4.0 Project Alternatives

Alternatives to the BSEP are presented in this section. The alternatives addressed include the "No Project" alternative, alternative plant sites, alternative linear facilities routes, plant design alternatives, and alternative power generation technologies. Section 4.1 summarizes the California Environmental Quality Act (CEQA) requirements with respect to alternatives evaluations; Section 4.2 presents the methodology used to identify and screen alternatives; Section 4.3 presents the CEQA-required "No Project" alternative; Section 4.4 provides those alternatives that were considered related to project location and linear routes; Section 4.5 focuses on Project design alternatives; and Section 4.6 presents the alternatives related to solar power generation technologies.

4.1 CEQA Requirements

CEQA requires the lead agency to consider "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" [14 CCR. 15126.6(a)]. The CEQA Guidelines [14 CCR 15126.6(c)] further provide that "among the factors that may be used to eliminate alternatives from detailed consideration in an Environmental Impact Report (EIR) are:

(i) failure to meet most of the basic project objectives,

(ii) infeasibility, or

(iii) inability to avoid significant environmental impacts."

4.2 Alternatives Screening Methodology

Beacon Solar evaluated a range of potential alternatives to the proposed Project in terms of location, linear facilities routes, design alternatives, etc. While the following screening methodology is presented in terms of alternative Project locations (sites), essentially the same process applies to alternative routes and technologies. In accordance with 14 CCR 15126.6 (c), alternatives were not carried forward for further analysis if:

1. The alternative failed to meet most the basic project objectives, or
2. The alternative would not avoid or substantially lessen significant environmental impacts of the proposed project, or
3. The alternative was not "feasible." Per 14 CRR 15126.6(f)(1), the factors that should be taken into account in determining whether an alternative is feasible are:
   a) Site suitability,
   b) Economic viability,
   c) Availability of infrastructure,

d) Land use/land use plan consistency or regulatory/jurisdictional limitations, and

e) Site control.

In order to implement this screening process for selecting the Project site, Beacon Solar needed to:

1. Define the Project objectives,
2. Identify the potential significant environmental impacts associated with the proposed project, and
3. Further define the feasibility criteria.

These Project objectives, potential significant environmental impacts, and feasibility criteria are presented below.

4.2.1 Project Objectives

The Project objectives are presented in Section 2.2 and are restated here as follows:

- To construct, operate and maintain an efficient, economic, reliable, safe and environmentally sound solar powered generating facility throughout its useful life to help: (i) achieve the State of California objectives mandated by SB 1078 (California Renewable Portfolio Standard Program), (ii) AB 32 (California Global Warming Solutions Act of 2006), and (iii) other local mandates adopted by the state's municipal electric utilities to meet the requirements for the long term wholesale purchase of renewable electric energy for distribution to their customers,
- To develop a site with an excellent solar resource,
- To develop a previously disturbed site with close proximity to transmission infrastructure in order to minimize environmental impacts,
- To interconnect directly to the LADWP electrical transmission system,
- To develop a new utility-scale solar energy project using proven concentrated solar trough technology, and
- To develop a site with available water resources to allow wet cooling in order to optimize power generation efficiency and reduce project cost.

4.2.2 Potential Significant Impacts

Sections 5.1 through 5.17 of the AFC assess in detail the BSEP's impacts for the full range of environmental topical areas. With the implementation of identified mitigation measures, the AFC finds that the Project would have no significant impacts in any topical area. The areas with the greatest potential for significant impacts that were used as a basis for alternatives screening, are summarized below.

- ***Biological, cultural and paleontological resources:*** Concentrated solar power (CSP) generating facilities require very large land areas. A minimum site size of approximately 1,600 acres is needed to generate 250 MW. Because of the large land area, such projects could affect biological resources, as well as cultural and paleontological resources.

- ***Water Resources:*** Because CSP facilities are thermal power plants, they require cooling, which leads to the potential for substantial water consumption and associated impacts.

Alternatives were dropped from further analysis if they could not avoid or substantially lessen potential Project impacts in these areas. Because of the size, nature, and relative remoteness from population centers of CSP facilities, AFC analyses indicate that impacts in environmental issue areas other than those identified above are minor and readily mitigable.

4.2.3 Site Feasibility Criteria Defined

An available site must meet the following criteria to achieve the Project objectives noted above:

- Site Suitability:
    - Solar Resource – The site needs to be located where high solar insolation is available to maximize the plant's output and support efficient utilization of the land area that would be affected by Project development. For a project to be economically viable, solar insolation levels of greater than 7.0 kilowatt-hours per day per square meter are desirable.
    - Size and Shape – The site should be large enough (approximately 1,600 acres at a minimum) to support the construction of a facility that can generate 250 MW of power using solar thermal technology, and arranged in a way that allows an efficient and cost-effective layout of the Project facilities.
    - Slope – The site needs to be relatively flat, with a slope of three percent or less
- Economic Viability – The Project needs to be economically viable and competitive with other renewable technology projects, including wind, geothermal, and other solar projects. To be viable, the site should be located on property currently available at a reasonable cost, have reasonable proximity to infrastructure and have good solar resources. Sites with excellent solar resources may be able to carry somewhat higher mitigation costs or infrastructure costs.
- Availability of Infrastructure – To minimize cost and potential environmental impacts, the site needs to be located so that it can be interconnected with an existing transmission system without the need for new, long dedicated transmission lines, while also providing good access to water for power plant cooling. The site also needs reasonable access to a natural gas pipeline.
- Site Control – The land for the power plant site and linear facilities has to be available for purchase or lease.

As discussed in Section 4.4, application of the above criteria eliminated all other potential project locations from being carried forward for more detailed analysis. This is largely because the proposed Project site is clearly superior to any of the alternative sites from an environmental impact perspective due to the use of an already-disturbed site and a relatively short transmission line. The site screening process that led to the selection of the proposed site and the elimination of alternative sites is discussed in the following section.

4.3 No Project Alternative

Under the No Project alternative, the Project would not be constructed, and the electrical power that would have been generated will be generated by other facilities, presumably natural gas-fired generation. Because the Project facilities would not exist, its direct environmental impacts would not occur. However indirect impacts would result in greater fossil fuel consumption and ultimately additional air pollution. It is expected that since solar power is generated close to peak consumption periods of the day, the peaking power needs met by BSEP-generated power otherwise would be met by fossil fuel-fired peaking units such as simple-cycle gas turbines and other rapid starting equipment (e.g., reciprocating engines) that would produce higher levels of air emissions than a solar thermal power plant.

In 2002, the state established the Renewable Portfolio Standard (RPS) program, with a goal of increasing the percentage of renewable energy in the state's electricity mix to 20 percent by 2017. The 2003 Energy Report recommended accelerating the 20 percent goal for renewables to 2010, while the 2004 Energy Report and the state's 2005 Energy Action Plan recommended increasing the target percentage to 33 percent by 2020. The 2006 Energy Report Update states that "California must accelerate its pace of development if it is to meet its long-term Renewable Portfolio Standard Goal of generating 33 percent of the state's electricity from renewable sources by 2020, as recommended by Governor Schwarzenegger, the Energy Commission, and the California Public Utilities Commission" (CEC, 2006). The 2007 IEPR states that "renewable resources are an essential tool for reaching AB 32 goals", but that "program adjustments" are needed to meet the 2010 and 2010 Renewable Portfolio Standard goals (CEC, 2007). The 2007 IEPR cites the "critical imperative to reduce greenhouse gas emissions" and "management of the risk borne by ratepayers for electricity generation" as the two main considerations driving the need to achieve the RPS goals. The IEPR states that the goal of 33 percent renewables by 2020 is achievable "with a concerted effort by and coordinated support from government, industry, and the public." (CEC, 2007)

The No Project alternative would mean that the proposed solar Project would not be developed and thus, the No Project alternative would not support the State's RPS program goals. The purpose of the Project is to generate renewable solar power and provide electric power to Californian electrical users. The No Project alternative is not the appropriate choice because it does not provide the additional power needed in California in a manner that assists the State in meeting its renewable power and greenhouse gas reduction goals.

4.4 Project Site and Linear Alternatives

4.4.1 Alternative Site Selection Criteria

In a report titled "California Solar Resources" (CEC, 2005) the CEC provides estimates of the solar resources located within California and potentially available for use in meeting the RPS and the California Power Authority's approved Energy Action Plan (EAP) goals. Estimates were provided on the "gross" potential (i.e., the potential unconstrained by technical, economic or environmental requirements) and the "technical" potential (i.e., unconstrained by economic or environmental requirements). Using National Renewable Energy Laboratory (NREL) direct beam insolation values on a grid size of 10 kilometers by 10 kilometers with NREL's Climatological Radiation Model, the CEC identified areas suitable for CSP systems in California. The CEC analysis shows that the best locations for CSP facilities generally tend to be in the southeastern portion of the state. For example, using the criteria selected by the CEC, the total "technical' potential area within Kern County (where the proposed Project site is located), is approximately 418,000 acres.

Beacon Solar conducted a similar Geographic Information System (GIS) analysis using NREL data, first preparing base maps of solar energy values and then applying exclusion criteria to identify study areas for further analysis. Maps were prepared reflecting the application of each of the following exclusion parameters separately, and then a final map was created incorporating all exclusion criteria:

- Solar indices less than 7.0 kilowatt-hours per square meter per day (kWh/m^2/day),
- Wilderness, parks, and military,
- Special status species habitat conservation areas (e.g., BLM Desert Wildlife Management Areas [DWMAs] and USFWS Critical Habitat),
- Slope greater than three percent, and
- Populated areas.

From this map, and numerous site visits, Beacon Solar identified public and private lands that had the potential to meet the remaining site suitability and feasibility criteria, namely:

- Size (minimum 1,600 acres),
- Located within 25 miles of an interconnection to a transmission system that could serve LADWP, and
- Available for sale or lease.

4.4.2 Project Site Alternatives

From the site screening process described above, seven candidate site locations (including the proposed site) were identified. The approximate locations of the sites other than the proposed site are shown on Figure 4-1 and described in Table 4-1.

Table 4-1 Alternative Sites Considered

Site	General Description/Location
South Edwards	Private property in general area south of Edwards Air Force Base
Antelope	Private property in general area east of Edwards Air Force Base
Manix	Federal property in general area between I-15 and I-40, east of Barstow
Pisgah	BLM property near the Pisgah substation
Highway 395	BLM property west of U.S. 395, between Kramer Junction and Johannesburg
Garlock	Private property and BLM property south of Garlock

Table 4-2 presents the reasons per CEQA guideline 14 CCR 15126 (c) why these alternatives sites were dropped from further analysis.

Table 4-2 Alternative Sites Dropped from Further Analysis

Alternative Site	Reason(s) Dropped from Further Analysis
South Edwards	Feasibility: • Site comprised of many land parcels and multiplicity of owners makes site control difficult to obtain; high land cost Lack of Consistency with Project Objectives: • Lengthy (greater than five miles) electrical interconnection needed; multiple small parcels complicate objective of utility-scale project Environmental Impacts: • Lengthy (greater than five miles) interconnection increases potential for resources impacts (e.g., special-status species habitat); no environmental advantage (i.e., reduced impact potential) compared to proposed site
Antelope	Feasibility: • Site comprised of many land parcels and multiplicity of owners makes site control difficult to obtain; high land cost Lack of Consistency with Project Objectives: • Lengthy (greater than five miles) electrical interconnection needed; multiple small parcels complicate objective utility-scale project Environmental Impacts: • Lengthy interconnection increases potential for resources impacts (e.g., special-status species habitats); no environmental advantage compared to proposed site
Manix	Feasibility: • Site size and shape marginal; multiplicity of owners makes site control difficult to obtain; high land cost Lack of Consistency with Project Objectives: • Lengthy (greater than five miles) electrical interconnection needed; site environmentally sensitive Environmental Impacts: • Environmentally sensitive site and lengthy transmission line increases potential for resources impacts (e.g., special-status species habitats) and higher mitigation costs; no environmental advantage compared to proposed site
Pisgah	Site Control: • BLM land reserved by others Environmental Impacts: • More environmentally sensitive site (undisturbed desert habitat) and relatively long transmission line increase potential for resources impacts (e.g., special-status species habitats) and higher mitigation costs; no environmental advantage compared to proposed site

Alternative Site	Reason(s) Dropped from Further Analysis
U.S. 395	Site Control: • BLM Land reserved by others Lack of Consistency with Project Objectives: • Lengthy (greater than five miles) electrical interconnection Environmental Impacts: • More environmentally sensitive site (undisturbed desert habitat) and relatively long transmission line increase potential for resources impacts (e.g., special-status species habitats) and higher mitigation costs; no environmental advantage compared to proposed site
Garlock	Site Control: • Transmission line would require multiple private party and BLM parcel crossings making site control more difficult. Large federal and private land parcels not available for sale or lease Environmental Impacts: • Longer transmission line than proposed site and greater potential for resources impacts and higher mitigation costs; no environmental advantage compared to proposed site

4.4.3 Transmission Route Alternatives

As discussed in Section 2.0, Project Description, for a number of reasons (primarily related to LADWP decisions concerning their need for system upgrades north of the Barren Ridge Switching Station and ROW acquisition issues), Beacon Solar is proposing two similar options for interconnecting with the LADWP regional transmission system, only one of which would actually be built. As discussed earlier, one of the primary siting criteria for the proposed Project has been to keep the generation transmission line distance to the interconnection point of any existing transmission system as short as possible and thereby minimize potential environmental impacts. The proximity of the proposed site to the existing LADWP transmission system and switching station with sufficient downstream transfer capability presents significant advantages for the proposed Project site. Both of the transmission routing options would involve minor and similar (to each other) impacts on habitats of specials-status wildlife species. Since any other transmission line route/alternative for the proposed plant site would involve a longer transmission line with greater environmental impacts, no transmission line alternatives were carried forward for detailed analysis.

4.4.4 Gas Pipeline Alternatives

Beacon Solar considered several alternative routes for a new natural gas pipeline to serve the Project from an interconnection with an existing Southern California Gas Company (SCG) gas line west of California City Boulevard and south of the site. As shown on Figure 4-2, one alternative would head west along California City Boulevard until it reached SR-14 and then would follow SR-14 north to the Project site. A second alternative would follow the route of the Union Pacific rail line all the way from near the interconnection point of the new gas line route with the existing SCG gas line north to the Project site. A third alternative route

would follow the same route as the proposed route east along California City Boulevard to Neuralia Road and then north on Neuralia Road. However, this alternative route would turn west along Phillips Road south of the site and then follow the Union Pacific rail line route north to the site.

All of the alternative routes would involve greater potential for adverse environmental impacts (primarily to biological resources) than the proposed gas pipeline route. The proposed route will be installed entirely in disturbed road shoulders, except for the portion from Neuralia Road into the plant site where the route will follow an area disturbed by an existing electric distribution line access road. Each of the alternative gas pipeline routes would traverse some undisturbed areas that potentially could be habitat for special-status wildlife species such as desert tortoise, while this would not be the case for the proposed route.

4.5 Power Generation Facility Design Alternatives

The following subsections address alternatives considered for several aspects of the proposed design of the power generation facility. These include project size, alternative heat rejection (cooling) technologies, alternative water supply sources, and alternative approaches for disposing of non-sanitary wastewater generated by the proposed facilities.

4.5.1 Project Size

The selection of a 250 MW project size considers several factors including available land aggregation, transmission capacity where land can be aggregated, design limitations, and operational constraints. Further, optimization studies show the size of a project utilizing parabolic trough technology to be most economically viable in blocks of 250 MW, with sizing significantly larger than 250 MW resulting in increasingly unacceptable parasitic losses due to pumping.

Since the facility's power output is directly related to the size of the solar collector area, a smaller facility would require a smaller site with a smaller footprint and thus, conceptually, lower potential for adverse environmental impacts. However, the site selection process carefully considered potential environmental issues and the selected site can accommodate a 250 MW plant without any significant environmental impacts. Therefore, there is no substantial environmental advantage to a smaller size BSEP, and given that a 250 MW facility is preferable from an economic perspective, the development of a smaller Project was rejected.

A larger project could also be considered, but additional land would be needed. The Project site is mostly made up of a number of contiguous parcels comprising approximately 1,900 acres purchased from one owner, supplemented by the purchase of some smaller adjacent vacant parcels to augment the entire site. The purchase of additional large parcels in order to develop a much larger project was not pursued.

4.5.2 Cooling Technology Alternatives

As proposed, the power generating equipment will utilize wet cooling technology, using site groundwater as the source of make-up water to the cooling tower. Two other cooling technology approaches were considered – dry cooling and a wet-dry hybrid cooling system. The following paragraphs summarize and compare these alternatives.

4.5.2.1 Description of Cooling Technologies

Wet Cooling Description

Wet cooling uses circulating water to condense turbine-generator exhaust steam in a shell and tube heat exchanger (condenser). Cool circulating water enters the tube side of the condenser where it is warmed by the shell-side steam, causing the steam to condense such that condensate pumps may return it to the steam generator feed water system. The warm circulating water then travels to a wet mechanical draft cooling tower. The cooling tower dissipates heat through circulating water evaporation and contact with ambient air. Once cooled, the circulating water is returned to the condenser to complete the cooling circuit.

Dry Cooling Description

Dry cooling technology uses an air cooled condenser (ACC) that cools the steam turbine-generator exhaust steam using a large array of fans that force air over finned tube heat exchangers. The exhaust from the steam turbine flows through a large diameter duct to the ACC where it is condensed inside the tubes through indirect contact with the ambient air. The heat is then rejected directly to the atmosphere.

Wet-Dry Hybrid Cooling Description

The wet-dry hybrid cooling approach involves the use of a combination of both wet and dry cooling technologies in parallel, and uses all of the equipment involved in both wet and dry cooling. As in a purely wet cooling system, cool water is circulated in a shell and tube heat exchanger to condense the turbine exhaust steam, and then a cooling tower is used to dissipate the heat in the warmed water. As in a purely dry cooling system, an air-cooled condenser uses a large array of fans to force air over finned tube heat exchangers, and the steam is condensed through indirect contact with the ambient air. Hybrid cooling technology divides the cooling function between the wet and dry systems with the dry cooling system always operating and the wet cooling system picking up the remaining cooling load, which varies with environmental and operational conditions.

4.5.2.2 Comparison of Cooling Technology Alternatives

A comparison of the proposed wet cooling approach to dry cooling and hybrid cooling alternatives is provided below. Differences between wet and dry cooling and a comparison of their advantages and disadvantages for the Project are presented first. Then, the pluses and minuses of hybrid wet-dry cooling are briefly discussed.

Wet Cooling vs. Dry Cooling for the BSEP

Wet cooling technology has clear performance advantages over dry cooling for the BSEP. Performance is enhanced because wet cooling relies primarily on evaporation to remove heat from the circulating water. Since evaporation occurs at the wet bulb temperature (the air temperature at 100 percent humidity), wet cooling achieves lower circulating water supply temperatures than dry cooling which is unable to operate below dry bulb temperatures (ambient air temperature). Dry bulb temperatures are generally much higher than wet bulb temperatures (especially in regions such as the Mojave Desert). As the dry bulb temperature increases and humidity decreases, the dry cooling system becomes less efficient as a heat rejection

method. This is the reason that wet cooling systems are even more efficient than dry cooling systems in areas with low humidity, as is the case at the Project site. In addition, the decreased efficiency of a dry cooling system at the Project site would be most noticeable in the hot summer months when plant output is highest.

The lower circulating water temperatures of wet cooling systems result in a significant improvement in cycle performance. This is because the lower temperatures result in lower steam turbine generator (STG) backpressures, which increase the STG's generation output. Conversely, the requirement to operate at the higher temperatures and higher STG backpressures associated with dry cooling would adversely affect the Project's power output. A wet cooling tower would be physically smaller than an ACC because water is more efficient as a heat exchange medium than air. Dry cooling requires much more surface area and very high flow rates of air to remove the same amount of heat as a wet cooling system. In addition, an ACC system has higher auxiliary loads due to the significant number of fans (32-40). Conversely an ACC would not need cooling water circulating pumps and circulating piping as would be needed for a wet tower, and also would need a smaller water treatment system (a small wet cooling system would be expected to be needed for cooling other plant equipment even if a dry cooling tower was used for the BSEP).

Capital cost estimates are lower for wet cooling as compared with dry cooling. An ACC system is more expensive than the equipment needed for a wet cooling system (condenser, cooling tower, circulating water pumps and piping). In addition, the lower steam cycle efficiency of a dry cooled facility requires increased steam flow in order to maintain the same power output, which increases the size of the following equipment:

- Solar field size,
- SSG heat exchangers,
- HTF pump,
- HTF expansion tanks and piping,
- Condensate and boiler feed water pumps,
- Feedwater heaters, and
- Condenser air removal system.

Table 4-3 summarizes the difference between capital costs for a wet and dry cooled plant of the same rated output (the less efficient dry cooled plant requires a larger solar field to achieve the same output). As discussed below, the table also compares costs if the solar field size was held the same (in which case the output of the dry cooled plant would be lower).

In addition to capital costs, operating costs have also been considered. Wet cooling operating costs could include the cost of pumping makeup cooling water (not needed for dry cooling), higher water treatment chemical costs than needed for dry cooling, and higher power requirements (and operating costs) for circulating pumps and water treatment activities. However, wet cooling systems require less parasitic loads (consumption of plant output by plant operations themselves) for pumps and fans compared to dry cooling.

Table 4-3 Annual Generation Impact and Net Present Value for Wet and Dry Cooling

Cost Component	Solar Field Size Held Constant [1]	Solar Field Size Increased [1]
Annual Net Generation Impact for Dry Cooing Compared to Wet Cooling (Megawatt-hour [MWh]) [2]	-45,162	0
Annual Revenue Impact from Net Generation Impact for Dry Cooling Compared to Wet Cooling [3]	($6,800,000)	0
Total Net Present Value of Generation Revenue Impact for Dry Cooling Compared to Wet Cooling	($63,900,000)	$0
Additional Capital Expenses for Dry Cooling Compared to Wet Cooling [4]	$20,500,000	$73,500,000
Total Net Present Value of O&M Expenses for Dry Cooling Compared to Wet Cooling [5]	$13,000,000	$13,000,000
Total Net Present Value for Dry Cooling Compared to Wet Cooling	($71,100,000)	($60,100,000)

[1] Dollar values rounded.

[2] Annual net generation for a dry cooled plant is based on a cycle efficiency difference of 3.6% relative to wet cooling.

[3] Based on a nominal $0.15/kWh.

[4] The capital costs shown in the table include cooling equipment, boiler feed water pumps, HTF pumps, and solar field addition for the case where the solar field size is increased.

[5] O&M Expenses include water treatment, operating, and water pumping costs. The O&M cost for the larger solar field case will be marginally higher then the constant solar field case but was considered equal this analysis.

As noted above, dry cooling would exact an efficiency penalty on the overall steam cycle. The unique nature of solar facilities brings another variable into play when considering the impact of the alternative cooling methods. Because solar energy varies greatly not only across 24-hour periods but also annually, the solar field is “oversized” compared to the rated steam cycle capacity in order to offset the loss of solar power in less than ideal solar conditions. The degree of “oversizing” is measured by the solar multiple. A solar multiple of 1.25 means the solar field is 25 percent larger than required to achieve the rated plant output under ideal solar conditions.

In analyzing the impact of lower cycle efficiency due to dry cooling, if the solar multiple is held constant, the facility can still produce the rated output by taking advantage of the excess solar field when operating in an non-ideal conditions, but the annual power generation produced will decrease compared to a wet cooling system. However, if the solar multiple is increased while holding the rated output the same, the annual power generation of the wet and dry cooled facilities could be held equal. Table 4-3 compares wet vs. dry cooling in two ways, with constant solar multiple and increased solar multiple. A lower efficiency would equate to lower annual power generation and operating revenues if the solar field size is not increased to offset the lower cycle efficiency. Table 4-3 shows the estimated net power effects of wet and dry-cooled systems and estimated net present value for each cooling technology for the BSEP.

As shown in Table 4-3, for the case where the solar field size is held constant, the net annual power generation loss due to dry cooling for the Project is estimated to be approximately 45,000 fewer MWh per year than that generated with the proposed wet cooling. The total net present value (NPV) impact due to lower revenues alone stemming from the lower efficiency of a dry cooled BSEP is estimated to be nearly $64 million during the life of the facility for a dry cooled plant compared to the proposed wet cooled Project. The total difference in NPV is estimated to be approximately $71.1 million, when the additional factors of the incremental higher capital cost but lower operating cost for a dry cooling system compared to a wet system are included, as shown in Table 4-3. If the solar field size is increased to compensate for the reduced efficiency penalty, the total capital cost for the dry cooled system compared to the wet system would increase by $73.5 million. For this case, the total difference in NPV between wet and dry cooling technologies is estimated at $60.1 million, as shown in Table 4-3 above.

An ACC for the BSEP is estimated to be approximately 120 feet tall and occupy over 84,000 square feet. The proposed wet tower will be 45 feet tall and occupy less than 34,000 square feet. Because it is larger, the ACC would be more visible and have greater impacts on visual resources. However, the wet cooling tower may occasionally produce a visible plume, which would not be the case for a dry cooling tower. It should be noted that visible plumes would be expected to occur very infrequently at the Project since the plant will only operate during sunny conditions, which correspond to low humidity periods, and thus would not represent a significant impact (see Section 5.15, Visual Resources).

A dry cooling system would have less direct emissions than a wet tower because it would not have the drift emissions of a wet tower (emissions of fine entrained droplets that contain dissolved solids that evaporate and form fine particles). However, dry cooling can cause higher indirect emissions if the resultant power loss is made up by producing the “replacement” power at a fossil-fuel fired power plant. In addition, the condenser of the proposed wet cooling tower system can be evacuated and steam seal established quickly for facility start-up, thus reducing emissions from the auxiliary boiler. .Finally, because a dry cooling system requires larger and more powerful fans than a wet system, an ACC would produce greater noise emissions than the proposed wet cooling system.

The primary disadvantage of wet cooling (and advantage of an ACC) is water consumption. Since wet cooling relies on evaporation as the primary mode of heat rejection, water consumption is higher. The cooling tower also requires that a portion of the circulating water be blown down (removed from the system for reuse or disposal) and replaced with fresh water to maintain water chemistry. Because an ACC does not rely on evaporation for heat transfer, cooling water supply, treatment, and disposal are not issues of concern. Table 4-4 summarizes expected water usage for wet and dry cooling.

Table 4-4 Annual Water Make-Up for Wet and Dry Cooling

	Wet Tower	**ACC**
Annual/Summer Makeup (gallons per minute [gpm])	3,353/4,054	178/192
Annual/Summer Blowdown (gpm)	197/240	0/0
Annual/Summer Flow to Evap Ponds (gpm)	462/563	82/92
Annual Makeup in Acre Feet per Year (acre-feet per year [AFY])	1,599	79
Annual Makeup Savings (AFY)	--	1,520

The following section compares wet cooling to hybrid wet-dry cooling.

Wet Cooling v. Hybrid Wet-Dry Cooling for Project Beacon

Hybrid cooling combines the advantages and disadvantages of both wet and dry systems. While hybrid cooling consumes water, it consumes less water than pure wet cooling. The capital costs for a hybrid wet-dry cooling system for the BSEP also fall between the wet and dry cooling technologies. As stated above, hybrid technology uses dry and wet cooling in parallel. As the heat duty varies depending on ambient conditions and plant output, the amount of cooling provided by the dry and wet components changes. Table 4-5 shows the sizing criteria and percent cooling ratios for the hybrid system evaluated for the BSEP.

Table 4-5 Hybrid Cooling: Share of Heat Duty Load for Wet and Dry Cooling Systems (Percentage)

Case	Ambient Temperature (Dry Bulb/Wet Bulb)	Dry Cooling Duty	Wet Cooling Duty	Net Output (MW)
Summer	104 ºF/68 ºF	51.4%	48.6%	250
Annual	71 ºF/52 ºF	100%	0%	200

Table 4-6 summarizes the difference between capital costs for a wet and hybrid cooled plant of the same rated output (the less efficient hybrid cooled plant requires a larger solar field to achieve the same output). As discussed below, the table also compares costs if the solar field size was held the same (in which case the output of the hybrid cooled plant would be lower).

In addition to capital costs, operating costs have also been considered. Wet cooling operating costs include the cost of pumping makeup cooling water (less water is needed for hybrid cooling), higher water treatment chemical costs than needed for hybrid cooling, and high power requirements (and operating costs) for circulating pumps and water treatment activities.

A BSEP facility with a wet-dry hybrid cooling system would have cycle efficiency between that of a wet cooled plant and a dry cooled plant. At higher ambient conditions, the wet cooling tower portion of the hybrid would have to operate at the same design STG backpressures as would an ACC, and the higher backpressures would impose an efficiency penalty. In terms of in-plant energy consumption (fans, circulating pumps, etc.), the hybrid cooled plant would fall between the wet and dry options – the hybrid cooling system would consume more power than a wet system but less than the dry system. When considering the net power effects (efficiency loss, fan and pump power, etc.), as well as the difference in the amount of makeup cooling water needed for a hybrid cooling system, operating costs (including lower revenues because of the efficiency penalty for the dry-cooled portion of the system), for a wet-dry hybrid cooling system for the BSEP would fall between the wet and dry cooled plant. Table 4-6 summarizes the operating cost differences between a wet and hybrid cooled plant for both constant solar field size and increased solar field size.

As shown in Table 4-6, for the case where the solar field size is held constant, the net power generation impact of hybrid cooling for the BSEP is estimated to be approximately 28,000 fewer MWh per year than that generated with the proposed wet cooling. As shown in Table 4-6, the total net present value (NPV) impact due to lower revenues stemming from the lower efficiency of a hybrid cooled BSEP is estimated to be approximately $39 million during the life of the facility for a hybrid cooled plant compared to the proposed

wet cooled Project. The total difference in NPV between wet and hybrid cooling technologies is estimated to be approximately $46 million when the higher capital costs and lower operating costs are included.

Table 4-6 Annual Generation Impact and Net Present Value for Wet and Hybrid Cooling

Cost Component	Solar Field Size Held Constant [1]	Solar Field Size Increased [1]
Annual Net Generation Impact Hybrid Cooling Compared to Wet Cooling (Megawatt-hour [MWh]) [2]	-27,756	0
Annual Revenue Impact from Net Generation Impact for Hybrid Cooling Compared to Wet Cooling [3]	($4,200,000)	0
Total Net Present Value of Generation Revenue Impact for Hybrid Cooling Compared to Wet Cooling	($39,300,000)	$0
Additional Capital Expenses for Hybrid Cooling Compared to Wet Cooling [4]	$12,900,000	$43,900,000
Total Net Present Value of O&M Expenses for Hybrid Cooling Compared to Wet Cooling [5]	$5,900,000	$5,900,000
Total Net Present Value for Hybrid Cooling Compared to Wet Cooling	($46,300,000)	($38,000,000)

[1] Dollar values rounded.

[2] Annual net generation for a hybrid cooled plant is based on a cycle efficiency difference of 2.1% relative to wet cooling.

[3] Based on a nominal $0.15/kWh.

[4] The capital costs shown in the table include cooling equipment, boiler feed water pumps, HTF pumps, and solar field addition for the case where the solar field size is increased.

[5] O&M Expenses include water treatment, operating, and water pumping costs. The O&M cost for the larger solar field case will be marginally higher then the constant solar field case but was considered equal this analysis.

In terms of cooling tower drift, water treatment and circulating water systems size, and noise emissions, the wet-dry hybrid system would fall between the purely wet cooling and dry cooling systems. It should be noted that during the summer months, hybrid cooling relies primarily on the wet portion of the system. Because wet cooling is more efficient than dry cooling, its use in the summer achieves substantially improved plant performance at the time of year when the demand for power is greatest. In the winter months, hybrid cooling relies primarily on dry cooling, which conserves water compared to a wet cooling tower.

As noted earlier, a disadvantage of wet cooling is water consumption. Since a hybrid system uses a smaller wet cooling tower, less make-up water is required for a hybrid cooled plant. Table 4-7 summarizes expected water usage for wet and hybrid cooling.

Table 4-7 Annual Water Make-Up for Wet and Hybrid Cooling

	Wet Tower	Hybrid Cooling
Annual/Summer Makeup (gpm)	3,353 / 4,054	157 / 2,502
Annual/Summer Blowdown (gpm)	197 / 240	0 / 144
Annual/Summer Flow to Evaporation Ponds (gpm)	462 / 563	36 / 349
Annual Makeup (AFY)	1,599	625
Annual Makeup Savings (AFY)	--	974

Summary of Cooling Technology Comparison

In conclusion, based on the information presented above and the use of concentrating solar trough technology, Beacon Solar has concluded that the use of dry cooling will likely render the project non-competitive and economically unsound. The incremental increase in parasitic facility electric energy requirements resulting from the use of dry cooling would require approximately 52 additional mirror collector loops to compensate for the dry cooling inefficiency during peak generation and to maintain the facility's 250 MW generation capacity during daily peak load hours.

The additional collectors would in turn require approximately an additional 144 acres of land to provide sufficient space for installation of such equipment. The site as now economically configured is not capable of handling the additional mirror assemblies necessary to compensate for the dry cooling parasitic load requirement. Similarly, the use of hybrid cooling would require an increase of 28 mirror collector loops and associated additional 78 acres of land. This additional land requirement is also an unacceptable option for the Project to remain viable economically.

The groundwater resource available to the Applicant, as a result of its ownership of the Project site, provides for a viable economic plant design that is required for the Project to remain attractive to potential utility customers. Beacon Solar has emphasized water conservation measures in its facility design to minimize water consumption associated with the use of wet cooling.

Beacon Solar is also exploring the use of tertiary treated reclaimed water as a potential supplemental source of water supply for the Project to augment the use of groundwater resources presently available at the site (see Section 4.5.3). More detailed information regarding the acceptance and feasibility of the potential source of reclaimed water is expected to be forthcoming during the AFC licensing process.

4.5.3 Cooling Water Supply Alternatives

An exhaustive search was conducted to identify a possible alternative source of cooling water for the BSEP. This search included inquiries to numerous wastewater treatment facilities in a large radius around the BSEP site. Information on several of these alternatives is provided in Table 4-8. In addition to the facilities shown in Table 4-8, 17 other facilities were investigated and similarly found infeasible due to remoteness, because water is already contracted to others and not available, or because the wastewater source is unsuitable for power plant cooling purposes (i.e., not treated to tertiary treatment standards as is required for power plant cooling use). Documentation of Beacon Solar's correspondence with various agencies as part of this investigation is provided in Appendix K.

Table 4-8 Water Supply Alternatives Considered

Organization Name	Delivery Distance	Year 2010+ Output (AFY)	Results of Contacting Organization and Information Regarding Water Availability
LADWP Aqueduct	1- 2 miles	N/A	LADWP indicated that they were legally unable to supply water to the BSEP because they did not have supplies that could be considered "surplus" as is required by the City of Los Angeles Charter. (See Appendix K)
California City Wastewater Treatment Facility	15 miles	320~370	Facility currently does not have tertiary treatment (treatment level required for power plant cooling use) at this time, but is planning a future project to provide tertiary treatment (See Appendix K). Not currently a feasible water supply source, but conceivably could become viable in the future. Beacon Solar will monitor the situation.
Rosamond Wastewater Treatment Plant	27 miles	560	Plans exist to produce 0.5 mgd of tertiary treated water (insufficient for BSEP use), and other entities also have expressed interest in this source; long distance to BSEP site (cost issue as well as potential for environmental issues) (See Appendix K). Not considered a viable alternative.
Ridgecrest Wastewater Treatment Plant	30 miles	2,000	Plans to treat all water to tertiary standards exist. Other entities (solar projects) more local to Ridgecrest interested in this source; lengthy distance to BSEP site creates cost and potential environmental issues. Not considered a viable alternative.
Tehachapi Wastewater Plant	35 miles	1,200	Project in development to produce tertiary treated water. Source not considered viable due to distance from BSEP site.
Lancaster Water Reclamation Plant	40 miles	15,700	Full tertiary treatment expected in 2010. Plans exist to sell/use water locally under the Antelope Valley Integrated Regional Water Management Plan (AV-IRWMP). Other projects (including power projects) considering this source. Source not considered viable for BSEP due to distance.
Palmdale Water Reclamation Plant	50 miles	15,700	Similar to Lancaster including participation in AV-IRWMP. Other projects (including power projects) considering this source). Source not considered viable for BSEP due to distance.
Victor Valley Wastewater Reclamation Authority	62 miles	4,500~6,700	Tertiary treated water expected to be available sometime in the future after meeting current and expected commitments. However, source not considered viable due to distance from BSEP site.

The results of the investigation show that there is currently no reclaimed water source that can be considered a feasible alternative for the BSEP upon commencement of commercial operation. Sources investigated could not provide a suitable supply (in terms of quality and/or quantity), and/or the sources

were so distant (greater than 20 miles) from the BSEP site as to be economically unsound (e.g., pipeline costs) and also pose potential for environmental impacts related to the need for a lengthy pipeline.

As indicated in Table 4-8 and in a February 12, 2008 letter from Michael J. Bevins, the California City Public Works Director (see Appendix K), California City is planning to upgrade its wastewater treatment plant to process up to approximately 4.0 million gallons per day (mgd) of municipal waste water to tertiary treatment standards. As mentioned in the correspondence, the California City treatment plant expansion project is expected to be completed by 2012 (whereas the BSEP is scheduled to begin commercial operation in the third quarter of 2011). A pipeline to the BSEP site is one of two alternatives potentially being considered by the City for the planned discharge of tertiary treated water in excess of 0.9 mgd (the other is discharge to Cache Creek). A pipeline route between the California City wastewater treatment plant and the BSEP plant site that heads west on Mendiburu Road and then north on Neuralia Road (see Figure 4-2) is mentioned in the City's correspondence.

While the California City reclaimed water alternative is the most promising as a supplemental source of water, it cannot be considered a feasible alternative for the BSEP at this time. The California City wastewater expansion project that will yield reclaimed water is not yet under construction and the California City expansion project's planned completion date is later than the BSEP schedule for commencing commercial operations Notwithstanding these uncertainties that render this alternative not feasible at present, Beacon Solar intends to monitor the development of the California City project as a possible future supplemental source of reclaimed water if the City's tertiary treatment project is developed as currently planned, and if suitable reclaimed water becomes available and its potential use is economically, environmentally, and operationally viable for the BSEP.

It should be noted that the use of reclaimed water to supply cooling water for a solar power plant poses issues related to matching water demand with water supply. Since a reclaimed water facility supplies water on a continuous basis and BSEP's water demand would vary between daytime and nighttime hours, as well as seasonally (high during the peak summer months and much lower during the winter months), the Project would require considerable onsite water storage in some scenarios. While the Project intends to provide for daily storage of water, seasonal storage would pose additional design challenges and would increase Project costs, rendering the economics less attractive to the Project.

4.5.4 Cooling Tower Blowdown Disposal Alternatives

As proposed, Project Beacon will utilize wet cooling technology and evaporation ponds for cooling tower blowdown disposal. Cooling tower blowdown consists of concentrated brine resulting from several cycles of reuse in the condenser cooling system. An alternative to evaporation ponds was considered: a mechanical zero liquid discharge (ZLD) system consisting of a reverse osmosis system and/or brine concentrator and a crystallizer, and supporting water treatment equipment including pumps, tanks, filters, mixing tanks, piping, control system, etc. It should be noted that the proposed Project approach includes raw water pretreatment that significantly reduces the brine flow to the evaporation pond by increasing the cycles of concentration within the cooling tower. The following paragraphs compare this alternative (mechanical ZLD) to the proposed approach (evaporation ponds).

Evaporation ponds and a mechanical ZLD system both eliminate the cooling tower blowdown wastewater stream. The evaporation ponds accomplish this by using solar energy to evaporate the cooling tower

blowdown to the atmosphere, leaving the solids in the pond. The evaporation ponds require no energy input (other than solar energy), and as currently planned, the ponds would be constructed with sufficient capacity that they would not require offsite transport of the dewatered salts during the intended life of the Project. Liquid and precipitated solids in the ponds would be exposed to the environment for an extended period with the associated need for groundwater monitoring. However, because the ponds would be lined and wildlife impacts would be carefully monitored (and measures taken to protect wildlife, if needed), potential pond impacts are considered minimal.

Alternatively, a mechanical ZLD system would concentrate the blowdown stream to produce a wet solid waste product that would require regular offsite truck transport to an appropriately permitted disposal facility. The ZLD system uses an external heat source (e.g., steam or electricity) to evaporate the water. Within the ZLD system, the water removal and crystallization processes occur in closed vessels and systems, with the only outputs being wet solids which are removed and stored in containers prior to offsite disposal, and water which is sufficiently pure that it can be reintroduced as make up water to the power plant cooling system. The crystallizer has minimal potential for groundwater impacts and wildlife exposure to ponds would not exist; thus, there would be no need for groundwater monitoring or wildlife protection measures. The crystallizer also would require less land area than evaporation ponds.

The crystallizer may use steam, but more likely would use electricity from the power plant and/or the power grid, due to the cycling nature of the solar plant compared with the continuous operation of the ZLD system. The reduction in plant energy output would be expected to be a fraction of the net plant output (e.g., ~1-2 percent) in the summer and a significant percentage (up to 10 percent) in the winter. The mechanical ZLD requires significant amounts of electric power to drive the process, often in excess of 1 MW (i.e., >24,000 kW-hr/day) depending on the system design. These demands reduce the available electrical output, decrease the overall thermal efficiency of the power facility, and likely would require energy purchase during the Project's non-power-generating hours. The evaporation ponds require minimal electrical power and result in higher plant efficiency.

No significant environmental issues have been identified with either option. The evaporation ponds will be required to undergo permitting review from the Lahontan Regional Water Quality Control Board (RWQCB) for issuance of Waste Discharge Requirements (WDR) and will be required to meet stringent regulatory requirements in terms of construction, materials, leak detection, etc. to ensure appropriate protection to underlying groundwater. Water quality will be monitored in order to ensure minimal risk to birds.

The offsite truck transport of residual solids from the crystallizer (estimated annual average of two truckloads per week), would involve ongoing air emissions and potential traffic impacts throughout the BSEP's operational life that would not occur with the proposed evaporation ponds. The contents of the evaporation ponds would be removed at the end of the Project's operational life, although it largely would be the timing of the removal that would differ rather than the amount of materials that would require offsite shipment. Since the plant will operate daily and the ponds will have some amount of water at all times (except during maintenance) particulate emissions from the ponds will be minimal. The total solids generation will be the same for a crystallizer and for ponds; however, the solids from the crystallizer option would need to be trucked offsite regularly compared to the solids remaining onsite in the ponds for the evaporation pond option.

The mechanical ZLD approach would require supplemental water treatment equipment beyond that required by the evaporation pond approach in order to reduce the worst-case summer blowdown flow from approximately 572 gpm (with a pre-treatment system) to typically less than 150 gpm. To reduce blowdown flow to this level, both raw water treatment and cooling tower blowdown treatment systems would be required, which would involve increased capital and O&M costs. The mechanical ZLD system would require an upstream storage tank to smooth out total blowdown flow throughout the day. In comparison, evaporation ponds eliminate the need for operator attention due to daily cycling of blowdown flow, as well as seasonal flow variations, where winter flows may be less than 10 percent of summer flow.

Table 4-9 compares the proposed evaporation pond and the ZLD approach in terms of capital and O&M costs. As shown, the proposed evaporation ponds involves both substantially lower annual costs ($1.3 milllion [MM]/year compared to $5.0 MM/year for ZLD) and lower capital costs ($22.6 MM compared to $26.5 MM for ZLD). The evaporation ponds will be designed, constructed, and operated in compliance with a broad range of regulatory requirements and standards that will ensure that impacts will be less than significant.

Table 4-9 Estimated Capital and O&M Costs for Evaporation Ponds and ZLD Water Treatment Systems

Cost Component	Raw Water Treatment and Evap Ponds	Post-Cooling Tower Water Treatment and ZLD System
Estimated Annual/Summer Flow to Evaporation Ponds (gpm)	462 / 563	0 / 0
Estimated Annual O&M Costs ($MM per year excluding power)	$1.2	$1.8
Estimated Operating Costs ($MM per year for electric power)	$0.1	$3.2
Estimated Evaporation Pond Capital Costs ($MM)	$6.3	$0.0
Estimated Water Treatment Capital Costs ($MM) Excluding Evaporation Ponds	$16.3	$26.5

Based on the information above, it was determined that mechanical ZLD systems are not an economically sound alternative to engineered evaporation ponds. In addition, using solar energy to generate steam to power a mechanical ZLD system is not an optimal use of renewable energy compared to using solar energy (in the form of evaporation) directly.

4.5.5 Solar Thermal Storage

The addition of molten salt-based thermal energy storage (TES) was considered. Including a TES system allows for time shifting of generation as well as generation of additional total annual energy output for a given size power block, depending on field sizing. However, it adds incremental cost, increases the acreage needed for the solar field, and unless the time shifting of power is of significant value to the system, is generally not justified. At this time TES is not economically justified for the BSEP by the expected market conditions.

4.6 Power Generation Technology Alternatives

The proposed Project would generate power by using concentrated solar thermal trough technology to produce high-pressure steam to drive a steam turbine generator. The following paragraphs discuss alternative power generation technologies and compare them to the proposed parabolic trough technology for the BSEP.

4.6.1 Alternative Solar Technologies

Several solar technologies exist, both on a large and small scale. Concentrated solar power can be adapted to a variety of technologies, including photovoltaic technologies, power tower configuration, Stirling engine concepts, and Fresnel reflector based systems, as well as trough technologies. Figure 4-3 shows several of these technologies.

- Photovoltaic technologies offer a relatively simple method of power conversion. However, photovoltaics at present do not offer the efficiency and cost that would make them attractive for a large-scale power generating facility.

- Stirling engines operate on a thermodynamic cycle invented and patented by Robert Stirling in the early 19th century. With this technology the engine is located at the focal point of a paraboloid shaped collector typically created by an array of smaller mirrors. To scale this technology, the entire system is repeated (multiple engines and collector arrays) many times, as scaling the base array above a size of approximately 50 kW is not physically practical. While this technology can offer higher thermal efficiencies than parabolic troughs because of higher operating temperatures, it involves more complex mechanical equipment and thus increased operational and maintenance difficulties. Also, this technology is not as well proven as parabolic trough mirrors, and the current cost of power produced from this technology on a large scale is not well known and could approach several times the cost of renewable power produced by solar trough mirror technology.

- Power tower configurations concentrate the light on an elevated tower from a large field of mirror surrounding the tower; facilities may have multiple fields of mirrors surrounding multiple towers. This approach can offer higher thermal efficiencies than parabolic trough technologies, but in terms of efficiency of land use, rows of parabolic troughs can use land somewhat more efficiently than groupings of mirror fields surrounding multiple towers. For this reason, a power tower facility can require more total land area per 100 MW generated than a parabolic trough facility. Also, the height of the tower(s) results in a greater potential for adverse visual impacts and aircraft fight issues than for a parabolic trough facility, particularly in the vicinity of military air bases such as in the eastern Kern County high desert area of California. Finally, as with the other solar technologies mentioned above, the power tower technology is not as well proven as parabolic trough mirrors and current projected costs of produced energy based on a recent installation in southern Spain is expected to be higher.

- There is another concentrating solar technology involving long flat reflectors, each moving on a single axis. Multiple reflectors are installed parallel to each other to create a virtual trough in a Fresnel pattern, all focusing on a set of tubes elevated above the mirrors. The mirrors concentrate the sun's heat on water-filled pipes and convert the water directly to steam to drive a steam turbine rather than collecting the heat in a high temperature fluid that then is used to generate steam, as is the case with parabolic

trough mirrors. This Fresnel reflector technology results in lower efficiencies throughout the process, but with correspondingly expected lower costs of components. This technology is still under development and while promising, it is not proven on a pilot or commercial scale at this time in contrast to parabolic trough mirrors.

Parabolic trough mirror technology was chosen for this Project primarily because it is the only well proven technology for this scale of power generation. Significant experience at the nine SEGS units takes most of the operational risk out of this technology. In addition, the recent resurge in solar thermal growth has been focused on this technology, including the completed construction of the Nevada Solar One unit and the current construction of several parabolic trough units in Spain. This new growth has also spawned the development of new sources for critical components in addition to the current manufacturers.

4.6.2 Other Renewable Technologies

As presented in Section 2.0, Project Description and Section 4.2.1 above, one of the Project objectives is to develop a new utility-scale solar energy project; therefore no other renewable technologies were considered for this Project.

4.6.3 Non-Renewable Technologies

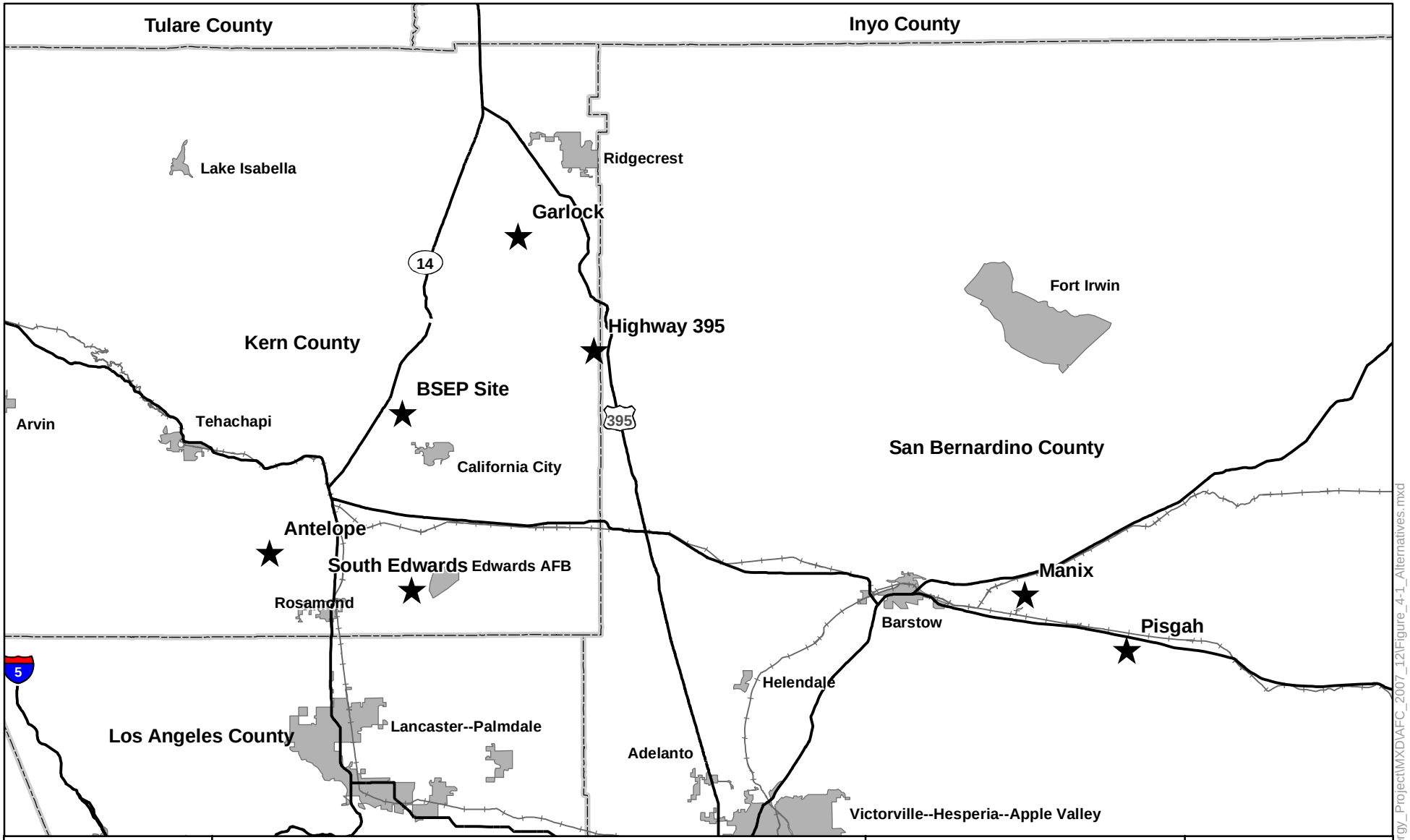
An objective of the Project is to support the State's policies/goals with respect to increasing the use of renewable energy sources. Fossil fuel technologies (simple cycle, combined cycle, advanced combustion turbine technologies, integrated gas combined cycle, fluidized bed boilers, etc.) by definition do not support these goals and objectives and thus were not considered as alternatives for the BSEP. Nuclear power also is not renewable energy and is prohibited by California law at present because of concerns about nuclear waste disposal.

4.7 References

California Energy Commission (CEC), 2005. Integrated Energy Policy Report. November.

CEC, 2007. Committee Draft Integrated Energy Policy Report. October.

State Water Resources Control Board, 1975. State Water Resources Control Board Resolution No. 75-58 Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling.



Map Location

Legend

- Alternative Sites Considered
- County Boundary
- Urban Area
- Highway
- Railroad

1:1,000,000

0 10 20 30 40 Miles

N W E S

Beacon Solar Energy Project

Figure 4-1
Alternative Sites Initially Considered

Source: ESRI 2007

Beacon Solar

ENSR | AECOM

Project: 10056-014
Date: March 2008

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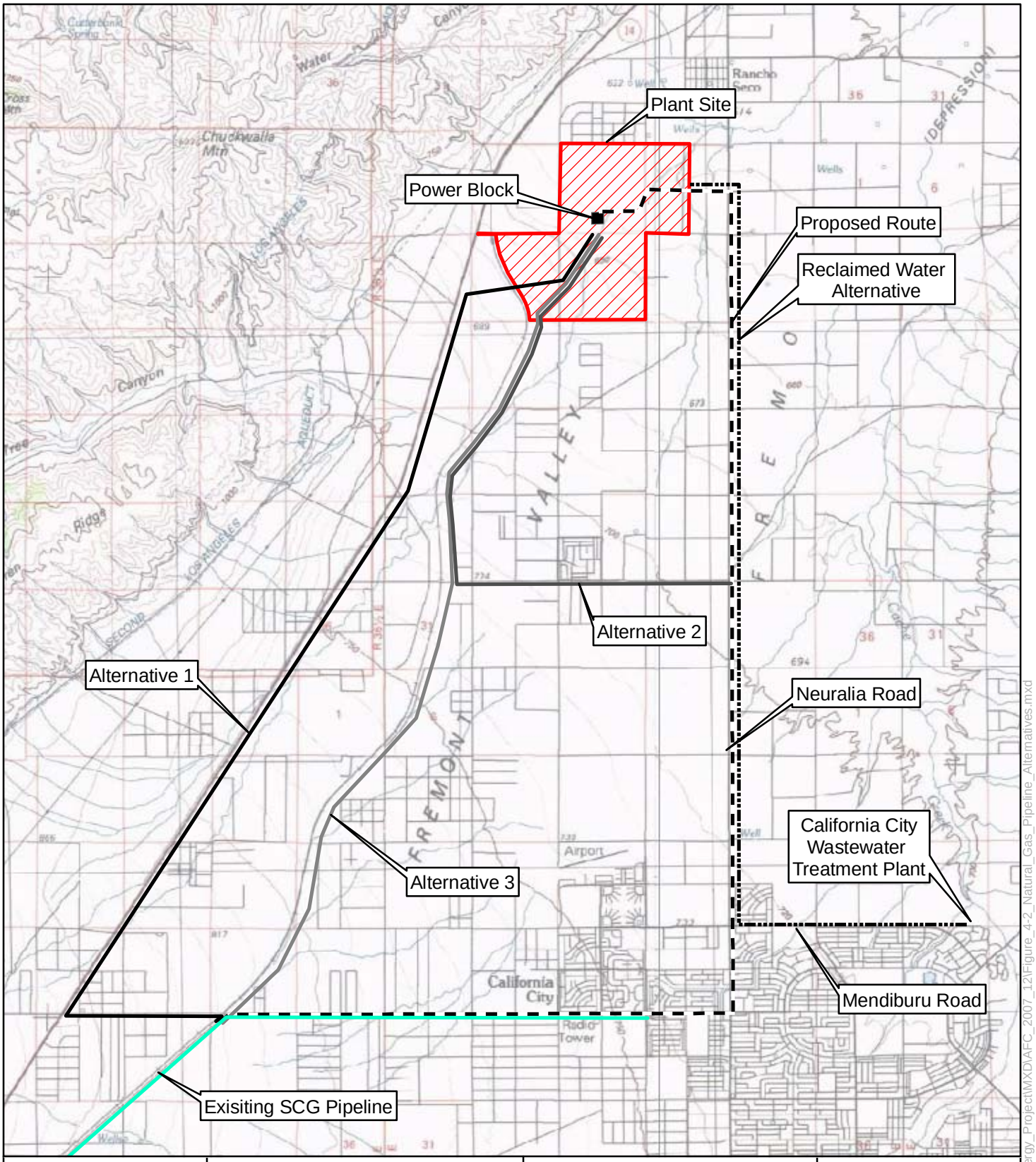

Map Location

Legend

- Plant Site
- Proposed Route
- Reclaimed Water Alternative
- Alternative 1
- Alternative 2
- Alternative 3
- Existing Transmission Line

N W E S

Beacon Solar Energy Project

Figure 4-2
Natural Gas and Reclaimed Water Pipeline Alternatives

1:100,000

0 1 2 Miles

Beacon Solar

ENSR | AECOM

Project: 10056-014
Date: March 2008

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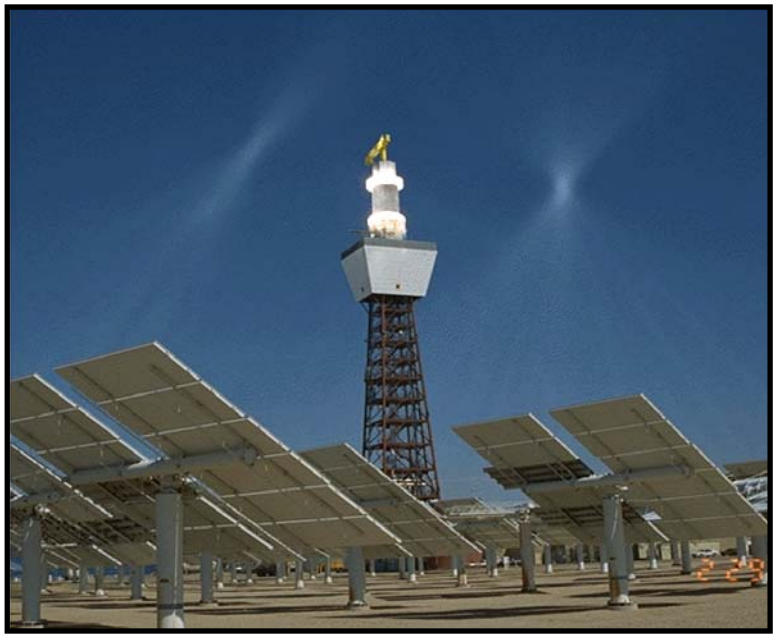
Photovoltaic Solar Power Panel

Parabolic Solar Collection Dish with Stirling Engine



Power Tower Solar Collector Field
Source: National Renewable Energy Laboratory; Wikipedia

Fresnel Lens Reflectors

Figure 4-3 Example Solar Power Generating Technologies