison to implementation at more flat, accommodating, locations. In addition, new mechanical-draft cooling towers would need to be constructed to support closed cycle cooling systems for the essentially new generation facilities. The environmental impacts of locating the gas-fired generation facility at an alternate location would depend on the past use of the location. If the site is a previously undisturbed site the impacts would be more significant than if the site was a previously developed site. Construction and operation of the gas-fired facility at an undeveloped site would require construction of a new cooling system, switchyard, offices, gas transmission pipelines, and transmission line ROWs.*

*The amount of acreage (habitat) required for each type of solar thermal technology varies. Assuming a parabolic trough system was located in a maximum solar exposure area, such as in a desert region, 500 acres per 100 MW (Reference 11) would be required. This corresponds to a site size of 2000 acres for 400 MW of generation.*

*Capacities of a single wind turbine range from 400 W up to 3.6 MW. Approximately 150,000 to 180,000 acres are required to produce 1,000 MW at a wind farm (Reference 27). This corresponds to a minimum site size of 283,860 to 341,130 acres for 830 MW of generation (Reference 27). Wind turbine "footprints" however, utilize only about 5 percent of the land on which the system is built. This allows for dual use of a site, such as for agriculture or ranching. Assuming that a solar PV system was* *located in a maximum solar exposure area, generation of 1,000 MW would require 54,000 acres. This corresponds to a site size of 143,132 acres for 1,160 MW of generation (Reference 27).*

*Commitment of land would also be required for the CAES facility. If existing mines or subterranean compressed air reservoirs are utilized, these would limit other uses, such as for natural gas or $CO_2$ storage. Regardless, the CAES facility would require additional land to support the air storage, turbines, and ancillary operational equipment and structures required. This adds to the cumulative land use impacts.*

*Geothermal generation of 100 MW would require at least 20 acres and many miles of new transmission facilities to deliver the power.*

*Other Impacts*
*Fugitive dust emissions could be anticipated from the natural gas component of the combination alternative, but would be minimized using best management practices. PG&E estimates a peak construction workforce of approximately 1,300 for the NGCC plant, therefore socioeconomic impacts of construction would be minimal. However, since PG&E estimates a workforce of approximately 62 for gas operations (Reference 7), the reduction in overall long-term site workforce would result in adverse socioeconomic impacts. PG&E believes these impacts would be small to moderate.*

*Combined-cycle power plants using evaporative cooling consume about 6 acre-feet of either fresh or recycled/reclaimed water per year per MW based on expected capacity factors. In addition, a new high efficiency combined-cycle power plant would burn approximately 3.25 million cubic feet of natural gas per hour. The natural gas would need to be delivered through a pipeline system that can support the level of natural gas needed for a baseload power plant. Regardless of where the natural gas-fired plant is built, additional land would be required for natural gas wells and collection stations. Approximately 3,665 acres would be needed for wells and stations (Reference 21).*

*Impacts to aquatic resources and water quality at the DCPP site from the natural gas component of the combination alternative would be smaller than the impacts of DCPP operations, due to the reduced generation and projected necessary use of mechanical draft cooling towers that would be constructed to support the closed cycle cooling systems. However, the additional stacks and boilers would increase the visual impact of the existing site. Impacts to cultural and ecological resources would be likely due to construction of a new natural gas pipeline on previously disturbed land. Additionally, use of closed cycle cooling systems with saltwater makeup would result in substantial air emissions from cooling towers. PG&E estimates that other construction and operation impacts of combined-cycle plants for the natural gas component of the combination alternative would be small. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved.*

*CSP facilities using closed loop cooling (e.g., a mechanical or natural draft cooling tower) can consume as much as 15 acre-ft/yr/MW, or approximately 4.89 million gallons/yr for every MW of capacity (Reference 28). While the plants do not generate problematic air emissions, construction of solar thermal plants leads to potential habitat destruction and substantial aesthetic changes.*

*In addition to the impacts of transmission systems, other challenges to siting wind farms are the bird mortality resulting from collisions with turbine blades, the noise of the rotors, and visual aesthetics. Solar PV systems have low water requirements, but can have negative visual impacts, especially if ground mounted. For the CAES facility needed to support wind and solar PV, the pressures involved in the subsurface storage could result in concerns about other environmental impacts, such as spread of contaminants into fresh water supplies similar to the concerns alleged in shale oil and gas production.*

*Overall, the majority of the impacts in the combination alternative are expected to come from the operation of an NGCC plant, though the impacts of the other portions of the combination are additive. Air quality and water use impacts, in particular, are driven by the natural gas component. However, the land use impacts from wind and solar are also substantial, and the water use impacts of the CSP facility can be significant.*

### 7.2.2.~~2~~ *3* Purchased Power

As discussed in Section 7.2.1.1, PG&E assumes that the generating technology used under the purchased power alternative would be one of those that NRC analyzed in the GEIS. PG&E is also adopting by reference the NRC analysis of the environmental impacts from those technologies. Under the purchased power alternative, therefore, environmental impacts would still occur, but they would likely originate from a power plant located elsewhere in California or other states in the West.

### *7.2.2.4 Demand Side Management and Energy Efficiency*

*Demand-side management programs are designed to reduce customer energy consumption and overall electricity use. Because there would be no construction, there would be no new environmental impacts created from this alternative. Analyses in recent NRC license renewal Supplemental GEISs (see NUREG-1437, Supplements 33, 37, 38 regarding Shearon Harris, Three Mile Island, Unit 1, and Indian Point, Units 2 and 3, respectively) indicate that impacts from conservation are small, though the impacts associated with loss of taxes and other revenues, as well as lost jobs, may result in up to moderate socioeconomic impacts, which would not be offset by conservation.*

## 7.3 REFERENCES


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TABLE 7.2-1

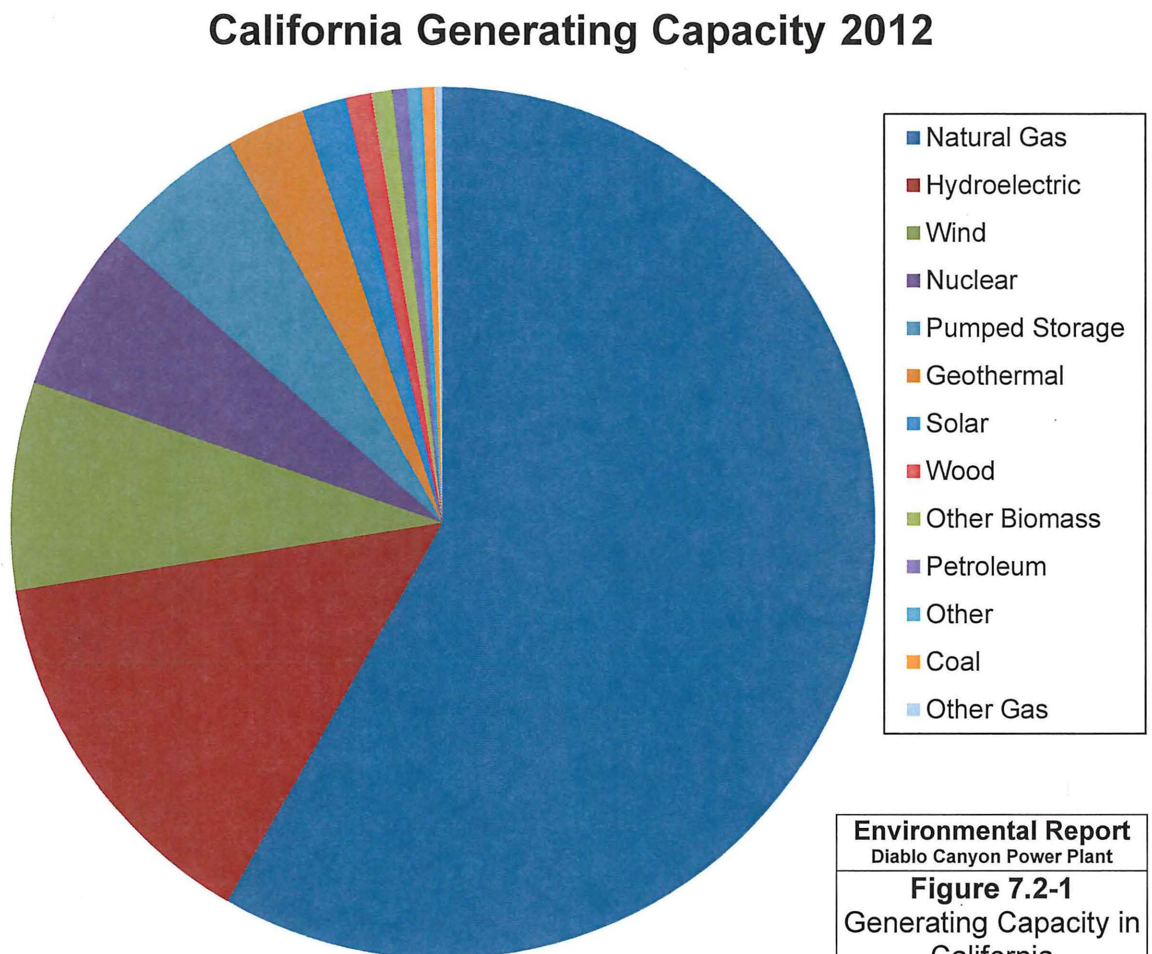
AIR EMISSIONS FROM NATURAL GAS-FIRED ALTERNATIVE

| Parameter | Calculation | Result |
|---|---|---|
| Annual Gas Consumption | $4 units\ x \frac{562.5MW}{unit} x \frac{6,600Btu}{kWxhr} x\,0.9x \frac{ft^3}{1,015Btu} x \frac{7,884hr}{year}$ | 115,347,192,118 $ft^3$ per year |
| Annual Btu Input | $\frac{115,347,192,118 ft^3}{year} x \frac{1,015Btu}{ft^3} x \frac{MMBtu}{10^6 Btu}$ | 117,077,400 MMBtu per year |
| $SO_X$[a] | $\frac{0.0034lb}{MMBtu} x \frac{ton}{2,000lb} x \frac{117,077,400MMBtu}{year}$ | 199 tons $SO_X$ per year |
| $NO_X$[b] | $\frac{0.0109lb}{MMBtu} x \frac{ton}{2,000lb} x \frac{117,077,400MMBtu}{year}$ | 638 tons $NO_X$ per year |
| CO[b] | $\frac{0.0023lb}{MMBtu} x \frac{ton}{2,000lb} x \frac{117,077,400MMBtu}{year}$ | 134 tons CO per year |
| PM[a] | $\frac{0.0019lb}{MMBtu} x \frac{ton}{2,000lb} x \frac{117,077,400MMBtu}{year}$ | 111 tons filterable PM per year |
| $CO_2$[c] | $4 units\ x \frac{562.5MW}{unit} x \frac{1,100\ lb\ CO_2}{MWxhr} x\,0.9\,x \frac{ton}{2,000lb} x \frac{7,884hr}{year}$ | 8,780,805 tons $CO_2$ per year |

* 0.9 = 90% Baseload Capacity Factor: This provides for 36 Days/Year for planned maintenance outages and unplanned forced outages. This is comparable to current capacity factors (inclusive of refueling outages) for DCPP Units 1 & 2.

a. Reference 20, Table 3.1-1
b. Reference 20, Table 3.2-2
c. Reference 12

$SO_X$ = oxides of sulfur
$NO_X$ = oxides of nitrogen
CO = carbon monoxide
PM = particulate
$CO_2$ = carbon dioxide




**Environmental Report**
**Diablo Canyon Power Plant**

**Figure 7.2-1**
Generating Capacity in California

Source: Reference 19