CENTER *for* BIOLOGICAL DIVERSITY

VIA EMAIL AND FEDERAL EXPRESS OVERNIGHT DELIVERY

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Allison Shaffer, Project Manager,
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Re: Comments on the Draft Environmental Impact Statement/Staff Assessment for the Genesis Solar Energy Project and Possible California Desert Conservation Area Plan Amendment (CEC Application For Certification (09-AFC-8))

Dear Project Manager Shaffer:

These comments are submitted on behalf of the Center for Biological Diversity's 255,000 staff, members and on-line activists in California and throughout the western states, regarding the Draft Environmental Impact Statement/Staff Assessment Genesis Solar Energy Project ("DEIS") and Possible California Desert Conservation Area Plan Amendment (CEC Application For Certification (09-AFC-8)) ("proposed project"), issued by the Bureau of Land Management ("BLM").

The development of renewable energy is a critical component of efforts to reduce greenhouse gas emissions, avoid the worst consequences of global warming, and to assist California in meeting emission reductions set by AB 32 and Executive Orders S-03-05 and S-21-09. The Center for Biological Diversity (the "Center") strongly supports the development of renewable energy production, and the generation of electricity from solar power, in particular. However, like any project, proposed solar power projects should be thoughtfully planned to minimize impacts to the environment. In particular, renewable energy projects should avoid impacts to sensitive species and habitats, and should be sited in proximity to the areas of electricity end-use in order to reduce the need for extensive new transmission corridors and the efficiency loss associated with extended energy transmission. Only by maintaining the highest environmental standards with regard to local impacts, and effects on species and habitat, can renewable energy production be truly sustainable.

As proposed, the project would permanently disturb approximately 1,800 acres of public lands in the Colorado desert that provide habitat for many species including the threatened desert tortoise and the imperiled Mojave fringe-toed lizard. The proposed project also includes a gen-tie

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line, and an expansion of the previously permitted but yet un-built Colorado substation. The DEIS for the proposed plan amendment and right-of-way application: fails to provide adequate identification and analysis of all of the significant impacts of the proposed project on the desert tortoise, the Mojave fringe-toed lizard, rare plants including ground water dependent vegetation, microphyll woodlands and other biological resources; fails to adequately address the significant cumulative impacts of the project; and lacks consideration of a reasonable range of alternatives.

Of particular concern is the BLM's failure to include adequate information regarding the impacts to resources and the failure to fully examine the impact of the proposed plan amendment to the California Desert Conservation Act Plan ("CDCA Plan") along with other similar proposed plan amendments and as a result the current piecemeal process may lead to the approval of industrial sites sprawling across the California Desert generally, and the Ford Dry Lake area in particular, within habitat that should be protected to achieve the goals of the bioregional plan as a whole. The DEIS discusses several "no action" alternatives but fails to adequately consider alternative plan amendments that would protect the most sensitive lands in this area from future development. Alternative siting and alternative technologies (including distributed PV) should have been fully considered in the DEIS, because they could significantly reduce the impacts to many species, soils, and water resources in the Colorado desert. Although the area of the proposed project is currently part of the evaluation being undertaken by the BLM for the solar PEIS for solar energy zones, within the "Riverside East" proposed solar energy study area ("SESA"), unfortunately, there has been no environmental documentation yet provided for that process and there is as yet no way to discern if the proposed project siting will be compatible with that planning. In scoping comments on the PEIS, the Center raised concerns about the impacts that development would have to species and habitats and particularly to connectivity. As the Center has emphasized in our comments on the various large-scale industrial solar proposals in the California desert, planning should be done *before* site specific projects are approved in order to ensure that resources are adequately protected from sprawl development and project impacts are avoided, minimized and mitigated.

The Center has been informed that the project applicant has continued to work with the agencies on alternative site configurations that may avoid or minimize some of the impacts of the project, however, the DEIS does not provide that information. Any new site configuration alternative will need to be circulated for public review and comment in a Supplemental or Revised DEIS that should also include additional information on those resources that were inadequately identified and analyzed in the DEIS and additional consideration of off-site alternatives and other alternatives. The Center urges the BLM to revise the DEIS to adequately address these and other issues detailed below and re-circulate the DEIS or a supplemental DEIS for public comment.

Even if the proposed project were to move forward on this site, the Center opposes the proposal to use wet-cooling for this large-scale industrial solar power project. The use of vast amounts of scarce groundwater resources in the Colorado desert is completely inappropriate particularly where alternative dry-cooling technology is available. That dry cooling is clearly a feasible alternative is shown by the fact that other solar companies have relied on dry-cooling in similar proposals and even in far larger proposals.

In the sections that follow, the Center provides detailed comments on the ways in which the DEIS fails to adequately identify and analyze many of the impacts that could result from the proposed project, including but not limited to: impacts to biological resources, impacts to water resources, impacts to soils, direct and indirect impacts from the gen-tie line and substation, and cumulative impacts.

Because the project approval process includes a quasi-judicial process in the California Energy Commission, the Center hereby incorporates by reference all of the materials before the California Energy Commission regarding the approval of this project. BLM is a party to the CEC process, which is being conducted in concert with the BLM approval process, and BLM has access to all of the documents (most of which are also readily accessible on the internet), therefore, BLM should incorporate all of the documents and materials from that process into the administrative record for the BLM decision as well.

I. The BLM's Analysis of the Proposed Plan Amendment and Proposed Project Fail to Comply with FLPMA.

As part of FLPMA, Congress designated 25 million acres of southern California as the California Desert Conservation Area ("CDCA"). 43 U.S.C. § 1781(c). Congress declared in FLPMA that the CDCA is a rich and unique environment teeming with "historical, scenic, archaeological, environmental, biological, cultural, scientific, educational, recreational, and economic resources." 43 U.S.C. § 1781(a)(2). Congress found that this desert and its resources are "extremely fragile, easily scarred, and slowly healed." *Id.* For the CDCA and other public lands, Congress mandated that the BLM "shall, by regulation or otherwise, take any action necessary to prevent unnecessary or undue degradation of the lands." 43 U.S.C § 1732(b).

The sum total of the plan amendment to the CDCA plan is one sentence: Permission granted to construct solar energy facility (proposed PSPP Project). DEIS at A-7. The DEIS then lists the criteria for consideration of the plan amendment and right of way application and BLM's responses to each issue. DEIS at A-7 to A-10. The Center appreciates BLM's effort in this regard (which were absent in other recent environmental documents prepared for large-scale solar projects), however, given the impact of the proposed project on other multiple uses of these public lands at the proposed site as well as other aspects of the bioregional planning, it is clear that BLM may also need to amend other parts of the plan as well and should have looked at additional and/or different amendments as part of the alternatives analysis.

Oddly, unlike other proposed projects in this area (notably the Palen and Blythe projects), BLM did not propose any potential plan amendments that would adopt right of way exclusion areas as part of a mitigation strategy in order to increase protection for the rare plants and animals. For example, by designation of the Palen-Ford Wildlife Habitat Management Area (WHMA) as exclusion areas for rights of way. As established under the NECO plan amendment, "Species would have positive benefits from designation of DWMAs and the Multispecies WHMA through prescriptions aimed at reducing surface disturbance and improving natural communities" (*See* NECO at 4-156). While the Center supports additional protections for species and habitats on public land, if the BLM considers adopting such mitigation in this instance as well, BLM needs to accurately address the limits of those protections on the ground under the current regulatory and statutory framework that applies to these public lands.

A. The DEIS Fails to Adequately Address the Plan Amendment in the Context of the CDCA Plan.

Unfortunately, the DEIS fails to adequately consider the impacts of the proposed project and plan amendment and reasonable alternatives in the context of FLPMA and the CDCA Plan. FLPMA requires that in developing and revising land use plans, the BLM consider many factors and "use a systematic interdisciplinary approach to achieve integrated consideration of physical, biological, economic, and other sciences . . . consider the relative scarcity of the values involved and the availability of alternative means (including recycling) and sites for realization of those values." 43 U.S.C. § 1712(c). As stated clearly in the CDCA Plan:

> The goal of the Plan is to provide for the use of the public lands, and resources of the California Desert Conservation Area, including economic, educational, scientific, and recreational uses, in a manner which enhances wherever possible—and which does not diminish, on balance—the environmental, cultural, and aesthetic values of the Desert and its productivity.

CDCA Plan at 5-6. The CDCA Plan also provides several overarching management principles:

> MANAGEMENT PRINCIPLES
>
> The management principles contained in the law (FLPMA)—*multiple use, sustained yield, and the maintenance of environmental quality*—are not simple guides. Resolution of conflicts in the California Desert Plan requires innovative management approaches for everything from wilderness and wildlife to grazing and mineral development. These approaches include:
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> —Seeking simplicity for management direction and public understanding, avoiding complication and confusing in detail which would make the Plan in comprehensive and unworkable.
>
> —Development of decision-making processes using appropriate guidelines and criteria which provide for public review and understanding. These processes are designed to help in allowing for the use of desert lands and resources while preventing their undue degradation or impairment.
>
> *—Responding to national priority needs for resource use and development, both today and in the future, including such paramount priorities as energy development and transmission, without compromising the basic desert resources of soil, air, water, and vegetation, or public values such as wildlife, cultural resources, or magnificent desert scenery. This means, in the face of unknowns, erring on the side of conservation in order not to risk today what we cannot replace tomorrow.*
>
> *—Recognizing that the natural patterns of the California Desert, its geological and biological systems, are the basis for planning*, and that human use

patterns, from freeways to fence lines, define its boundaries. Only in this way can the public resources can be understood and protected by the Plan that can be publicly comprehended, accepted, and followed.

CDCA Plan 1980 at 6 (first emphasis in original, second emphasis added).

The CDCA Plan anticipated that there would be multiple plan amendments over the life of the plan and provides specific requirements for analysis of Plan amendments. Those requirements include determining "if alternative locations within the CDCA are available which would meet the applicant's needs without requiring a change in the Plan's classification, or an amendment to any Plan element" and evaluating "the effect of the proposed amendment on BLM management's desert-wide obligation to achieve and maintain a balance between resource use and resource protection." CDCA Plan at 121. BLM reads this portion of the CDCA plan extremely narrowly and attempts to divorce it from the required NEPA analysis and alternatives. Looking at the CDCA Plan requirement in context with the NEPA review it is clear that the BLM was required to analyze not only whether alternative locations were available that would not require a plan amendment, but also how the proposed amendment would affect desert-wide resource protection and whether alternative locations and alternative plan amendments would avoid or lessen those impacts—BLM fails to address the latter issue and did not look at any site alternatives. The inclusion of multiple "no action" alternatives, a reduced acreage alternative, and a reconfigured alternative as part of the NEPA analysis failed to cure this omission.

The CDCA Plan includes the Energy Production and Utility Corridors Element which is focused primarily on utility corridors with brief discussion of powerplant siting. Even in 1980 the CDCA Plan contemplated that alternative energy projects would likely be developed in the future but did not expressly provide planning direction for solar energy production. Nonetheless, the overarching principles expressed in the Decision Criteria are also applicable to the proposed project here including minimizing the number of separate rights-of-way, providing alternatives for consideration during the processing of applications, and "avoid[ing] sensitive resources wherever possible." CDCA Plan at 93. Nothing in the DEIS shows that BLM considered the landscape level issues and management objectives or alternatives to the proposed plan amendment *in the DEIS*.

In addition, BLM should have considered the impacts to existing land use plans for these public lands across several scales including, for example: in the Chuckwalla valley, in the Colorado Desert in California; and in the CDCA as a whole.

B. The DEIS Fails to Adequately Address Impacts to Multiple Use Class M Lands and Loss of Multiple Use in Favor of a Single Use for Industrial Purposes.

As FLPMA declares, public lands are to be managed for multiple uses "in a manner that will protect the quality of the scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource, and archeological values." 43 U.S.C.§ 1701(a)(7) & (8). The CDCA Plan as amended provides for four distinct multiple use classes based on the sensitivity of resources in each area. The proposed project site is in MUC class M lands. DEIS at C.12-38.

Under the CDCA Plan, Multiple-use Class M (Moderate Use) "protects sensitive, natural, scenic, ecological, and cultural resources values. For public lands designated as Class M the CDCA Plan intends a "*controlled balance* between higher intensity use and protection of public lands. This class provides for a wide variety o[f] present and future uses such as mining, livestock grazing, recreation, energy, and utility development. Class M management is *also* designed to conserve desert resources and to mitigate damage to those resources which permitted uses may cause." CDCA Plan at 13 (emphasis added). The proposed project is a high-intensity, single use of resources that will displace all other uses and that will significantly diminish (indeed, completely destroy) of approximately 1,800 acres of habitat including impacting aeolian transport in the dunes ecosystem, directly impacting habitat for desert tortoise, and other impacts to species and habitats. The DEIS does consider alternative configurations that would avoid some impacts to some resources but still fails to consider how the impacts to sand dunes and Aeolian transport along with the loss of a large area of habitat will affect the biological resources of this area. Moreover, BLM does not address how the loss of multiple uses in such a large area might affect other nearby public lands in the CDCA such as creating greater pressures on those land for the remaining multiple uses.

The DEIS does not consider whether and how the new primary access road (or any secondary access road) created for the proposed project may increase off-road vehicle use in this area and thereby significantly increase impacts from ORVs on species and habitats surrounding the proposed project and specifically whether this expanded access would increase unlawful vehicle use in the adjacent wilderness. As another example, the DEIS is unclear as to the extent that the proposal would require changes in the route network resulting a number of routes which would need to be moved—those changes to the route network are simply not addressed in the DEIS (nor are the likely direct, indirect and cumulative impacts of changing those route designations adequately identified or analyzed, as discussed in detail below). Any changes to routes would require BLM to amend the route designations in the area because these routes are part of a network that was adopted through a plan amendment. When BLM does consider these issues, as it must, in a revised or supplemental DEIS, a range of alternatives must be considered in addition to the fact that such changes may increase use of this area by ORVs and change use of the previously existing nearby routes, most likely causing increased use on other nearby routes. BLM should consider limiting access to the primary access route (and any secondary route) in order to help ensure against unauthorized off-road vehicle use in the area. Even if BLM attempts to simply reroute along the fenceline for the proposed project a plan amendment would be required and BLM must then consider that new unauthorized routes to provide connections to the other routes, and/or entirely new unauthorized routes may be created by off-road vehicle users *to avoid the industrial site entirely*. There is no evidence that recreational off-road vehicle users will be content to drive for miles along a fence adjoining an industrial site rather than striking off cross-country to connect with more scenic routes. Past experience shows that the latter is quite understandably a much more likely outcome and BLM should recognize this in analyzing the impacts of this project on the existing route network and any proposal to amend that network. Currently there are very few routes in the general vicinity of the proposed project. The proposed project would actually increase the accessibility of this currently remote area which could put additional pressure on the remaining natural resources.

C. Fails to Adequately Address Other Ongoing Planning Efforts

As noted above, the DEIS fails to adequately address the proposed project in the context of other connected projects (including multiple renewable energy projects, substations and additional transmission lines) and the ongoing PEIS planning process for solar development in six western states undertaken by BLM and DOE. The scoping and early maps for the PEIS did identify this area as a proposed solar energy study area.[1] Unfortunately, that planning process has been slow to move forward. Without prior planning, there is a high risk that the direct, indirect and cumulative impacts of the proposed project in conjunction with others may lead to sprawl development in the area and undermine the planning for renewable energy industrial zones that BLM has undertaken.

Of particular concern is the failure of the DEIS to fully analyze the impacts of the gen-tie line and the Colorado River substation which is listed as a cumulative project but no location is provided and the BLM has failed to explore alternatives that would minimize impacts of the placement of that substation. *See, e.g.,* DEIS at C12.14 (length of the gen-tie unclear). The Devers to Palo Verde No. 2 environmental review preferred alternative (as revised for the California-only line adopted by the CPUC) did not analyze a *substation* in this area. The BLM cannot lawfully piecemeal this project approval. Although the applicant has recently submitted additional information on regarding the substation impacts to the CEC, *that information is not included in the DEIS* and therefore the DEIS must be revised or supplemented. Moreover, the BLM has failed to explain how this site specific approval would interface with, or alternatively undermine, the solar programmatic planning by federal agencies for the western states. This critical issue regarding planning on public lands is not adequately addressed in the DEIS which only mentions the PEIS process briefly, and then includes the PEIS as a foreseeable future project with no explanation (DEIS at B.4-16). The BLM does not analyze how the PEIS could be affected by the approval of this and other projects in the area and does not address how the piecemeal analysis of the substation and gen-tie line may undermine the planning for a solar zone in this area. Such analysis *after the fact* is not consistent with the planning requirements of FLPMA or, indeed, any rational land use planning principles.

D. BLM Failed to Inventory the Resources of these Public Lands Before Making a Decision to Allow Destruction of those Resources

FLPMA states that "[t]he Secretary shall prepare and maintain on a continuing basis an inventory of all public lands and their resource and other values," and this "[t]his inventory shall be kept current so as to reflect changes in conditions and to identify new and emerging resource and other values." 43 U.S.C. § 1711(a). FLPMA also requires that this inventory form the basis of the land use planning process. 43 U.S.C. § 1701(a)(2). *See Center for Biological Diversity v. Bureau of Land Management*, 422 F.Supp.2d 1115, 1166-67 (N.D. Cal. 2006) (discussing need for BLM to take into account known resources in making management decisions); *ONDA v. Rasmussen,* 451 F.Supp. 2d 1202, 1212-13 (D. Or. 2006) (finding that BLM did not take a hard look under NEPA by relying on outdated inventories and such reliance was inconsistent with BLM's statutory obligations to engage in a continuing inventory under FLPMA). It is clear that

[1] http://solareis.anl.gov/documents/maps/studyareas/Solar_Study_Area_CA_Ltt_7-09.pdf

BLM should not approve a management plan amendment based on outdated and inadequate inventories of affected resources on public lands.

As detailed below in the NEPA sections, here BLM has failed to compile an adequate inventory of the resources of the public lands that could be affected by the proposed project *before* preparing the DEIS (including, e.g., rare plants, golden eagle surveys, and other biological resources) which is necessary in order to adequately assess the impacts to resources of these public lands in light of the proposed plan amendment and BLM has also failed to adequately analyze impacts on known resources. Indeed, the DEIS states that surveys are ongoing after the DEIS was issued where protocol level surveys for desert tortoise will be conducted as well as surveys for rare plants and Couch's spadefoot toad See DEIS at C.2-6. Similarly for golden eagles, the DEIS says "the USFWS recommends that the Applicant conduct nest surveys for this species in Spring 2010 (Engelhard pers. comm.)" *See* DEIS at C.2-81. Although the Center understands that golden eagle surveys have now been completed, because that information was not included in the DEIS and no analysis of impacts is provided, the BLM must revise and recirculate the DEIS or a supplement to include that new information.

Therefore, it appears that a revised DEIS or supplemental DEIS must be prepared to include several categories of new information including new survey data about the resources of the site and potential impacts of the project on resources of our public land and water, and that document must be circulated for public review and comment.

E. The DEIS Fails to Provide Adequate Information to Ensure that the BLM will Prevent Unnecessary and Undue Degradation of Public lands

FLPMA requires BLM to "take any action necessary to prevent unnecessary or undue degradation of the lands" and "minimize adverse impacts on the natural, environmental, scientific, cultural, and other resources and values (including fish and wildlife habitat) of the public lands involved." 43 U.S.C. §§ 1732(b), 1732(d)(2)(a). Without adequate information and analysis of the current status of the resources of these public lands, BLM cannot fulfill its duty to prevent unnecessary or undue degradation of the public lands and resources. Thus, the failure to provide an adequate current inventory of resources and environmental review undermines BLM's ability to protect and manage these lands in accordance with the statutory directive.

BLM has failed to properly identify and analyze impacts to the resources including the impacts from all of the project components. As detailed below, the BLM's failure in this regard violates the most basic requirements of NEPA and in addition undermines the BLM's ability to ensure that the proposal does not cause unnecessary and undue degradation of public lands. *See Island Mountain Protectors*, 144 IBLA 168, 202 (1998) (holding that "[t]o the extent BLM failed to meet its obligations under NEPA, it also failed to protect public lands from unnecessary or undue degradation."); *National Wildlife Federation*, 140 IBLA 85, 101 (1997) (holding that "BLM violated FLPMA, because it failed to engage in any reasoned or informed decisionmaking process" or show that it had "balanced competing resource values").

II. The DEIS Fails to Comply with NEPA.

NEPA is the "basic charter for protection of the environment." 40 C.F.R. § 1500.1(a). In NEPA, Congress declared a national policy of "creat[ing] and maintain[ing] conditions under which man and nature can exist in productive harmony." *Or. Natural Desert Ass'n v. Bureau of Land Mgmt.,* 531 F.3d 1114, 1120 (9th Cir. 2008) (quoting 42 U.S.C. § 4331(a)). NEPA is intended to "ensure that [federal agencies] … will have detailed information concerning significant environmental impacts" and "guarantee[] that the relevant information will be made available to the larger [public] audience." *Blue Mountains Biodiversity Project v. Blackwood,* 161 F.3d 1208, 1212 (9th Cir. 1998).

Under NEPA, before a federal agency takes a "'major [f]ederal action[] significantly affecting the quality' of the environment," the agency must prepare an environmental impact statement (EIS). *Kern v. U.S. Bureau of Land Mgmt.,* 284 F.3d 1062, 1067 (9th Cir. 2002) (quoting 43 U.S.C. § 4332(2)(C)). "An EIS is a thorough analysis of the potential environmental impact that 'provide[s] full and fair discussion of significant environmental impacts and … inform[s] decisionmakers and the public of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the human environment.'" *Klamath-Siskiyou Wildlands Ctr. v. Bureau of Land Mgmt.,* 387 F.3d 989, 993 (9th Cir. 2004) (citing 40 C.F.R. § 1502.1). An EIS is NEPA's "chief tool" and is "designed as an 'action-forcing device to [e]nsure that the policies and goals defined in the Act are infused into the ongoing programs and actions of the Federal Government.'" *Or. Natural Desert Ass'n,* 531 F.3d at 1121 (quoting 40 C.F.R. § 1502.1).

An EIS must identify and analyze the direct, indirect, and cumulative effects of the proposed action. This requires more than "general statements about possible effects and some risk" or simply conclusory statements regarding the impacts of a project. *Klamath Siskiyou Wildlands Center v. BLM,* 387 F.3d 989, 995 (9th Cir. 2004) (citation omitted); *Oregon Natural Resources Council v. BLM,* 470 F.3d 818, 822-23 (9th Cir. 2006). Conclusory statements alone "do not equip a decisionmaker to make an informed decision about alternative courses of action or a court to review the Secretary's reasoning." *NRDC v. Hodel*, 865 F.2d 288, 298 (D.C. Cir. 1988).

NEPA also requires BLM to ensure the scientific integrity and accuracy of the information used in its decision-making. 40 CFR § 1502.24. The regulations specify that the agency "must insure that environmental information is available to public officials and citizens before decisions are made and before actions are taken. The information must be of high quality. Accurate scientific analysis, expert agency comments, and public scrutiny are essential." 40 C.F.R. § 1500.1(b). Where there is incomplete information that is relevant to the reasonably foreseeable impacts of a project and essential for a reasoned choice among alternatives, the BLM must obtain that information unless the costs of doing so would be exorbitant or the means of obtaining the information are unknown. 40 C.F.R. § 1502.22. Here the costs are reasonable to obtain information needed to complete the analysis and the BLM must provide additional information in the EIS—through a supplement or revised EIS. Even in those instances where complete data is unavailable, the EIS also must contain an analysis of the worst-case scenario resulting from the proposed project. *Friends of Endangered Species v. Jantzen*, 760 F.3d 976, 988 (9th Cir. 1985) (NEPA requires a worst case analysis when information relevant to impacts is essential and not known and the costs of obtaining the information are exorbitant or the means of obtaining it are not known) *citing Save our Ecosystems v. Clark*, 747 F.2d 1240, 1243 (9th Cir. 1984); 40 C.F.R. § 1502.22.

A. Purpose And Need and Project Description are Too Narrowly Construed and Unlawfully Segment the Analysis

1. Purpose and Need:

Agencies cannot narrow the purpose and need statement to fit only the proposed project and then shape their findings to approve that project without a "hard look" at the environmental consequences. To do so would allow an agency to circumvent environmental laws by simply "going-through-the-motions." It is well established that NEPA review cannot be "used to rationalize or justify decisions already made." 40 C.F.R. § 1502.5; *Metcalf v. Daley*, 214 F.3d 1135, 1141-42 (9th Cir. 2000) ("the comprehensive 'hard look' mandated by Congress and required by the statute must be timely, and it must be taken objectively and in good faith, not as an exercise in form over substance, and not as a subterfuge designed to rationalize a decision already made.") As Ninth Circuit noted an "agency cannot define its objectives in unreasonably narrow terms." *City of Carmel-by-the-Sea v. U.S. Dept. of Transportation*, 123 F.3d 1142, 1155 (9th Cir. 1997); *Muckleshot Indian Tribe v. U.S. Forest Service*, 177 F. 3d 900, 812 (9th Cir. 1999). The statement of purpose and alternatives are closely linked since "the stated goal of a project necessarily dictates the range of 'reasonable' alternatives." *City of Carmel*, 123 F.3d at 1155. The Ninth Circuit recently reaffirmed this point in *National Parks Conservation Assn v. BLM*, 586 F.3d 735, 746-48 (9th Cir. 2009) (holding that "[a]s a result of [an] unreasonably narrow purpose and need statement, the BLM necessarily considered an unreasonably narrow range of alternatives" in violation of NEPA).

The purpose behind the requirement that the purpose and need statement not be unreasonably narrow, and NEPA in general is, in large part, to "guarantee[ ] that the relevant information will be made available to the larger audience that may also play a role in both the decision-making process and the implementation of that decision." *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989). The agency cannot camouflage its analysis or avoid robust public input, because "the very purpose of a draft and the ensuing comment period is to elicit suggestions and criticisms to enhance the proposed project." *City of Carmel-by-the-Sea*, 123 F.3d at 1156. The agency cannot circumvent relevant public input by narrowing the purpose and need so that no alternatives can be meaningfully explored or by failing to review a reasonable range of alternatives.

The BLM's purpose and need for the proposed Genesis project is "respond to Genesis Solar, LLC's application under Title V of Federal Land Policy and Management Act, FLPMA (43 U.S.C. 1761) for a ROW grant to construct, operate, and decommission a solar thermal facility on public lands in compliance with FLPMA, BLM ROW regulations, and other Federal applicable laws." (DEIS at 6; *see also* DEIS at B.2-10 (same with NextEra)), and also states that the "BLM authorities include:

- Executive order 13212, dated May 18, 2001, which mandates that agencies act expediently and in a manner consistent with applicable laws to increase the "production and transmission of energy in a safe and environmentally sound manner."

• The Energy Policy Act 2005, which requires the Department of the Interior (BLM's parent agency) to approve at least 10,000 MW of renewable energy on public lands by 2015.

• Secretarial Order 3285, dated March 11, 2009, which "establishes the development of renewable energy as a priority for the Department of the Interior."

DEIS at 7. The DEIS notes that an amendment to the CDCA Plan is needed in order to approve the project but does not clearly identify the plan amendment as a part of the project being evaluated. Rather, the DEIS states: "If the BLM decides to approve the issuance of a ROW grant, the BLM will also amend the CDCA Plan as required." DEIS at 7. BLM's purpose and need is very narrowly construed to the proposed project itself and an amendment to the Plan *for the project only*. The purpose and need provided in the DEIS is impermissibly narrow under NEPA for several reasons, most importantly because it foreclosed meaningful alternatives review in the DEIS. Because the purpose and need and the alternatives analysis are at the "heart" of NEPA review and affect nearly all other aspects of the EIS, on this basis and others, BLM must revise and re-circulate the DEIS.

The DOE purpose and need statement provides:

> The Applicant has applied to the Department of Energy (DOE) for a loan guarantee under Title XVII of the Energy Policy Act of 2005 (EPAct 05), as amended by Section 406 of the American Recovery and Reinvestment Act of 2009, P.L. 111-5 (the "Recovery Act"). DOE is a cooperating agency on this EIS pursuant to an MOU between DOE and BLM signed in January 2010. The purpose and need for action by DOE is to comply with its mandate under EPAct by selecting eligible projects that meet the goals of the Act.

DEIS at 7.

In discussing the cumulative scenario, the DOE loan guarantee program is also described as one of the incentive programs for funding renewable energy projects:

> Example[s] of incentives for developers to propose renewable energy projects on private and public lands in California, Nevada and Arizona, include the following:
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> ● U.S. Treasury Department's Payments for Specified Energy Property in Lieu of Tax Credits under §1603 of the American Recovery and Reinvestment Act of 2009 (Public Law 1115) - Offers a grant (in lieu of investment tax credit) to receive funding for 30% of their total capital cost at such time as a project achieves commercial operation (currently applies to projects that begin construction by December 31, 2010 and begin commercial operation before January 1, 2017).

> ● U.S. Department of Energy (DOE) Loan Guarantee Program pursuant to §1703 of Title XVII of the Energy Policy Act of 2005 - Offers a loan guarantee that is also a low interest loan to finance up to 80% of the capital cost at an interest rate much lower than conventional financing. The lower interest rate can reduce the cost of financing and the gross project cost on the order of several hundred million dollars over the life of the project, depending on the capital cost of the project.

DEIS at B.3-2.

The Center is well aware that deadlines for funding, particularly for the American Recovery and Reinvestment Act ("ARRA") funds, have driven the pace of the environmental review for this project and others and, while such funding mechanisms are important, deadlines cannot be used as an excuse for rushed and inadequate NEPA review. The BLM and DOE must be concerned with the adequate NEPA review and even if the agencies can properly have an objective of *timely* approval of projects they cannot properly have as purpose and need of the project a *rushed* inadequate environmental impact review.

Moreover, in its discussion of the need for renewable energy production the DEIS fails to address risks associated with global climate change in context of including both the need for climate change mitigation strategies (e.g., reducing greenhouse gas emissions) and the need for climate change adaptation strategies (e.g., conserving intact wild lands and the corridors that connect them). All climate change adaptation strategies underline the importance of protecting intact wild lands and associated wildlife corridors as a priority adaptation strategy measure.

The habitat fragmentation, loss of connectivity for terrestrial wildlife, and introduction of predators and invasive weed species associated with the proposed project in the proposed location may run contrary to an effective climate change adaptation strategy. For example, this project includes a proposal for a new paved road cutting into previously undisturbed habitat and ending at the proposed project site which abuts a designated wilderness area. The proposed project will admittedly impact sand transport and habitat for the Mojave fringe-toed lizard and other species and proposes to use large amounts of pristine groundwater for wet-cooling which also threatens the long-term health of the local ecosystem as well as the groundwater resources of the Chuckwalla Valley and connected aquifers. Siting the proposed project in the proposed location impacting sand dune ecosystems, occupied habitat and important habitat linkage areas, major washes and other fragile desert resources could undermine a meaningful climate change adaptation strategy with a poorly executed climate change mitigation strategy. Moreover, the project itself will emit greenhouse gases and the DEIS contains no discussion of ways to avoid, minimize or off set these emissions although such mitigation is clearly feasible and other technologies have far less or no GHG emissions during operations are also likely to have fewer emissions when calculated on a lifecycle basis. The way to maintain healthy, vibrant ecosystems is not to fragment them and reduce their biodiversity.

2. Project Description

The project description remains incomplete in several ways. First, there is no clear description of the proposed expansion of the Colorado River substation or the impacts it would have. Second, is the outstanding issue of a second access road needed for public and worker safety. The DEIS discusses the need for a second access road but does not provide information about where it would be or the impacts it would have on the environment. The applicant recently suggested a "spur" road off the main proposed access road as the secondary access but it is not yet clear whether the local emergency management authorities in the County would accept this as providing sufficient safety for workers or the public. Moreover, those impacts were not discussed or analyze in the DEIS.

B. The DEIS Does Not Adequately Describe Environmental Baseline

BLM is required to "describe the environment of the areas to be affected or created by the alternatives under consideration." 40 CFR § 1502.15. The establishment of the baseline conditions of the affected environment is a practical requirement of the NEPA process. In *Half Moon Bay Fisherman's Marketing Ass'n v. Carlucci*, 857 F.2d 505, 510 (9th Cir. 1988), the Ninth Circuit states that "without establishing . . . baseline conditions . . . there is simply no way to determine what effect [an action] will have on the environment, and consequently, no way to comply with NEPA." Similarly, without a clear understanding of the current status of these public lands BLM cannot make a rational decision regarding proposed project. *See Center for Biological Diversity v. U.S. Bureau of Land Management, et al*., 422 F. Supp. 2d 1115, 1166-68 (N.D. Cal. 2006) (holding that it was arbitrary and capricious for BLM to approve a project based on outdated and inaccurate information regarding biological resources found on public lands).

The DEIS fails to provide adequate baseline information and description of the environmental setting in many areas including in particular the status of rare plants, animals and communities.

The baseline descriptions in the DEIS are inadequate particularly for the areas where surveys are ongoing. As discussed below, because of the deficiencies of the baseline data for the proposed project area, the DEIS fails to adequately describe the environmental baseline. Many of the rare and common but essential species and habitats have incomplete and/or vague on-site descriptions that make determining the proposed project's impacts difficult at best. Some of the rare species/habitats baseline conditions are totally absent, therefore no impact assessment is provided either. A supplemental document is required to fully identify the baseline conditions of the site, and that baseline needs to be used to evaluate the impacts of the proposed project.

C. Failure to Identify and Analyze Direct and Indirect Impacts to Biological Resources

The EIS fails to adequately analyze the direct, indirect, and cumulative impacts of the proposed project on the environment. The Ninth Circuit has made clear that NEPA requires agencies to take a "hard look" at the effects of proposed actions; a cursory review of environmental impacts will not stand. *Idaho Sporting Congress v. Thomas*, 137 F.3d 1146, 1150-52, 1154 (9th Cir. 1998). Where the BLM has incomplete or insufficient information, NEPA requires the agency to do the necessary work to obtain it where possible. 40 C.F.R. §1502.22; *see National Parks & Conservation Ass'n v. Babbitt,* 241 F.3d 722, 733 (9th Cir. 2001) ("lack of knowledge does not excuse the preparation of an EIS; rather it requires [the agency] to do the necessary work to obtain it.")

Moreover, BLM must look at reasonable mitigation measures to avoid impacts in the DEIS but failed to do so here. Even in those cases where the extent of impacts may be somewhat uncertain due to the complexity of the issues, BLM is not relieved of its responsibility under NEPA to discuss mitigation of reasonably likely impacts at the outset. Even if the discussion may of necessity be tentative or contingent, NEPA requires that the BLM provide some information regarding whether significant impacts could be avoided. *South Fork Band Council of Western Shoshone v. DOI* , 588 F.3d 718 , 727 (9th Cir. 2009).

The lack of comprehensive surveys is particularly problematic. Failure to conduct sufficient surveys prior to construction of the project also effectively eliminates the most important function of surveys - using the information from the surveys to minimize harm caused by the project and reduce the need for mitigation. Often efforts to mitigate harm are far less effective than preventing the harm in the first place. In addition, without understanding the scope of harm before it occurs, it is difficult to quantify an appropriate amount and type of mitigation.

The DEIS also acknowledges that additional special status species surveys will be conducted in 2010 surveys (DEIS at C.2-6). The results of those surveys are not available in the DEIS. Therefore, it is impossible to evaluate the potential impact of the proposed project based on the lack of adequate survey data.

The DEIS recognizes that the project is within a Wildlife Habitat Management Areas (WHMAs) as established under NECO – the Palen-Ford WHMA which was "specifically established to protect the dunes and playas (NECO sensitive habitat types) and the Mojave fringe-toed lizard". (DEIS at C.2-133). In addition numerous other large-scale industrial solar projects are proposed in the Palen-Ford WHMA. No mitigation is proposed to mitigate the identified losses specifically to the Palen-Ford WHMA.

1. *Desert Tortoise*

The desert tortoise has lived in the western deserts for tens of thousands of years. In the 1970's their populations were noted to decline. Subsequently, the species was listed as threatened by the State of California in 1989 and by the U.S. Fish and Wildlife Service in 1990, which then issued a Recovery Plan for the tortoise in 1994. The U.S. Fish and Wildlife Service is in the process of updating the Recovery Plan, and a Draft Updated Recovery Plan was issued in 2008, however it has not been finalized. Current data indicate a continued decline across the range of the listed species[2] despite its protected status and recovery actions.

[2] USFWS 2009

The original and draft Updated Recovery Plans both recognize uniqueness in desert tortoise populations in California. This particular subpopulation of tortoise at the proposed project site are part of the Eastern Colorado Recovery unit[3]. Recent population genetics studies[4] have further confirmed 1994 Recovery Plan conclusions the Eastern Colorado Recovery unit was one of the most genetically unique recovery units. While the proposed project site may have low desert tortoise densities (the DEIS fails to identify the actual number of desert tortoise estimated to be onsite), this particular recovery unit has also been documented to have the second highest declines in population over the last two years – 37% decline [5]. The DEIS fails to identify and consider the localized impact to this recovery unit that is already in steep decline.

While Bio-10 requires a Desert Tortoise Relocation/Translocation Plan (DEIS at pg. C.2-174), no desert tortoise relocation/translocation plan was included in the DEIS. Recent desert tortoise translocations have resulted in significant short-term mortality up to 45%[6] and unknown long-term survivorship. It is imperative to have this important plan available in the revised DEIS in order for the public and decision makers to be able to evaluate the effectiveness of the proposed strategies.

Mechanisms need to be included to assure that any and all mitigation acquisitions will be conserved in perpetuity for the conservation of the desert tortoise. If those acquisitions are within existing Desert Wildlife Management Areas (DWMAs), higher levels of protection than are currently in place for DWMAs need to be put in place. NEPA mandates consideration of the relevant environmental factors and environmental review of "[b]oth *short- and long-term* effects" in order to determine the significance of the project's impacts. 40 C.F.R. § 1508.27(a) (emphasis added). BLM has clearly failed to do so in this instance with respect to the impact to the desert tortoise.

The 1:1 mitigation ratio of desert tortoise habitat outside of critical habitat is actually inadequate to mitigate for the destruction of habitat. Mitigation presumes that acquisition will be appropriate tortoise habitat (occupied or unoccupied) which is currently existing and providing benefits to the species, to off-set the elimination of the proposed project site. However, this strategy is still *a net loss of habitat* to the desert tortoise, as currently they are using or could use both the mitigation site and the proposed project site. Therefore, in order to aid in recovery of this declining species, at a minimum a 2:1 mitigation ratio should be required as mitigation for the total elimination of desert tortoise habitat on the proposed project site.

If tortoises are relocated or translocated, then the relocation and/or translocation areas need to be secured for tortoise conservation, to preclude moving the animals subsequently if additional projects move forward on the relocation or translocation site(s).

2. Desert Bighorn Sheep and Burro Deer

[3] USFWS 1994
[4] Murphy et al. 2007
[5] USFWS 2009.
[6] Gowan and Berry 2010.

The DEIS completely dismisses any desert bighorn sheep and burro deer impacts from the proposed project because of the I-10 interstate. While we agree that the I-10 is currently a significant barrier to the movement of bighorn and burro deer (and other species), clearly the DEIS fails to evaluate the opportunity via the propose project to re-establish historic linkage for bighorn sheep and burro deer across the Chuckwalla Valley between the Palen-McCoy Mountains and the Chuckwalla Mountains (Bighorn WHMA). The DEIS simply proposes to add another significant block to bighorn and wildlife movement in the area, without considering ways to ameliorate or improve the existing conditions.

3. Mojave fringe-toed lizard/Sand dunes/Sand Transport System

The proposed project would directly impact 66 acres of Mojave fringe-toed lizard habitat and would interfere with part of a regional sand transport corridor, affecting approximately 453 acres of downwind sand dunes (DEIS at pg. C.2-62). The DEIS inappropriately considers the downwind impact to be indirect impacts, when actually they are direct impacts to habitat. While occupied habitat of stabilized and partially stabilized dunes and playa and sand drifts over playa are proposed to be mitigated at 3:1, the "indirect impacts to MFTL habitat" are only proposed to be mitigated at 0.5:1 (DEIS at pg C.2-65). Other solar energy projects proposed to impact Mojave fringe-toed lizard habitat have identified mitigation ratios of 5:1 and 3:1 for direct impacts to all occupied Mojave fringe-toed lizard habitat. The DEIS fails to identify why different mitigation ratios are being used in different areas, when clearly the direct impacts will affect all occupied habitat of Mojave fringe-toed lizards on the site, as well as directly impact down wind sand deposits as well.

The DEIS also fails to evaluate the impacts of the proposed project on Mojave fringe-toed lizard outside of the project site. As Barrows et al. (2006)[7] found, edge effects are significant for fringe-toed lizards and, in addition, the increase in predators associated with developed edges may also have a significant adverse effect on fringe-toed lizards and other species.

4. Rare and Special Status Plants

As mentioned above, the botanical surveys were one of the inadequate surveys identified, and 2010 surveys were/are being done (DEIS at C.2-3). These incomplete data sets preclude evaluation of the impacts, or more importantly the ability to design the project to avoid and minimize impacts. Clearly a supplemental DEIS is required to present these missing data.

5. Migratory Birds and Raptors

<u>Birds</u>

The DEIS downplays the fatalities that have been documented to occur from birds running into mirrors[8]. The proposed project site includes 60 acres of evaporation ponds (DEIS at ES-5), which also attract birds and small mammals. The DEIS does not quantify the number of

[7] Barrows et al. 2006
[8] McCrary 1986

birds (rare, migratory or otherwise) that use/traverse the project site from the avian point count surveys, nor does it evaluate the impact to birds. McCrary et al.[9] estimated 1.7 birds deaths per week on a 32 ha site with mirrors and a power tower configuration. The proposed project site is approximately 728 ha (over 20 times larger). While it is a solar trough technology and has a different kind of mirror and power plant configuration McCrary et al. evaluated, impacts to avian species from reflective surfaces and power lines[10] are also a concern. Once again, the DEIS incorrectly considers the impacts of collisions of birds into mirrors as indirect impacts (DEIS at C.2-63). The revised DEIS needs to analyze likely impacts to birds from the proposed project and mirror configuration based on the point counts. The failure to provide the baseline data from which to make any impact assessment violates NEPA. This failure to analyze impacts is not only a NEPA violation, but for migratory birds, may also lead to a violation of the Migratory Bird Treaty Act, 16 U.S.C. §§ 703 -711, because migratory birds may be "taken" if the proposed project is constructed. Bio-16 requires an Avian Protection Plan which is proposed to "monitor death and injury of birds from collisions with facility features such as reflective mirror-like surfaces and from heat, and bright light from concentrating sunlight, and to implement adaptive management measures to minimize such impacts" (DEIS at pg. C.2-183). However, the Avian Protection Plan is not available to the public and decision makers to allow an assessment of impacts to migratory birds.

Between sixty acres (DEIS at ES-5) and forty-eight acres (DEIS at C.2-95) – the DEIS gives conflicting information - of evaporation ponds are part of the project. While Bio-21 lays out a strategy for netting and monitoring the evaporation ponds, which we support, additional avoidance of impacts to wildlife should be included in the supplemental DEIS that places these ponds in the center of the solar facility, to minimize attraction to wildlife.

Additionally Executive Order 13186 states "Each Federal agency taking actions that have, or are likely to have, a measurable negative effect on migratory bird populations is directed to develop and implement, within 2 years, a Memorandum of Understanding (MOU) with the Fish and Wildlife Service (Service) that shall promote the conservation of migratory bird populations." [11] Furthermore the EO states that goals pursuant to the MOU include "3) prevent or abate the pollution or detrimental alteration of the Environment for the benefit of migratory birds, as practicable;" and "(6) ensure that environmental analyses of Federal actions required by the NEPA or other established environmental review processes evaluate the effects of actions and agency plans on migratory birds, with emphasis on species of concern;". Clearly, the supplemental DEIR needs to adequately identify the migratory bird issues on site and evaluate the impact to those species in light of the guidance in Executive Order 13186.

Burrowing Owls

The DEIS notes that two burrowing owls were located in the proposed project area (DEIS at C.2-79). Preliminary results from the 2006-7 statewide census identified that the Sonoran

[9] Ibid
[10] Klem 1990, Erickson et al. 2005
[11] http://ceq.hss.doe.gov/nepa/regs/eos/eo13186.html

desert harbors few Western burrowing owls.[12] The DEIS fails to evaluate the potential impact of the proposed project on this regional distribution of owls.

While "passive relocation" does minimize immediate direct take of burrowing owls, ultimately the burrowing owls' available habitat is reduced, and "relocated" birds are forced to compete for resources with other resident burrowing owls and may move into less suitable habitat, ultimately resulting in "take". While Bio-18 requires a Burrowing Owl mitigation plan, that plan is not provided. As with other species, the lack of these plans does not enable the evaluation of proposed mitigation. Additionally, the requirements of the plan do not explicitly include long-term monitoring of passively relocated birds in order to evaluate survivorship of passively relocated birds.

Golden Eagle

According to the DEIS, no golden eagles were documented on the project site and the nearest nest is identified as being 14 miles away from the proposed project. However, the Center is aware that subsequent surveys for golden eagle nests were conducted nests were found within 10 miles of the proposed project[13]. The DEIS fails to present exactly how to mitigate the loss of a substantial amount of foraging habitat for the golden eagle. The fact still remains that significant amounts of foraging habitat will decrease carrying capacity of the landscape and could result in a potential loss of habitat needed to support a nesting pair, which would impact reproductive capacity.

Scientific literature on this subject is clear - the presence of humans detected by a raptor in its nesting or hunting habitat can be a significant habitat-altering disturbance even if the human is far from an active nest[14]. Regardless of distance, a straight-line view of disturbance affects raptors, and an effective approach to mitigate impacts of disturbance for golden eagles involves calculation of viewsheds using a three-dimensional GIS tool and development of buffers based on the modeling[15]. Golden eagles have also been documented to avoid industrialized areas that are developed in their territory.[16] Additionally, the DEIS does not actually clearly analyze the impacts to and mitigations for the golden eagle under the Bald Eagle and Golden Eagle Protection Act, which prohibits, except under certain specified conditions, the take, possession, and commerce of such birds.

In addition, the potential impacts to eagles (and other birds) from the gen-tie line are not identified or analyzed including the potential for collisions and electrocution.

6. Badger and Desert Kit Foxes

Badgers and desert kit foxes were identified to occur throughout the project area (DEIS C.2-4). Literature on the highly territorial badger indicates that badger home territories range

[12] IBP 2008
[13] WRI 2010
[14] Richardson and Miller 1997
[15] Camp et al. 1997; Richardson and Miller 1997
[16] Walker et al. 2005

from 340 to 1,230 hectares[17]. Therefore, the proposed project could displace *at least* one badger territory. While surveys prior to construction are clearly essential, even passive relocation of badgers into suitable habitat may result "take". Excluding badger from the site is likely to cause badgers to move into existing badger's territory. The same scenario of passive relocation for kit fox may also result in "take". Studies need to be provided on both on- and off-site badger and kit fox territories if animals are to be passively relocated in order to increase their chances of persistence. At a minimum, the revised or supplemental DEIS should identify suitable habitat nearby if the project is relying on passive relocation as a mitigation strategy in order to get the animals to move into the best available habitat.

7. Cryptobiotic soil crusts and Desert Pavement

The proposed project is located in the Mojave Desert Air Quality Management District area, which is already in non-attainment for PM-10 particulate matter[18]. The construction of the proposed project further increases emissions of these types of particles because of the disruption and elimination of potentially hundreds of acres of cryptobiotic soil crusts. Cryptobiotic soil crusts are an essential ecological component in arid lands. They are the "glue" that holds surface soil particles together precluding erosion, provide "safe sites" for seed germination, trap and slowly release soil moisture, and provide CO_2 uptake through photosynthesis[19].

The FEIS does not describe the on-site cryptobiotic soil crusts. The proposed project will disturb an unidentified portion of these soil crusts and cause them to lose their capacity to stabilize soils and trap soil moisture. The DEIS fails to provide a map of the soil crusts over the project site, and to present any avoidance or minimization measures. It is unclear how many acres of cryptobiotics soils will be affected by the project. The DEIS must identify the extent of the cryptobiotic soils on site and analyze the potential impacts to these diminutive, but essential desert ecosystem components as a result of this project.

While desert pavements are mentioned as occurring on the proposed project site (DEIS at C.9-44), quantitative acreage of pavement are not identified. Disruption of these stabilized soils could have significant impacts on air quality. The impact to air quality from disturbance of desert pavement is not analyzed.

8. Insects

The DEIS fails to address insects on the proposed project site. In fact no surveys or evaluation of rare or common insects are included in the DEIS. Dune habitats are notorious for supporting endemic insects, typically narrow habitat specialists[20].

9. Bats

While no bats were noted on site during general wildlife surveys, no bat-specific surveys were undertaken. With the introduction of 48-60 acres of evaporation ponds, bats may actually

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[17] Long 1973, Goodrich and Buskirk 1998

[18] http://www.mdaqmd.ca.gov/index.aspx?page=214

[19] Belnap 2003, Belnap et al 2003, Belnap 2006, Belnap et al. 2007

[20] Dunn 2005.

be attracted to the proposed project site. The mitigation measure proposed for netting ponds may help to preclude bats from using the ponds also. However, smaller gauge netting may be more useful in keeping bats out of the ponds. Alternatively, for many reasons, the proposed project should be a dry cooled project, minimizing the amount of water and evaporation ponds required. Regardless, no analysis of the impacts to bats is provided in the DEIS. At a minimum, after the analysis is provided in the supplemental DEIS, a Bat Protection Plan needs to be required.

10. Decommissioning and Reclamation Plan

Desert lands are notoriously hard to revegetate or rehabilitate[21] and revegetation never supports the same diversity that originally occurred in the plant community prior to disturbance[22]. The task of revegetating almost eleven square miles will be a Herculean effort that will require significant financial resources. In order to assure that the ambitious goals of the revegetation effort is met post project closure, it will be necessary to bond the project, so that all revegetation obligations will be met and assured. The bond needs to be structured so that it is tied to meeting the specific revegetation criteria.

The project will cause permanent impacts to the on-site plant communities and habitat for wildlife despite "revegetation", because the agency's regulations based on the Northern and Eastern Colorado Plan's rehabilitation strategies[23] only requires 40% of the original density of the "dominant" perennials, only 30% of the original cover. Dominant perennials are further defined as "any combination of perennial plants that originally accounted cumulatively for at least 80 percent of relative density".[24] These requirements fail to truly "revegetate" the plant communities to their former diversity and cover even over the long term. While Bio-23 requires the development of a Decommissioning Plan, that plan is not available for public review. In fact, the DEIS states that "The Applicant's Draft Decommissioning and Closure Plan (Worley Parsons 2010b) provides some of the information requested by staff, but does not include a conceptual revegetation plan that could be used to guide reclamation of the Project site after closure and decommissioning, nor does it provide sufficient information to develop an estimate of the funding needed for those activities" DEIS at C.2-101. BLM's own regulations 43 CFR 3809.550 et seq. require a detailed reclamation plan and a cost estimate, they need to be included in the revised EIS. A comprehensive decommissioning plan must be developed for the whole project site. This plan must be included in the revised or supplement DEIS in order to evaluate its effectiveness as mitigation.

11. Fire Plan

Fire in desert ecosystems is well documented to cause catastrophic landscape scale changes[25] and impacts to the local species[26]. The DEIS mentions the impacts of fire via the

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[21] Lovich and Bainbridge 1999
[22] Longcore 1997
[23] http://www.blm.gov/ca/st/en/fo/cdd/neco.html
[24] Ibid
[25] Brown and Minnich 1986, Lovich and Bainbridge 1999, Brooks 2000, Brooks and Draper 2006, Brooks and Minnich 2007

proliferation of nonnative weeds (DEIS at C.2-21), it fails to analyze the impacts of fire on adjacent natural desert habitat. The DEIS fails to adequately analyze the impact that an escaped fire originated from the proposed project could have on the natural lands adjacent to the project site if it escaped from the site. The DEIS also fails to address the mitigation of this potential impact. Instead it defers it to the Worker Environmental Awareness Program (WEAP) and only requires "a discussion of fire prevention measures to be implemented by workers during project activities" (DEIS at C.2-164). A fire prevention and protection plan needs to be developed and required to prevent the escape of fire onto the adjacent landscape (avoidance), lay out clear guidelines for protocols if the fire does spread to adjacent wildlands (minimization) and a revegetation plan if fire does occur on adjacent lands originating from the project site (mitigation) or caused by any activities associated with construction or operation of the site even if the fire originates off of the project site.

12. Failure to Identify Appropriate Mitigation

Because the DEIS fails to provide adequate identification and analysis of impacts, inevitably, it also fails to identify adequate mitigation measures for the project's environmental impacts. "Implicit in NEPA's demand that an agency prepare a detailed statement on 'any adverse environmental effects which cannot be avoided should the proposal be implemented,' 42 U.S.C. § 4332(C)(ii), is an understanding that an EIS will discuss the extent to which adverse effects can be avoided." *Methow Valley*, 490 U.S. at 351-52. Because the DEIS does not adequately assess the project's direct, indirect, and cumulative impacts, its analysis of mitigation measures for those impacts is necessarily flawed. The DEIS must discuss mitigation in sufficient detail to ensure that environmental consequences have been fairly evaluated." *Methow Valley*, 490 U.S. at 352; *see also Idaho Sporting Congress*, 137 F.3d at 1151 ("[w]ithout analytical detail to support the proposed mitigation measures, we are not persuaded that they amount to anything more than a 'mere listing' of good management practices"). As the Supreme Court clarified in *Robertson*, 490 U.S. at 352, the "requirement that an EIS contain a detailed discussion of possible mitigation measures flows both from the language of [NEPA] and, more expressly, from CEQ's implementing regulations" and the "omission of a reasonably complete discussion of possible mitigation measures would undermine the 'action forcing' function of NEPA."

Although NEPA does not require that the harms identified actually be mitigated, NEPA does require that an EIS discuss mitigation measures, with "sufficient detail to ensure that environmental consequences have been fairly evaluated" and the purpose of the mitigation discussion is to evaluate whether anticipated environmental impacts *can be avoided*. *Methow Valley*, 490 U.S. at 351-52. As the Ninth Circuit recently noted: "[a] mitigation discussion without at least *some* evaluation of effectiveness is useless in making that determination." *South Fork Band Council of Western Shoshone v. DOI* , 588 F.3d 718 , 727 (9th Cir. 2009) (emphasis in original).

Here, the DEIS does not provide a full analysis of possible mitigation measures to avoid or lessen the impacts of the proposed project and therefore the BLM cannot properly assess the likelihood that such measures would actually avoid the impacts of the proposed project.

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[26] Dutcher 2009

D. Key Plans Not Included

The DEIS fails to include key plans for public review. Plans identified in the DEIS and relied upon for adequate mitigation but which are unavailable include:

- Weed Management Plan (DEIS at C.2-181)
- Biological Resources Mitigation Implementation and Monitoring Plan (DEIS at C.2-165)
- Raven Management and Monitoring Plan (DEIS at C.2-181)
- Detailed revegetation plan for temporary disturbance (DEIS at C.2-198)
- Decommissioning and Reclamation Plan (for permanent closure) (DEIS at C.2-197)
- Burrowing Owl Mitigation and Monitoring Plan (DEIS at C.2-185)
- Avian Protection Plan (DEIS at C.2-183)
- Desert Tortoise Relocation/Translocation Plan (DEIS at C.2-174)
- Management Plan for Compensatory Mitigation Lands (DEIS at C.2-192) for tortoise, fringe-toed lizards, drainages etc.
- Special-status Plant Impact Avoidance and Mitigation Plan (DEIS at C.2-187)
- Ground Water Dependent Vegetation Monitoring Plan (DEIS at C.2-199), which should include a remedial action plan if vegetation shows signs of stress
- Couch's Spadefoot Toad Protection and Mitigation Plan (DEIS at C.2-202)

Plans that are not currently required but need to be included:

- Compensatory Mitigation Plan for State Waters
- Desert Tortoise Compensatory Mitigation Plan
- Bat Protection Plan
- Plan for restoring sheet flow to the terrain downslope of the Project boundaries
- Management Plan for Sand Dune/Fringe-toed Lizard
- Fire Plan

All of these plans are key components to evaluating the avoidance, minimization and mitigation to biological resources by the proposed project. Some of these plans were submitted to agencies in draft form, but were not included in the DEIS. Their absence makes it impossible to evaluate the impacts from the proposed project. Each of these plans needs to be included in the supplemental EIS.

E. Impacts to Water Resources— Surface and Groundwater Water Impacts

As the DEIS notes, the proposed project is on an alluvial fan and it may impact a large number of small braided washes and ephemeral streams. DEIS at C.9-1, C.9-35 to 36. These areas provide important habitat values that will be completely lost by the grading proposed for the project site. Moreover, the loss of natural surface water flows and the re-direction of surface waters will have significant impacts to the dunes ecosystems nearby. The impacts on soils and particularly on sand transport from the proposed project have not been adequately addressed in the DEIS.

The Center urges the BLM not to approve any large-scale solar projects in the California Desert that would use wet-cooling as proposed here. The proposal to use an average of 1,644 acre-feet/yr and nearly 50,000 acre-feet over the 30-year life of the project is excessive and wasteful. DEIS at C.9-5.[27] Wet-cooling is also entirely unnecessary as evidenced by other project proposals with similar trough technology that are proposed with dry cooling and would use far less water (e.g. Palen and Blythe) as well as PV alternatives which would use even less water. The Center sponsored testimony for the CEC hearings from hydrologist Tom Myers PhD (Attachment 1) shows that the DEIS overestimates recharge in this area and underestimates the impacts of groundwater pumping under the wet-cooling alternative.

Even with the dry cooling alternative, the amount of water use by the proposed project will be significant in this arid area and the DIES does not contain sufficient information to show that surface resources on other public lands will not be affected by the drawdown of the water table *over the life of the project*. Moreover, the cumulative impacts to groundwater resources from this project and others in the area could be significant annually and over the life of the project.

Reserved Water Rights: As BLM is well aware, the California Desert Protection Act ("CDPA") expressly reserved water rights for wilderness areas that were created under the act including the Palen-McCoy Wilderness and others. 16 U.S.C. §410aaa-76.[28] The CDPA reserved sufficient water to fulfill the purposes of the Act which include to "preserve unrivaled scenic, geologic, and wildlife values associated with these unique natural landscapes," "perpetuate in their natural state significant and diverse ecosystems of the California desert," and "retain and enhance opportunities for scientific research in undisturbed ecosystems." 103 P.L. 433, Sec. 2. The priority date of such reserved water rights is 1994 when the CDPA was enacted. Therefore, at minimum, the BLM must ensure that use of water for the proposed project (and cumulative projects) *over the life of the proposed projects* will not impair those values in the wilderness that depend on water resources (including perennial, seasonal, and ephemeral creeks, springs and seeps as well as any riparian dependent plants and wildlife), including the McCoy Spring which is located within a wilderness area.

The conclusory statements in the DEIS that the use of large amounts of groundwater will not affect McCoy Spring or other water resources are based on conjecture alone and are not adequately supported with data or analysis. DEIS at C.9-36 ("McCoy Spring and Chuckwalla Spring are perennial springs; however, there is no information available regarding the discharge quantity for these springs.") NEPA requires that where there is incomplete information that is relevant to the reasonably foreseeable impacts of a project and essential for a reasoned choice among alternatives, the BLM must obtain that information unless the costs of doing so would be exorbitant or the means of obtaining the information are unknown. 40 C.F.R. § 1502.22. Here the costs are reasonable to obtain information needed regarding these springs and any other

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[27] Using large amounts of water for cooling will also lead to large amounts of evaporative residue "Approximately 6,150 tons of evaporative residue will be accumulated yearly, which equates to approximately 50,000 tons of evaporative residue being removed during each cleanout and a total estimated amount of 214,500 tons over 30 years." DEIS at C.9-52. The removal and disposal of this waste has not been adequately addressed in the DEIS and is entirely avoidable by the use of dry-cooling.

[28] The reservation excluded two wilderness areas with regard to Colorado River water. See 103 P.L. 433; 108 Stat. 4471; 1994 Enacted S. 21; 103 Enacted S. 21, SEC. 204. COLORADO RIVER. ("With respect to the Havasu and Imperial wilderness areas designated by subsection 201(a) of this title, no rights to water of the Colorado River are reserved, either expressly, impliedly, or otherwise.")

nearby springs and to complete the analysis and therefore the BLM must provide additional information in the EIS—through a supplement or revised EIS. The irreplaceable water resources of the CDCA must be protected by the BLM under existing law.

Even where no *express* reservation of rights has been made for waters that are essential to the resources of public lands in the CDCA, the DEIS should have addressed the federal reserved water rights afforded to the public to protect surface water sources on all public lands affected by the proposed project. Pursuant to Public Water Reserve 107 ("PWR 107"), established by Executive Order in 1926, government agencies cannot authorize activities that will impair the public use of federal reserved water rights.

PWR 107 creates a federal reserved water right in water flows that must be maintained to protect public water uses. *U.S. v. Idaho*, 959 P.2d 449,453 (Idaho, 1998) *cert. denied; Idaho v. U.S.* 526 U.S. 1012 (1999); *Cappaert v. U.S.*, 426 U.S. 128, 145 (1976). PWR 107 applies to reserve water that supports riparian areas, reserve water that provides flow to adjacent creeks and isolated springs that are "nontributary" or which form the headwaters of streams. *U.S. v. City & County of Denver*, 656 P.2d 1, 32 (Colo., 1982). Accordingly, BLM cannot authorize activities that will impair the public use of reserved waters covered by PWR 107.

BLM must examine the federal reserved water rights within the area affected by the proposed project and other proposed projects in this area that will cumulatively use significant amounts of groundwater. This examination must include a survey of the any water sources potentially affected by the proposed project. The BLM must ensure that any springs, seeps, creeks or other water sources on public land and particularly within the wilderness areas are not degraded by the proposed projects' use of water and continue meet the needs of the existing wildlife and native vegetation that depend on those water resources.

PWR 107 also protects the public lands on which protected water sources exist. Accordingly, BLM should not only consider the impact of the proposed project's excessive use of groundwater on water sources present on public lands, but also the direct and indirect impacts of the proposed project's excessive and unnecessary use of groundwater on the surrounding lands as well as impacts to the ecosystem as a whole.

The Center is also concerned that the discussion in the DEIS is also incomplete because it fails to address any potential water rights that could arguably be created from use of any amount of groundwater by the proposed project on these public lands. While the Center recognizes that this issue may involve somewhat complex legal issues, at minimum, the BLM must address this question and to ensure that any water rights that could *arguably* be created will be conveyed back to the BLM owner and run with the land at the end of the proposed project ROW term. The BLM must provide a mechanism to insure that in no case will the use of water for the proposed project on these public lands result in water rights accruing to the project applicant that it could arguably convey to any third party. Therefore, any water rights *arguably* created by groundwater pumping on these public lands for the proposed project must not ultimately accrue to any third party for use *off-site or on-site* in the future for any other project. Moreover, BLM should ensure that the applicant will not use the groundwater associated with the project off-site for any purpose.

In sum, the wet-cooling alternative would waste water resources (in violation of California law) and significantly impact resources of these public lands. These impacts have not been adequately or accurately identified or analyzed in the DEIS in violation of NEPA and other laws.

F. The DEIS Fails to Adequately Identify, Analyze and Off-set Impacts to Air Quality and GHG Emissions.

Federal courts have squarely held that NEPA requires federal agencies to analyze climate change impacts. *Center for Biological Diversity v. National Highway Traffic Safety Administration*, 508 F.3d 508 (9th Cir. 2007). As most relevant here, NEPA requires consideration of greenhouse gas emissions ("GHG emissions") associated with all projects and, in order to fulfill this requirement the agencies should look at all aspects of the project which may create greenhouse gas emissions including operations, construction, and life-cycle emissions from materials. Where a proposed project will have significant GHG emissions, the agency should identify alternatives and/or mitigation measures that will lessen such effects.

As part of the NEPA analysis federal agencies must assess and, wherever possible, quantify or estimate GHG emissions by type and source by analyzing the direct operational impacts of proposed actions. Assessment of direct emissions of GHG from on-site combustion sources is relatively straightforward. For many projects, as with the proposed project, energy consumption will be the major source of GHGs. The indirect effects of a project may be more far-reaching and will require careful analysis. Within this category, for example, the BLM should evaluate, GHG and GHG-precursor emissions associated with construction, electricity use, fossil fuel use, water consumption, waste disposal, transportation, the manufacture of building materials (lifecycle analysis), and land conversion. Moreover, because many project may undermine or destroy the value of carbon sinks, including desert soils, projects may have additional indirect effects from reduction in carbon sequestration, therefore both the direct and quantifiable GHG emissions as well as the GHG effects of destruction of carbon sinks should be analyzed.

The discussion of greenhouse gas emissions ("GHG") in the DEIS notes that the solar project will produce GHGs primarily from the auxiliary gas boilers (however the emissions from the Heat Transfer Fluid ("HTF") heaters are not listed). The GHG emissions from the boilers during project operations is estimated to be 3,520 metric tons CO2 equivalent (however the emissions from the HTF heaters are not listed), with the metric tons CO2 equivalent annually for total operations emissions (including all sources) of 4,133 metric tons CO2 equivalent annually. DEIS at C.1-73 (Greenhouse gas table 3). The boilers and heaters are stated to be for start up or freeze protection(DEIS at C.1-73), but the DEIS assumes that they may be allowed to be used for very long periods of time – up to 14 hours per day for the boilers up to 1,000 hours per year. *See* DEIS at C.1-52 (no clear limits on the HTF heaters is provided). With an average of 3 hours per day of use the limits for the auxiliary heaters appear to be reasonably in line with the use for start up however no clear explanation is provided regarding the GHG produced by the HTF heaters or the likely time period for use of such heaters. The DEIS also fails to adequately explore whether an alternative solar technology (such as PV) would reduce greenhouse gas emissions both during operations and over the life-cycle of the components of the proposed project. There is no discussion of reducing these sources by using alternative fuels or highly efficient vehicles and equipment on site and no discussion of providing off sets for these GHG emissions.

Another GHG emission source for this proposed project is SF6 from electrical equipment leakage. DEIS at C.1-73. However, the DEIS does not mention additional sources of SF6 from transmission lines associated with the project. Moreover, leakage of SF6 is of particular concern as it is many times more potent greenhouse gas than CO2—indeed, its potential as a GHG has been estimated at 23,900 times that of CO2 (for a 100 year time horizon) and it can persist in the atmosphere far longer than CO2 as well—up to 3,200 years.[29] The DEIS fails to state the actual amount of SF6 that is estimated to leak from equipment and provides only that 3.4 MTCO2E is expected in emissions each year. No information is provided on the calculation. Moreover, the DEIS does not analyze any alternatives to avoid or minimize the long-term emissions of this powerful GHG from operations and no mitigation measures are provided. The DEIS also does not explain if the figure includes SF6 leakage associated with the gen-tie line or not.

The GHG emissions from the construction phase of the project are stated to be over 52,974 metric tons CO2 equivalent (Greenhouse gas table 2, DEIS C.1-72). Again, there is no discussion of reducing these emissions by using more efficient equipment or vehicles during construction.

The DEIS also fails to adequately address other air quality issues including PM10 both during construction and operation which is of particular concern in this area which is a nonattainment area for PM10 and ozone. It is clear that extensive on-site grading will result in significant amounts of bare soils and increased PM10 may be introduced into the air by wind and that the use of the area during construction and operations will lead to additional PM10 emissions from the site. Although some mitigation measures are suggested they are not specific and enforceable and because the extent of the impact has not been adequately addressed as an initial matter there is no way to show that the mitigation measures proffered will reduce the impacts to less than significance.

BLM fails to identify any significant GHG emissions and therefore does not provide for avoidance, minimization, or mitigation. BLM has also failed to include the loss of carbon sequestration from soils in its calculations or to provide a lifecycle analysis of GHG emissions that include manufacturing and disposal. Moreover, it is undisputed that in the near-term GHG emissions will increase emissions during construction, and in the manufacturing and transportation of the components. BLM fails to consider any alternatives to the project that would minimize such emissions or to require that these near-term emissions be off set in any way.

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[29] P. Forster et al., *Changes in Atmospheric Constituents and in Radiative Forcing, in* CLIMATE CHANGE 2007: THE PHYSICAL SCIENCE BASIS. CONTRIBUTION OF WORKING GROUP I TO THE FOURTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (Solomon, S., et al. eds., Cambridge University Press 2007) at p. 212, Table 2.14.

Although the proposed project may reduce GHG's overall it will also emit GHGs during both construction and operations that are not accounted for or off-set, BLM completely fails to explore this aspect of the impacts of the project in the DEIS in violation of NEPA.

G. The Analysis of Cumulative Impacts in the DEIS Is Inadequate

A cumulative impact is "the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time." 40 C.F.R. § 1508.7. The Ninth Circuit requires federal agencies to "catalogue" and provide useful analysis of past, present, and future projects. *City of Carmel-By-The-Sea v. U.S. Dept. of Transp.*, 123 F.3d 1142, 1160 (9th Cir. 1997); *Muckleshoot Indian Tribe v. U.S. Forest Service*, 177 F.3d 800, 809-810 (9th Cir. 1999).

"In determining whether a proposed action will significantly impact the human environment, the agency must consider '[w]hether the action is related to other actions with individually insignificant but cumulatively significant impacts. Significance exists if it is reasonable to anticipate a cumulatively significant impact on the environment.' 40 C.F.R. § 1508.27(b)(7)." *Oregon Natural Resources Council v. BLM,* 470 F.3d 818, 822-823 (9th Cir. 2006). NEPA requires that cumulative impacts analysis provide "some quantified or detailed information," because "[w]ithout such information, neither courts nor the public . . . can be assured that the Forest Service provided the hard look that it is required to provide." *Neighbors of Cuddy Mountain v. United States Forest Service*, 137 F.3d 1372, 1379 (9th Cir. 1988); *see also id*. ("very general" cumulative impacts information was not hard look required by NEPA). The discussion of future foreseeable actions requires more than a list of the number of acres affected, which is a necessary but not sufficient component of a NEPA analysis; the agency must also consider the actual environmental effects that can be expected from the projects on those acres. *See Klamath-Siskiyou Wildlands Ctr. v. BLM*, 387 F.3d 989, 995-96 (9th Cir. 2004) (finding that the environmental review documents "do not sufficiently identify or discuss the incremental impact that can be expected from each [project], or how those individual impacts might combine or synergistically interact with each other to affect the [] environment. As a result, they do not satisfy the requirements of the NEPA.") Finally, cumulative analysis must be done as early in the environmental review process as possible, it is not appropriate to "defer consideration of cumulative impacts to a future date. 'NEPA requires consideration of the potential impacts of an action *before* the action takes place.'" *Neighbors*, 137 F.3d at 1380 *quoting City of Tenakee Springs v. Clough*, 915 F.2d 1308, 1313 (9th Cir. 1990) (emphasis in original).

The DEIS identifies many of the cumulative projects but does not meaningfully analyze the cumulative impacts to resources in the California desert from the many proposed projects (including renewable energy projects and others). Moreover, because the initial identification and analysis of impacts unfinished, the cumulative impacts analysis cannot be complete. For example, the identification of plant communities on site is unfinished and incomplete as is the evaluation of the impacts of the second access road and the Colorado River substation expansion, the cumulative impacts are also therefore inadequate.

The DEIS also fails to consider all reasonably foreseeable impacts in the context of the cumulative impacts analysis. *See Native Ecosystems Council v. Dombek, et al,* 304 F.3d 886 (9th Cir. 2002) (finding future timber sales and related forest road restriction amendments were "reasonably foreseeable cumulative impacts"). The DEIS also fails to provide the needed analysis of how the impacts might combine or synergistically interact to affect the environment in this valley or region. *See Klamath-Siskiyou Wildlands Ctr. v. BLM*, 387 F.3d 989, 995-96 (9th Cir. 2004).

The NEPA regulations also require that indirect effects including changes to land use patterns and induced growth be analyzed. "Indirect effects," include those that "are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable. Indirect effects may include *growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems*." 40 C.F.R. s.1508.8(b) (emphasis added). *See TOMAC v. Norton*, 240 F. Supp.2d 45, 50-52 (D.D.C. 2003) (finding NEPA review lacking where the agency failed to address secondary growth as it pertained to impacts to groundwater, prime farmland, floodplains and stormwater run-off, wetlands and wildlife and vegetation); *Friends of the Earth v. United States Army Corps of Eng'rs*, 109 F. Supp.2d 30, 43 (D.D.C. 2000) (finding NEPA required analysis of inevitable secondary development that would result from casinos, and the agency failed to adequately consider the cumulative impact of casino construction in the area); *see also Mullin v. Skinner*, 756 F. Supp. 904, 925 (E.D.N.C. 1990) (Agency enjoined from proceeding with bridge project which induced growth in island community until it prepared an adequate EIS identifying and discussing in detail the direct, indirect, and cumulative impacts of and alternatives to the proposed Project); *City of Davis v. Coleman*, 521 F.2d 661 (9th Cir. 1975) (requiring agency to prepare an EIS on effects of proposed freeway interchange on a major interstate highway in an agricultural area and to include a full analysis of both the environmental effects of the exchange itself and of the development potential that it would create).

Among the cumulative impacts to resources that have not been fully analyzed are impacts to desert tortoise, impacts to Mojave fringe-toed lizard and sand dunes ecosystems, impacts to golden eagles, and impacts to water resources. The cumulative impacts to the resources of the California deserts has not been fully identified or analyzed, and mitigation measures have not been fully analyzed as well.

H. The EIS' Alternatives Analysis is Inadequate

NEPA requires that an EIS contain a discussion of the "alternatives to the proposed action." 42 U.S.C. §§ 4332(C)(iii),(E). The discussion of alternatives is at "the heart" of the NEPA process, and is intended to provide a "clear basis for choice among options by the decisionmaker and the public." 40 C.F.R. §1502.14; *Idaho Sporting Congress*, 222 F.3d at 567 (compliance with NEPA's procedures "is not an end in itself . . . [but] it is through NEPA's action forcing procedures that the sweeping policy goals announced in § 101 of NEPA are realized.") (internal citations omitted). NEPA's regulations and Ninth Circuit case law require the agency to "rigorously explore" and objectively evaluate "all reasonable alternatives." 40 C.F.R. § 1502.14(a) (emphasis added); *Envtl. Prot. Info. Ctr. v. U.S. Forest Serv.*, 234 Fed.

Appx. 440, 442 (9th Cir. 2007). "The purpose of NEPA's alternatives requirement is to ensure agencies do not undertake projects "without intense consideration of other more ecologically sound courses of action, including shelving the entire project, or of accomplishing the same result by entirely different means." *Envtl. Defense Fund, Inc. v. U.S. Army Corps of Engrs.*, 492 F.2d 1123, 1135 (5th Cir. 1974). An agency will be found in compliance with NEPA only when "all reasonable alternatives have been considered and an appropriate explanation is provided as to why an alternative was eliminated." *Native Ecosystems Council v. U.S. Forest Serv.*, 428 F.3d 1233, 1246 (9th Cir. 2005); *Bob Marshall Alliance v. Hodel*, 852 F.2d 1223, 1228-1229 (9th Cir. 1988). The courts, in the Ninth Circuit as elsewhere, have consistently held that an agency's failure to consider a reasonable alternative is fatal to an agency's NEPA analysis. *See, e.g., Idaho Conserv. League v. Mumma*, 956 F.2d 1508, 1519-20 (9th Cir. 1992) ("The existence of a viable, but unexamined alternative renders an environmental impact statement inadequate.").

If BLM rejects an alternative from consideration, it must explain why a particular option is not feasible and was therefore eliminated from further consideration. 40 C.F.R. § 1502.14(a). The courts will scrutinize this explanation to ensure that the reasons given are adequately supported by the record. *See Muckleshoot Indian Tribe v. U.S. Forest Service*, 177 F.3d 800, 813-15 (9th Cir. 1999); *Idaho Conserv. League*, 956 F.2d at 1522 (while agencies can use criteria to determine which options to fully evaluate, those criteria are subject to judicial review); *Citizens for a Better Henderson*, 768 F.2d at 1057.

Here, BLM too narrowly construed the project purpose and need such that the DEIS did not consider an adequate range of alternatives to the proposed project. Moreover, the project description remains incomplete as there is the outstanding issue of a second access road. The applicant recently suggested a "spur" road off the main proposed access road but it is not yet clear whether the local emergency management authorities in the County would accept this as providing sufficient safety for workers or the public.

The alternatives analysis is inadequate even with the inclusion of a reduced acreage alternative and the dry cooling alternative. Additional feasible alternatives should be considered which would avoid all of the dunes habitat as well as alternatives that would have looked at alternative sites for the Colorado River substation to avoid impacts to additional resources. In addition a phased alternative should have been included which would allow the portions of the project that have the fewest impacts to move forward while also affording the project proponent time to find and acquire permits for more appropriate sites for one or more additional phases of the project reconfigured on other BLM lands or on previously degraded disturbed lands in this area (for example such as the lands discussed in the Gabrych Alternative) and also to explore other off-site alternatives.

The document also includes other alternatives that were stated as being "Site Alternatives Evaluated only under CEQA" which includes the proposed site and one off-site alternative – the Gabrych Alternative which is on active farmland in the Blythe area. The document eliminated from consideration a distributed renewable energy alternative. The BLM (as well as the CEC) should have also looked alternative siting on previously degraded lands such as nearby farmlands, distributed solar alternatives, and other alternatives that could avoid impacts of the proposed project as well as impacts of the associated transmission lines and substations. In addition, as discussed above, the BLM should have looked at alternatives for construction and operations that would reduce GHG emissions by using alternative technology and/or on site conservation measures and offsets. The Center sponsored testimony from Bill Powers in the CEC process (Attachment 2) which shows that a distributed PV alternative is viable and should have been fully considered in the DEIS.

The BLM failed to consider any off-site alternative that would significantly reduce the impacts to biological resources including dunes ecosystems, key movement corridors, golden eagles, and others. Because such alternatives are feasible, on this basis and other the range of alternatives is inadequate. The Center urges the BLM to revise the DEIS to adequately address a range of feasible alternatives and other issues detailed above and then to re-circulate a revised or supplemental DEIS for public comment.

In addition, in order to meet the DOE's purpose and need states that: "The two principal goals of the loan guarantee program are to encourage commercial use in the United States of new or significantly improved energy-related technologies and to achieve substantial environmental benefits. The purpose and need for action by DOE is to comply with their mandate under EPAct by selecting eligible projects that meet the goals of the Act." DEIS at B.2-11. Assuming for the sake of argument alone that these are proper project objectives, the DEIS should have considered alternatives that would provide funding to other types of projects. Such alternatives could include, for example, conservation and efficiency measures that both avoid and reduce energy use within high-energy use load-centers including the Los Angeles area and the Inland Empire.

Alternative measures could include funding community projects for training and implementation of conservation measures such as increased insulation, sealing and caulking, and new windows for older buildings and new or improved technologies for accomplishing these important goals. For example, air conditioning creates the largest demand for energy during peak times and there already exist methods to reduce the energy use from air conditioning but implementation has lagged well behind technology. Conservation and efficiency measures are an excellent and quick way of reducing demand in both the short- and long-term and reduce the need for additional power sources. In addition, many of the existing conservation and efficiency measures can provide immediate jobs and training in high population areas with significant unemployment (particularly among low skilled workers and youth).

The existence of these and other feasible but unexplored alternatives shows that the BLM's analysis of alternatives in the DEIS is inadequate.

IV. Conclusion

Thank you for your consideration of these comments. In light of the many omissions in the environmental review to date, we urge the BLM to revise and re-circulate the DEIS or prepare a supplemental DEIS before making any decision regarding the proposed plan amendment and right-of-way application. In the event BLM chooses not to revise the DEIS and provide adequate analysis, the BLM should reject the right-of-way application and the plan amendment. Please feel free to contact us if you have any questions about these comments or the documents provided.

Sincerely,

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Attachment 1: Testimony of Tom Myers and exhibits (exhibits provided on CD)
Attachment 2: Testimony of Bill Powers and exhibits (exhibits provided on CD)

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PANEL ON CLIMATE CHANGE (Solomon, S., et al. eds.,Cambridge University Press 2007) at p. 212, Table 2.14.

STATE OF CALIFORNIA

Energy Resources Conservation and Development Commission

In the Matter of: APPLICATION FOR CERTIFICATION FOR THE GENESIS SOLAR ENERGY PROJECT	DOCKET NO. 09-AFC-8

INTERVENOR CENTER FOR BIOLOGICAL DIVERSITY

Testimony of Tom Myers

Re: Impacts to Water Resources from the Proposed Genesis Solar Energy Project

Docket 09-AFC-8

Summary of Testimony

The proposed project will have a significant impact to water resources that have not been adequately addressed to date. The SA and Revised SA and the hydrology reports from the applicant's contractor vastly underestimate the impacts the proposed project will have on the groundwater balance and flow systems of Chuckwalla Valley and the nearby Colorado River. As an initial matter, the recharge to the basin is overstated by many times which leads to a significant overestimate of the perennial yield. Moreover, the discussion of the deep aquifer and the impacts of the proposed pumping of up to 1650 af/y on the shallow aquifer are based on unsubstantiated assumptions of the aquifer and inaccurate groundwater modeling. As a result, the identification and analysis of impacts of the proposed water use is inadequate.

The proposed project in itself as well as in conjunction with other cumulative projects would significantly impact groundwater resources and cause far larger drawdown of the aquifer than acknowledged in the SA and Revised SA.

Qualifications

My qualifications are provided on my Resume attached to this Testimony and as discussed below.

I have over 25 years of experience as a hydrogeologist, primarily in Nevada but also including California and the Mojave Desert. Approximately 16 of those years have been as an independent consultant based in Nevada and working throughout the western United States, including the Great Basin and Mojave Desert of California.

I have a Ph.D and M.S. in Hydrology/Hydrogeology from the University of Nevada Reno. I have a B.S. in Civil Engineering from the University of Colorado. I have continuing education in various aspects of hydrogeology, including fractured rock analysis, groundwater monitoring, and environmental forensics from MidWest Geosciences and National Groundwater Association.

I have published articles on hydrological issues, including groundwater modeling, stochastic modeling, and river morphology in peer-reviewed scientific journals such as the *Journal of Hydrology* and presented papers/posters at professional meetings of hydrologists and water resource professionals.

I have provided expert testimony on hydrological issues and water resources in proceedings before the Nevada State Engineer, Nevada State Environmental Commission, and Billings Federal District Court.

Statement

The project applicant's Groundwater Resources Investigation (GWRI) and Supplement Groundwater Resources Investigation (SGWRI) are inaccurate. The Discussion of Water Resources in the Staff Assessment (SA) and Revised SA are also incomplete and inaccurate. This statement is a review of those documents and is organized into three broad categories: Water Balance, Groundwater Model, and Impact on the Colorado River, along with a References section.

Water Balance

The GWRI discusses various aspects of the water balance and perennial yield for Chuckwalla Valley. With the exception of discharge, the GWRI grossly overestimates all of the water balance components, as explained in the following comments.

1) Water balance is a simple concept in that inflow equals outflow. In groundwater hydrology, it is common to consider water balance at steady state or for pre-development conditions. In this case for predevelopment conditions, recharge plus interbasin inflow equals discharge through evapotranspiration (ET) and springs plus interbasin outflow.
2) The GWRI (at 34) estimates discharge to evapotranspiration (ET) at Palen Lake to be approximately 350 af/y. The discharge is mostly through exfiltration. This estimate is reasonable.
3) The GWRI (at 31) estimates interbasin outflow to Palo Verde Valley to be approximately 400 af/y. This estimate also appears reasonable although it is not possible to examine the original reference. Rather, considering the cross-section from the GWRI, Figure 4, the flow passes a trapezoidal area about 1500 foot thick at its thickest point and about six miles wide for an area about 35,000,000 ft^2 or

4) The estimate for interbasin inflow from Pinto and Orocopia Valley, at 3500 af/y, is very high. To be correct there must be that much recharge in those valleys. Considering the discussion below on recharge for Chuckwalla Valley, such an estimate appears to be very high. Also, the width of the boundary with Chuckwalla Valley, shown on GWRI Figure 6, appears to be less than the boundary with Palo Verde Valley which had been estimated to have just a little more than one-tenth of the estimated inflow from Pinto Valley.
5) Pumping is not part of the pre-development, steady state discharge. It should not be included in the GWRI Table 3-5.
6) Ignoring the pumpage (discussed in the GWRI (at 26-30)), the natural discharge from the valley appears to be approximately 750 af/y.
7) Recharge and interbasin inflow therefore must balance the steady state discharge.

The GWRI has a long discussion on recharge trying to justify an estimate that exceeds the natural discharge by ten times or more. For many reasons, the estimate of recharge is incorrect.

8) The in-basin recharge estimate is grossly too high, based on a comparison with other methods used in the southwest and based on a detailed consideration or understanding of the principles of recharge.
9) The applicant cites favorably the Maxey-Eakin method as an empirical method used in arid basins throughout the Southwest (GWRI, at 23). The report fails to note that application of the method in the Chuckwalla Valley would yield an estimated recharge equal to zero. This is because the Maxey-Eakin method established a recharge efficiency coefficient equal to zero for precipitation zones less than 8 inches/year (in/y) (Avon and Durbin, 1994, at 100). (I used Avon and Durbin (1994) to reference the Maxey-Eakin method because it best describes the methodology and assesses its accuracy.)
10) The GWRI criticizes the Maxey-Eakin recharge methodology citing to Lerner et al (1990); the reference list does not include the citation for this reference so the basis of the criticism cannot be assessed.
11) Avon and Durbin (1994, at 109) estimated new coefficients, finding that for basins with precipitation less than 8 inches the coefficients would be 1.1%; the GWRI does not mention this. Thus, Avon and Durbin's coefficient for areas with less than 8 in/y precipitation implicitly acknowledges that recharge will occur in any basin because there will be wetter years with runoff that does infiltrate into the fans causing recharge. If 1.1% applies to the Chuckwalla basin, the recharge would be about 3465 af/y, or about 1/3rd the value estimated in the GWRI (at 24).
12) Another methodology used in the Southwest and developed by the US Geological Survey is the Anderson method (Anderson, 1995) which also limits recharge to basins which have average precipitation in excess of eight inches (*Id*., at A16).
13) The GWRI references a US Geological Survey study to claim that basinwide recharge rates, for arid Southwestern basins, vary from 3 to 7% of the basinwide precipitation (GWRI, at 23). The citation is to USGS (2007), which is a

14) The USGS recharge sites described in Constantz et al (2007) differ substantially from Chuckwalla Valley in that they have significantly higher elevation and would have significantly less potential ET (PET) than does the Chuckwalla Valley. The Mojave River site faces north and the Amargosa River site is both higher and significantly further north. Both would lead to lower PET than in Chuckwalla Valley. More PET would increase the amount of exfiltration of the infiltrated runoff, thereby decreasing the amount of alluvial fan infiltration which actually becomes recharge.
15) The Mojave River and Amargosa River sites (Constantz et al 2007) are closest in climate and geology to the Chuckwalla Valley. The altitude of the two gages is 1003 and 1234 m amsl (3290 and 4048 ft, respectively), which exceeds the elevation of the lower end of Chuckwalla Valley by from 3000 to 3800 feet. Both of these USGS study watersheds have significantly higher elevation areas which likely have much higher precipitation than does the higher elevations in the Chuckwalla Valley.
16) Waste water and irrigation return flow is not part of the steady state recharge.

The overall groundwater budget discussion mixes development stresses and natural fluxes, as if they should balance (GWRI, at 34, 35). When development occurs, the new discharge initially causes groundwater to be released from storage. As the water table or potentiometric surface lowers, the new discharge begins to capture natural discharge from some area. In this case, it appears the basin is currently being pumped at rates exceeding the perennial yield, as noted below.

17) The GWRI cites a perennial yield estimate of 12,200 af/y, based on Hanson (1992). This reference is a letter, not a peer-reviewed or even agency-reviewed analysis of the amount of water available from the basin. It should not be considered authoritative and should not be relied upon when considering water availability.
18) The GWRI does not estimate perennial yield, but provides a groundwater balance table to suggest that the amount of water available is of the order of the Hanson perennial yield.
19) The groundwater budget table (GWRI, Table 3-5 at 35) shows substantial pumpage – most is in western Chuckwalla Valley. The 1992 groundwater contour map (GWRI, at Figure 11) does not include this area around Desert Center. The hydrographs presented for western Chuckwalla Valley do not continue into the 21st century, the time period for which most of the reported pumping has occurred. Therefore, there is no estimate of the drawdown which must be occurring. At no point does the GWRI consider this flux from storage to the water balance. It would be part of a current water balance for the valley, but the GWRI does not present such a water balance.

20) Using the Avon and Durbin (1994) Maxey-Eakin coefficient estimate and accepting for the sake of argument the 3500 af/y inflow from Pinto and Oracopia Valley, the total natural inflow to the valley would be 6965 af/y. Subtracting the 350 af/y ET discharge at Palen Lake, the interbasin flow to Palo Verde Valley would be 6615 af/y, which would require a conductivity of 28 ft/d, based on the cross-section for flow to Palo Verde Valley described in comment 3. This is much higher than any average that could be obtained using conductivity values in the GWRI. It is therefore reasonable to conclude that overall inflow to the basin is overestimated and that natural discharge is underestimated.
21) If an average of the inflow and outflow estimates is used, the flux through the valley would be an average of 6965 af/y and 750 af/y, as derived above in comments 2, 3, and 20, or about 3850 af/y. Note that this would require a discharge to Palo Verde Valley of 3500 af/y which would require conductivity equal to 14.8 ft/d, still a very high value. Based on this estimate, the project would pump, and consumptively use, about 41% of the natural flux through the basin.
22) Based on the estimate of 3850 af/y as pre-development flux through Chuckwalla Valley, the perennial yield is currently exceeded by the existing pumping near Desert Center and the prison. There is no water available in the Chuckwalla Valley based on the concept of perennial yield for the basin based on the average from comment 21 and the pumping estimates in the GWRI (at Table 3-5).

The summary of the water budget for the valley is as follows. The valley is arid with little in-basin recharge and interbasin flow passing through from upgradient to the Colorado River floodplain. The estimated fluxes that can be considered predevelopment values presented in the GWRI do not balance. The estimated inflow from Pinto/Oracopia Valleys is about three times the estimated ET discharge and interbasin flow to Palo Verde Valley; add any of the in-basin recharge estimates from the GWRI and the natural inflow to the basin far exceeds the natural discharge – a situation that cannot be correct, which demonstrates the GWRI contains errors that were not considered within the document.

Comments 21 and 22 lay out an argument for a perennial yield that is much less than the 12,000 af/y discussed in the GWRI and referenced by the SA. Using an average flux through the valley based on the pre-development estimates of recharge and discharge, the proposed pumping is about 41% of the perennial yield or flux through the basin. Current pumpage exceeds this natural flux by more than two times. Adding the project to the existing demands of 10,475 af/y (GWRI, Table 3-5), more than 12,000 af/y would be removed from the basin annually. This is about 3.1 times a reasonable perennial yield estimate of 3850 af/y.

Groundwater Model

The applicant's groundwater model is insufficient to predict the impacts of this project. It is poorly designed and calibrated. The following comments are specific to its development and use.

23) The authors call the model impact modeling (GWRI, at 44) which means they are only considering drawdown from pumping and not trying to implement the conceptual flow model of the valley. The model considers neither recharge nor discharge. The model does not account for the heterogeneous aquifers in the basin.
24) There is no justification for the number of layers chosen for the model. The model assumes each layer extends continuously over the entire model domain which ignores the heterogeneity present in the basin. Every layer with low conductivity is assumed to provide an unbroken barrier across the entire domain, again without justifying data.
25) The supplemental GWRI also indicates the layers are not continuous. "The general sequence of sediments described above appears substantially similar to other closely logged borings in the eastern Chuckwalla Valley; however, the **depths of specific coarse grained units cannot be widely correlated** based on the available data. Based on this observation and the results of the pumping test of units in the middle Bouse Formation, described below, **coarse grained units in this part of the basin appear to be of relatively limited lateral continuity**" (SGWRI, at 4).
26) If the coarse grained unit are of "limited lateral continuity", as indicated in the quote in the previous bullet, it is absolutely unjustified to model the coarse units as continuous layers, as was done in the model.
27) If the depths of the units cannot be "widely correlated", also as noted in bullet 25, dividing the domain into a dozen layers with valleywide continuity is absolutely unjustified.
28) The geophysical log provided for well OBS-2 does not justify the layering or assigned/calibrated conductivity values at the well, except, possibly the confining clay layer observed 260 to 280 ft bgs. However, the model simulates that clay in layers 3 and 4, which are 39 feet thick (GWRI, at Figure 21), not the 20 feet observed on the log.
29) All layers below the clay, in the model, have horizontal conductivity high enough to yield sufficient water to the proposed well (Kh≥0.1 ft/d), but the assigned vertical conductivity is very low, leading to a high vertical anisotropy and a tendency for the model to prevent vertical flow.
30) The geophysical log shows substantial poorly graded sand between 360 and 410 ft bgs. This zone should have the highest conductivity, based on gradation, but spans part of layers 7 and 8 with Kh=3 ft/d. Deeper layers which show more clay interbedded with the sand have higher conductivity, near 15 ft/d. The proposed pumping would be constructed in these lower layers. The model layers do not match nor are justified by the geophysical log; the high horizontal and low vertical conductivity values for layers that do not correspond with the geophysical log, could limit the drawdown so that most is limited to deeper layers.
31) The model simulates clay in layers 3 and 4. Because of its extremely low vertical conductivity, it controls the drawdown in overlying layers. The model assumes that the clay layer separating the Bouse formation from the overlying alluvium extends over the entire model domain. This assumption is absolutely without justification because the report provides **no supporting data** to show it is

The model calibration was based on a seven-day pump test completed for near the proposed project location. The GWRI presents a substantial amount of sensitivity analysis, which apparently is an attempt to substitute for a decent flow model of the basin and to adequately calibrate/validate it. The following comments demonstrate the problems with the calibration and sensitivity analysis and explain why it is no substitute for an accurate model.

32) The calibration effectively considers groundwater level responses measured during a 7-day pump test at one point in the valley. The **calibration is for essentially a single point** when the model is of a large basin.
33) The calibration pump test pumped at 87 gpm but the project will pump at 1000 gpm. The **pump test does not stress the aquifer sufficiently** to assess how it would perform with pump rates closer to that required for this project.
34) The pump test well was screened between 350 and 550 feet bgs (lithologic log for TW-1 in GWRI App 2), but the proposed pumping well will be screened from 800 to 1800 ft bgs. **Thus, the calibration data available for this project is for pumping an aquifer layer not targeted for pumping for this project**.
35) Fluctuations in the observed data for OBS #2_270 and Transducer #2_315 indicate that **barometric pressure may have affected the values**. The report does not indicate whether barometric pressure adjustments were made. Because the level changes for these wells were less than 1.5 feet, the variability induced by not considering pressure changes could have biased the calibration.
36) The calibration sensitivity analysis (GWRI, at Tables 4-4, 4-5) shows that the results depend on the chosen vertical conductivity in the clay layer. Drawdown in the layer 3 and layer 5 observation wells was roughly 2.5 to 3 times higher for a one order of magnitude increase in clay layer vertical conductivity. Although the absolute values are small, the drawdown in the unconfined well OBS-1 is **36 times greater** for the same increase in clay layer vertical conductivity. **The model depends on the (supposedly) calibrated vertical conductivity to limit drawdown in the unconfined alluvial layer**.
37) The validation model runs using the prison wells (GWRI, at 52) do not prove the model's ability to predict drawdown. **A three-day validation does not compare with a 33-year simulation period**. After just three days, the simulated drawdown varies from observed by from 15 to 25% - this is not reasonably close – based on the sensitivity analyses completed in the GWRI they suggest the transmissivity is off by a factor of 10, at least. The residuals in the validation are that the simulation underestimated the drawdown (GWRI, App 8, figures for WP-38 and -39)

The GWRI presents drawdown estimates for specific locations, a map of drawdown, and predicted changes in boundary flows. Because the model is based on so little data and lots of unwarranted assumptions, there is little confidence in the results. The sensitivity analyses actually demonstrate the lack of confidence in the predictions and the boundary flows show that the impacts even with the "calibrated" data are significant. The following comments demonstrate the uncertainty in the predictions and the certainty that impacts are significant.

38) The magnitude of boundary flow changes is estimated with the model to be about 20% of the pumping rate after just 33 years (GWRI, Table 4-9). Even if pumping ceases at 33 years, the changes in boundary flow will continue to increase as drawdown recovers. This magnitude of change shows that this project will have a major effect on the water balance of the Chuckwalla Valley and significantly change flows to and from adjoin basins, such as the Palo Verde Valley (the Colorado River floodplain aquifer).
39) The GWRI (at 64) inappropriately calls this decrease in flow to Palo Verde Valley "insignificant" without considering the water budget of that valley. The decrease in flow is about 80% of the predicted 400 af/y flow to Palo Verde Valley (GWRI, at 31). This is most definitely significant. See also the discussion on water budget above.
40) Increasing the vertical conductivity in the clay layers 3-6 tripled the drawdown in the water table aquifer. The magnitude of the changes remains small which demonstrates the importance of the clay layering in the model to the results presented in the GWRI. The assumed clay layer in the model is necessary to "protect" surface aquifers and prevent deep pumping from drawing salty water into the deeper layers.
41) Decreasing the horizontal conductivity in the pumping layer to one tenth the "calibrated" value increased drawdown at the pumping well from about 10 to 70 feet. By itself, this is a huge difference in drawdown. However, this change increased the drawdown in the water table by more than six times, over twice as much as lowering the vertical conductivity, because the increased drawdown at the well increased the gradient drawing flow from the water table layer.
42) The GWRI completely fails to consider the effects of different drawdown by layer because it does not report the changes in flux among layers; because the project seeks to prevent drawing salty near-surface water into the deeper layers, the report should have honestly presented this important aspect of the sensitivity analysis.

An accurate full groundwater model of the project is needed. There appears to be sufficient well and pumping data available in Chuckwalla Valley, and presented in the appendices of the GWRI, to develop a proper groundwater model using justifiable assumptions. Considering the magnitude of the proposed pumping with the flux in the water balance for the valley, a full groundwater model is the only way to estimate the long-term impacts of the project.

Impact on the Colorado River

The Chuckwalla Valley is tributary to the Colorado River, which means that all of the flux from the valley will eventually reach the river. It also means that all of the pumpage will eventually be lost to the Colorado River. This is basic water balance analysis.

However, it will take a long time and the management of the Colorado River is generally based on consideration of more finite time frames.

The GWRI applied Leake et al (2008) and found that the proposed pumping will occur in an area where just 1% of the pumping will be depleted from the Colorado River after 100 years. They are wrong. The one percent value would have been based on the lower transmissivity estimate by Leake et al (2008); this estimate is inaccurate because based on flow and cross-section values discussed in comment 3, the transmissivity is about 15,750 ft^2/d (although through the valley it would be variable). This is between the values used by Leake et al (2008), which suggests the depletion from the Colorado River from the proposed pumping would be between 1 and 10%.

Conclusions

I would like to summarize my conclusions as follows:

Current pumping in Chuckwalla Valley far exceeds the perennial yield, which has been estimated in the past and it the GWRI to be much higher than it should have been estimated. This project would make the pumping in the valley exceed a more reasonable perennial yield estimated by more than three times. The groundwater model used by the applicant is insufficient for analyzing the impacts and is biased, through clay layering in the model, to underestimate the drawdown. All of the water withdrawn for this project will eventually deplete flows in the Colorado River because the only interbasin discharge from Chuckwalla Valley is to Palo Verde Valley, an alluvial valley in significant connection with the Colorado River.

References

Exhibit 800: Anderson, T.W., 1995. Summary of the Southwest Alluvial Basins, Regional Aquifer-System Analysis, South-Central Arizona and Parts of Adjacent States. U.S. Geological Survey Professional Paper 1406-A.

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Exhibit 802: Constantz, J., K.S. Adams, and D.A. Stonestrom, 2007. Ground-Water Recharge in the Arid and Semiarid Southwestern United States – Chapter C. U.S. Geological Survey Professional Paper 1703C.

Exhibit 803: Leake, S.A., Greer W., Watt, D., and Weghorst, P., 2008, Use of superposition models to simulate possible depletion of Colorado River water by ground-water withdrawal: U.S. Geological Survey Scientific Investigations Report 2008-5189, 25 p.

Declaration of Tom Myers

Re: Impacts to Water Resources from the Proposed Genesis Solar Energy Project

Docket 09-AFC-8

I, Tom Myers, declare as follows:

1) I am currently a Hydrologic Consultant and have held this position for 16 years.

2) My relevant professional qualifications and experience are set forth in the attached resume and the testimony above and are incorporated herein by reference.

3) I prepared the testimony attached hereto and incorporated herein by reference, relating to the impacts of the proposed project on water resources.

4) I prepared the testimony above and incorporated herein by reference relating to the proposed Genesis Solar Energy Project in Riverside County, California.

5) It is my professional opinion that the testimony above is true and accurate with respect to the issues that is addressed.

6) I am personally familiar with the facts and conclusions described within the testimony above and if called as a witness, I could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: ____June 16, 2010______ Signed: Thomas J Myers

At: ___Reno, NV______________

Tom Myers, Ph.D.

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Statement of Qualifications

Tom Myers is a researcher and consultant in hydrogeology and water resources. Tom specializes in groundwater modeling, hydrogeology, environmental forensics, regulatory compliance, water rights, NEPA analysis, and environmental and water policy. He focuses on mining and water resource development issues, coal-bed methane development and groundwater contamination.

With a Ph.D. and M.S. in hydrology/hydrogeology and more than 28 years experience as a consultant, government planner, academic researcher, teacher and advocate for environmental responsibility and good science, Tom brings a strong technical, regulatory, and public relations background to his work. His work includes major hydrology studies for federal government, hydrogeologic assessments for county governments, expert and evidence reports for use in litigation and administrative hearings, expert witnessing for private industry and nonprofit groups, and testimony to Congress and National Academy of Science. Tom has testified as an expert before the Nevada State Engineer and State Environmental Commission. He has provided evidentiary testimony before federal court in Billings MT.

Because of his experience as a watchdog of government agencies and different industries, Tom has a unique background from which he draws on as a consultant. For example, he has worked to locate the source of pollution from many mines or to determine the cause of drawdown at private wells. He combines a strong technical background with a working knowledge of state environmental and federal NEPA, BLM mining, water law and Clean Water Act regulations which enables him to work with attorneys and conservation groups.

Tom's experience and training uniquely qualifies him to provide diverse and affordable services to clients ranging from nonprofit conservation groups to law firms, industry and governments in many areas of hydrogeology and environmental and water policy. His client base includes nonprofit conservation groups, Native American tribes, the federal government and private industry.

Client List

NON-PROFIT ORGANIZATIONS	***GOVERNMENTAL ENTITIES***
Natural Resources Defense Council	Pima County, AZ
Great Basin Resource Watch	White Pine County, NV
Greater Yellowstone Coalition	Anaconda-Deer Lodge County, MT
Great Basin Water Network	Town of Indian Springs, NV
Keep Local Water Local	Bureau of Land Management, Carson City, NV
Citizens Looking at Impacts of Mining	University of Nevada, Reno
Defenders of Wildlife	***PRIVATE INDUSTRY***
Northern Plains Resource Council	Yonkee and Toner, LLC, Sheridan WY
McCloud Watershed Council	Public Resource Associates, Reno, NV
	Kuipers and Associates, Butte, MT

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Curriculum Vitae

Objective: To provide diverse research and consulting services to nonprofit, government, legal and industry clients focusing on groundwater modeling, hydrogeology, environmental forensics and compliance, NEPA analysis, federal and state regulatory review, fluvial morphology and environmental and water policy.

Education

Years	Degree	University
1992-96	Ph.D. Hydrology/Hydrogeology	University of Nevada, Reno Dissertation: Stochastic Structure of Rangeland Streams
1990-92		University of Arizona, Tucson AZ Classes in pursuit of Ph.D. in Hydrology.
1988-90	M.S. Hydrology/Hydrogeology	University of Nevada, Reno Thesis: Stream Morphology, Stability and Habitat in Northern Nevada
1981-83		University of Colorado, Denver, CO Graduate level water resources engineering classes.
1977-81	B.S., Civil Engineering	University of Colorado, Boulder, CO

Special Coursework

Years	Course	Sponsor
2009	Fractured Rock Analysis	MidWest Geoscience
2005	Groundwater Sampling Field Course	Nielson Environmental Field School
2004	Environmental Forensics	National Groundwater Association
2004 and -5	Groundwater and Environmental Law	National Groundwater Association
1998	MapInfo GIS Systems	MapInfo Corporation Tutorial
1993	Applied Fluvial Morphology	Wildlands Hydrology
1988	Fortran Programming	University of Nevada, Las Vegas

Professional Experience

Years	Position	Duties
1993-Pr.	Hydrologic Consultant	Surface, groundwater and systems modeling, hydrogeology studies, stream restoration design, watershed modeling studies and expert testimony for industry, nonprofit groups, and government agencies.
1999-2004	Great Basin Mine Watch Executive Director	Responsible for reviewing and commenting on mining projects with a focus on groundwater and surface water resources, preparing appeals and litigation, writing reports about mining, fundraising, organizational development, supervision and personnel management.
1992-1997	University of Nevada, Reno Research Associate	Research on riparian area and watershed management including stream morphology, aquatic habitat, cattle grazing and low-flow and flood hydrology.
1990-1992	University of Arizona, Tucson Research and Teaching Assistant	Research on rainfall/runoff processes and climate models. Taught lab sections for sophomore level "Principles of Hydrology". Received 1992 Outstanding Graduate Teaching Assistant Award in the College of Engineering
1988-1990	University of Nevada, Reno Research Assistant	Research on aquatic habitat, stream morphology and livestock management.
1983-1988	US Bureau of Reclamation, Boulder City, NV Hydraulic Engineer	Performed hydrology planning studies on topics including floodplains, water supply, flood control, salt balance, irrigation efficiencies, sediment transport, stream morphology, flood frequency, rainfall-runoff modeling and groundwater balances.
1981-1983	Faulkner-Kellogg and Assoc., Lakewood Co Design Engineer	Basic drainage, grading and subdivision design. Flood control studies.

Representative Reports, Presentations and Projects

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STATE OF CALIFORNIA

Energy Resources Conservation and Development Commission

In the Matter of: APPLICATION FOR CERTIFICATION FOR THE GENESIS SOLAR ENERGY PROJECT	DOCKET NO. 09-AFC-8

THE CENTER FOR BIOLOGICAL DIVERSITY

OPENING TESTIMONY

TESTIMONY OF BILL POWERS, P.E.

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I. Introduction

My testimony addresses: 1) the inadequate analysis of the distributed photovoltaic (PV) alternative to the proposed Genesis Solar Energy Project (GSEP) in the Revised Staff Analysis (RSA), and 2) the proposed Westlands Water District Competitive Renewable Energy Zone, located on retired farmland in the Central Valley and served by 5,000 MW of existing transmission capacity, as a superior alternative location for central station solar projects like GSEP.

I am a registered professional mechanical engineer in California with over 25 years of experience in the energy and environmental fields. I have permitted five 50 MW peaking turbine installations in California, as well as numerous gas turbine, microturbine, and engine cogeneration plants around the state. I organized conferences on permitting gas turbine power plants (2001) and dry cooling systems for power plants (2002) as chair of the San Diego Chapter of the Air & Waste Management Association. I am the author of the October 2007 strategic energy plan for the San Diego region titled "San Diego Smart Energy 2020." The plan uses the state's Energy Action Plan as the framework for accelerated introduction of local renewable and cogeneration distributed resources to reduce greenhouse gas emissions from power generation in the San Diego region by 50 percent by 2020. I am the author of several 2009 articles in Natural Gas & Electricity Journal on use of large-scale distributed solar PV in urban areas as a cost-effective substitute for new gas turbine peaking capacity.

II. Rooftop PV Is at the Top of the Energy Action Plan Loading Order

The RSA states, in discussing the conservation and demand-side management alternative to GSEP, that cost-effective energy efficiency is the resource of first choice in meeting California's energy needs (p. B.2-84):

> "Conservation and demand-side management consist of a variety of approaches to reduce of electricity use, including energy efficiency and conservation, building and appliance standards, and load management and fuel substitution. In 2005 the Energy Commission and CPUC's Energy Action Plan II declared cost effective energy efficiency as the resource of first choice for meeting California's energy needs."

The CEC and the CPUC developed the "Energy Action Plan" in 2003 to guide strategic energy decisionmaking in California. The Energy Action Plan establishes the energy resource "loading order," or priority list that defines how California's energy needs are to be met. Energy Action Plan I was published in May 2003.[1] Energy Action Plan I describes the loading order in the following manner (p. 4):

> "The Action Plan envisions a "loading order" of energy resources that will guide decisions made by the agencies jointly and singly. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate

[1] Energy Action Plan I: http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

> time to "get to scale," the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation."

Energy Action Plan I, Under "Optimize Energy Conservation and Resource Efficiency," states (p. 5):

> "Incorporate distributed generation or renewable technologies into energy efficiency standards for new building construction."

Energy Action Plan I identifies rooftop PV as a de facto energy efficiency measure with this statement. As noted in the GSEP RSA (p. B.2-84), energy efficiency is at the top of the loading order. Energy Action Plan I also states, Under "Promote Customer and Utility-Owned Distributed Generation," (p. 7):

> "Distributed generation is an important local resource that can enhance reliability and provide high quality power, without compromising environmental quality. The state is promoting and encouraging clean and renewable customer and utility owned distributed generation as a key component of its energy system. Clean distributed generation should enhance the state's environmental goals. This determined and aggressive commitment to efficient, clean and renewable energy resources will provide vision and leadership to others seeking to enhance environmental quality and moderate energy sector impacts on climate change. Such resources, by their characteristics, are virtually guaranteed to serve California load. With proper inducements distributed generation will become economic.
>
> - Promote clean, small generation resources located at load centers.
> - Determine system benefits of distributed generation and related costs.
> - Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program."

Energy Action Plan I prioritizes rooftop PV as the preferable renewable resource, but indicates obliquely that it is costly and that in any case distributed PV is not eligible to participate in the Renewable Portfolio Standard (RPS) program. Therefore investor-owned utilities have no incentive to develop distributed PV resources. Since Energy Action Plan I was approved in 2003, PV cost has dropped dramatically. Commercial distributed PV is half the cost it was in 2003 and costs continue to drop. Residential PV is following quickly behind. Distributed PV is also now eligible for the RPS program.[2]

Energy Action Plan II was adopted in September 2005.[3] The purpose of Energy Action Plan II is stated as (p. 1): "EAP II is intended to look forward to the actions needed in California over the next few years, and to refine and strengthen the foundation prepared by EAP I." Energy Action Plan II reaffirms the loading order stating (p. 2):

> "EAP II continues the strong support for the loading order – endorsed by Governor

[2] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009. "The energy generated from the project will be used to serve Edison's retail customers and the output from these facilities will be counted towards Edison's RPS goals."
[3] Energy Action Plan II: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

Schwarzenegger – that describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation."

The CEC's *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report* (December 2009), underscores the integration of building PV as a critical component of "net zero" energy use targets for new residential and commercial construction, under the heading "Energy Efficiency and the Environment," explaining:[4]

> "With the focus on reducing GHG emissions in the electricity sector, energy efficiency takes center stage as a zero emissions strategy. One of the primary strategies to reduce GHG emissions through energy efficiency is the concept of zero net energy buildings. In the 2007 IEPR, the Energy Commission recommended increasing the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings could be zero net energy by 2020 for residences and by 2030 for commercial buildings.
>
> A zero net energy building merges highly energy efficient building construction and state-of-the-art appliances and lighting systems to reduce a building's load and peak requirements and includes on-site renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid. The goal is for the building to use net zero energy over the year."

The GSEP RSA acknowledges the state's commitment to net zero residential and commercial buildings, stating (RSA, p. B.2-84):

> "The CPUC, with support from the Governor's Office, the Energy Commission, and the California Air Resources Board, among others, adopted the California Long-Term Energy Efficiency Strategy Plan for 2009 to 2020 in September 2008 (CPUC 2008). The plan is a framework for all sectors in California including industry, agriculture, large and small businesses, and households. Major goals of the plan include:
>
> - All new residential construction will be zero net energy by 2020;
> - All new commercial construction will be zero net energy by 2030;
> - Heating, ventilation, and air conditioning industries will be re-shaped to deliver maximum performance systems;
> - Eligible low-income customers will be able to participate in the Low Income Energy Efficiency program and will be provided with cost-effective energy efficiency measures in their residences by 2020."

The RSA is flawed in its failure to identify rooftop PV as a higher priority in the Energy Action Plan loading order, and California's long-term energy efficiency strategy plan, than utility-scale remote solar resources like GSEP. Rooftop (or parking lot) distributed PV is an integral component of the long-term energy efficiency strategy plan adopted by the CPUC in 2008.

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[4] CEC, *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report*, December 2009, p. 56.

Energy Action Plan II declares cost-effective energy efficiency as the resource of first choice for meeting California's energy needs. The CEC rejection of distributed PV as a superior alternative to the proposed GSEP solar thermal projects ignores the integral role of distributed PV in the CEC's own definition of energy efficiency and net zero buildings in the 2009 IEPR.

III. RSA Rationale for Eliminating Rooftop PV is Flawed

The RSA correctly describes that a distributed rooftop PV alternative has essentially no environmental impact, stating (p. B.2-68):

- Distributed solar PV is assumed to be located on already existing structures or disturbed areas so little to no new ground disturbance would be required and there would be few associated biological impacts.
- Relatively minimal maintenance and washing of the solar panels would be required.
- Because most PV panels are black to absorb sun, rather than mirrored to reflect it, glare would be minimal relative to reflective technologies (like GSEP)
- Additionally, the distributed solar PV alternative would not require the additional operational components, such as dry-cooling towers, substations, transmission interconnection, maintenance and operation facilities with corresponding visual impacts.

The RSA then eliminates distributed PV, citing a number of reasons why achieving 250 MW of distributed PV is not a feasible substitute for GSEP (RSA, p. B.2-69):

- Would require accelerated deployment of distributed PV at more than double the historic rate of deployment under the California Solar Initiative.
- Would require lower PV cost - distributed PV is higher cost than central station solar thermal.
- Integrating large amounts of distributed PV on distribution systems throughout California presents challenges – will require development of a new transparent distribution planning framework.

Each of these justifications for elimination of distributed PV is flawed, as explained in the following paragraphs.

A. Distributed PV Is Already Being Deployed at a Much Faster Rate in California than Central Station Solar Thermal

The RSA notes that more than 540 MW of distributed PV was in operation in California through May 2009, and that the PV installation rate doubled between 2008 and 2007. California has approximately 360 MW of installed solar thermal capacity as of June 2010. With the exception of the 5 MW eSolar power tower demonstration project that came online in 2009 (p. B.2-68), all of this solar thermal capacity was installed between 1984 and 1990.[5]

[5] CEC, Large Solar Energy Projects webpage: http://www.energy.ca.gov/siting/solar/index.html

The RSA correctly describes that both SCE and PG&E, the two largest investor-owned utilities (IOU) in California, are constructing large distributed PV projects (p. B.2-67). SDG&E has a much smaller distributed PV project in development. The 500 MW SCE urban PV project was approved by the CPUC in June 2009. The 500 MW PG&E distributed PV project was approved by the CPUC in April 2010. These projects are RPS-eligible and will consist of a 250 MW IOU-owned component and a 250 MW third-party component. The power purchase agreement (PPA) between GSEP and SDG&E is same type of contract mechanism that will be used by SCE and PG&E to contract for the 250 MW third-party component of their respective distributed PV projects.

Progress in distributed PV installation rates under the California Solar Initiative (CSI) program provides no insight into the ability of the solar industry to carry-out multiple large-scale distributed PV projects simultaneously, in the range of 250 to 500 MW each, in California. The CSI program is not the vehicle that will be used to build these projects. These projects will be built under long-term PPAs between the distributed PV project developer and a utility within the framework of the RPS program.

An example is the PPA between PG&E and Sempra Generation for 10 MW of fixed thin-film PV in Nevada.[6] Sempra Resources is the holding company that owns both Sempra Generation and SDG&E. The PG&E/Sempra PPA is a technology-differentiated renewable energy contract at a price incrementally higher than the market price referent (MPR) to assure that the project developer, Sempra Generation, makes a reasonable return on its investment. The contract is in effect the equivalent of a technology differentiated feed-in tariff for solar power. No incentives beyond the federal investment tax credit and accelerated depreciation available to any solar energy project were necessary. No incentives beyond those already available would be necessary to build 250 MW of distributed PV under a long-term PPA to substitute for GSEP.

Sempra Generation touts the cost of power generated by its 10 MW PV installation in Nevada as “the lowest cost solar energy in the world.”[7] The company specifically mentions solar thermal projects like GSEP as producing higher-cost solar energy and being commercially unproven, stating:[8]

> “Sempra has also evaluated solar thermal power technologies, which use a field of mirrors to concentrate the sunlight to produce heat for electricity generation. The company has found that using solar panels is the cheaper option, (CEO) Allman said. He noted that some of the solar thermal power technologies, such as the use of a central tower for harvesting the heat and generating steam, have yet to be proven commercially.”

SCE has a similar RPS-eligible PPA with NRG for the output of a 21 MW fixed thin-film PV array in Blythe, California.[9] This project began operation in December.

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[6] CPUC Resolution E-4240, *Approval of a power purchase agreement (PPA) for generation from a new solar photovoltaic facility between PG&E and El Dorado Energy*, LLC (Sempra Generation), May 18, 2009.

[7] GreenTech Media, *Sempra Wants 300 MW Plus of Solar in Arizona*, April 22, 2009. "The electricity we are getting out of the 10-megawatt is the lowest cost solar energy ever generated from anywhere in the world.” (CEO Michael Allman).

[8] Ibid.

[9] First Solar press release, *First Solar Sells California Solar Power Project to NRG*, November 23, 2009.

B. IOUs and California's Energy Policy Makers Acknowledge the Obvious Benefits of Large-Scale Distributed PV Projects as a Direct Complement/Substitute for Remote Central Station Renewable Energy and Associated Transmission

SCE expressed confidence in its March 2008 application to the CPUC for a 250 to 500 MW urban PV project that it can absorb thousands of MW of distributed PV without additional distribution substation infrastructure, stating "SCE's Solar PV Program is targeted at the vast untapped resource of commercial and industrial rooftop space in SCE's service territory"[10] and "SCE has identified numerous potential (rooftop) leasing partners whose portfolios contain several times the amount of roof space needed for even the 500 MW program."[11]

SCE stated it has the ability to balance loads at the distribution substation level to avoid having to add additional distribution infrastructure to handle this large influx of distributed PV power.[12] SCE explains:

> "SCE can coordinate the Solar PV Program with customer demand shifting using existing SCE demand reduction programs on the same circuit. This will create more fully utilized distribution circuit assets. Without such coordination, much more distribution equipment may be needed to increase solar PV deployment. SCE is uniquely situated to combine solar PV Program generation, customer demand programs, and advanced distribution circuit design and operation into one unified system. This is more cost-effective than separate and uncoordinated deployment of each element on separate circuits."[13]

SCE also notes that it will be able to remotely control the output from individual PV arrays to prevent overloading distribution substations or affecting grid reliability:[14]

> "The inverter can be configured with custom software to be remotely controlled. This would allow SCE to change the system output based on circuit loads or weather conditions."

As SCE states, "Because these installations will interconnect at the distribution level, they can be brought on line relatively quickly without the need to plan, permit, and construct the transmission lines."[15] This statement was repeated and expanded in the CPUC's June 18, 2009 press release regarding its approval of the 500 MW SCE urban PV project:[16]

> Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts. By authorizing both utility-owned and private development of these projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

[10] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, p. 6.
[11] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 44.
[12] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, pp. 8-9.
[13] Ibid, p. 9.
[14] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 27.
[15] Ibid, p. 6.
[16] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009.

The CPUC made a similar observation with its approval of the PG&E 500 MW distributed PV project in April 2010:[17]

> "This solar development program has many benefits and can help the state meet its aggressive renewable power goals," said CPUC President Michael R. Peevey. "Smaller scale projects can avoid many of the pitfalls that have plagued larger renewable projects in California, including permitting and transmission challenges. Because of this, programs targeting these resources can serve as a valuable complement to the existing Renewables Portfolio Standard program."

The use of the term "smaller scale" in the CPUC press release is a misnomer. Clearly a 500 MW distributed PV project is larger-scale than the 250 MW GSEP solar thermal project. Individual rooftop PV arrays in a large distributed PV project are functionally equivalent to single rows of reflective mirrors in a solar thermal project. Each rooftop or row is a small contributor to a much bigger whole.

C. IOUs Need Only Provide a Basic Level of Existing Information on Individual IOU Substation Capacities to PV Developers to Interconnect Over 13,000 MW of Distributed PV with Minimal Interconnection Cost

The CPUC has also calculated, for the entire inventory of approximately 1,700 existing IOU substations, the amount of distributed PV that could be accommodated with minimal interconnection cost based on the following reasoning:[18]

> "Rule 21 specifies maximum generator size relative to the peak load on the load at the point of interconnection at 15%. So, for example, if a generator is interconnected on the low side of a distribution substation bank with a peak load of 20 MW, the maximum Rule 21 interconnection criteria would allow a 3 MW system (3 MW = 15% * 20 MW).
>
> However, the 15% criterion, which is established for all generators regardless of type, was adjusted to 30% for the purposes of determining the technical potential of PV. The 15% limit is established at a level where it is unlikely the generator would have a greater output than the load at the line segment, even in the lowest load hours in the off-peak hours and seasons (such as the middle of the night and in the spring). Since the peak output for photovoltaics is during the middle of the day, PV is unlikely to have any output when loads are lowest. Therefore, a 30% criterion was used for technical interconnection potential estimates. The discussion was held with utility distribution engineers, however, we did not consider formal engineering studies or Rule 21 committee deliberation since the purpose of the analysis was only to define potential."

As a component of the DG FIT development process, the CPUC requested data on peak loads at all IOU substations from the IOUs and compiled that information graphically as shown in Figure

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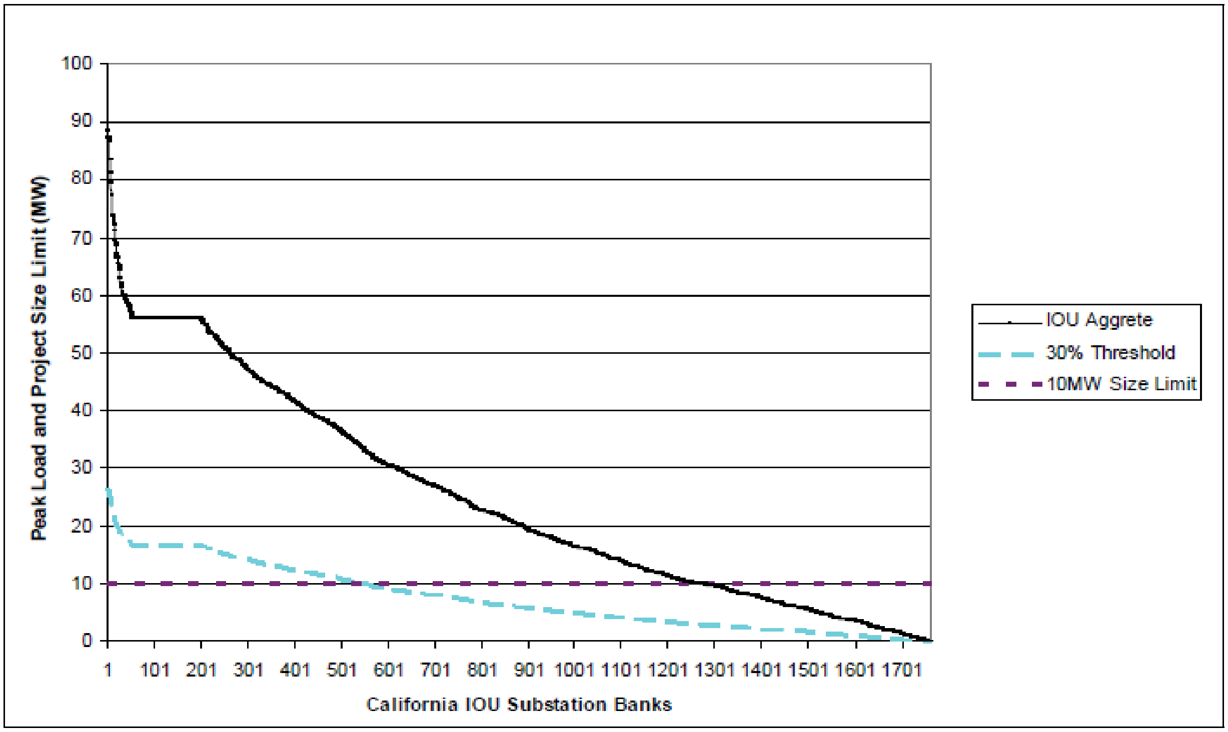
[17] CPUC Press Release – Docket A.09-02-019, *CPUC Approves Solar PV Program for PG&E*, April 22, 2010.
[18] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, p. 15.

1. According to the CPUC, this data was obtained from IOU distribution engineers.[19] I calculate that approximately 13,300 MW of PV can be connected directly to IOU substation load banks based on the data in Figure 1. The supporting calculations for this estimate are provided in Table 1.

The IOUs provide about two-thirds of electric power supplied in California, with publicly-owned utilities like the Los Angeles Department of Water & Power and the Sacramento Municipal Utility District and others providing the rest.[20] Assuming the substation capacity pattern in Figure 1 is also representative of the non-IOU substations, the total California-wide PV that could be interconnected at substation low-side load banks with no substantive substation upgrades would be [13,300/(2/3)] = 19,950 MW.

Figure 1. IOU Substation peak loads, 30% of peak load, and 10 MW reference line



[19] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, pp. 15-16.
[20] CEC, *2007 Integrated Energy Policy Report*, December 2007, Figure 1-11, p. 27.

Table 1. Calculation of distributed PV interconnection capacity to existing IOU substations with minimal interconnection cost from data in Figure 1

Substation range	Number of substations	Calculation of distributed PV that could be interconnected with minimal substation upgrades (MW)	Total distributed PV potential (MW)
1-200	200	average peak ~60 MW x 0.30 = 18 MW	3,600
201-500	300	average peak ~45 MW x 0.30 = 13.5 MW	4,000
501-800	300	average peak ~30 MW x 0.30 = 9 MW	2,700
801-1,000	200	average peak ~20 MW x 0.30 = 6 MW	1,200
1,001-1,600	600	average peak ~10 MW x 0.30 = 3 MW	1,800
		Distributed PV total:	13,300

In sum, approximately 20,000 MW of distributed PV interconnection capacity is available now in California that would require little or no substation upgrading to accommodate the PV.

D. Cost to Upgrade Existing Distribution Substations and Associated Distribution Feeders to Maximize Distributed PV Deployment is Minimal

An upgrade at the substation would be necessary to accommodate the higher power flows in cases where distributed PV, concentrated on clusters of large rooftops, could provide up to 100 percent of a single substation's peak load. A typical 12 kV/69 kV substation can be upgraded to allow two-way (bidirectional) power flows for up to 100 MW of interconnected distributed PV. SDG&E estimates the cost to build a new 12 kV/69 kV substation is $25 million.[21]

The upgrades necessary to allow problem-free bidirectional power flow across an existing substation is far less than the cost of a new substation. The upgrade would consist of retrofitting substation metering and protective equipment from one-way power flow to bidirectional power flow. The cost of such an upgrade for a typical 100 MW distribution substation would be approximately $500,000.[22] This is well under 1 percent of the gross capital cost of 100 MW of state-of-the-art PV at 2010 prices.

Even the cost of a new 100 MW distribution substation, at $25 million, is less than 10 percent of the gross capital cost of 100 MW of state-of-the-art PV at 2010 prices. The substation upgrade cost would be relatively minor compared to the gross capital cost of 100 MW of PV arrays, and would not present a substantive financial hurdle to developing a 100 MW distributed PV resource concentrated in an area served by a single existing substation.

The 2007 IEPR makes clear that incorporating bidirectional capability into distribution substation is a commonsense need in a smart grid environment where higher-and-higher levels of distributed generation are encouraged and expected:[23]

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[21] Ibid, p. 5.21.

[22] E-mail from M. Martyak, PowerSecure (www.powersecure.com), to B. Powers, Powers Engineering, January 13, 2010. Approximate cost to upgrade older 100 MW distribution substation to full bidirectional flow, assuming four 25 MW load banks with four circuit breakers each (16 total), would be $400,000 to $450,000.

[23] CEC, *2007 Integrated Energy Policy Report*, December 2007, pp. 155-156.

> "Utilities spend approximately three-fourths of their total capital budgets on distribution assets, with about two-thirds spent on upgrades and new infrastructure in most years. These investments will remain for 20 to 30 or more years. As utilities throughout the state plan to build new distribution assets and replace old assets, the magnitude of these investments suggests that the state must understand what it is investing in and whether these investments will result in a distribution system that will serve customers in the future. Planning for investment in these assets should include requiring utilities, before undertaking investments in non-advanced grid technologies, to demonstrate that alternative investments in advanced grid technologies that will support grid flexibility have been considered, including from a standpoint of cost effectiveness."

The CPUC assumes that larger PV arrays will be connected directly to the substation low-side (12 kV) load bank. SDG&E estimated that the cost of a 10 MW feeder is \$0.6 million per mile.[24] The cost of a 3-mile long dedicated feeder from multiple rooftop PV arrays with a combined capacity of 10 MW to the low-side bus of the substation would be less than \$2 million based on SDG&E's cost estimate.

The current capital cost for state-of-the-art commercial rooftop PV is approximately \$3,700/kW_{ac}. The gross capital cost of 10 MW of rooftop PV at current prices would be \$3,700/kW x (1,000 kW/MW) x 10 MW = \$37 million. The cost to construct a dedicated feeder to interconnect 10 MW of rooftop PV would be approximately 5 percent of the gross project capital cost. This is a relatively minor cost and represents no financial impediment to developing urban rooftop PV resources.

E. There Is No Security Justification for IOU's Withholding Information on Substation Capacities and Locations from Private PV Developers, and No Economic or Technical Justification for Failure to Incorporate Smart Grid Features in New and Upgraded Distribution Substations

The RSA notes that accommodating large quantities of distributed generation PV located at customer sites efficiently and cost-effectively will require the development of a new, transparent distribution planning framework (p. B.2-70). Transparent distribution planning by the IOUs is a reasonable expectation. Lack of transparent distribution planning is not a credible justification by an IOU or the CEC to reject distributed PV as a substitute for GSEP.

The CEC is already on record advocating that IOUs must incorporate smart grid elements, including bidirectional power flow, into new and upgraded distribution substations.[25] It would likely come as a surprise to most California ratepayers that it is not already standard practice for California IOUs to incorporate bidirectional power flow capability into any new distribution substation or major upgrade of an existing substation. As noted, approximately 20,000 MW of distributed PV can flow into California distribution substations without retrofitting these substations for bidirectional power flow. The lack of bidirectional power flow capability on

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[24] Application No. 06-08-010, Matter of the Application of San DiegoGas & Electric Company (U-902-E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, *Chapter 5: Prepared Rebuttal Testimony of SDG&E in Response to Phase 2 Testimony of Powers Engineering*, March 28, 2008, p. 5.20.

[25] CEC, *2007 Integrated Energy Policy Report*, December 2007, pp. 155-156.

California distribution substations is not a short- or mid-term impediment to maximizing distributed PV deployment.

However, at some point over the operational lifetime of a new or upgraded distribution substation it is prudent to assume that failure to equip the substation to accommodate bidirectional power flow will act as an artificial brake on the quantity of distributed PV the substation can accept. Equipping a distribution substation for bidirectional power flow is not expensive, costing in the range of $500,000 for a typical 100 MW distribution substation. Failure of IOUs to incorporate smart grid features as standard elements in new and upgraded distribution substations is not a credible justification by an IOU or the CEC to reject distributed PV as a substitute for GSEP.

The rationale put forth for restricting information to private distributed PV project developers includes "Providing details on distribution system could compromise homeland security" and "Information on peak loads and system configuration may be considered commercially sensitive."[26] There is no sound basis for these two justifications.

In the first instance, climate change is seen as a major threat to national security by the U.S. defense establishment.[27] Withholding information that would allow rapid progress on addressing climate change on homeland security grounds is contrary to the national security interest. Secondly, all IOU expenditures are passed on to customers. The withholding of information on peak loads and system configuration by the IOU to protect unsubstantiated commercial sensitivity concerns, to the extent it prevents the rapid deployment of competitively-bid distributed PV in urban centers at or near the point-of-use, would have a potentially substantial negative impact on ratepayers and slow progress on addressing climate change.

Much of the necessary information is already in the public domain in some form and should be compiled and made available to distributed PV developers in a transparent and efficient format. For example, the CPUC already has the data on IOU substation interconnection limitations as shown in Figure 1. Another example is information on the location of IOU substations. Maps showing the location of all IOU substations are readily available for purchase from the CEC Cartography Unit.

The province of Ontario (Canada) makes publicly-available information on substation location and available capacity to facilitate the development of distributed PV in the province.[28] This same information protocol should be followed by California IOUs.

Finally, SCE must provide this type of information to third-party PV developers for the 250 MW private PV developer set-aside component of its 500 MW urban PV project approved by the CPUC in June 2009.

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[26] E3 and Black & Veatch, *Straw proposal of solution to address short-term problem of information gap*, presentation at CPUC Re-DEC Working Group Meeting, December 9, 2009, p. 9. Online at: http://www.cpuc.ca.gov/PUC/energy/Renewables/Re-DEC.htm
[27] New York Times, *Climate Change Seen as Threat to U.S. Security*, August 9, 2009.
[28] E3 and Black & Veatch, *Straw proposal of solution to address short-term problem of information gap*, presentation at CPUC Re-DEC Working Group Meeting, December 9, 2009, p. 8.

F. There is Sufficient Existing Large Commercial Roof Space in PG&E and SCE Territories to Build at Least Thirty GSEP Plants

The 2009 IEPR Final Committee Report recognizes the huge technical potential of rooftop distributed PV to meet California's renewable energy targets, stating:[29]

> "Recent studies indicate substantial technical potential for distribution-level generation resources located at or near load. A 2007 estimate from the Energy Commission suggests that there is roof space for over 60,000 MW of PV capacity, although the study did not factor in roof space that is shaded or being used for another purpose."

60,000 MW is approximately the peak summertime load for all of California, and 250 times the 250 MW capacity of GSEP. It is important to note that the 2009 IEPR document is incorrect in asserting the 2007 rooftop PV estimate did not factor in roof shading or other limitations. The 60,000 MW estimate assumes only 24 percent of the rooftop of a typical tilt-roof residential rooftop is available for PV, and only 60 to 65 percent of flat-roof commercial rooftops are available for PV. The rationale for these estimates is explained in the 2007 (Navigant) estimate.[30]

The 60,000 MW rooftop PV estimate by Navigant does not account for any of the distributed PV described in the Renewable Energy Transmission Initiative (RETI) process. RETI is California's ongoing renewable energy transmission siting process. RETI evaluated a distributed PV alternative that would produce 27,500 MWac from 20 MW increments of ground-mounted PV arrays at 1,375 non-urban substations around the state.[31] This is similar to the approach that PG&E is following. Constructing distributed PV arrays around substations is the primary focus of PG&E's 500 MW distributed PV project.[32]

Black & Veatch is the engineering contractor preparing the RETI reports. Energy & Environmental Economics, Inc. (E3) is the engineering contractor that prepared the June 2009 CPUC preliminary analysis of the cost to reach 33 percent renewable energy by 2020. These two firms now lead the CPUC's renewable distributed generation ("Re-DEC") working group process. The presentation of E3 and Black & Veatch at the December 9, 2009 initial meeting of the Re-DEC Working Group included an estimate of over 8,000 MWac of large commercial roof space in SCE and PG&E service territories in close proximity to existing distribution substations.[33]

Black & Veatch used GIS to identify large roofs in California and count available large roof area. The criteria used to select rooftops included:

- Urban areas with little available land
- Flat roofs larger than ~1/3 acre
- Assume 65 percent usable space on roof

[29] CEC, *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report*, December 2009, p. 193.
[30] See: http://www.energy.ca.gov/2007publications/CEC-500-2007-048/CEC-500-2007-048.PDF
[31] Renewable Energy Transmission Initiative, *RETI Phase 1B Final Report*, January 2009, p. 6-25.
[32] PG&E Application A.09-02-019, *Application of Pacific Gas and Electric Company to Implement Its Photovoltaic Program*, February 24, 2009.
[33] E3 and Black & Veatch, *Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis*, presentation at Re-DEC Working Group Meeting, December 9, 2009, p. 24. Online at: http://www.cpuc.ca.gov/PUC/energy/Renewables/Re-DEC.htm

- Within 3 miles of distribution substation

The Black & Veatch estimate for PG&E territory is 2,922 MWac. The estimate for SCE territory is 5,243 MWac. This is a combined rooftop PV capacity of over 8,000 MWac. The combined large commercial rooftop capacity is more than 30 times the 250 MW capacity of GSEP.

Large commercial rooftop PV capacity is a subset of the universe of all commercial rooftop capacity, which includes medium and small commercial rooftops as well. A 2004 Navigant study prepared for the Energy Foundation estimated the 2010 commercial rooftop PV capacity in California at approximately 37,000 MWdc.[34] There is a tremendous amount of commercial roof space available for PV.

G. There is Sufficient Existing Commercial Roof Space in SDG&E Territory to Build at Least Six GSEP Plants

The RSA states that the output from GSEP will be sold to SDG&E under a long-term power purchase agreement if the project is built (p. B.2-41). SDG&E was co-author of a 2005 renewable energy potential assessment for San Diego County that includes a detailed inventory of rooftop PV potential.[35] The core of this inventory is an estimate of 769 MWac of commercial building PV potential in the City of San Diego based direct quantification of available roofspace on 15,157 commercial buildings using GIS analysis. This inventory was extrapolated to other cities in San Diego County, based on population, to calculate an estimated County-wide commercial building PV potential of 1,624 MWac in 2010. The analysis assumed a very conservative dc-to-ac conversion factor of 0.67. Use of a more realistic 0.80 dc-to-ac conversion factor results in a San Diego County adjusted 2010 commercial rooftop PV potential of 1,624 MWac × (0.80/0.67) = 1,939 MWac.

Commercial building rooftops are classified as Category 1 and Category 2 in the 2005 rooftop inventory. Category 1 means 80 percent or more of the rooftop is available for PV. See photographs of Category 1 and Category 2 commercial rooftops in Figure 2. Approximately eighty (80) percent of the commercial building PV potential in San Diego County is classified as Category 1.[36] This means there is over 1,500 MWac of PV potential on Category 1 commercial rooftops in San Diego County, sufficient for the equivalent capacity of six 250 MW GSEP projects.

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[34] Navigant, *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, prepared for The Energy Foundation, September 2004, p. 83. California commercial rooftop PV potential estimated at approximately 37,000 MWp.
[35] San Diego Regional Renewable Energy Study Group, *Potential for Renewable Energy in the San Diego Region*, Chapter 2: Solar Photovoltaic Electric, August 2005.
[36] Ibid, Table 2-9, p. 11.

Figure 2. Aerial photos of Category 1 and 2 commercial rooftops

H. RSA Uses Outdated PV Cost Assumption to Erroneously Assert GSEP is Lower Cost than Equivalent Distributed PV Capacity

There is no justification for the RSA using an obsolete cost assumption to eliminate large-scale distributed PV as an alternative to the GSEP. The RSA relies on the June 2009 CPUC *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results* assertion that the cost of a high distributed PV case is significantly higher than the other 33 percent RPS alternative cases (p. B2-69). The 33 percent reference case includes 10,000 MW of remote central station solar plants like GSEP. The assertion that the high distributed generation case is significantly higher cost than the reference case was incorrect in June 2009 and is definitively obsolete in June 2010.

The CPUC erroneously assumed a distributed PV cost of over $7/Wac in its June 2009 analysis. However, the CPUC also analyzed a sensitivity case with the capital cost of fixed thin-film PV at $3.70/Wac. The CPUC determined that at $3.70/Wac, the cost of the 33 percent standard remote case and the high DG alternative are similar. RETI has confirmed that the PV pricing cited by the CPUC in its sensitivity analysis is commercially available and not a projection, stating,"Thin film solar PV was previously treated as a sensitivity study, but due to falling costs and the increased prevalence of thin film, it is now being considered as one of the available commercial technologies in addition to tracking crystalline PV." [37]

Accurate PV pricing data has been available from the SCE urban solar PV application for over two years. SCE provided an installed cost of $3.50/Wdc (~$4/Wac) in its March 2008 application to the CPUC to build a 250 MW urban PV project. RETI states that the commercially

[37] RETI, *Phase 2B Final Report*, May 2010, p. 4-6.

available thin-film PV has a capital cost range of \$3.60 to \$4/Wac, and commercially available single-axis tracking polysilicon PV has a cost range of \$4 to \$5/Wac.[38]

These PV costs compare to a capital cost range for solar thermal, assumed to be dry-cooled, of \$5.35 to \$5.55/Wac. RETI indicates the capacity factor for thin-film PV is essentially the same as for dry-cooled solar thermal (assuming the same location). The capacity factor for single-axis tracking polysilicon PV is significantly better than that of dry-cooled solar thermal (assuming the same location). Operations and maintenance cost for either fixed thin-film PV or single-axis tracking polysilicon PV is lower than for dry-cooled solar thermal. This RETI data is summarized in Table 2 below.

Table 2. RETI capital cost, capacity factor, and O&M cost – dry-cooled solar thermal, fixed thin-film PV, and single-axis tracking polysilicon PV

Solar Technology	Capital Cost (\$/kWac)	Capacity Factor (%)	O&M Cost (\$/MWh)
Dry-cooled solar thermal	5,350 – 5,550	20 – 28	30
Fixed thin-film PV	3,600 – 4,000	20 - 27	20 - 27
Single-axis tracking polysilicon PV	4,000 – 5,000	23 - 31	17 - 25

The RSA comment on the capacity factors of solar thermal and rooftop PV is out-of-date (p. B.2-67): "The Renewable Energy Transmission Initiative (RETI) assumed a capacity factor of approximately 30 percent for solar thermal technologies and tracking solar PV and approximately 20 percent capacity factor for rooftop solar PV which is assumed to be non-tracking, for viable solar generation project locations (B&V 2008; CEC 2009)." As shown in Table 2, the RETI capacity factors of solar thermal and fixed (rooftop) solar PV are essentially the same assuming the same location.

The effect of the values in Table 2 on the levelized cost-of-energy (COE) for dry-cooled solar thermal, fixed thin-film PV, and single-axis tracking polysilicon PV is shown in Table 3.[39] The average levelized COE for either fixed thin-film PV or single-axis tracking polysilicon PV is significantly lower than the levelized COE of dry-cooled solar thermal plants.

Table 3. RETI cost-of energy (COE) comparison - dry-cooled solar thermal, fixed thin-film PV, and single-axis tracking polysilicon PV

Solar Technology	Levelized COE (\$/MWh)
Dry-cooled solar thermal	\$195 – 226 (mean: \$210)
Fixed thin-film PV	\$135 – 214 (mean: \$175)
Single-axis tracking polysilicon PV	\$138 – 206 (mean: \$172)

The CPUC determined that there would be little difference in the cost of meeting state renewable energy targets by relying predominantly on distributed PV, when current state-of-the-art pricing is assumed, instead of building 10,000 MW of remote solar capacity under the 33 percent RPS

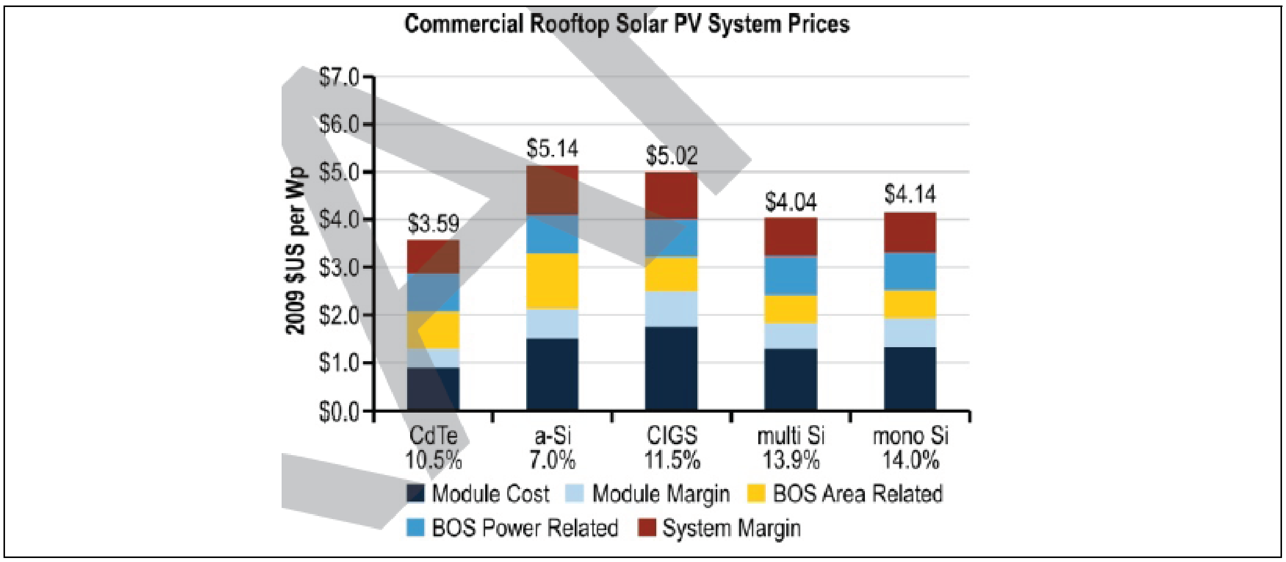
[38] Ibid, Tables 4-5, 4-7, 4-8, pp. 4-6 and 4-7.
[39] Ibid, Figure 4-1, p. 4-8.

reference case.[40] This conclusion was reached despite a number of controversial cost assumptions by the CPUC that favored the 33 percent RPS reference case.[41] An additional controversial assumption is the low assumed cost of new transmission to realize the 33 percent reference case. The CPUC assumed the total cost of new transmission would be $12 billion. The current estimate is over $27 billion.[42] When current projections regarding the cost of new transmission and associated upgrades are used, the high distributed generation alternative is more cost-effective than the 33 percent reference case.

The RETI capital cost values for PV assume 20 MW systems located at distribution substations. However, even the cost of individual commercial rooftop PV installations is now lower than the RETI cost of $5.35 to $5.55/Wac for dry-cooled solar thermal plants.

The May 2010 DOE Solar Vision Study (draft) projection of current commercial rooftop PV capital cost is provided in Figure 3.[43] These capital cost values are provided in Wdc. As shown in Figure 2, the current capital cost of commercial rooftop polysilicon PV (multi Si and mono Si) is approximately $4/Wdc. RETI identifies the range of dc-to-ac conversion factors of 0.77 to 0.85.[44] Using an average dc-to-ac conversion factor of 0.80, the capital cost of commercial rooftop polysilicon PV is approximately $4/Wdc ÷ 0.80 = $5/Wac. This is incrementally less than the $5.35 to $5.55/Wac capital cost of dry-cooled solar thermal, and the commercial rooftop PV array could be as little as 1/1,000th the size of the solar thermal plant. The most common form of thin-film PV, CdTe (cadmium-telluride), is lower in cost than polysilicon PV at approximately $3.60/Wdc. This converts to $3.60/Wdc ÷ 0.80 = $4.50/Wac.

Figure 3. Cost of commercial rooftop PV identified by DOE



a-Si: amorphous silicon thin-film PV; CIGS: copper-indium-gallium-selenide thin-film PV.

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[40] CPUC, *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results*, June 2009, p. 31.
[41] RightCycle Inc. comment letter, working group member response to June 2009 *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results*, in response to CPUC request for comments, August 28, 2009.
[42] J. Firooz, P.E., CAISO: *How Its Transmission Planning Process has Lost Sight of the Public's Interest*, April 2010, Table 2, p. 10. Total new transmission and upgrades necessary to realize 33 percent RPS reference case as of September 2009 - $27.544 billion.
[43] DOE, *DOE Solar Vision Study – DRAFT*, May 28, 2010, Chapter 4, Figure 4-4, p. 7.
[44] RETI, *Phase 1A Final Report*, August 2008, Appendix B, p. 5-5.

I. Market Price Referent with Adjustment for On-Peak Power Output Benefit of Distributed PV would be Sufficient Price to Assure Rapid Construction of 250 MW Distributed PV Alternative to GSEP

The MPR that renewable energy projects are currently compared to, the cost of power generation from a hypothetical new natural gas-fired baseload power plant, is $0.12126/kWh.[45] Solar PV produces a substantial amount of output during on-peak summer demand periods. The electric power tariff during summer on-peak periods is much higher than the average tariff over the course of a year. For example, SCE's tariff pays 3.13 times the base MPR for deliveries during the summer on-peak period.[46] SCE has determined that the adjusted MPR for a distributed PV system is 1.39 times the MPR for a baseload plant.[47] Multiplying the $0.12126/kWh MPR by 1.39 gives an adjusted MPR of $0.169/kWh. This price alone, based on my experience with the current pricing of distributed PV PPAs, may be a sufficient price signal for private developers to rapidly develop large-scale distributed PV in SCE and PG&E service territories.

However, the transmission & distribution benefits of distributed PV are real and have been quantified.[48] The estimated value range of the transmission and distribution benefits of distributed PV include $0.058/kWh in SDG&E territory and $0.023 to $0.037/kWh in SCE territory. The transmission & distribution benefits of distributed PV in PG&E territory vary widely. Some examples in PG&E territory include Fresno at $0.026/kWh and Stockton at $0.039/kWh. These estimates were developed using the E3 model for calculating transmission & distribution benefits.[49]

An MPR-adjusted price of $0.169/kWh, plus an average transmission & distribution benefit of approximately $0.030/kWh, is equivalent to an overall value to the IOU of approximately $0.20/kWh. Any price paid for distributed PV by an IOU below this price threshold should result in a net benefit to all of the IOU's ratepayers. A distributed PV price in the range $0.20/kWh would be more than sufficient to create a dynamic market for third party development of large-scale distributed PV in California urban areas.

J. Rooftop Commercial PV is More Space Efficient than GSEP and has None of the Environmental Impacts of GSEP

The RSA states, without citation: "However, based on SCE's use of 600,000-square-feet for 2 MW(ac) of energy, 75 million square feet (approximately 1,750 acres) would be required for 250 MW" (p. B2-67). SCE states in its March 2008 solar PV program testimony that 125,000 square feet of polysilicon panels are required to generate 1 MWdc.[50] This converts to about 150,000

[45] CPUC Resolution E-4214, *2008 Market Price Referent values for use in the 2008 Renewable Portfolio Standard solicitations*, December 18, 2008. MPR, 2012 operational date, 20-yr PPA: $0.12126/kWh.
[46] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Supplemental Rebuttal Testimony*, October 14, 2008, p. 3, footnote 2. "ToD (time of day) adjustment estimate calculated as weighted average of (512 summer – on hours at 3.13, 768 summer – mid at 1.35, and 2,189 winter – mid hours at 1.00) = 1.39."
[47] Ibid.
[48] CPUC Rulemaking R.06-02-012, Develop Additional Methods to Implement California RPS Program, *Pre-Workshop Comments of GreenVolts, Cleantech America, and Community Environmental Council on the 2008 Market Price Referent*, March 6, 2008, p. 15.
[49] Ibid, p. 14.
[50] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 32.

square feet per MWac, or approximately 3.5 acres per MWac.[51] This is one-half the square-footage per MWac that the RSA erroneously attributes to SCE rooftop installations. SCE has signed contracts with SunPower and Trina Solar, both suppliers of polysilicon PV panels, to provide a combined total of 245 MW of the 250 MW of PV capacity that will be owned by SCE.[52,53]

Rooftop PV is also approximately twice as space efficient as the GSEP project. The RSA states that 1,800 acres will be developed to produce 250 MWac (p. B1-2). This is more than 7 acres per MWac.

The predominant advantage of rooftop (or parking lot) PV is that it represents a compatible dual use of existing developed structures with no environmental impacts. As the RSA correctly notes, “Distributed solar PV is assumed to be located on already existing structures or disturbed areas so little to no new ground disturbance would be required and there would be few associated biological impacts” (p. B.2-68).

K. RSA Concerns about Sufficient PV Panel Manufacturing Capacity Are Baseless

The concerns expressed in the RSA regarding the availability of distributed solar PV are without foundation. The RSA states (p. B.2-70): “While it will very likely be possible to achieve 250 MW of distributed solar energy over the coming years, the very limited number of existing facilities make it difficult to conclude with confidence that it will happen within the timeframe required for the GSEP. As a result, this technology is eliminated from detailed analysis in this RSA.” Over 21,000 MW of PV systems, most of them distributed PV systems, were operational worldwide by the end of 2009.[54] More than 7,000 MW of PV was installed worldwide in 2009 alone.[55] In contrast, only 127 MW of solar thermal plants were constructed in 2009.[56]

Thin-film PV manufacturing capacity is projected to reach 7,400 MW per year in 2010.[57] First Solar alone manufactured and shipped more than 1,000 MW of thin-film panels in 2009.[58]

Worldwide conventional polysilicon PV production capacity reached 13,300 MW a year in 2008.[59] It is projected to reach 20,000 MW a year in 2010. The 2010 projections were made just as the economic slump began in late 2008. It is likely there will be some scale-back on the 2010 capacity additions due to the state of the world economy. Nonetheless, there is a tremendous amount of available worldwide PV manufacturing capacity.

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[51] There are 43,560 square feet per acre. Therefore, 150,000 square feet per MWac ÷ 43,560 square feet per acre = 3.44 acre/MWac.
[52] SNL Financial, *SoCalEd orders 200 MW of solar panels, plans solicitation for 250 MW more*, March 10, 2010.
[53] SNL Financial, *SoCalEd taps Trina Solar to supply 45 MW of PV modules*, June 9, 2010.
[54] Worldwatch Institute, *Record Growth in Photovoltaic Capacity and Momentum Builds for Concentrating Solar Power*, June 3, 2010.
[55] Ibid.
[56] Ibid.
[57] Schreiber, D. - EuPD Research, *PV Thin-film Markets, Manufacturers, Margins*, presentation at 1st Thin-Film Summit, San Francisco, December 1-2, 2008.
[58] First Solar press release, *First Solar Becomes First PV Company to Produce 1GW in a Single Year*, December 15, 2009.
[59] Schreiber, D. - EuPD Research, *PV Thin-film Markets, Manufacturers, Margins*, presentation at 1st Thin-Film Summit, San Francisco, December 1-2, 2008.

PV panel manufacturing capacity has greatly expanded worldwide in the last 2 to 3 years. The current estimated oversupply of PV panel manufacturing capacity for 2010 is 8,000 MW.[60] As a result of this oversupply, the cost of conventional polysilicon PV panels has dropped precipitously and is approaching the cost of thin-film PV panels (see Figure 3).

The RSA states that California added 158 MW of distributed PV in 2008 (p. B.2-66). California is a relatively minor player on the world PV stage. Spain added approximately 2,500 MW of primarily distributed ground-mounted PV resources in 2008.[61] Spain has a smaller economy than California. Germany, approximately the same size as California and with considerably lower solar intensity, added approximately 1,500 MW of distributed PV resources in 2008 and 3,800 MW in 2009.[62,63] Germany had an installed PV capacity of nearly 9,000 MW at the end of 2009 and has set a target PV installation rate of 3,500 MW per year.[64] The RSA expresses concerns regarding the feasibility of California doubling its 158 MW per year (2008) distributed PV installation rate as a substitute for GSEP, stating (p. B.2-69): "This would require an even more aggressive deployment of PV at more than double the historic rate of solar PV implementation than the California Solar Initiative program currently employs." This doubling of distributed PV deployment is equivalent to going from 1/20th to 1/10th the current German distributed PV installation rate. The feasibility concern expressed in the RSA is unfounded in light of German success with a high rate of distributed PV deployment.

The high distributed PV alternative studied by the CPUC anticipates the installation of 15,000 MW of distributed PV by 2020.[65] RETI has gradually dropped the amount of new renewable energy resources needed to reach 33 percent by 2020, the "net short," from 74,650 gigawatt-hours (GWh) per year initially to a current "low load" net short of 36,926 MW.[66] The low load net short is one-half the net short used by the CPUC in June 2009 to estimate the cost of achieving 33 percent by 2020. 15,000 MW of distributed PV would provide about 30,000 GWh/yr.[67] 15,000 MW of distributed PV would provide over 80 percent of the low load net short of 36,926 MW.

California could easily install 15,000 MW of distributed PV by 2020 if it approached the annual distributed PV installation rates that have already been achieved in practice in Spain and Germany. Existing worldwide PV manufacturing capacity, either thin-film alone or thin-film and

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[60] B. Murphy – Fulcrum Technologies, Inc., *The Power and Potential of CdTe (thin-film) PV*, presented at 2nd Thin-Film Summit, San Francisco, December 1-2, 2009.
[61] PV Tech, *Worldwide photovoltaics installations grew 110% in 2008, says Solarbuzz*, March 16, 2009.
[62] PV Tech, *German market booming: Inverter and module supplies running out at Phoenix Solar*, November 15, 2009.
[63] Worldwatch Institute, *Record Growth in Photovoltaic Capacity and Momentum Builds for Concentrating Solar Power*, June 3, 2010.
[64] Chadbourne & Parke Project Finance Newswire, *Germany Cuts Solar Subsidy*, April 2010.
[65] CPUC, *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results*, June 2009.
[66] RETI discussion draft, *RETI Net Short Update - Evaluating the Need for Expanded Electric Transmission Capacity for Renewable Energy*, February 22, 2010. Low load scenario, net short = 36,926 MW.
[67] The CPUC reference case assumes 3,235 MW of solar PV will generate 6,913 GWh per year under ideal Southern California desert solar insolation conditions. This is a production ratio of 2,137 GWh per MWac. However, solar insolation in the Central Valley and California urban areas will on average be approximately 10 less than ideal desert sites. For this reason a production ratio of 2,000 GWh per year per MWac is assumed for the Central Valley and urban areas.

conventional polysilicon, could readily supply a PV demand of 1,500 to 2,500 MW a year in California.

L. Slight Reduction in Output from Distributed PV in Los Angeles, Central Valley, or Bay Area Is Offset by Transmission Losses from GSEP to These Load Centers

The RSA implies that the superior solar intensity at the GSEP location in the Mojave Desert is a substantive reason for eliminating distributed PV from consideration, stating (p. B.2-67):

> "The location of the distributed solar PV would impact the capacity factor of the distributed solar PV. Capacity factor depends on a number of factors including the insolation of the site. Because a distributed solar PV alternative would be located throughout the state of California, the insolation at some of these locations may be less than in the Mojave Desert."

The solar insolation at the GSEP site is about 10 to 15 percent better than the composite solar insolation for Los Angeles, the Central Valley, and Oakland.[68,69] However, the CEC estimates average transmission losses in California at 7.5 percent and peak transmission losses at 14 percent.[70] The incrementally better solar insolation at the GSEP site is almost completely negated by the losses incurred by transmitting GSEP solar power to California urban areas. In contrast, distributed PV has minimal losses between generation and user.

M. CEC Has Already Determined Distributed PV Can Compete Cost-Effectively with Other Forms of Generation

The CEC denied an application for a 100-megawatt natural-gas-fired gas turbine power plant, the Chula Vista Energy Upgrade Project (CVEUP), in June 2009 in part because rooftop solar PV could potentially achieve the same objectives for comparable cost.[71]

This June 2009 CEC decision implies that any future applications for gas-fired generation in California, or any other type of generation including remote central station renewable energy generation like GSEP that require public land and new transmission to reach demand centers, should be measured against using urban PV to meet the power need. The CEC's final decision in the CVEUP case stated:[72]

> "Photovoltaic arrays mounted on existing flat warehouse roofs or on top of vehicle shelters in parking lots do not consume any acreage. The warehouses and parking lots continue to perform those functions with the PV in place. (Ex. 616, p. 11.)….Mr. Powers (expert for intervenor) provided detailed analysis of the costs of such PV, concluding that there was little or no difference between the cost of energy provided by a project such as

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[68] U.S. DOE, *Stand-Alone Flat-plate Photovoltaic Systems: System Sizing and Life-Cycle Costing Methodology for Federal Agencies*, 1984, Appendix, p. A-27.
[69] NREL, *Solar Radiation Data Manual for Flat-Plate and Concentrating Collectors*, California cities data: http://rredc.nrel.gov/solar/pubs/redbook/PDFs/CA.PDF
[70] E-mail communication between Don Kondoleon, manager - CEC Transmission Evaluation Program, and Bill Powers of Powers Engineering, January 30, 2008.
[71] CEC, Chula Vista Energy Upgrade Project - Application for Certification (07-AFC-4) San Diego County, *Final Commission Decision*, June 2009.
[72] Ibid, pp. 29-30.

> the CVEUP (gas turbine peaking plant) compared with the cost of energy provided by PV. (Ex. 616, pp. 13 – 14.)….PV does provide power at a time when demand is likely to be high—on hot, sunny days. Mr. Powers acknowledged on cross-examination that the solar peak does not match the demand peak, but testified that storage technologies exist which could be used to manage this. The essential points in Mr. Powers' testimony about the costs and practicality of PV were uncontroverted."

The CEC concluded in the CVEUP final decision that PV arrays on rooftops and over parking lots may be a viable alternative to the gas turbine project proposed in that case, and that if the gas turbine project proponent opted to file a new application a much more detailed analysis of the PV alternative would be required.

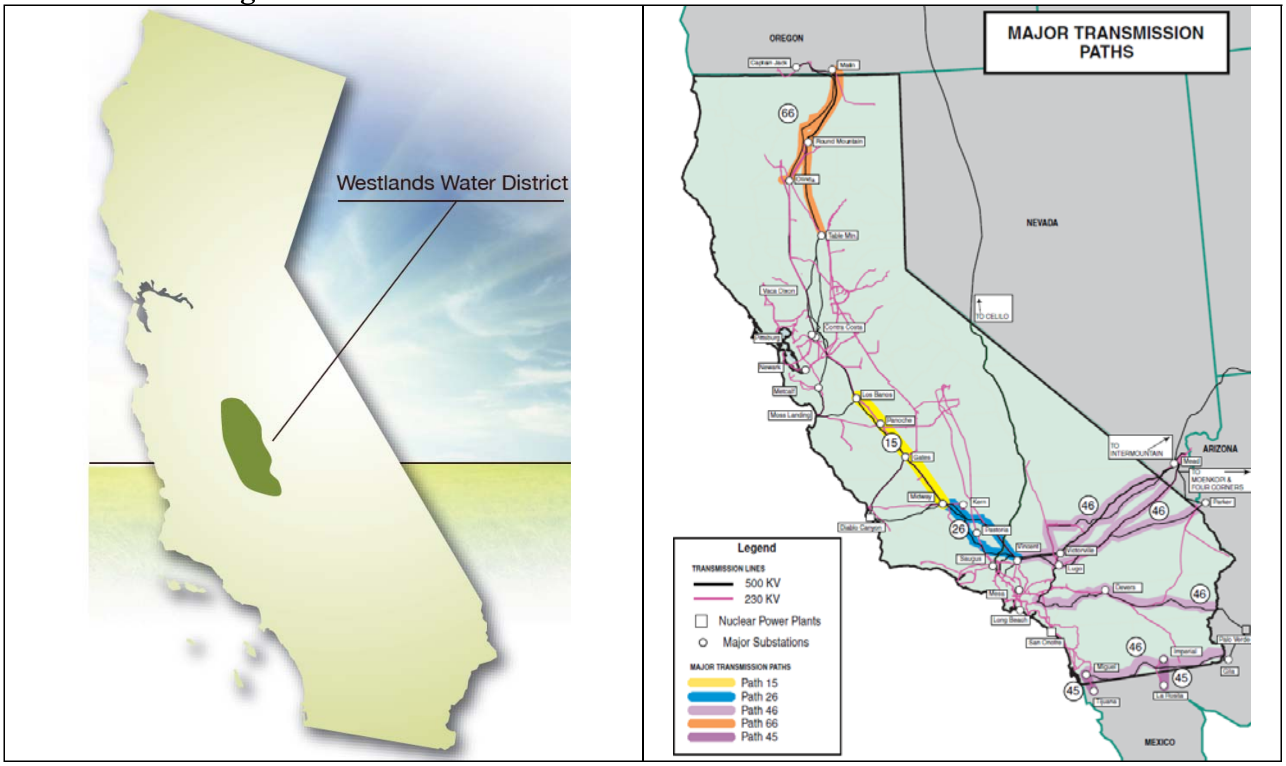
IV. Locating GSEP in the Proposed Westlands Water District CREZ would Avoid Environmental Impacts at the GSEP Site

The Westlands Water District ("Westlands"), on the west side of the Central Valley, is undergoing study by RETI as a Competitive Renewable Energy Zone (CREZ) capable of providing 5,000 MW of utility-scale solar development. Westlands covers over 600,000 acres of farmland in western Fresno and Kings Counties. The proposed "Central California Renewable Master Plan" will utilize permanently retired farmlands in Westlands for solar development. An overview of this master plan is attached. As stated in the master plan overview, "Due to salinity contamination issues, a portion of this disturbed land has been set aside for retirement and will be taken out of production under an agreement between Westlands and the U.S. Department of Interior." Approximately 30,000 acres of disturbed Westlands land, equivalent to 5,000 MW of solar capacity, will be allocated for renewable energy development under the plan.

Transmission Pathway 15 passes through Westlands. Path 15 can transmit 5,400 MW from south-to-north.[73] The transmission capacity from north-to-south is 3,400 MW. The location of Westlands relative to Path 15 is shown in Figure 4.

[73] Transmission & Distribution World, California bulks up to provide more transmission capacity, June 1, 2004.

Figure 4. Location of Westlands Water District and Path 15[74,75]



5,000 MW of solar power can be developed in Westlands with potentially no expansion of the existing Path 15 high voltage transmission capacity that serves Westlands now.

5,000 MW is half of the total remote in-state utility-scale solar contemplated in the June 2009 CPUC 33 percent reference case.[76] The remote in-state solar component of the reference case consists of 3,235 MW central station PV and 6,764 MW central station solar thermal. The anticipated energy output of 5,000 MW of fixed PV in Westlands would be about 10,000 GWh/yr.[77] This is approximately 30 percent of the RETI low load net short of 36,926 MW.

The RSA states that the Gabrych disturbed lands alternative near the GSEP site does not meet project objectives due to the inability to assure site control of multiple private parcels by the end of 2010 (p. B.2-53). Site control would not be an issue in the proposed Westlands CREZ. Westlands is actively marketing the 30,000-acre area for development of central station solar power plants. Development of solar projects on the Westlands property is intended (by Westlands) to serve as a source of income on land that has been permanently retired from agricultural production.

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[74] Anthem Group press release, Central California Renewable Master Plan, March 2010.
[75] CEC, *Strategic Transmission Investment Plan*, November 2005, p. 11.
[76] CPUC, *33% RPS Implementation Analysis Preliminary Results*, June 2009, Appendix C, p. 87.
[77] The CPUC reference case assumes 3,235 MW of solar PV will generate 6,913 GWh per year under ideal Southern California desert solar insolation conditions. This is a production ratio of 2,137 GWh per MWac. However, solar insolation in the Central Valley and California urban areas will on average be approximately 10 less than ideal desert sites. For this reason a production ratio of 2,000 GWh per year per MWac is assumed for the Central Valley and urban areas.

Prioritizing distributed PV projects, combined with the location of central station solar projects in Westlands, would allow California to achieve its 33 percent by 2020 renewable energy target with almost no environmental impacts related to the solar energy component of the renewable energy portfolio.

V. Conclusions

The RSA analysis of the distributed PV alternative to GSEP uses flawed logic and outdated data to improperly eliminate distributed PV as an alternative. In fact, distributed PV is a fully viable and cost-effective alternative that eliminates the environmental impacts that would be caused by the GSEP project. The RSA should have concluded that distributed PV is a superior alternative to the GSEP project.

Beyond the issue of distributed PV being a superior alternative to GSEP on cost and environmental grounds, there are lower-impact sites in California for central station solar projects like GSEP. The Westlands Water District is a low impact "shovel ready" alternative to the GSEP site for central station solar projects. Westlands requires no new high voltage transmission to move up to 5,000 MW of solar power to California load centers. This means solar projects located in Westlands will not face project delays due to lack of high voltage transmission capacity. The steadily declining renewable energy net short to achieve the 33 percent by 2020 target, now as low as 36,926 MW, means fewer renewable projects overall are necessary to meet the 33 percent target. The CEC should not approve solar projects with unmitigatable impacts like GSEP when 5,000 MW of otherwise unusable disturbed land with no environmental issues and 5,000 MW of high voltage transmission capacity sits idle.

Declaration of Bill Powers, P.E.

Re: Testimony on Alternatives to the Application for Certification for the Genesis Solar Energy Project

Docket No. 09-AFC-8

I, Bill Powers, declare as follows:

1) I am a self-employed consulting engineer.

2) My relevant professional qualifications and experience are set forth in the attached resume and the attached testimony and are incorporated herein by reference.

3) I prepared the testimony attached hereto and incorporated herein by reference, relating to the distributed PV alternative to the project.

4) I prepared the testimony attached hereto and incorporated herein by reference relating to the proposed Genesis Solar Energy Project.

5) It is my professional opinion that the attached testimony is true and accurate with respect to the issues that it addresses.

6) I am personally familiar with the facts and conclusions described within the attached testimony and if called as a witness, I could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: JUNE 18, 2010 Signed: Bill Powers, P.E.

At: SAN DIEGO, CA

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Master of Public Health – Environmental Sciences, University of North Carolina
Bachelor of Science – Mechanical Engineering, Duke University

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
American Society of Mechanical Engineers
Air & Waste Management Association

TECHNICAL SPECIALTIES

Twenty-five years of experience in:

- San Diego and Baja California regional energy planning
- Power plant technology, emissions, and cooling system assessments
- Combustion and emissions control equipment permitting, testing, monitoring
- Oil and gas technology assessment and emissions evaluation
- Latin America environmental project experience

SAN DIEGO AND BAJA CALIFORNIA REGIONAL ENERGY PLANNING

San Diego Smart Energy 2020 Plan. Author of October 2007 "San Diego Smart Energy 2020," an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. CHP systems would provide approximately 47 percent. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. This target is based on City of San Diego experience. San Diego has consistently achieved energy efficiency reductions of 20 percent on dozens of projects. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy whether, and for grid reliability support.

Photovoltaic technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Photovoltaic arrays as alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The preliminary decision issued by the presiding CEC commissioner in the case recommended denial of the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines. No final decision has yet been issued in the proceeding (as of May 2009).

San Diego Area Governments (SANDAG) Energy Working Group. Public interest representative on the SANDAG Energy Working Group (EWG). The EWG advises the Regional Planning Committee on issues related to the coordination and implementation of the Regional Energy Strategy 2030 adopted by the SANDAG Board of Directors in July 2003. The EWG consists of elected officials from the City of San Diego, County of San Diego and the four subareas of the region. In addition to elected officials, the EWG includes stakeholders representing business, energy, environment, economy, education, and consumer interests.

Development of San Diego Regional Energy Strategy 2030. Participant in the 18-month process in the 2002-2003 timeframe that led to the development of the San Diego Regional Energy Strategy 2030. This document was adopted by the SANDAG Board of Directors in July 2003 and defines strategic energy objectives for the San Diego region, including: 1) in-region power generation increase from 65% of peak demand in 2010 to 75% of peak demand in 2020, 2) 40% renewable power by 2030 with at least half of this power generated in-county, 3) reinforcement of transmission capacity as needed to achieve these objectives. The SANDAG Board of Directors voted unanimously on Nov. 17, 2006 to take no position on the Sunrise Powerlink proposal primarily because it conflicts the Regional Energy Strategy 2030 objective of increased in-region power generation. The Regional Energy Strategy 2030 is online at: http://www.energycenter.org/uploads/Regional_Energy_Strategy_Final_07_16_03.pdf

Imperial Valley Study Group. Participant in the Imperial Valley Study Group (IVSG), and effort funded by the CEC to examine transmission options for maximizing the development of geothermal resources in Imperial County. Advised the IVSG that no alternatives other than the Sunrise Powerlink or a similar variant were be considered to move Imperial Valley geothermal generation to San Diego. Initiated a dialogue on IVSG's failure to consider alternatives that was incorporated into the IVSG April 12, 2005 meeting minutes (see: http://www.energy.ca.gov/ivsg/documents/2005-04-12_meeting/2005-04-12_AMNDED_IVSG_MINUTES.PDF). Also co-authored with the Utility Consumers' Action Network an October 14, 2005 alternative letter report to the September 30, 2005 IVSG final report that documents numerous feasible transmission alternatives to the Sunrise Powerlink that were not considered by IVSG. The October 14, 2005 IVSG alternative letter report also served as a comment letter on the CEC's 2005 Integrated Energy Policy Report webpage is available at: http://www.energy.ca.gov/2005_energypolicy/documents/2005-10-11_DER_comments/10-14 05_Utility_Consumers_Action_Network_BPPWG.pdf

COMBUSTION AND EMISSIONS CONTROL EQUIPMENT PERMITTING, TESTING, MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author. Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California. Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the wide availability of urea on the island. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California. Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines will be equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea will be used as the SCR reagent to avoid trigger hazardous material storage requirements. A separate permit will be obtained for the NO_x and CO continuous emissions monitoring systems. The ATCs is pending.

Industrial Boilers – NO_x BACT Evaluation for San Diego County Boilers. Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for three industrial boilers to be located in San Diego County. The BACT included the review of low NO_x burners, FGR, SCR, and low temperature oxidation (LTO). State-of-the-art ultra low NO_x burners with a 9 ppm emissions guarantee were selected as NO_x BACT for these units.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County. Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District. Project manager and lead engineer for preparation of air permit application and BACT evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output. Project manager and lead engineer for preparation of BACT evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM. Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM passed the subsequent annual RATA without problems as a result of changes to some of the CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "\$/kwh" and "\$/ton" cost of these control systems was developed in the evaluation.

Gas Turbines – Evaluation of Proposed NO_x Control System to Achieve 3 ppm Limit. Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed Best Available Retrofit Control Technology (BARCT) emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

Ethanol Plant Dryer – Penn-Mar Ethanol, LLC. Lead engineer on BACT evaluation for ethanol dryer. Dryer nitrogen oxide (NO_x) emission limit of 30 ppm determined to be BACT following exhaustive review of existing and pending ethanol plant air permits and discussions with principal dryer vendors.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for a BARCT evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system and replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

POWER PLANT TECHNOLOGY, EMISSIONS, AND COOLING SYSTEM ASSESSMENTS

IGCC and Low Water Use Alternatives to Eight Pulverized Coal Fired 900 MW Boilers. Expert for cities of Houston and Dallas on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas. Also analyzed East Texas as candidate location for CO_2 sequestration due to presence of mature oilfield CO_2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Assessment of CO_2 Capture and Sequestration for IGCC Plants. Author of assessment prepared for a public interest client of CO_2 capture and sequestration options for IGCC plants. The assessment focuses on: 1) CO_2 sequestration performance of operational large-scale CO_2 sequestration projects, specifically the Weyburn CO_2 enhanced oil recovery (EOR) project, and 2) CO_2 EOR as the vehicle to offset the cost of CO_2 capture and serve as the platform for an initial set of U.S. IGCC plants equipped for full CO_2 capture and storage.

Assessment of IGCC Alternative to Proposed 250 MW Circulating Fluidized Bed (CFB) Unit. Lead engineer to evaluate IGCC option to proposed 250 MW CFB firing Powder River Basin coal. Project site is in Montana, where CO_2 EOR opportunities exist in the eastern part of the state.

500 MW Coal-Fired Plant –Air Cooling and IGCC. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^oF. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Retrofit of SCR to Existing Natural Gas-Fired Units. Lead expert in successful representation of interests of the city of Carlsbad, California to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a 1,000 MW merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. Ultimately the plant owner was compelled to comply with the existing NO_x rule and install SCR on all five boilers at the plant. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Proposed 1.500 MW Pulverized Coal Power Plant. Provided testimony challenge to air permit issued for Peabody Coal Company's proposed 1,500 MW pulverized-coal fired power plant in Kentucky. Presented case that IGCC is a superior method for producing power from coal, from both environmental and energy efficiency perspective, than the proposed pulverized-coal plant. Presented evidence that IGCC is technically feasible and cost-competitive with pulverized coal.

Presidential Permits to Two Border Power Plants – Contested Air and Water Issues. Provided testimony on the air emissions and water consumption impact of two export power plants, Intergen and Sempra, in Mexicali, Mexico, and modifications necessary to minimize these impacts, including air emission offsets and incorporation of air cooling. These two plants are located within 3 miles of the California border, are interconnected only to the SDG&E transmission grid, and under the local control of the California Independent System Operator. Provided evidence that the CAISO had restricted the amount of power these two plants could export when commercial operation began in June 2003 to avoid unacceptable levels of transmission congestion on SDG&E's transmission system. The federal judge determined that the DOE had conducted an inadequate environmental assessment before issuing the Presidential Permits for these two plants and ordered the DOE to prepare a more comprehensive assessment.

300 MW Coal-Fired Circulating Fluidized Bed Boiler Plant - Best Available NO_x Control System. Provided testimony in dispute in case where approximately 50 percent NO_x control using selective non-catalytic reduction (SNCR) was accepted as BACT for a proposed 300 MW circulating fluidized bed (CFB) boiler plant in Kentucky. Presented testimony that SNCR was capable of continuous NO_x reduction of greater than 70 percent on a CFB unit and that low-dust, hot side selective catalytic reduction (SCR) and tail-end SCR were technically feasible and could achieve greater than 90 percent NO_x reduction.

Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Prepared preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^oF and 13 ^oF were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^oF and 13 ^oF. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW

Roseton Generating Station in New York. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications. Closed-cycle cooling has been accepted as an issue that will be adjudicated.

2,000 MW Nuclear Power Plant – Closed-Cycle Cooling Retrofit Feasibility. Prepared assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station in New York. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Best Available NO_x Control System for 525 MW Coal-Fired Circulating Fluidized Bed Boiler Plant. Provided testimony in dispute over whether 50 percent NO_x control using selective non-catalytic reduction (SNCR) constituted BACT for a proposed 525 MW circulating fluidized bed (CFB) boiler plant in Pennsylvania. Presented testimony that SNCR was capable of continuous NO_x reduction of greater than 70 percent on a CFB unit and that tail-end selective catalytic reduction (SCR) was technically feasible and could achieve greater than 90 percent NO_x reduction.

Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

Emission Increases Associated with Retrofit of SCR Existing Coal-Fired Units. Provided testimony in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling. Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant in central coastal California. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ^oF) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network – Lima, Peru. Project leader for project to prepare specifications for a fourteen station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM_{10} and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project – Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Renewable Energy Resource Assessment Proposal – Panama. Translated and managed winning bid to evaluate wind energy potential in Panama. Direct interaction with the director of development at the national utility monopoly (IRHE) was a key component of this project.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at turbocharger/air cooler assembly plant in Mexicali, Mexico. Source specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish for review by the Mexican federal environmental agency (SEMARNAP).

Air Pollution Control Equipment Retrofit Evaluation – Mexico. Project manager and lead engineer for comprehensive evaluation of air pollution control equipment and industrial ventilation systems in use at assembly plant consisting of four major facilities. Equipment evaluated included fabric filters controlling blast booth emissions, electrostatic precipitator controlling welding fumes, and industrial ventilation systems controlling welding fumes, chemical cleaning tank emissions, and hot combustion gas emissions. Recommendations included modifications to fabric filter cleaning cycle, preventative maintenance program for the electrostatic precipitator, and redesign of the industrial ventilation system exhaust hoods to improve capture efficiency.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at automotive components assembly plant in Acuña, Mexico. Source-specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, *"Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,"* presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, *"Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,"* presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* to be presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

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S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094