SECTION 9.0

Alternatives Analysis

This section considers whether reasonable alternatives to the South Bay Replacement Project (SBRP) exist that may reduce or eliminate any significant, adverse environmental impacts of the proposed Project, while still being able to feasibly attain most of the basic project objectives. The SBRP objectives are described in more detail in this Application for Certification (AFC), and developing an electrical generating facility that:

- Is commercially-viable[1] and capable of supplying economical electrical services—capacity, reliability, ancillary services, and energy supply—to the San Diego region.
- Is capable of ensuring the timely removal of the existing South Bay Power Plant (SBPP) and that fulfills the obligation found in Article 7.1.a of the Cooperation agreement.[2]
- Will meet applicable laws, ordinances, regulations and standards (LORS) of the CEC, City of Chula Vista, the San Diego Unified Port District (Port) and other agencies, and complies with LSP South Bay, LLC's (LSP) Environmental Policy.
- Is consistent with the objectives, guidelines and timing goals of the emerging Bay Front Master Plan.
- Assists in maintaining and/or increasing the regional electrical system's efficiency and reliability.
- Does not conflict with the state-mandated 20 percent Renewable Portfolio Standard (RPS) requirements for renewable energy.

The SBRP site was chosen based on its physical, environmental and land use characteristics consistent with the above objectives. The Project site consists of 19.4 acres (12.9 acres will be utilized by the SBRP and 6.5 acres is reserved for the relocation of the SDG&E South Bay substation) of the 33-acre former Liquid Natural Gas (LNG) site owned by the Port in the City of Chula Vista. The site is adjacent to the existing SBPP site. As part of the project, the Applicant will enter into an agreement with the Port to lease the 12.9-acre site. The site is flat and zoned for industrial use. The site was used previously by SDG&E to liquefy and store LNG in two, large above ground tanks. These LNG tanks were removed by SDG&E in 1989 and only the tank foundations, miscellaneous foundations, roadway and an earthen spill containment berm remain. Supporting infrastructure (natural gas, electric transmission, and water supply lines) are located adjacent to the site along Bay Boulevard. The area adjacent to the Site consists of the existing SBPP on the north, industrial and commercial properties on the east and south, and salt ponds and the San Diego Bay to the west. Bay Boulevard and Interstate 5 (I-5) are located east of the Site.

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[1] Commercially viable is defined as a facility that can successfully participate in power purchase procurement activities of San Diego Gas & Electric (SDG&E) or other load serving entities.

[2] Article 7.1.a of the Cooperation agreement reads "use commercially reasonable efforts to develop, finance, construct and place into commercial operation a new generation plant replacing the SBPP… which shall have a generating capability at lease sufficient to cause the ISO to terminate (or fail to renew) the must run designation application to the SBPP on or before the termination of the lease".

9.1 Alternatives Analysis Requirements

The CEC's power plant siting procedure is a certified functional equivalent process to the environmental review required by California Environmental Quality Act (CEQA). The alternatives analysis required by CEC regulations in CCR, Title 20, Appendix B, is similar to the CEQA requirement to analyze alternatives. Thus, CEQA provides further guidance regarding the appropriate level of alternatives analysis to include in this AFC.

The Guidelines for Implementation of CEQA (CEQA Guidelines) provide the framework for analyzing alternatives to a proposed project as part of an Environmental Impact Report (EIR). CEQA Guidelines, Section 15126.6—Consideration and Discussion of Alternatives to the Proposed Project provides, in relevant part, the following:

> *(a) Alternatives to the Proposed Project. An EIR shall describe a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives. An EIR need not consider every conceivable alternative to a project. Rather, it must consider a reasonable range of potentially feasible alternatives that will foster informed decisionmaking and public participation. An EIR is not required to consider alternatives which are infeasible.*
>
> *(c) Selection of a range of reasonable alternatives. The range of potential alternatives to the proposed project shall include those that could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects... Among the factors that may be used to eliminate alternatives from detailed consideration in an EIR are: (i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts.*
>
> *(f) Rule of reason. The range of alternatives required in an EIR is governed by a 'rule of reason' that requires the EIR to set forth only those alternatives necessary to permit a reasoned choice. The alternatives shall be limited to ones that would avoid or substantially lessen any of the significant effects of the project. Of those alternatives, the EIR need examine in detail only the ones that the lead agency determines could feasibly attain most of the basic objectives of the project...*
>
> > *(1) Feasibility. Among the factors that may be taken into account when addressing the feasibility of alternatives are site suitability, economic viability, availability of infrastructure, general plan consistency, other plans or regulatory limitations, jurisdictional boundaries (projects with a regionally significant impact should consider the regional context), and whether the proponent can reasonably acquire, control or otherwise have access to the alternative site (or the site is already owned by the proponent).*
> >
> > *(3) An EIR need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative.*

9.2 Selection of Alternatives to Be Evaluated

Pursuant to Section 15126.6(a) of the CEQA Guidelines, a reasonable range of alternatives to the SBRP has been defined, and the alternatives are evaluated in the following sections. The alternatives were selected based on their potential to feasibly meet most of the basic project objectives and to avoid or substantially lessen the significant environmental effects of the SBRP. The alternatives analysis presented here provides a sufficient amount of information to allow for a meaningful evaluation and comparison of the Project with each alternative.

Consistent with section 9.1 above, the selection of alternatives for consideration in this analysis is governed by the rule of reason, which requires an environmental document to "set forth only those alternatives necessary to permit a reasoned choice" (CCR Title 14, Section 15126.6[f]). A key issue is whether the selection and discussion of alternatives fosters informed decision-making and public participation based on the various economic, environmental, social and technological factors involved. An environmental document need not consider an alternative where the effect cannot be reasonably ascertained and where implementation is remote and speculative (CCR Title 14, Section 15126.6[f][3]). For purposes of this analysis, the reasonable range of alternatives considered is: (1) the "no project" alternative; (2) power plant site alternatives; (3) cooling alternatives; and (4) technology alternatives.

Alternatives considered in this analysis are described and evaluated in the sections below. A comparative analysis of alternatives follows the separate evaluations and is summarized in Table 9.1-1.

9.3 No Project Alternative

The "no project" alternative assumes that the SBRP is not developed. The site for the SBRP would remain in its existing condition and would be available for other industrial development. In addition, under the "no project" alternative it is expected that at least some of the SBPP units will continue to be needed to meet the grid reliability needs of the San Diego region. As such, it is unlikely that the California Independent System Operator (CAISO) would release the existing SBPP from its reliability must run (RMR) obligation.[3] Until released from its RMR obligation, the SBPP will continue to operate under the terms of the existing Port lease agreement.[4] If the project is not developed, the SBPP will continue to be required by the CAISO to be operated unless and until the CAISO concludes either sufficient new generation is built in the San Diego Area (see 9.5 Power Plant Site Alternatives), or that CAISO determines that sufficient new transmission is built and new or existing generation is available outside of the region to support SDG&E load and reliability needs that allows increased import capacity into the South Bay portion of the San Diego Area (see 9.4 Transmission Alternatives).

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[3] SBPP units must continue to operate for as long as the CAISO determines the plant is needed for grid reliability, regardless of whether the requirement to operate is imposed through the existing RMR contract or an alternative ruling, such as a local resource adequacy requirement.

[4] Section 2.1 sets forth the lease term expiration date conditions. They include three conditions: (a) first, the payment in full and retirement of the bonds associated with the facility's purchase from SDG&E; (b) second, the reaching of the end of the primary lease term [at the end of 2009], and (c) the "termination by the ISO of (and the failure by ISO to subsequently reinstate) those must-run obligations imposed by ISO under the Must-Run Contract in respect of the Facility".

Although either of these two options could potentially provide sufficient capacity to the SDG&E service territory to permit the retirement of the capacity represented by the SBPP (i.e. fulfill the RMR need), absent other local transmission system enhancements they may not address the needs of the local area supported by the South Bay substation, which consumes around 600 MW of South Bay generation that includes 240MW of the Main Street substation load.[5] SDG&E has previously identified the need to install 230 kV to 69 kV transformation at the South Bay switchyard to support the area 69 kV transmission system in the event all generation at South Bay is removed.[6] In addition to this new transformation, other modifications will be required. Possible options include a reconfiguration or a reinforcement of the 69 kV system. The exact plans will require a detailed analysis to identify the recommended solution.

The addition of 230 to 69 kV transformation at South Bay results in a system that has contingency flows in excess of the applicable ratings on portions of the 69 kV system. One solution is to increase the rating of the impacted facilities. A second option is open or radialize the 69 kV system to eliminate the transfers through the system that are creating the high flows. This option requires an extensive review of the 69 kV system to insure that opening lines does not create other reliability problems.

9.3.1 RMR Assessment

This section follows the method used by the CAISO in its annual Reliability Must-Run (RMR) Technical Study.[7] Through this study, the CAISO determines its need for local area reliability services (LARS) for the next year and then, based on these results, contracts for the needed capacity. It is anticipated that the CAISO LARS process will ultimately be superseded by the CPUC's Local Capacity Requirement (LCR), which would require that load serving entities procure sufficient local capacity to meet their peak demand within transmission-constrained areas. The CPUC is in the process of establishing the LCR rules and requirements. Until the LCR is in place and RMR services are no longer required, however, the CAISO will continue to implement its LARS process based on the results of its annual RMR Technical Study.

To evaluate the need for SBPP to provide these services during the Project timeframe (i.e., beginning in 2010), it is necessary to develop assumptions about future loads and resources in San Diego. (CAISO performs this modeling work on a year by year basis). These assumptions also include identifying projects that can reasonably be expected to be in place. Given project development timelines, these would only include generation and transmission projects with the necessary regulatory approvals to begin construction.[8]

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[5] The South Bay substation currently supports around 600 MW of load. The South Bay 69kV lines feed into the Border, Imperial Beach, Montgomery, National City, Otay, Otay Lake, San Ysidro and Sweetwater substations. Communities served by the South Bay substation include Chula Vista, National City, Imperial Beach, San Ysidro, South San Diego, Otay and Nestor.

[6] See the SDG&E presentation dated January 15, 2004, titled *South Bay Power Plant Site, SDG&E Electric Facilities,* page 9. "Substation is needed to serve South Bay area load no matter whether South Bay Power Plant stays or is retired." Page 17 also reads, in reference to the one option of eliminating the South Bay Power Plant: "Build new 230/69kV substation to supply South Bay area load", and "Extend existing 69kV transmission lines to new substation site."

[7] 2006 Reliability Must-Run Technical Study of the ISO-Controlled Grid, Grid Planning Department, CAISO, May 2005 and Year 2007 RMR Study, San Diego Area, Summary of Findings, Prepared by Janice Zewe, Regional Transmission South - California ISO, June 8, 2006.

[8] Generation projects located in San Diego that are in the CEC siting queue ahead of the Project would also be included, however, there are no such projects seeking CEC approval at this time.

The CAISO uses a 1 in 5 year forecast of summer peak loads to determine RMR needs for the next year. For 2007, the CAISO 1 in 5 forecast of loads and losses in the San Diego area is 4,611 MW. To maintain overall consistency with the CAISO RMR assessment, the CAISO's 2007 forecast of 1 in 5 peak loads is escalated to future years using the escalation rate implicit in the CEC's 1 in 5 year forecast of SDG&E Planning Area peak loads from the 2005 Integrated Energy Policy Report (IEPR).[9]

San Diego is at the end of an "electrical cul-de-sac" that effectively limits the ability to import power into the area to serve San Diego electrical loads. There are two major pathways over which power is imported into San Diego: Path 44 to the North and the Southwest Power Link (SWPL) to the East.[10] The critical contingency used to determine RMR requirements consists of the coincident outage of a section of the 500 kV SWPL between Imperial Valley and Miguel Substations (i.e., N-1) and the largest in-area generating unit (i.e., G-1).[11] With the outage of SWPL, the simultaneous import limit into San Diego is reduced from 2,850 MW to 2,500 MW.

The CAISO's requirement for RMR units is equal to the difference between the peak load and the N-1 import limit, further adjusted to account for the G-1 outage. In 2010, the RMR requirement for SDG&E is forecast to be 2,894 MW, rising to 3,232 MW in 2015.

Resources available to meet this RMR requirement include existing generators in the SDG&E area (2,933 MW in 2007 according to the CAISO[12]) plus projects that have been permitted and contracted for by SDG&E. These include:

Plant Name	Capacity (MW)	Anticipated On-Line Date
Calpine Otay Mesa	561	2008
Lake Hodges Pumped Storage	40	2008

A large portion of the existing in-area generation consists of aging plants, including SBPP, that are at risk of retirement. In its 2005 Integrated Energy Policy Report (IEPR), the CEC formulated a policy goal calling for the "orderly retirement or repowering of the aging power plants in [the 2004 IEPR Update] study group by 2012."[13] In San Diego, aging plants included in the IEPR study group are the Encina Power Plant and SBPP. For the purpose of this "no project" assessment, the consequences of removing the existing SBPP from service in 2010 was examined, and the Encina Power Plant is assumed to be taken out of service after 2011. Although this assessment assumes that the existing SBPP retires in 2010, there is no formal requirement for SBPP to retire by that date. Under the terms of SBPP's RMR contract, the plant can be removed from service only if the CAISO determines that the RMR needs may be met using alternative resources.

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[9] California Energy Demand 2006-2016, Staff Energy Demand Forecast, Revised September 2005, CEC-400-2005-034-SF-ED2, Chapter 4, Form 1.5 - SDG&E, September 2005.

[10] According to the CAISO, the Mexico Commission Federal de Electricidad (CFE) system is assumed to not have the capability for surplus resources for supplying the San Diego area and therefore the import/export for CFE is assumed to be zero. This assumption for CFE results in that system having no effect on the San Diego RMR Study results.

[11] The G-1 contingency represents the largest single generator outage possibility. Currently the G-1 is the Palomar plant at 542 MW. The G-1 contingency increases to 561 MW in 2008 when the Otay Mesa plant is expected to begin operation. The entire plant output is used to calculate the G-1 contingency because the CAISO considers combined cycle plants with a single point of failure to represent a single contingency.

[12] Year 2007 RMR Study, San Diego Area, Summary of Findings, Prepared by Janice Zewe, Regional Transmission South - California ISO, June 8, 2006.

[13] 2005 Integrated Energy Policy Report, CEC-100-2005-007-CMF, November 2005, p. 171.

As shown in Table 9.3-1, the "no project" alternative is not feasible in that there is an RMR deficit of 54 MW beginning in 2010, when the SBPP is taken out of service. Under certain scenarios, the deficit could be even greater. If aging combustion turbines in the San Diego area were retired, the deficit would be greater. If expected resources, such as the Otay Mesa Power Plant, that are not currently under construction and which face completion uncertainty, were not included, the deficit would be much greater.

TABLE 9.3-1
Assessment of San Diego RMR Needs

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CEC 1 in 5 Year Peak Load Forecast	4,779	4,866	4,941	5,014	5,085	5,158	5,230	5,300	5,367	5,433
CEC Annual Escalation Rate		1.8%	1.5%	1.5%	1.4%	1.4%	1.4%	1.3%	1.3%	1.2%
CAISO 1 in 5 Year Peak Load Forecast	4,611									
CAISO Forecast Escalated at CEC Rate	4,611	4,695	4,767	4,838	4,906	4,977	5,046	5,114	5,178	5,242
Import Capacity	(2,850)	(2,850)	(2,850)	(2,850)	(2,850)	(2,850)	(2,850)	(2,850)	(2,850)	(2,850)
N-1 (SWPL)	350	350	350	350	350	350	350	350	350	350
G-1 (Largest Unit)	542	561	561	561	561	561	561	561	561	561
RMR Requirement	2,653	2,756	2,828	2,899	2,967	3,038	3,107	3,175	3,239	3,303
New In-Area Generation (since 2001)	822	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423
Existing QF Generation	192	192	192	192	192	192	192	192	192	192
Existing "At-Risk" Resources										
Encina Steam	946	946	946	946	946	-	-	-	-	-
South Bay Steam	689	689	689	-	-	-	-	-	-	-
Older Combustion Turbines	200	200	200	200	200	200	200	200	200	200
Electrovest Otay and Escondido	84	84	84	84	84	84	84	84	84	84
Total "At-Risk" Resources	1,919	1,919	1,919	1,230	1,230	284	284	284	284	284
Total Resources	2,933	3,534	3,534	2,845	2,845	1,899	1,899	1,899	1,899	1,899
RMR Surplus (Deficit)	280	778	706	(54)	(122)	(1,139)	(1,208)	(1,276)	(1,340)	(1,404)

As a result of the deficit that would occur if the SBPP were removed without replacement, the CAISO would not be able to remove the RMR designation from all the SBPP units. Therefore, as a result of the "no project" alternative, existing SBPP units would be required to continue to operate. Alternatively, the proposed Project would provide the same reliability services as the SBPP, but with lower costs and environmental impacts. As such, the Project is clearly superior to the "no project" alternative of continuing to operate the existing SBPP.

9.3.2 Energy and Capacity Issues

In addition to RMR considerations, the Project is also superior to the "no project" alternative with respect to providing needed energy and capacity to the San Diego region. The CEC has recently completed an assessment of SDG&E's resource needs and identified a significant shortfall of energy and capacity in the 2010 to 2016 timeframe.[14] This assessment is based on confidential reports filed by all load serving entities that detail the supply of contracted resources. The total amount of contracted resources reported by each utility service is then compared to CEC forecasts of loads to determine need. Even after accounting for the development of specified preferred resources, including energy efficiency, demand response and renewables, there is still an identified need for SDG&E to procure additional capacity and energy in the 2010 to 2015 timeframe.[15] In its 2005 IEPR Transmittal Report, the CEC

[14] "Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission" (2005 IEPR Transmittal Report), CEC-100-2005-008-CMF, November 2005.

[15] Note, the CEC has acknowledged that the targets it established for preferred resources are aggressive and may not be feasible (2005 IEPR Transmittal Report, p. 120-125), which would suggest that the resource need may be even greater than estimated.

identified a need for SDG&E to procure 1,000 MW to 1,600 MW of additional resources, *not including capacity needed to replace the existing aging plants*.[16] On an energy basis, the identified need is roughly 1,000 GWh to 4,000 GWh per year over the same time period. [17] The CEC conducted similar assessments for all California utilities and found a significant shortfall statewide.

The Project will fill part of the identified need by providing competitively-priced power to the California electricity market to help meet the state's growing demand for electricity, and to help replace less efficient generation resources retired due to age or high cost of producing power. The "no project" alternative would not meet these objectives.

The "no project" alternative could substantially delay the development of modern, efficient, power generation in San Diego. As a result, the region would continue to rely in part on older steam/electric power plants and simple-cycle gas turbine peaking plants to meet the demand for electricity. These older plants have less efficient technology than the SBRP, resulting in significantly more fuel required and air emissions per unit of power generated.

In the longer run, the net effect of implementing the "no project" alternative is that future electrical generating capacity will likely be displaced to other sites. Although the location, availability, cost and environmental footprint of future replacement generation is highly speculative, virtually any alternative site will result in a greater level of environmental impact than the Project (see Section 9.5).

9.3.3 Other Issues

The "no project" alternative would result in a loss of the projected socioeconomic benefits related to the Project's construction and operation, including employment, local expenditures, gas franchise fees, and additional sales and property taxes. In addition, the "no project" alternative provides no visual improvements and does not accommodated the Bay Front Master Plan, so these key benefits of the SBRP are also lost.

9.4 Transmission Alternative Description

The "no project" assessment identified grid reliability as an important consideration in the evaluation of alternatives to the Project. Transmission projects that increase the N-1 import capability can be an alternative to the construction of new in-area generating capacity. Each type of project has its advantages and disadvantages and it is difficult to weigh the relative benefits of transmission and generation because the services that they provide and the time period over which they can be expected to operate can differ.

In order to serve as an effective alternative, a transmission project must be able to feasibly attain most of the objectives of the Project. To do so, a transmission project must significantly increase the N-1 import capability of the SG&E system such that the SBPP can be released from its RMR obligation and removed from service. Furthermore, it must meet this objective in a timely manner, since continued operation of the SBPP longer than is

[16] 2005 IEPR Transmittal Report, CEC-100-2005-008-CMF, November 2005, Table B-17.

[17] 2005 IEPR Transmittal Report, CEC-100-2005-008-CMF, November 2005, Table B-14, when other load serving entities are included, the overall need in San Diego is even greater

necessary is counter to the interests of SDG&E ratepayers, the Port of San Diego, the City of Chula Vista, and the environmental community. Furthermore, a feasible alternative is premised on the availability of environmentally clean and economically out-of-area generation, the existence of which is not certain in the 2010 and beyond time frame. In addition, while an out-of-area gas-fired combined-cycle plant would have a similar environmental signature as the SBRP, and similar efficiency, energy produced by an out-of-area power plant would be disadvantage by the significant power loss associated with transmitting energy over a large distance.

This section will consider transmission alternatives that increase import capacity into San Diego with a reasonable possibility of entering service in the same timeframe as the proposed SBRP, which has an anticipated on-line date of 2010. Given the development timeline for transmission projects, this would only include projects that have a Certificate of Public Convenience and Necessity (CPCN) or which have applied for a CPCN. There is one such project in the SDG&E service territory: the 500kV Sunrise Powerlink proposed by SDG&E.

On December 14, 2005 SDG&E filed a CPCN application for the Sunrise Powerlink, a 500-kV transmission line from the Imperial Irrigation District (IID) to a new substation in central San Diego County. The initial application sought a bifurcated proceeding at the CPUC that would focus first on determination of need followed later by a review of environmental impacts of the selected route. The application to bifurcate the proceeding was denied on April 7, 2006 and SDG&E has announced that it expects to file an amended application in July 2006 that would include an updated purpose and need filing as well as a proponent's environmental assessment. The CPUC proceeding will therefore resume once the amended application is filed by SDG&E.

As described in the initial application, the project would also include a 230 kV connection between the new substation and the existing Sycamore and Penasquitos substations in SDG&E's load center. According to SDG&E's application, the Sunrise Powerlink would increase the N-1 import limit from 2,500 MW to 3,500 MW, thereby addressing the grid reliability shortfall anticipated with the retirement of the SBPP. The application also claims that the Sunrise Powerlink will reduce SDG&E's energy costs, including the cost of importing renewable energy to meet California's renewables portfolio standard.

The analysis performed by SDG&E to determine its grid reliability planning requirements is very similar to the RMR analysis performed by the CAISO, with the exception that SDG&E uses a 1 in 10 year peak demand forecast rather than the 1 in 5 year forecast used by the CAISO, and there is a slight variation in the estimated capacity of available resources. In SDG&E's base case assessment, SBPP is assumed to retire in 2010.This is a reasonable conservative assumption used to evaluate SDG&E's grid reliability needs absent availability of SBPP, however as discussed previously, there is no requirement that SBPP be removed from service at that time. Table 9.3-2 summarizes SDG&E's base case grid reliability analysis.[18]

TABLE 9.3-2
SDG&E Grid Reliability Analysis (Assumes South Bay Retired by 2010)

[18] SDG&E Sunrise Powerlink Purpose and Need Filing, December 10, 2005, Table III-3, p. III-ix.

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1 in 10 Year Load Forecast	4,636	4,742	4,849	4,947	5,038	5,129	5,223	5,316	5,413	5,513
Available Generation	2,938	2,938	3,539	3,539	2,837	2,837	2,837	2,837	2,837	2,837
less G-1	(541)	(541)	(561)	(561)	(561)	(561)	(561)	(561)	(561)	(561)
Generation (less G-1)	2,397	2,397	2,978	2,978	2,276	2,276	2,276	2,276	2,276	2,276
"G-1/N-1" Import Level	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Generation + Imports	4,897	4,897	5,478	5,478	4,776	4,776	4,776	4,776	4,776	4,776
Surplus/(Deficiency)	261	155	629	531	(262)	(353)	(447)	(540)	(637)	(737)
Sunrise Powerlink Addition					1,000	1,000	1,000	1,000	1,000	1,000
Surplus/(Deficiency) with Sunrise	261	155	629	531	738	647	553	460	363	263

Although SDG&E's application shows that additional import capability provided by the proposed Sunrise Powerlink would address the grid reliability shortfall that results from retirement of the SBPP, further analysis shows that as an alternative to the Project, the Sunrise Powerlink is not feasible, nor is it sufficient.

In addition to the factors discussed herein relating to grid reliability, the SBRP will also have different environmental effects than the Sunrise Powerlink project. An analysis of these differences is not included at this time, but such an analysis may consider the potentially important differences on land use, visual resources, biological resources, water resources, and air quality (both long-term and short-term construction related). Also of note, is the fact that by itself the Sunrise Powerlink project does not produce electrical energy, but rather it simply delivers electrical energy. Power plants need to be connected to the transmission line and the operations of these power plants will have environmental impacts. The transmission alternative includes the local changes needed in the South San Diego Bay area to reconfigure the substation and nearby 69 and 138 kV circuits.

9.4.1 Reasonable Timing of the Transmission Alternative

SDG&E has proposed an on-line date of 2010 for the Sunrise Powerlink. If that ambitious goal is achieved, then the Transmission Alternative would meet the first project objective, which includes the timely removal of SBPP, provided that certain local transmission improvements are also made that allow for the removal of SBPP. It is highly unlikely, however, that a transmission project of this scope could be completed within the proposed timeframe.

Although SDG&E filed a CPCN application in December 2005, the application was not complete and did not propose a route for the transmission line. SDG&E has subsequently chosen a proposed transmission route that traverses Anza Borrego State Park and, as discussed above, is expected to file an amended CPCN application in August 2006.

The transmission siting and review process is often protracted, especially in the case of projects establishing new transmission routes outside of existing transmission corridors, let alone one that proposes crossing through a state park as is the case with the proposed Sunrise Powerlink. Even projects within existing corridors require a lengthy review and construction timeline. Southern California Edison Company, in the Supplement to its Renewable Procurement Plan, states that "the typical length of time from when a generator applies for an interconnection to the completion of transmission upgrades currently ranges from approximately five to seven years...."[19] It is inconceivable that a 500 kV line requiring

[19] Southern California Edison Company's Supplement to its Renewable Procurement Plan 2005-2014, R.04-04-026, December 7, 2005, p. 5.

a new route through Southern California would take less time to complete than the interconnection upgrades described by SCE. In fact, SDG&E's 2004 Long Term Plan addressed this issue stating that "given the length of the permitting process, right-of-way acquisition and construction timing, it is estimated that a minimum of five years is required from the filing of a CPCN until the commercial in-service date.

In light of an anticipated August 2006 CPCN application, the Sunrise Powerlink would therefore not be expected to be complete before mid-2011 at the earliest. More likely, given the scale of this project and potential siting difficulty, the line may not be operational until sometime after this date combined with the need for local transmission improvements in addition to the Sunrise PowerLink Project. There is not a reasonable assurance that the Transmission Alternative could be completed within the timeframe needed to satisfy the Project objective concerning the timely removal of the SBPP while ensuring continued grid reliability in San Diego, the Transmission Alternative is not a feasible alternative to the Project.

9.4.2 Reasonable Range of Available Generation

Even if the Transmission Alternative can be completed in a timely manner (Sunrise PowerLink plus other local projects), it would not be sufficient to meet the Project objectives given the range of uncertainty surrounding the availability of in-area generation. In its evaluation of the need for the Sunrise Powerlink, SDG&E considered a range of resource scenarios, including one in which the South Bay and Encina power plants are retired at the end of 2009 and 2010, respectively. Given the CEC's policy recommendation concerning the replacement of aging power plants, it is reasonable to present this scenario as the base case, rather than as an alternative to SDG&E's base case in which only SBPP is retired. Table 9.4-2 presents the results of this scenario, which is the same as Table 9.4-1 with the exception that in addition to the assumed retirement of SBPP at the end of 2009, the Encina power plant is retired at the end of 2010.[20]

TABLE 9.4-2
SDG&E Grid Reliability Analysis (South Bay and Encina Retired)

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1 in 10 Year Load Forecast	4,636	4,742	4,849	4,947	5,038	5,129	5,223	5,316	5,413	5,513
Available Generation	2,938	2,938	3,539	3,539	2,837	1,877	1,877	1,877	1,877	1,877
less G-1	541	541	561	561	561	561	561	561	561	561
Generation (less G-1)	2,397	2,397	2,978	2,978	2,276	1,316	1,316	1,316	1,316	1,316
"G-1/N-1" Import Level	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Generation + Imports	4,897	4,897	5,478	5,478	4,776	3,816	3,816	3,816	3,816	3,816
Surplus/(Deficiency)	261	155	629	531	(262)	(1,313)	(1,407)	(1,500)	(1,597)	(1,697)
Sunrise Powerlink Addition					1,000	1,000	1,000	1,000	1,000	1,000
Surplus/(Deficiency) with Sunrise	261	155	629	531	738	(313)	(407)	(500)	(597)	(697)

As shown in Table 9.4-2, the Sunrise Powerlink addition, even if it occurs in 2010, is not sufficient to address the grid reliability shortfall that occurs in 2010-2015 as a result of the recommended retirement of the aging plants in San Diego. To address this shortfall new

[20] SDG&E Sunrise Powerlink Purpose and Need Filing, December 10, 2005, Table III-8, p. III-xi.

transmission, availability of economic out-of-area generation, **and** new in-area generation are required. Transmission alone is not a feasible alternative to the SBPP.

9.4.3 Other Issues

In addition to grid reliability, the Project objectives include the provision of "economic, reliable, and environmentally-sound electrical energy, capacity, and a variety of electrical energy services." Given the Project's location close to San Diego loads and its state of the art design, the Project is superior to the Transmission Alternative at providing these services.

The Transmission Alternative increases the import capability of the San Diego transmission system by providing an additional high-voltage link to the East. The new transmission provides additional access to potentially available generation resources located in the Imperial Valley, Mexico and Arizona, as well as to imports from more distant markets. While there are benefits from access to these resources, they do not outweigh the benefits of competitive local generation.

At the margin, power imported from outside of the load area is supplied by generation from combined-cycle gas turbine power plants similar to the technology used in the Project (see Section 9.6 Alternative Technologies). The difference is that imported power suffers from transmission losses that are not incurred by the project and non-coastal plants operate at higher ambient temperatures which lowers efficiency. As a result, the Project generates an equivalent amount of power delivered to load at a lower cost and with fewer environmental impacts than imported power generated using similar technology.[21]

While the Transmission Alternative could also provide access to renewable resources not available within San Diego, these resources would have access to existing or planned transmission lines that would provide for delivery to California loads. For example, LADWP and IID have proposed a new transmission line from the Imperial Valley to Los Angeles, the "Green Path," that would provide access to the same resources as the Sunrise Powerlink.[22] Furthermore, although supplies from renewable resources are increasing, gas-fired resources still represent the marginal power supply in the West. Given their low operating costs, renewable supplies are infra-marginal and do not affect the dispatch of marginal gas-fired resources during most hours of the day. As a result, the additional import capability provided by the Transmission Alternative does not change the fundamental tradeoff between gas-fired generation located in the load area and gas-fired generation located outside the load area. Conversely, added in-area generation reduces dependence on imported power, and increases existing transmission capacity available for out-of-area renewable resources without costly transmission investments.

Given the transmission losses and associated economic and environmental costs that result from increased reliance on out-of-area generation, the Transmission Alternative cannot be

[21] Additionally, the SDG&E resource plan assumes that there will be excess generation available to import in the timeframe in question. As load requirements grow throughout the west during the next several years, it is questionable how much excess generation, if any, will be available.

[22] See <http://www.ladwp.com/ladwp/cms/ladwp007434.jsp>. Although SDG&E's amended application for the Sunrise Powerlink is expected to include the integration of the Sunrise Powerlink and the Green Path (see http://www.nctimes.com/articles/2006/03/24/news/sandiego/15_53_303_23_06.txt), the Green Path as originally proposed could deliver renewable energy from IID without completion of the Sunrise Powerlink.

considered a superior alternative to the Project, even if the Transmission Alternative were feasible.

9.5 Power Plant Site Alternatives

9.5.1 Introduction

On December 11, 1998, the Applicant entered into lease and Cooperation Agreements (Agreements) with the San Diego Unified Port District (Port), in which the Port agreed to lease the power generating facility known as the SBPP (formerly owned by San Diego Gas & Electric [SDG&E]) to Applicant to operate the facility for a period of 10 years, after which the time the facility would need to be decommissioned. Pursuant to Section 7 of the Agreement, and for as long as the California Independent System Operation (ISO) designates the existing SBPP as a "must-run" facility, LSP, the current lessee is obligated to diligently pursue development of a "Replacement Generation Plant" to replace the SPBB.

Two general locations for the replacement plant were identified in the Agreements: (1) on South Bay properties owned by the Port, as defined in the Agreement; and (2) at an offsite location, i.e., at a location other than South Bay Properties.

In early 2001, the Applicant began a comprehensive search to identify commercially viable replacement sites. Sites were evaluated and compared using criteria grouped into three broad categories: natural resources, community, and technical/commercial. A rating system was developed to compare and contrast the relative suitability among sites, and several sites were selected for further study.

9.5.2 Methodology Used in Evaluating Potential Power Plant Sites

To guide the identification of offsite locations for SBRP, the Applicant developed the following goals:

- Goal 1: Focus the search within the San Diego County airshed—This goal was established to utilize the emissions offsets that become available from shutting down the SBPP.
- Goal 2: Focus the search on western San Diego County—The load center for the existing SBPP and hence the replacement plant is in western and southern San Diego County. Construction of extensive new transmission facilities must be avoided.
- Goal 3: Minimize environmental impacts—Potential environmental impacts be avoided to the extent possible during this initial stage of project site selection and planning.
- Goal 4: Concentrate on sites that can be permitted.
- Goal 5: Establish a siting process acceptable to the CEC—The Warren-Alquist Act, as codified in Public Resources Code section 25000 et seq., establishes a basis for identifying and evaluating potential power plant sites.
- Goal 6: Development and operation costs must be reasonable for the replacement plant to be commercially viable in a deregulated business environment.

With these goals in mind, a two-step evaluation process was developed:

Step 1—Regional Screening to identify candidate areas

- Step 1A: Eliminate Unsuitable Areas—Focusing on western San Diego County, a set of eight restrictive criteria was developed to further eliminate areas unsuitable for power generation, including:
  - Restricted or dedicated land use areas
  - Federal/state government land
  - Airports
  - Areas exhibiting topographic relief in excess of 25 percent slope
  - Major faults
  - Lakes and lagoons
  - Landfills
  - Dedicated habitat conservation areas
- Step 1B: Identify Siting Attributes—Delineating the location of four physical attributes within the study region:
  - Natural gas pipelines of 16 inches diameter or greater
  - Electrical transmission lines and substations of 138 kV or greater
  - Cooling water from facilities that could produce sufficient amounts of tertiary-treated water
  - Industrially-zoned land
- Step 1C: Identify Candidate Areas—By overlaying site attribute information (from Step 1B) on the restrictive criteria listed in Step 1A, areas of highest suitability are identified. These areas became the focus for the efforts conducted in Step 2.

Step 2—Candidate Area Screening to screen candidate areas for potentially viable sites

Six activities were undertaken to screen candidate areas from Step 1 (above) for potentially viable sites:

- Identification of available sites
- Site reconnaissance (sites were eliminated from consideration because of size, land use incompatibility, and other factors)
- Initial electrical/gas tie-in engineering (identified the most logical tie-in point for the gas supply line and the electrical transmission line tie to the grid)
- Right-of-way analysis
- Selection of candidate sites based on site control, site characteristics, linear facilities, and environmental issues.

Sites where control could reasonably be acquired at a fair value were given preference. Likewise, sites where the parcel was an adequate sized and zoned, with compatible land uses, and access to linear facilities was feasible were also given a preference. Finally, and

of significant importance, sites that showed the potential for minimal environmental issues or environmental issues that could be mitigated to below significant levels were given a preference.

9.5.3 Summary of Alternative Site Screening Results

By using these criteria described above, sites were identified as having potential merit for power plant uses. In addition to these sites, the Applicant also reviewed in 2005 two sites recommended by San Diego Gas and Electric (SDG&E), referred to as the Pala and Rainbow sites. The Rainbow site is located in the northern part of San Diego County, in a rural portion of the county. The Pala site is adjacent to SDG&E's Pala substation, located near the Pala Band of Mission Indians Reservation and casino.

The Pala site was rejected due to concerns with site access, terrain, and socioeconomic impacts.

Details on the sites identified as satisfying the selection criteria are presented in the following section. Figure 9.5-1 presents the location of the six alternative sites analyzed.

9.5.4 Descriptions of Sites with Some Favorable Characteristics

9.5.4.1 Proposed Project Site (Site 1)

The proposed Project site has been historically industrial in use as a Liquid Natural Gas storage site, located in the City of Chula Vista. The site has an existing power plant is located to the north, the J Street marina to the northwest, light industrial uses to the east, mixed residential/industrial across I-5 to the east, and salt evaporation operations and South Bay National Wildlife Refuge to the south. By virtue to being in close proximity of the South Bay Power Plant, all infrastructure is available close by.

Biological issues identified for this site include (1) its proximity to the South Bay National Wildlife Refuge, (2) the site includes disturbed ruderal habitat that is periodically mowed, (3) has a low likelihood of having sensitive plants and species onsite. This site is considered to have low potential environmental impacts.

The nearest viewers are located at the commercial and business park located south of the site. The nearest residence is located approximately 1,500 feet from the site, and a mobile home is located to the east from the site across I-5. Existing trees screen views to the east. There are distant views of the site from Coronado Cays, scenic highway State Route (SR) 75, and South Bay Biological Park.

Noise impacts are not expected to be significant during construction, operation, or demolition.

9.5.4.2 South County Coastal Site (Site 2)

This site is under the jurisdiction of the City of San Diego, approximately 6 miles from the proposed site. The parcel is a former disturbed gravel mining site and is zoned Commercial Recreation.

The site is undeveloped. The eastern portion of the site has been heavily graded. Onsite is lighting for the Border Patrol. There is a water reclamation plant located to the east and

northeast, agricultural/equestrian land to the north and west, and the U. S.-Mexico border lies to the south. South of the border, the area is densely developed into urban land uses. The Tijuana Slough National Wildlife Refuge located to the north of the project site. During the AFC preparation, the refuge acquired several parcels that included this project site. Therefore, the site is no longer available for development of a power plant.

9.5.4.3 North County Inland Site (Site 3)

This site is under the jurisdiction of the City of Oceanside. The site is industrial zoned property. The site consists of rolling hills and slopes to a high point in the middle of the site. The site is in agricultural land use (various flowers, corn, and vegetables). Residential land uses are located to the north, east, and south; a business park is located to the south; and undeveloped land is located to the west.

There are no biological issues identified for this site; however, the potential exists for raptors along the southern site boundary.

There are unobscured views of the site from the east and northeast. Residences located to the north of the site may currently have unobscured views, but development located between the residences and the site would likely screen views of the site. Residences to the south of the site likely have views screened by intervening development. The nearest residences are located approximately 100 feet to the north and east.

The site is not preferable for the following reasons:

- The site is not constrained by size, but is potentially constrained by terrain.
- The potential for encountering special-status raptors exists.
- Depending on the location of the power plant siting within the parcel, the power plant may be visible to sensitive viewers (residents) within 100 feet of the site. Transmission lines would be prominent to the surrounding community.
- The proximity of residential units makes noise compliance very difficult if at all feasible.

9.5.4.4 Central San Diego County Site (Site 4)

The site is under the jurisdiction of the County of San Diego and is located within the City of Lakeside. The site is zoned M-52 (Industrial/Commercial). Some areas of the site are currently used for gravel mining operations, and some areas are used for equipment storage. Construction and grading activities are occurring throughout the site.

The San Diego River crosses the southern portion of the site. A large warehouse/distribution center exists along the northern boundary of the site; mining operations are located to the southeast. State Route (SR) 67 is located to the south. Mixed industrial uses are located to the southwest. Residential land uses are located to the north, east, and south of SR 67. There is vacant land to the west.

The site has been graded flat; it slopes into the riverbed and ponded areas.

Biological issues identified for this site include (1) very little biological value is retained at the site because the parcels have been severely disturbed by the onsite mining activities, (2)

there are some small patches of disturbed wetland habitat, (3) the San Diego River, which has a mature cottonwood-willow riparian forest, is located in the southern portion of the site; the riparian habitat is suitable for the following federally threatened or endangered species: southwestern willow flycatcher, least Bell's vireo, and southwestern arroyo toad, and (4) the potential to encounter San Diego ambrosia exists if there is any grassland or scrub habitat remaining in or near the upper floodplain.

The potential exists for visual impacts to occur if this site is developed. Residences are located to the north, east, and south of SR 67. The nearest residences are located less than 500 feet from the site.

The site is not preferable for the following reasons:

- The potential for encountering special-status biological resources exists, including wetland habitat and riparian habitat.
- Depending on the location of the power plant siting within the parcel, the power plant may be visible to sensitive viewers (residents) within 500 feet of the site. The proximity of residential units makes noise compliance very difficult.
- There is the potential of a significant air impact to residences on nearby hills.

9.5.4.5 North County Inland #2 (Site 5)

This site is owned by the City of Oceanside. The site is disturbed grasslands with a wastewater treatment plant to the northeast side of the site. Camp Pendleton and Windmill Lake are located to the north of the site. The San Luis Rey River is located to the south of the site. A residential area abuts the eastern boundary of the site, and another residential area is located south of the site (on the south side of the San Luis Rey River). Hills to the northeast are undeveloped, and a golf course is located further northeast.

The 73-acre Whelan Lake Bird Sanctuary is located adjacent to the west. Biological issues identified for this site include (1) the northeastern one-third of the site contains low rolling hills with grassland and areas of coastal sage scrub, with the potential of encountering the federally threatened California gnatcatcher and the endangered Quino checkerspot butterfly, and (2) the site encompasses the southern part of Windmill Lake; the lake is fringed with wetland vegetation and may include freshwater marsh and riparian forest or scrub communities, with the potential for encountering the following federally threatened or endangered species: southwestern willow flycatcher, least Bell's vireo, and southwestern arroyo toad.

The potential exists for visual impacts to occur if this site is developed. The nearest viewers are located at the residences located to the east and south of the site. The nearest residences are located less than 500 feet from the site (toward the southeast). Elevated views from residential areas to the southeast could be significant.

Access to the site occurs through residential areas along the southern edge of the wastewater treatment plant.

The site is not preferable for the following reasons:

- The site is not constrained by size, but is potentially constrained by terrain and nearby surface waters.
- The potential for encountering special-status biological resources exists.
- Depending on the location of the power plant siting within the parcel, the power plant may be visible to sensitive viewers (residents).
- The proximity of residential units makes noise compliance very difficult.
- There is the potential of a significant air impact to residences on nearby hills.
- Traffic concerns due to access road being through residential areas.

9.5.4.6 North County Inland #3 Site (Site 6)

This site is under the jurisdiction of San Diego County and is owned by the SDG&E. The site is in a rural portion of the north county, located in the coastal range, southwest of the City of Temecula, near the community of Fallbrook. The area is rural residential with large homes sparsely located around the project site. Hills to the north and south are undeveloped. The nearest residence is a rural home located approximately 0.25 miles to the east. Access to the site in along single lane county roads, traveling through rural residential areas up the coastal range toward the peak. The access roads have numerous switchbacks that pose a significant constraint for equipment deliveries. Transmission access would be via a looping scheme with an existing 230 kV transmission line that borders the project site. Natural gas and water pipelines would originate along Interstate 5 and be routed to the up to the project site through the hilly terrain.

Biological issues identified for this site include areas of coastal sage scrub, with the potential of encountering the federally threatened California gnatcatcher and the endangered Quino checkerspot butterfly.

A low potential exists for visual impacts to occur if this site is developed. The site is located in a small valley near the peak of the coastal range, with scattered residences on the hillside below, but with limited views of the project site. The nearest residence, 0.25 miles east, would be able to see the plant features through the existing trees.

The site project site has the following constraints.

- The site is not constrained by size, but is potentially constrained by terrain.
- The potential for encountering special-status biological resources exists.
- There is the potential of air emissions impacts on the nearby steep hill sides.
- Natural gas and water are located approximately 7 miles from the site.

9.5.4.7 Summary of Alternative Site Analyzed

Table 9.5-1 presents a summary of the potential impacts of the alternative sites reviewed by the Applicant. As shown in Table 9.5-1, the proposed project site avoids potential impacts to biological resources. Furthermore, development of the proposed site is consistent with historic uses of the site, with linear facilities located adjacent to the site or in the adjacent

utility easement. The alternative sites would require significant linear facilities, traversing both open space and developed areas, which could result in impacts to biological, water, cultural, and paleontological resources, as well as traffic and transportation impacts.

TABLE 9.5-1
Comparison of Alternative Sites

Site	Site Characteristics	Linear Facilities	Environmental
Former LNG Site (Site 1)	Correctly zoned, adequate surrounding buffers. Site control feasible.	Transmission, gas supply, water and sewer adjacent to site	Disturbed industrial site, no significant impacts to biological resources.
South County Coastal (Site 2)	Site is no longer available as the parcel has been sold and is now open space	—	—
North County Inland (Site 3)	Encumbered by hilly terrain. Zoned industrial. Site is in close proximity to residential areas. Site is currently planned for development as a corporate park. Power plant development may be inconsistent with development plans.	Transmission and gas supply within 2 miles of the site	Site historically in agricultural production providing potential forage areas for significant biological resources
Central San Diego County (Site 4)	Zoned industrial/commercial, with residential areas close by on the north and south. Site is currently planned for development as a business park. Power plant development may be inconsistent with development plans.	Gas line approximately 4 miles and transmission approximately 1 mile. Linear corridors are through both residential and open space areas.	Potential for encountering special-status biological resources exists, including wetland habitat and riparian habitat
North County Inland #2 (Site 5)	Siting of a power plant adjacent to a bird sanctuary may be inconsistent with development plans for this area.	Transmission facilities nearby, but gas facilities located over 5 miles away with linear route through both open space and residential areas requiring numerous stream crossings.	Potential significant air quality impacts due to elevated terrain and biological impacts to the adjacent bird sanctuary.
North County Inland #3 (Site 6)	Site is owned by SDG&E and is very constrained construction access. The site is not constrained by size, but is potentially constrained by terrain. Inconsistent with surrounding rural residential setting.	Transmission interconnection near the site. Gas and water (supply and disposal) linear route through developed rural residential areas. Significant construction costs due to terrain and geology.	Greenfield site with potentially significant biological resource issues.

9.6 Cooling Alternatives

There are currently three cooling technology alternatives that are technically feasible for rejecting heat from the steam turbine surface condenser: wet cooling, dry cooling and hybrid wet/dry cooling. Wet cooling can utilize once-through cooling or a conventional evaporative cooling tower. Dry cooling requires an air-cooled condenser, and hybrid wet/dry cooling requires a conventional evaporative cooling tower plus an air-cooled condenser. These cooling technology alternatives are described in the following sections.

9.6.1 Once-Through Cooling

This technology passes a steady stream of water through the steam condenser/heat exchanger to condense the steam exiting the steam turbine. The water makes a single pass through the condenser/heat exchanger, entering at the ambient temperature of the water supply and exiting at an increased temperature due to the heat removed in condensing the steam. This is the cooling technology use by the existing SBPP.

Once-through cooling technology requires a large water throughput for effective cooling and to keep the temperature increase of the water within acceptable limits. A temperature rise of 15 to 20 degrees Fahrenheit (°F) would be typical. While once-through cooling is an effective, efficient and widely use method of power plant cooling, based on the SBRP's planning and conceptual design process, and input from the community, the Applicant has decided to use air-cooled condensers as the cooling technology for SBRP.

9.6.2 Conventional Evaporative Cooling Tower

A conventional evaporative cooling tower system uses a water cooled condenser to cool exhaust steam from the low pressure steam turbine. Circulating water from the cooling tower is pumped through this condenser thus heating the water which then flows over the top of the cooling tower and falls through the cooling tower fill to a water basin below the cooling tower and is pumped back to the condenser form there. Large fans located on top of the tower pull air through the cooling tower fill which cools the circulating water mostly by evaporating water. If once-through cooling is not used and an economical source of sufficient quantities of water is available, this is an economical cooling technology. If this cooling technology was used at SBRP, it would require approximately 5 million gallons per day (mgd) at peak operations.

For SBRP sufficient quantities of fresh water are not available. Sufficient quantities of recycled water are available from the South B ay Water Reclamation Plant located approximately seven miles from the SBRP site. However, for the SBRP, the Applicant has not selected cooling towers because of the relatively high cost associated with obtaining a long-term reclaimed water supply, and because of uncertainty associated with the disposal of cooling cycle wastewater.

9.6.3 Natural-Draft Cooling Tower

A natural-draft cooling tower system is similar in principal to the Project's mechanical draft system described above under wet cooling systems. The primary difference is the mechanical fans to move the cooling air are replaced by what is essentially a very large chimney. Air is drawn in at the base of the tower due to the less dense, warmer air that is expanding and rising to exit the top of the tower. This natural air circulation contacts the returned cooling water inside the tower and cools the water, mainly by evaporation. As a result, the cooling water recirculation, blowdown, and makeup rates and quality would be similar to the selected mechanical draft system.

A natural-draft cooling tower to serve the SBRP would be approximately 175 feet in diameter at the base and about 300 to 400 feet in height. This alternative was eliminated based on the adverse visual impact of such a massive structure.

9.6.4 Dry Cooling (Air-Cooled Condenser)

In the dry cooled system using an air-cooled condenser (ACC) system, exhaust steam from the steam turbine is cooled and condensed in a large external heat exchanger, using atmospheric air as the cooling medium. Large, electric motor-driven fans move large quantities of air across finned tubes (similar in principle to an automobile radiator), through which the exhaust steam is flowing. Heat transfer from the hot steam to the air cools the steam, which condenses and is returned to the steam cycle. This is the cooling technology the Applicant has selected for the SBRP.

For combined-cycle power plants in the range of 500 to 600 MW, most of the water demand (5 mgd peak/3 mgd average) is associated with cooling tower make-up due to evaporative losses, which would be avoided by the use of "dry" air-cooled condenser technology.

9.6.5 Hybrid Wet/Dry System

A parallel condensing wet/dry system utilizes a parallel condensing cooling system where the steam turbine exhaust steam is condensed simultaneously in both a standard steam surface condenser (SSC) and in an air cooled direct condenser (ACC). This parallel cooling system is sometimes called a "hybrid" system.

The amount of steam condensed in each device depends on the overall heat rejection load, availability of makeup water and ambient conditions. During operation, the condensing pressures in both the SSC and ACC constantly equilibrate due to self-adjustment of steam flows entering each device. For example, if the water temperature in the SSC were incrementally raised, steam flow to the SSC would decrease. Steam flow to the ACC then would increase, and turbine backpressure would increase slightly. As ambient conditions, load conditions and heat rejection capability of each device vary over time, the steam flow to each automatically adjusts without any active components being required on the steam side. Steam flowing to the SSC is taken off the main steam duct in a manner that best suits the specific steam turbine exhaust configuration and steam duct routing to the ACC. A conventional circulating water system interconnects the SSC with a conventional mechanical draft cooling tower system. Steam condensed in the SSC is returned to the main condensate tank via a condensate forwarding pump. The air ejection system is appropriately connected to both the SSC and the ACC.

Another variation of the hybrid system is to put the ACC on top of the wet cooling tower surface with the fans on top of the dry surface. The air is drawn up through the wet surface and then through the dry surface. The circulating water fall through the dry surface and then through the wet surface.

The primary benefit of this type of system is that, if a small amount of makeup water is available, a "wet" side or cooling tower can be used to enhance cooling efficiency relative to full dry cooling. The ACC fans of the hybrid system dry side are operated at full speed during the warmer periods of the year. When in operation, the hybrid system wet side cooling tower fan speeds are adjusted to maintain a prescribed evaporation rate. This system is a feasible choice for the proposed project site, but was not selected based on similar reasons that conventional evaporative cooling tower was not selected.

9.6.6. Conclusion

The technical merits of each alternative cooling technology were considered, and air-cooled condenser system (dry cooling) was selected for the Project based on permitting, environmental and economic aspects, and community acceptance.

9.7 Technology Alternatives

A variety of technology alternatives were reviewed to determine the most appropriate configuration for the SBRP. The ability of the Project to operate efficiently is paramount to the success of the Project, so the generating technology proposed has been carefully selected. The following sections include a discussion of power generating technologies, fuel technology alternatives, combustion turbine alternatives, NO_x control alternatives and inlet air cooling alternatives. Cooling technology alternatives are addressed in Section 9.5.

9.7.1 Selection Methodology

Technologies considered were primarily those that could provide base load or load-following power as opposed to those that would exclusively provide peaking or intermittent power. The reason for using this screening criterion was that the operating efficiency of the facility is interrelated with the substantial investment in its design.

The selection methodology included a stepped approach, with each step containing a number of criteria. The selected technology would have to pass Steps 1 and 2 and provide the lowest or near lowest cost in Step 3. The steps are:

- **Step 1—Commercial Availability**—The technology must be proven commercially practical with readily available, reliable equipment.
- **Step 2—Implementable**—The technology must be implementable; that is, it must meet environmental, public safety, public acceptability, fuel availability, financial and system integration requirements.
- **Step 3—Cost-Effective**—The technology must be incrementally cost competitive, not only with existing generating units, but also with units that will probably enter the newly deregulated market during the early commercial operation period of the Project. Incremental cost considerations include capital as well as operation and maintenance (O&M) costs, which would translate into a busbar cost represented in cents per kilowatt-hour.

This methodology was applied to a number of base load and load-following technologies as described in the following sections.

9.7.2 Alternative Natural Gas-Fired Technologies

Selection of the power generation technology focused on those technologies that can utilize natural gas. These technologies include conventional boiler-steam turbine units, combustion turbines in various configurations, and fuel cells.

9.7.2.1 Combined-Cycle (Selected) Generating Technology—Selected for the Project

This technology integrates combustion turbines and steam turbines in a combined-cycle to achieve higher efficiencies compared to simple-cycle technologies. The combustion turbine drives a generator and, instead of exhaust gases being released to the atmosphere, as they would under a single-cycle configuration, the exhaust gases from the combustion turbine are instead used to produce steam that drives an additional generator. The resulting efficiency of the system is 50 to 54 percent, considerably above most other alternatives. By augmenting the energy output with duct firing, a combined-cycle power plant can also provide efficient peaking capability. This efficiency results in low air emissions per kilowatt-hour generated. In addition, natural gas fuel emits little sulfur dioxide and little particulate matter. For these reasons, the system is considered the benchmark against which other technologies are compared. This technology is commercially available and can be implemented. Because of its high efficiency and relatively low cost of generation, this technology is cost-effective. This technology is the one selected for the SBRP, as well as most other new base load and load following units recently developed in the United States.

9.7.2.2 Conventional Boiler-Steam/Turbine

In conventional boiler-steam/turbine technology, fuel is burned in a furnace/boiler to create steam, which is passed through a steam turbine that drives a generator. This is the technology used in the existing SBPP. The steam is condensed and returned to the boiler. This technology is able to achieve a maximum thermal efficiency on the order of 35 to 40 percent. Applying the review methodology, the technology is commercially available and could be implemented. However, due to its relatively low efficiency, it will emit a greater quantity of air pollutants per kilowatt-hour generated than more efficient technologies. Furthermore, its cost of generation is higher than the selected combined-cycle technology. This technology therefore does not satisfy Step 3 and was eliminated from further consideration.

9.7.2.3 Supercritical Boiler-Steam/Turbine

This technology is basically the same as the conventional boiler-steam/turbine except it utilizes considerably higher pressures. Plants using this type of technology are more expensive to construct per unit of power generated compared to conventional boiler-steam/turbine plants. Higher construction costs are generally offset by increased efficiency, so cost of power produced is about the same as a conventional boiler-steam/turbine plant. Applying the review methodology, the technology is commercially available and could be implemented. However, because it is not as efficient as the combined-cycle technology, it would emit a greater quantity of air pollutants per kilowatt hour compared to the Project. This technology was eliminated due to its being less efficient than the selected combined-cycle technology. Based on the lower efficiency, this technology does not satisfy Step 3 and was eliminated from consideration.

9.7.2.4 Simple Combustion Turbine

This technology uses a gas or combustion turbine to drive a generator. Air is compressed in the compressor section of the combustion turbine, then passed into the combustion section where fuel is added and ignited. The resulting hot combustion gases pass through a turbine, which drives a generator. The combustion turbines have a relatively low capital cost and have efficiencies approaching 44 percent in the larger units (GE's LMS100). Because they are fast-

starting and have a relatively low capital cost, they are used primarily for meeting high peak demand (about 1,000 hours/year), where their relatively low efficiency compared to combined-cycle technology is acceptable for peaking capacity, but not necessarily for base load capacity. Applying the review methodology, this technology is definitely commercially available and could be implemented. However, due to its lower efficiency compared to the selected combined-cycle technology, it will emit a greater quantity of air pollutants per kilowatt hour generated. Also, the incremental cost of generation would be higher. All things considered, the technology does satisfy Step 3, but does not satisfy the project objectives as defined.

Based on comments received during public outreach meetings conducted by LSP, an analysis of a smaller simple cycle project was prepared. The basis of smaller simple cycle project analysis at the proposed project site is a 100 MW peaking project consisting of two GE LM6000 combustion turbines. The proposed project would require approximately a 4-acre site and would consist of two combustion turbine generators; emission control systems; approximately 85-foot-tall exhaust stacks; two waste storage tanks; a compressor enclosure; a chiller system; and a two-story building.

Those environmental impacts that correlate with the size of the areas disturbed (i.e., biological resources, cultural resources, agriculture and soil resources, geologic hazards and resources, and paleontological resources) would be lower for the smaller peaking project and were not addressed. Likewise, the linears associated with the smaller peaking are assumed to be similar to those presented for the proposed project and environmental impacts are considered comparable. Impacts associated with this proposed smaller peaking project are presented below.

9.7.2.4.1 Smaller Simple Cycle Peaking Project Air Quality Impacts

The air quality impacts are associated with both construction and operation. The construction of the smaller peaking project will require approximately one-third the land, resulting in approximately one-third the construction impact of the proposed project. The smaller peaking project would have a lower construction air quality impact.
The simple cycle LM6000PC combustion turbines are typically being permitted at higher emission rates than the proposed SBRP. Table 9.6-1 presents emission estimates for the smaller peaking turbines. Table 9.7-1 presents the maximum steady state emission rates for a simple cycle peaking facility. Table 9.7-2 presents a comparison of the emission rates for the simple cycle facility and the SBRP, which shows that the simple cycle facility would emit ozone precursor compounds at a higher rate than the SBRP.

TABLE 9.7-1
Maximum Steady State Emission Rates for a 100 MW Simple Cycle Peaking Facility—Each CTG

Pollutant	ppmv @ 15% O_2	lb/MMBtu	lb/hr
NOx	2.5	0.009	4.41
CO	4.0	0.0088	4.30
VOC	2.0	0.0025	1.23
SO_2*	0.15	0.00092	0.45
PM_{10}	n/a	0.0066	3.0

Note:

* Based on annual average natural gas sulfur content of 0.33 gr/100 scf.

TABLE 9.7-2
Comparison of the Smaller Peaking Project's and SRPF Air Emissions

	Simple Cycle/SBRP	Simple Cycle/SBRP[a]	Simple Cycle/SBRP
	ppmvd @ 15% O_2	lb/MMBtu	lb/MW-Hr[b]
NOx	2.5/2.0	0.009/0.0073	0.088/0.057
SO_2	0.15/0.139	0.00092/0.0007	0.009/0.0049
CO	4.0/4.0	0.0088/0.0088	0.09/0.07
VOC	2.0/2.0	0.0025/0.0025	0.025/0.02
PM_{10}	n/a	0.0066/0.0042	0.06/0.033

[a] Simple cycle project emissions from San Francisco Electric Reliability Project AFC Table 8.1-17 and SBRP emissions data from Table 8.1-20 of the AFC Air Quality Section.

[b] Lb/MW-Hr emission rates calculated by dividing the hourly emission rate (Lb/Hr) by 50 MWs for the simple cycle facility and 500 MWs for SBRP.

Although the total annual mass of air emissions would be expected to be less for the smaller peaking project as compared to the SBRP, the smaller peaking project may not provide sufficient capacity in terms of MW for the CAISO to remove the RMR designation of the existing SBPP. It is also difficult for CAISO to determine RMR status of particular generating units years in advance without certainty about other system conditions and the future availability of other local generating resources, such as the disposition of the Encina Power Plant, the Sunrise PowerLink, and the Otay Mesa Power Plant. For this reason, the CAISO forecasts the RMR needs on a year-by-year basis. Furthermore, the electrical generation associated with the smaller peaking facility would be expected to be on the order of 800 gigawatt-hours per year (100 MWs for 8,000 hours per year), where, as the SBRP would be expected to generate approximately 4,380 gigawatt-hours per year. Consequently, the peaker would only be able to supply a fraction of the basis energy supply that SBRP would supply. Moreover, this example assumes that the peaker is running 8,000 hours per year, which is a very high level of service for a peaker. A simple cycle peaking project would result in significantly greater air quality impacts than the proposed project on an equivalent generating basis.

9.7.2.4.2 Smaller Peaking Project Visual Resource Impacts

The visual resource impacts associated with the smaller peaking project would be expected to be less due to the absence of larger, bulkier structures associated with the SBRP. Therefore, the visual impacts associated with smaller project would be less, however, as discussed in Section 8.11—Visual Resources of this AFC, the visual impacts of the proposed SBRP are considered to represent an improvement over the visual aspects of the existing SBPP.

9.7.2.4.3 Conclusion

The smaller simple cycle peaking project would not provide the following benefits of the SBRP (as outlined in the Section 2.0, Project Description).

- The economics of developing a peaker project at South Bay are challenging. There are fewer MW of capacity to spread over the fixed cost of site preparation and construction of a peaker project as compared to the SBRP. A peaker would not be able to supply basic

energy services, and so this potential revenue source would not exist for a peaker. Rather, it would provide a more limited set of electrical services. In addition, the local community of Chula Vista has expressed a lack of interest in peaking power plants due to concerns that such facilities may not provide the needed flexibility and range of electrical services that could help support local community choice programs, which are programs that allow local communities to purchase electrical supply directly.

- Provide Economical Energy, Capacity, and Local Grid Reliability Services to the Region
- Accelerated Decommissioning and Removal of the Existing SBPP and therefore the advanced the Cessation of Once-Through Cooling
- Advance the Goals and Obligations of the Chula Vista Memorandum of Understanding
- Reduce Dependence on Older and Less Efficient In Basin Generation

Additionally, as show in Subsection 9.3.1, the projected deficit in RMR load in the area is 122 MWs in 2011, and a smaller peaking facility will not entirely alleviate this deficit in 2011 or beyond.

9.7.2.5 Kalina Combined Cycle

This technology is similar to the conventional combined cycle except water in the heat recovery boiler is replaced with a mixture of water and ammonia. Overall efficiency is expected to be increased 10 to 15 percent. However, this technology is still in the testing phase. Applying the review methodology, the technology fails to pass Step 1, since it is not commercially available. It was therefore eliminated from consideration.

9.7.2.6 Advanced Gas Turbine Cycles

There are a number of efforts to enhance the performance and/or efficiency of gas turbines by injecting steam, by intercooling and by staged firing. These include the steam-injected gas turbine (SIGT), the intercooled steam recuperated gas turbine (ISRGT), the chemically recuperated gas turbine (CRGT) and the humid air turbine (HAT) cycle. With the exception of the SIGT, none of the technologies is commercially available, so they all fail to pass Step 1 of the review methodology. The SIGT is marginally commercially available and might pass Steps 1 and 2 of the review methodology, but its efficiency is lower than conventional combined-cycle technology, so it fails on Step 3. Consequently, all of these technologies were eliminated from consideration.

9.7.3 Fuel Alternatives

Technologies based on fuels other than natural gas, such as fuel cells, coal and oil, nuclear, solar and water, are described in the following sections.

9.7.3.1 Fuel Cells

This technology uses an electrochemical process to combine hydrogen and oxygen in order to liberate electrons, thereby providing a flow of current. The types of fuel cells include phosphoric acid, molten carbonate, solid oxide, alkaline and proton exchange membrane. With the exception of the phosphoric acid fuel cell and possibly the molten carbonate fuel cell, none of these technologies is commercially available on the scale of a commercial power

plant. Therefore, they fail Step 1. The phosphoric acid fuel cell has operated in smaller size units, and the molten carbonate fuel cell has completed testing. At this time, however, neither of these technologies is cost competitive with conventional combined-cycle technology. Therefore, fuel cells fail Step 3 of the review methodology.

9.7.3.2 Coal

The technologies that use coal for fuel include conventional furnace/boiler steam turbine/generator, fluidized bed steam turbine/generator, integrated gasification combined-cycle, direct-fired combustion turbine, indirect-fired combustion turbine, and magnetohydrodynamics.

9.7.3.2.1 Conventional Furnace/Boiler Steam Turbine/Generator

Coal is burned in the furnace/boiler, creating steam that is passed through a steam turbine connected to a generator. The steam is condensed in a condenser, passed through a cooling tower and returned to the boiler. Designs include stoker, pulverized coal and cyclone. The efficiency of this technology is equivalent to a conventional gas/oil fired steam turbine/generator unit (35 to 40 percent) and, because of the usually lower price of coal compared to natural gas, the technology can be cost competitive under most conditions. However, the tons of air emissions per kilowatt-hour generated are greater than for a conventional combined-cycle because of its lower efficiency, resulting in more fuel consumed per kilowatt-hour. In addition, coal receiving and handling costs and ash solid waste disposal costs would be high. Applying the review methodology, the technology is definitely commercially available (Step 1). The technology could be implementable in California except for possible public perception that large coal-fired units cause visible air emissions (untrue with modern units). In addition, coal would have to be imported from outside California (resulting in increased truck and/or train traffic), and the time to construct a facility would probably be about twice that for a conventional combined-cycle unit. The technology may therefore not pass Step 2. In addition, the generation cost of the technology could be greater than for a combined cycle (Step 3). Due to the potential problems under Step 2 and the potentially higher cost in Step 3, the technology was eliminated from consideration.

9.7.3.2.2 Atmospheric and Pressurized Fluidized Bed Combustion

Both of these technologies burn coal in a hot bed of inert material containing limestone that is kept suspended or fluidized by a stream of hot air from below. Water coils within the furnace create steam that drives a steam turbine/generator. The combustion chambers of the pressurized units operate at 150 to 250 psig to increase efficiency. Efficiencies of atmospheric fluidized bed combustion (AFBC) units are on the order of 35 to 40 percent; pressurized (pressurized fluidized bed combustion [PFBC]) units are between 40 and 45 percent. Coal receiving and handling costs and ash solid waste disposal costs would be high. The technology is commercially available for the AFBC technology, at least up to the 200-MW size. The PFBC technology is not commercially available. Applying the review methodology, the AFBC may pass Step 1, but the PFBC is eliminated from consideration. Implementation of the AFBC technology in California is possible, particularly for cogeneration applications (several new units have recently been constructed). Coal would have to be imported from outside California, increasing train and/or truck traffic. The technology should pass Step 2, although possibly the generation cost of the technology, would be greater than for a combined cycle (Step 3). Due to the increased air emissions, high

coal handling and waste disposal costs and potentially higher generation cost, the AFBC technology was eliminated from consideration.

9.7.3.2.3 Integrated Gasification Combined-Cycle

Integrated gasification combined-cycle (IGCC) gasifies coal to produce a medium Btu gas that is used as fuel in a combustion turbine, which exhausts to an HRSG that supplies steam to a steam turbine/generator. The coal gasifier is located at the same site as the combustion turbine, HRSG and steam turbine/generator. It is sized to supply the combustion turbine and is integrated with it and the rest of the equipment to provide an integrated generating system. While a 100-MW unit has been fully tested in California, the technology is probably not fully commercially available. Applying the review methodology, the IGCC will not pass Step 1. Implementation of the IGCC technology in California is possible, except that coal would have to be imported from outside California (resulting in increased truck and/or train traffic). Coal receiving and handling costs and ash solid waste disposal costs would be high. The generation cost of the technology could be competitive with a conventional gas-fired combined cycle (Step 3), but this is a relatively unknown factor. Due largely to the probable lack of full commercial availability, IGCC technology was eliminated from consideration.

9.7.3.2.4 Direct- and Indirect-Fired Combustion Turbines

Direct-fired units burn finely powdered coal directly in the combustion chamber of the combustion turbine. Indirect-fired units burn the coal in a fluidized bed or other combustor. Both use a heat exchanger to transfer the heat from the combustion gases to air, which is then expanded through the turbine. Neither of these units is commercially available. Therefore, they both fail to pass Step 1 of the selection methodology and were eliminated from consideration.

9.7.3.2.5 Magnetohydrodynamics

High temperature (3,000ºF) combustion gas is ionized and passed through a magnetic field to directly produce electricity. This technology is not commercially available. Therefore, it fails to pass Step 1 of the review methodology and was eliminated from consideration.

9.7.3.3 Nuclear Reactors

Nuclear technology includes nuclear fission and nuclear fusion. Nuclear fission breaks atomic nuclei apart, giving off large quantities of energy. For nuclear fission, pressurized water reactors (PWRs) and boiling water reactors (BWRs) are commercially available. California law prohibits new nuclear plants until the scientific and engineering feasibility of disposal of high-level radioactive waste has been demonstrated. To date, the Nuclear Regulatory Commission has been unable to make the findings of disposal feasibility required by law for this alternative to be viable in California. Nuclear fission would also require very large quantities of fresh water for cooling, a resource that is not readily available. The technology therefore is not implementable and fails to pass Step 2 of the review methodology. It was therefore eliminated from consideration.

Nuclear fusion forces atomic nuclei together at extremely high temperatures and pressures, giving off large quantities of energy. Nuclear fusion is not available commercially, and it is not clear if or when it will become available. The technology, therefore, fails to pass Step 1 of the review methodology and was eliminated from consideration.

9.7.3.4 Water

These technologies use water as "fuel." They include hydroelectric, geothermal and ocean energy conversion.

9.7.3.4.1 Hydroelectric

This technology uses falling water to turn turbines that are connected to generators. A flowing river or, more likely, a dammed river, is required to obtain the falling water. This technology is commercially available. However, most of the sites for hydroelectric facilities have already been developed in California, and any remaining potential sites face formidable environmental licensing problems. There are no large bodies of water near the SBRP site that can be used for hydroelectric power. Therefore, it would fail to pass Step 2 of the review methodology. It was therefore eliminated from consideration.

9.7.3.4.2 Geothermal

These technologies use steam or high-temperature-water (HTW) obtained from naturally occurring geothermal reservoirs to drive steam turbine/generators. There are vapor dominated resources (dry, superheated steam) and liquid-dominated resources that use a number of techniques to extract energy from the HTW. Geothermal is a commercially available technology. However, geothermal resources are limited, and most, if not all, currently economic resources have been discovered and developed in California. Geothermal development is not viable at the Project location. It was, therefore, eliminated from consideration.

9.7.3.4.3 Ocean Energy Conversion

A number of technologies use ocean energy to generate electricity. These include: tidal energy conversion, which uses the changes in tide level to drive a water turbine/generator; wave energy conversion, which uses wave motion to drive a turbine/generator; and ocean thermal energy conversion, which employs the difference in water temperature at different depths to drive an ammonia cycle turbine/generator. While all of these technologies have been made to work, they are not fully commercially available. Even if they were commercially available, they are considerably more costly than conventional combined-cycle technology and so would fail Step 3 of the review methodology. They were therefore eliminated from consideration.

9.7.3.5 Biomass

Major biomass fuels include forestry and mill wastes, agricultural field crop and food processing wastes, and construction and urban wood wastes. Several techniques are used to convert these fuels to electricity, including direct combustion, gasification and anaerobic fermentation. While these technologies are available commercially on a limited basis, their cost tends to be high relative to a conventional combined-cycle unit burning natural gas. This technology, therefore, does not pass Step 3 of the review methodology and was eliminated from consideration.

9.7.3.6 Municipal Solid Waste

This technology consists of extracting energy from garbage by burning or other means, such as pyrolysis or thermal gasification, and is commonly referred to as waste-to-energy (WTE). The most efficient known methods incorporate mass burn and refuse-derived fuel (RDF)

facilities. Both mass burn and RDF are commercially available methods of municipal solid waste (MSW) technology. Other methods are co-firing with coal, using fluidized-bed furnace/boilers, and pyrolysis or thermal gasification. There is only one 10-MW mass burn unit operating in California and no RDF facilities or facilities using the other methods. The economic feasibility of MSW technology depends heavily on the level of the "tipping fee" in the vicinity of the MSW facility. The tipping fee is the price charged by landfills for depositing waste or garbage in the landfill, and it is usually expressed in dollars per ton. In effect, a waste collection company would pay the WTE facility for taking and burning its garbage, resulting in a negative fuel cost to the WTE. A recent study for development of a WTE facility in the San Francisco area estimated that the tipping fee would have to be about $80 per ton for a facility to be economical. The current tipping fees in the San Diego area are approximately $50 per ton. This technology therefore fails to satisfy Step 3 of the review methodology, which requires the technology to be cost competitive. This technology was therefore eliminated from consideration.

9.7.3.7 Solar Radiation

Solar radiation (sunlight) can be collected directly to generate electricity with solar thermal and solar photovoltaic technologies, or indirectly through wind generation technology in which the sunlight causes thermal imbalance in the air mass, creating wind. Wind generation and two types of solar generation, thermal conversion and photovoltaics, were considered as alternative technologies to the combined cycle. These are described in the following subsections.

9.7.3.7.1 Solar Thermal

Most of these technologies collect solar radiation, then heat a working fluid to power a turbine/generator. The primary systems that have been used in the United States capture and concentrate the solar radiation with a receiver. These more advanced technologies are referred to as concentrating solar systems and are classified by how they collect solar energy. The three main receiver types are mirrors located around a central receiver (power tower), parabolic dishes and parabolic troughs.

The power tower systems use many large helostats (sun-tracking mirrors) to concentrate and focus sunlight on a tower mounted receiver. The receiver contains the heat transfer fluid that is used to generate electricity in a turbine/generator. The Solar Two plant located near Barstow, CA is a power tower solar project.

The parabolic dish and trough systems use parabolic structures (either dishes or troughs) to collect and concentrate sunlight onto receiver pipes (attached to the parabolic structures) containing a working fluid. The working fluid, typically oil, is used to generate electricity in a conventional steam generator.

Another solar system with good commercial prospects is the Dish/Engine (D/E) system. This system is a solar collection/concentration array coupled to a Stirling engine. A D/E system collects solar energy in a similar manner. However, instead of the concentrators heating a working fluid that is directed to a turbine generator, it heats a working gas in a Stirling engine/generator. The Stirling engine/generator works like a standard engine generator, with pistons being moved by the heated gases (from energy concentrated by the

collector). Individual D/E systems range in side from 9 to 25 kilowatts and can be grouped to provide large efficient systems.

All require considerable land for the collection receivers and are best located in areas of high solar incidence. Land requirements for concentrating solar technologies are on the order of 10 acres per megawatt[23]. Based on the proposed project site size of approximately 13 acres, these technologies would not be able to generate a fraction of the electricity currently generated by the existing SBPP or the proposed Project.

In addition, power is typically only generated while the sun shines, so the units do not supply power when clouds obscure the sun or from early evening to late morning. However, recently the Solar 2 plant near Barstow, CA successfully generated electricity Solar Two successfully demonstrated power delivery to the electric grid continuously for nearly 7 days before cloudy weather interrupted operation. These factors, for the most part, fail Step 2, and may not be implementable due to land unavailability and/or the ability to finance. Hence, solar thermal was eliminated from consideration.

9.7.3.7.2 Solar Photovoltaic

This technology uses photovoltaic "cells" to convert solar radiation directly to direct current electricity, which is then converted to alternating current. Panels of these cells can be located wherever sunlight is available. This technology is environmentally benign and is commercially available, since panels of cells can theoretically be connected to achieve any desired capacity. While this technology may have a bright future, at the current time the cost is higher than the selected combined-cycle technology. This technology fails Step 3, cost-effectiveness, and was therefore eliminated from consideration.

9.7.3.7.3 Wind Generation

This technology uses a wind-driven rotor (propeller) to turn a generator and generate electricity. Only limited sites in California have an adequate wind resource to allow for the installation of wind generators, and most of these sites have already been developed or are remote from electric load centers and have limited or no transmission access. Even in prime locations the wind does not blow continuously, so capacity from this technology is not always available. In California, the average wind generation capacity factor has been approximately 22 percent[24]. In addition, depending on the site and/or season, the technology cannot be depended upon to be available at system peak load since the peak may occur when the wind is not blowing. The technology is commercially available and implementable at certain sites. The technology is relatively benign environmentally, although at some sites land consumption and effects on visual resources and avian species are a concern. A wind farm of equivalent capacity to the SBRP would require approximately 8,500 acres (approximately 13 square miles) of land[25]. The cost of generation is above the cost of the selected combined-cycle technology. Due to the unavailability of good sites near the San Diego load center (excluding offshore sites), limited dependability, and relatively high cost, this technology was eliminated from consideration.

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[23] http://www.energylan.sandia.gov/sunlab/overview.htm

[24] Wind Power Generation Trends at Multiple California Sites, Table 2.9, California Energy Commission (CEC-500-2005-185), December 2005.

[25] Based on 17 acres per megawatt (Source: http://energy.ca.gov/wind/overview.html)

9.7.3.8 Conclusion

Using the selection methodology identified in Section 9.6.1, power generating technology fuel alternatives were eliminated from consideration because they do not meet the Project objective of achieving its environmental and operational advantages. Additional factors rendering alternative fuel technologies unsuitable for the Project are as follows:

- No geothermal or hydroelectric resources exist in area.
- Biomass fuels, such as wood waste, are not locally available in sufficient quantities to make them a practical alternative fuel.
- Solar and wind technologies are not feasible at the SBRP site or in the western portion of San Diego County due to lack of consistent wind and peaking nature of these technologies.
- Coal and oil technologies emit more air pollutants than technologies utilizing natural gas.

The availability of natural gas, as well as the environmental and operational advantages of mature natural gas technologies, make natural gas the logical choice for the Project.

FIGURE 9.5-1
LOCATION OF ALTERNATIVE SITES CONSIDERED
SOUTH BAY REPLACEMENT PROJECT
SAN DIEGO COUNTY, CALIFORNIA
CH2MHILL

SAC \\GLACIER\SACGIS\DUKEENERGY\MAPFILES\ALTERNATIVE_SITES.MXD 06/23/2006 15:20:17