Clean and Diversified Energy Initiative

WESTERN GOVERNORS' ASSOCIATION

Solar Task Force Report

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Western Governors' Association
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The Western Governors' Association's Clean and Diversified Energy Advisory Committee (CDEAC) commissioned this task force report in February 2005. Members of the Task Force are listed below. This is one of several task force reports presented to the CDEAC on December 8, 2005 and accepted for further consideration as the CDEAC develops recommendations for the Governors. While this task force report represents the consensus views of the members, it does not represent the adopted policy of WGA or the CDEAC. At their Annual Meeting in June, 2006, Western Governors will consider and adopt a broad range of recommendations for increasing the development of clean and diverse energy, improving the efficient use of energy and ensuring adequate transmission. The CDEAC commends the Task Force for its thorough analysis and thoughtful recommendations.

Members of the Solar Task Force

Glenn Hamer (Chair)	First Solar (CDEAC member)
Fred Morse	Morse Associates, Inc.
Steve Chadima	Energy Innovations, Inc.
David Kearney	Kearney & Associates
Don Aitken	Donald Aitken Associates
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Jon Bertolino	Sacramento Municipal Utility District
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Facilitator

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Quantitative Working Group

The quantitative working group was created by the CDEAC to compare the analysis of data among task forces in order to ensure consistency in assumptions across the reports. The following members contributed to this report:

Doug Arent	National Renewable Energy Laboratory
John Tschirhart	Department of Economics, University of Wyoming
Dick Watson	Quantitative Working Group

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Overview

To the Western Governors:

The continued prosperity of the West depends on strong economic growth, which in turn requires a secure and predictable energy supply. The recent volatility of wholesale natural gas prices, which have risen from under $3.00/MBTU in 2001[1] to more than $14/MBTU in October of 2005[2]**,** are having a dramatic impact on natural gas and electricity prices facing the citizens in your states, prompting many to look for alternative sources of energy to meet their needs. The solar radiation in your states is the most abundant of all the renewable sources and a practical energy resource of great economic value. Solar energy can make a major contribution to the 2015 goal of 30,000 MW of clean energy adopted by the WGA in 2004. In fact, we project that as much as 8,000 MW of capacity could be installed with a combination of distributed solar electricity systems and central concentrating solar power (CSP) plants by 2015, and an additional 2,000 MW_{th} of solar thermal systems could be installed in the same timeframe. At that point, the cost of electricity from future CSP plants should be on a par with that from plants burning costly natural gas, and distributed systems should have declined in price to the point that they should be able to produce electricity below retail utility rates in most parts of the West. Best of all, the fuel source for these systems is free. Once the systems are installed, all price volatility is removed, yielding the secure and predictable energy supply so critical to the region's growth.

Initial system expense is currently the single biggest barrier to widespread deployment of solar. Worldwide experience has shown, however, that these costs can be driven down through accelerated growth sparked by temporary economic-development policies. The recently enacted two-year, 30 percent Federal investment tax credit is a case in point. For distributed solar technologies, this credit will provide short-term help to increase the number of systems installed throughout the WGA states. It will have little effect on central-station solar installations not already well underway, however, because the two-year duration is too short relative to the time needed to develop projects and bring them into operation. It is imperative, therefore, that you use your considerable leverage in Washington to ensure that this credit is extended for a full ten years. Without the assurance of this support, large central systems will find it difficult to attract financial backers, and manufacturers of components used in distributed solar systems will not have the confidence to make investments to expand production capacity that will ultimately drive down costs for everyone.

This report outlines additional initiatives needed at the state and Federal level to unleash private investment in solar. Many involve changes in policies or regulations with little or no budgetary impact. Where direct incentives are involved, they are designed to decline over the next ten years to the point that they are no longer needed to sustain a rapidly expanding industry.

The Solar Task Force offers the following set of recommendations to the Governors that if enacted will enable solar technologies to make a meaningful contribution to the 30,000 MW of new clean, diversified energy.

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1 http://futures.tradingcharts.com/hist_NG20013.html

2 http://www.wtrg.com/daily/gasprice.html

- Work aggressively with your Congressional delegations to extend the 30% Federal investment tax credit to a 10-year term and remove the $2000 cap on residential systems.
- Expand the deployment of central solar plants by encouraging 30-year power purchase agreements and aggregation of utility plant orders and project bids to accelerate scale-up cost reductions.
- Encourage widespread adoption of distributed solar by creating incentives either in the form of declining up-front rebates that help reduce the "first cost" challenge in purchasing a solar system or by establishing ongoing performance-based incentives that pay for production of electricity, both of which have been adopted in certain WGA states. Incentives should be available to both solar thermal (space heating and cooling as well as water heating) and solar electricity systems and apply equally to residential and commercial buildings.
- Reward solar production and encourage conservation during critical peak periods by facilitating simplified interconnection standards, net metering, and rate structures that will benefit distributed solar systems.
- Exempt both CSP plants and distributed solar systems from state and local sales and property taxes. The loss to your treasury of these taxes will be more than compensated by increases in tax revenues through growth in personal and corporate income taxes, gross receipts taxes from equipment sales, compensating taxes on imported equipment and other taxes specific to electric utilities. In addition some of the money that now leaves your state's economy for energy purchases will instead remain at home.
- Integrate solar into existing state policies such as a Renewable Portfolio Standard, which can help develop central and distributed solar markets when structured properly.
- Consider adopting target tariffs that reflect the value of solar energy for peak periods and that adjust for natural gas price changes.

With these policies implemented, an additional 32,500 jobs will be created and a new solar energy manufacturing industry will emerge in the West.

Broadly speaking, there are two technology market segments that can take advantage of the West's abundant solar resource: central station and distributed generation. Central station solar fits the typical power-production model employed throughout the grid, generating electricity at an often remote location and wheeling that energy across the grid to recipient utilities and other customers. In contrast, distributed solar systems are installed on rooftops or on land adjacent to buildings, enabling homeowners, businesses, schools and government buildings to generate their own electricity and/or heat.

Central – Kramer Junction (CA) Solar Electric Generating Station

Distributed – Rooftop PV system at Swinerton, Inc. offices in Concord, CA

Both central station and distributed solar can be successfully deployed in the West, and both will be needed to help meet the Governors' target of 30,000 MW of new clean, diversified energy by 2015. However, the barriers to widespread adoption and consequently the policies needed to overcome them are in most cases as different as the two deployment strategies themselves. For these reasons, the balance of this report is divided into two sections, one covering central station solar and the other distributed solar. Beginning with an executive summary, each section presents the various types of solar systems that can be deployed; specific barriers they face; the policies and programs we recommend that the Governors consider to overcome those barriers; and the potential impact in energy production, jobs and other economic and environmental benefits that the WGA states will enjoy as a result.

Respectfully submitted,

The Solar Task Force

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Part I. Central Station Solar

Summary

The Case for Central Station Solar Power Deployment Now in the Southwest

- **Deploying 4 GW of central station solar plants can establish a new industry in the Southwest**
- **At that scale central station solar, which works best near peak demand times, can produce power at under 10¢/kWh**
- **Such central station solar deployment would add thousands of jobs and millions of revenue dollars to the States**
- **With Federal and State policy help to deploy 4 GW, central station solar power can turn the intense southwestern sunshine into a plentiful source of low-cost electricity**
- **The policy initiatives needed to spur central station solar deployment may require no State funds**

"Western North America is blessed with an abundance of natural energy resources that have been critical to accommodating substantial population growth and fueling a dynamic economy…. Western Governors, and especially Governors from the Southwestern States, have long recognized the vast and largely untapped potential for solar powered generation in the region."[3]

Increasingly volatile fossil-fuel prices since the WGA adopted this 2004 resolution have underscored the growing need for a more secure energy supply, especially during peaks in the West's burgeoning demand.[4] The projected 2015 Western electricity market peak load is 199 GW—a 58% increase over today's peak.[5]

Central station solar power technologies include both solar thermal electric and photovoltaic (PV) generators. The vast majority of the central station solar projects underway or actually deployed today are concentrating solar power (CSP) technologies, which as a class include all the thermal generators as well as concentrating PV. Flat-plate PV can also be used for utility-scale systems, but the much higher energy market values of distributed generation make it the more attractive deployment mode for flat plate PV today. As PV costs decline and its market volume grows, central station flat plate PV deployment will become more commonplace. This section, therefore, focuses on CSP, while the Distributed Generation (DG) section deals exclusively with PV and solar water heating systems.

The four principal CSP technologies are parabolic troughs, dish-Stirling engine systems, power towers, and concentrating photovoltaic systems (CPV). CSP plants are utility-scale generators that produce electricity by using mirrors or lenses to efficiently concentrate the sun's energy to drive turbines, engines, or high-efficiency photovoltaic cells. CSP plants inherently generate maximum power on summer afternoons, near peak demand periods. Trough and tower configurations include large power blocks for MW-scale output, whereas dish-Stirling and CPV systems are comprised of a large number of smaller modular units. Parabolic trough systems have been deployed in major commercial installations. The other principal CSP technologies have less commercial experience, but all have seen significant pre-commercial

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[3] WGA Policy Resolution 04-14, "Clean and Diversified Energy for the West," Santa Fe, NM, June 22, 2004.
[4] NREL analysis of historical and projected fuel prices. (Doug Arent, National Renewable Energy Laboratory)
[5] Based on The Seams Steering Group of the Western Interconnection (SSG-WI) 2015 load projection for transmission reference case expansion studies and U.S. DOE Energy Information Administration 2005 load projection.

Figure I-1.   CSP Technologies (from upper left, tower, trough, dish-Stirling, and CPV)

development in the past two decades. Therefore, the Task Force anticipates that they all have ample potential for large-scale commercialization.

The CSP industry core is small, but draws extensively upon production capacity of major corporations. There are 12 Solar Energy Industry Association CSP members. The four largest of these, Solargenix, Solel, Solar Millennium and Stirling Energy Systems, today employ a total of 220 people. CSP suppliers and contractors today include Flabeg, Schott, Siemens, 3M, Schuff Steel, Hoffman Construction and Sundt Construction, collectively with over $8.8 billion annual net income. This infrastructure can support a very rapid CSP build-up in the next 10 years.

The southwestern United States possesses a world-class, well-distributed, and nearly untapped solar energy resource. It is most abundant in California, Nevada, Arizona, and New Mexico and can ultimately support CSP plants totaling several thousand GW. The Task Force assessed the overall near-term potential for CSP capacity in the Southwest, using a sophisticated geographical information system (GIS) technique that identified areas having all the necessary conditions for development. The eligibility requirements included high insolation, near-level land, non-sensitivity to CSP use, and proximity to transmission. Figure I-2 shows the resulting numerous prime plant sites, totaling 200 GW of potential power production.

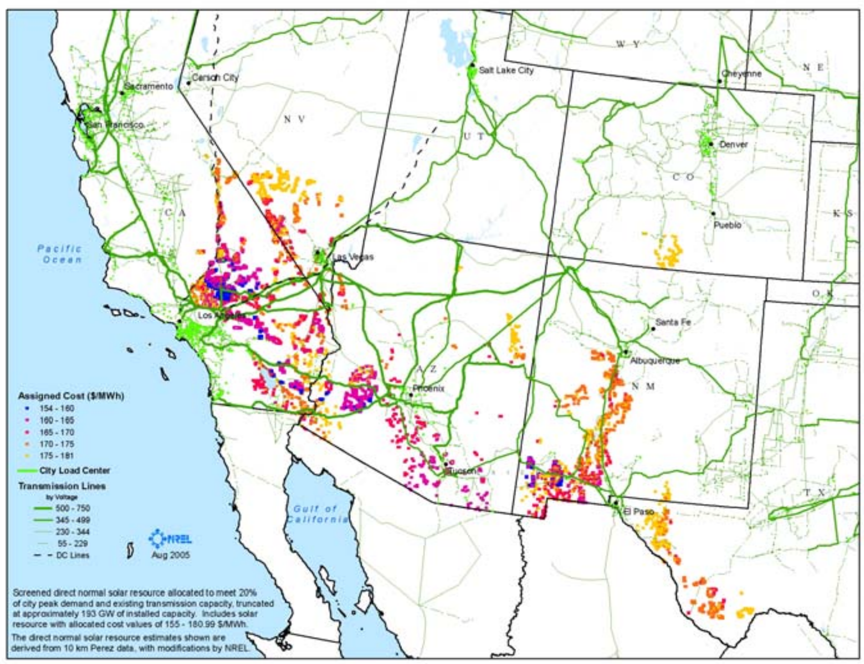

Figure I-2. Optimal CSP Sites in the SW using GIS Mapping

Large-scale central station solar deployment can help meet some of the West's most pressing needs:

- ***Peak energy supply –*** central station solar plants naturally have superior load matching because high sunlight periods create both peak demand and peak production. Further, some CSP technologies can be *dispatchable*, delivering firm power during peak demand. Trough and tower plants using thermal storage or supplemental fossil-fired components are particularly suited to this purpose.
- ***Fuel price volatility*** – Central station solar power provides a hedge against natural gas price fluctuations. The variable O&M costs for central station solar plants are low and predictable because the fuel (sunlight) is free after the plant capital costs are amortized. Central station solar plants, much

like hydropower plants, can operate well for longer then 30 years, generating extremely low-cost power for many years past their amortization periods.

- ***Water conservation*** – Dish and PV systems require no water for cooling and only minimal amounts for mirror washing. Trough and tower plants can be built to use dry cooling technologies and then also consume very little water. Thus, central station solar power can be an attractive power option in the dry Southwestern States.
- ***Economic development*** – Central station solar deployment can stimulate significant job creation and growth of manufacturing infrastructure, ancillary commerce, and tax revenues, as well as growth and diversity in Gross State Product. Recently, for example, Black & Veatch projected that 4 GW of CSP deployment in California would produce a net $22 billion increase in gross State output, including 13,000 construction jobs, 1,100 permanent operations jobs, and $2 billion in State tax revenues.[6]

CSP can become price competitive in the near term. The Solar Task Force projects that, with a deployment of 4 GW, total nominal cost of CSP electricity would fall below 10¢/kWh. Analysis shows that CSP at 10¢/kWh is equivalent to a blended base load-peak value of natural gas generation at a fuel cost of $7/MMbtu.[7] Achieving 4 GW of CSP deployment by 2015 from the current 354-MW base requires growth similar to that of the PV and wind industries in the past decade. A Solar Task Force poll of the CSP industry indicated capability to produce over 13 GW by 2015 if the market could absorb that much.

Central station solar power will produce societal and environmental benefits. Large central station solar deployments will cause reductions in natural gas, oil, and coal use, consequently reducing greenhouse gas production. Black & Veatch conservatively projected the annual CO_2 reduction from 4 GW of CSP to be 7.6 million tons, or 7% of present California electric utility output.[6, 8] They also project substantial avoided emissions of NO_x, CO, and volatile hydrocarbons.

Policy can effectively stimulate central station solar development. The following examples highlight central station solar developments encouraged by local policy measures.

> ***California (1984):*** Incentives including a 25% Federal Investment Tax Credit (ITC), a 25% State ITC, property tax exemptions, and "standard offer" contracts that guaranteed a long-term market for their output, fostered development of 9 Solar Electric Generating Station (SEGS) plants between 1984 and 1990 near Barstow, CA. When the policies expired in 1990, project development activity on the SEGS abruptly stopped. With combined output of 354 MW and a design life of 30 years, all the plants are still in operation today.
>
> ***Arizona and Nevada (2001):*** Utility renewable energy portfolio requirements in Arizona and Nevada have been key drivers in launching 1-MW and 64-MW CSP plants with anticipated start-up in 2006 and 2007, respectively. Arizona Public Service will own and operate the 1-MW plant and Nevada Power will purchase the 64-MW plant's output. Another key factor for the Nevada plant was legislation enabling Nevada Power to enter into a long term Power Purchase Agreement (PPA) with the developer. Both States mandate that part of the required renewable energy be solar and this stimulated Tucson Electric Power's 4.6-MW central station PV prototype installation in eastern Arizona, one of the largest PV systems in the world. It uses conventional PV technologies to power some auxiliary loads at an existing fossil-fired generating station.
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> ***Spain (2004):*** The first European country to introduce a solar "feed-in tariff", Spain offered an extra 12 € cents/kWh for CSP in 2002. Little development occurred until the feed-in tariff was

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[6] "Economic Benefits of Concentrating Solar Power in California", Draft Final Report, Black & Veatch for NREL, August 2005
[7] This analysis is further detailed later in this section of the report.
[8] Current emissions estimates from: California Energy Commission, June 2005, "Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2002 Update," Sacramento, CA, CEC-600-2005-025

increased to 18 € cents/kWh in 2004 and guaranteed for 25 years with annual adjustments for average price increases. This launched a race of major Spanish power-market players and, by mid 2005, a total of 795 MW of CSP capacity additions were planned.

California (2005): Phoenix-based Stirling Energy Systems signed PPAs for two large CSP plants in Southern California. The PPA with Southern California Edison is for a 500 MW facility with an optional 350 MW addition. The one with San Diego Gas & Electric is for a 300 MW plant with another 600 MW optional. These two contracts, totaling up to 1,750 MW, were motivated by California's 20% Renewable Portfolio Standard (RPS), now to be enforced by 2010, and they depend upon the 30% Federal ITC. Both projects are slated to start construction in 2008 or early 2009.

Central station solar deployments can help the Western States Governors to meet their clean energy goals and economic growth needs if key policies are in place. The Solar Task Force identified key policies for enabling successful scale-up of central station solar deployments. These measures do not require State expenditures. They encourage private investments that will provide significant State economic gain.

The policies are:

- **Extend the 30% Federal ITC and expand its use to utilities** – The present 2-year 30% federal ITC needs a 10-year term to allow time to design, permit, finance, and build central station solar plants. This is extremely important because it gives about a 3¢/kWh price reduction for CSP plants. Allowing utilities to use the ITC would further reduce the price by 1-2¢/kWh.
- **Exempt sales and property taxes on solar power plants** – These exemptions will result in a 1-2¢/kWh price reduction. The apparent loss to the State treasury will be offset by new tax revenues from activities caused by the new plants. For example, the increase to the New Mexico treasury as a result of CSP deployment was estimated to be about ten times larger than the forgone taxes.[9]
- **Allow longer-term Power Purchase Agreements and set equitable central station solar power price references –** Encourage State PUCs to extend the allowed PPA term to 30 years. This provides the market stability needed for capital-intensive solar power development. The State PUC and utilities also should consider adopting target tariffs that reflect the value of central station solar power for peak periods and adjust for natural gas price changes.
- **Encourage State PUCs, utilities, and project developers to seek means for aggregating plant orders and project bids to accelerate CSP scale-up cost reductions.** – Some California utilities can issue bids for large CSP plants in the 500 MW range, but others may need to coordinate[10] to aggregate CSP demand. Without sufficient orders for CSP capacity, or in the absence of any of the above recommended policies, States may have to cover cost gaps with additional incentives, perhaps including a capital buy-down or a performance-based incentive such as a declining State production tax credit.

Central station solar power scale up faces risks and barriers, including delays for siting permits, limited access to existing transmission lines, and technology innovation slowdown.

[9] "The Economic Impact of CSP in New Mexico," University of New Mexico Bureau of Business and Economic Research, December 2004, comprising Chapter 7 in "New Mexico Concentrating Solar Plant Feasibility Study," Draft Final Report, Black & Veatch, for New Mexico Energy, Minerals and Natural Resources Department, February 2005.

[10] For example, Renewable Energy Credit (REC) trading between States may provide an aggregation avenue. REC trading: (1) allows CSP plant siting at the most advantageous regional resources; (2) encourages joint development and ownership of larger, more economic projects; (3) reduces transmission constraints in delivering renewable energy; and (4) promotes scale efficiencies by allowing multiple owners of the attributes without having multiple owners of the physical plant.

Each central station solar MW requires about 5 acres. Therefore, time is needed for siting and permitting these plants. On Federal land, the Bureau of Land Management's streamlined and standardized permitting program can accelerate the process. Designated solar development zones could also help to shorten this step. Many prime solar power sites are close to growing load centers, but installing 4 GW of central station solar power will place some new demands on existing transmission systems and may require some new or upgraded lines. The WGA CDEAC Transmission Task Force is addressing this issue. The technology risks, existing with any evolving technology, will be born primarily by the industry investors and project developers, aided by the U.S. Department of Energy's ongoing solar R&D.

When combined with central station solar power's presently uncompetitive prices, these risks are sufficient to inhibit nearly all potential investors. However, as the cited case studies illustrate, central station solar power's risks may be overcome with modestly supportive policies.

In summary:

- Continued economic growth requires energy, much in the form of electricity, and especially during peak demand periods.
- Using in-State renewable energy resources creates economic gains for the State and helps meet environmental targets, especially carbon emission reductions.
- In Arizona, California, New Mexico, and Nevada, the most abundant renewable energy resource is solar energy.
- CSP is able to provide firm dispatchable on-peak power and is a large-scale central station technology.
- Building in-State central station solar plants, rather than natural gas plants, creates more jobs, adds more money to the State's economy, adds more revenue to the tax base, and provides a hedge against volatile natural gas prices.
- The policies needed to facilitate central station solar plant deployment include (1) extending the Federal 30% ITC and allowing utilities to use it, (2) exemptions from State property and sales taxes, (3) encouraging 30 year PPAs, and (4) fostering large-block purchases.
- These policies cost State treasuries nothing and, in fact, increase tax revenues.
- Lack of any of the above four policies imposes a need for additional State incentives, such as a declining production tax credit.
- The CSP industry is ready, the technology is ready and central station solar power has the potential to add a new engine to the Western States' economies.

Introduction

Solar energy resources in the Southwest[11] offer a vast potential for generating electricity. Technology cost reduction is the key to utilizing CSP to harvest those resources. Public policy can also play a role in effecting that cost reduction. The important findings of the Solar Task Force have been summarized in the Summary. The following discussion provides a basis for those findings and gives more detail on the analysis leading to conclusions in several areas, particularly, the:

- Overall potential for CSP capacity in the Southwestern States
- Potential for CSP cost reduction to an economically competitive level

[11] The Southwest States considered in this report for the implementation of concentrating solar power facilities (which require the utilization of the direct, or beam, component of solar radiation) include portions of Arizona, California, Colorado, Nevada, New Mexico, and Utah.

- Most effective policy actions that the Western Governors can undertake to facilitate commercial development of the CSP technologies and aid their transformation into cost-effective generation options

Solar Resource for CSP Plants

Solar energy is the largest renewable energy resource worldwide. The solar energy resource in the southwestern United States is enormous and largely untapped. It is among the best in the world and has a very high potential for electricity generation. In combination with ample land availability and excellent proximity to growing population centers, the solar energy resource in the southwestern States has the potential to support central solar electric plants totaling several thousand GW of electrical capacity.

Concentrating solar power systems require direct normal insolation (DNI), or beam radiation[12] for cost-effective operation. The solar resource, since it drives the cost of the array of solar collectors (or "solar field"), is a significant factor in the economics of a solar plant. Thus, not only do sites with excellent solar radiation offer more attractive levelized electricity prices, but this single factor normally has the most significant physical impact on the cost of solar-generated electricity using a given technology.

Satellite measurements are an important source of the DNI data. This evaluation used a new, high-resolution solar resource data set developed using satellite data and correlated to good ground station data. The map shown in Figure I-3 gives the distribution of DNI over the southwest States. The radiation increases in intensity from the yellow areas through to the dark brown regions, but all are attractively high. The six southwest States with suitably high solar radiation for CSP plants are Arizona, California, Colorado, Nevada, New Mexico, and Utah. In this region, the amount of solar energy falling on an area the size of a basketball court is, in thermal energy terms, equivalent to about 650 barrels of oil a year.

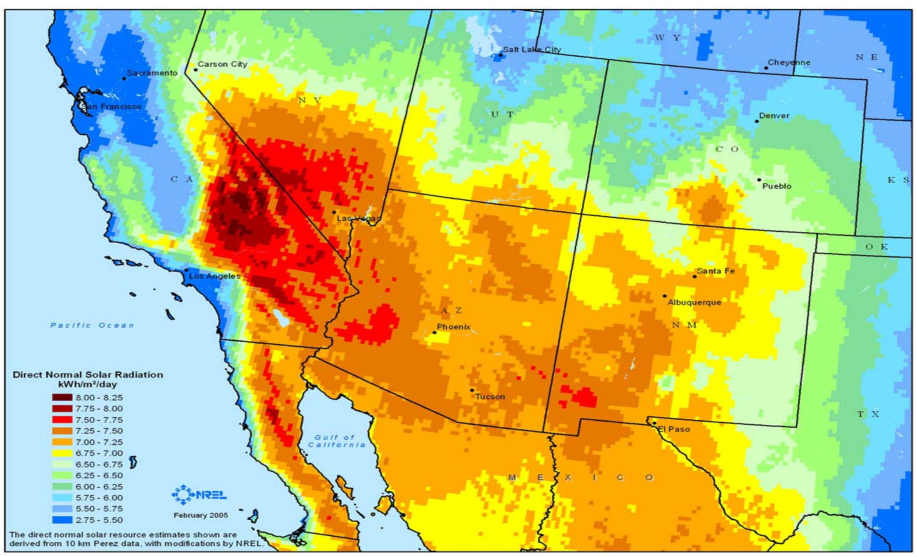

Figure I-3. Direct Normal Solar Radiation in the Southwest

[12] To further clarify this point, beam radiation is capable of casting a shadow on a sunny day, in contrast to diffuse, or scattered, radiation.

Capacity Supply Curves and Optimal CSP sites

Capacity Supply Curves

Capacity supply curves are provided in the Appendix as requested by the WGA Quantitative Working Group (QWG). Examination of the supply curves shows the proximity of the Southwest's immense solar resource to existing transmission. The curves provide a means for describing the relative cost of generation for a particular technology (renewable or conventional) and the generating capacity coincident with the cost. For renewable technologies, costs are driven primarily by two factors: resource availability and proximity to available transmission. For this analysis "busbar costs" (technology costs exclusive of transmission, that is, those costs accumulated within the perimeter of the plant site, up to and including the point of delivery to a transmission system, or "busbar") were based on a fixed charge rate (FCR) methodology supplied by the QWG. While the FCR methodology provides a simple determination of the relative cost of generation for a given resource, it overestimates the real and nominal levelized cost of energy when compared to the more detailed cash flow model used for the CSP cost analyses cited later.

Optimal CSP Sites

CSP plant siting depends on factors additional to solar resource and busbar cost. To estimate the potential for deploying CSP systems in the region, NREL performed a Geographic Information Systems (GIS) analysis of the Southwest to identify candidate areas. Not all of the land with high DNI shown in Figure I-3 is suitable for large-scale CSP plants. To be feasible and cost-effective, such plants require relatively large tracts of nearly level open land with other appropriate siting characteristics. GIS data filters were applied with the following criteria: land type (e.g., urban or agriculture), ownership (private, State, Federal), environmental sensitivity, contiguous area, and topography. The terrain available for CSP development was conservatively estimated using these filters, so that the results represent land with slope ≤ 1% and exclude sensitive lands, defined to be national parks, national preserves, wilderness areas, wildlife refuges, water and urban areas. To narrow consideration to areas with a high economic potential, only lands with an average daily solar resource of about 7 kWh/m^2 were deemed acceptable for this analysis. Capacity estimates assume a need for 5 acres/MW; for example, a 100 MW plant would require 500 acres of contiguous land (less than 1 mile per side). Further, the proximity to transmission lines was taken into account using the methodology described in the Appendix.

The result of the evaluation is illustrated in Figure I-2. In essence, that figure combines the solar resource map (Figure I-3), the supply curve methodology (Appendix I-1), and the application of the other filters using the GIS mapping methodology. **The remaining identified areas have a very large total <u>potential</u> for CSP with a cumulative generation capacity of approximately 200 GW.** This capacity could produce about 473,000 GWh per year, equivalent to approximately 17% of the total U.S. current consumption. Additional practical development factors may well limit this very high potential, but the analysis emphasizes that **the readily accessible solar resource in the Southwest is large enough to play a major role in meeting the region's future energy needs.** This is clearly a very significant and valuable renewable energy resource for the region.

To fully identify favorable solar power plant siting opportunities, additional factors such as land ownership, road access, and local transmission infrastructure capabilities and loadings must be examined in greater detail. This will involve discussion with local experts and utility specialists, and will likely include visits to prospective locations. In addition, the impact of solar resources on the transmission system must be fully analyzed by constructing security-constrained load flow model scenarios. Finally, State-level policies and regulatory frameworks must be assessed to determine the favorability of renewable resource development in a particular State. The availability and relative cost of other renewable power technologies must be considered in this context.

Expected Electricity Demand and Industry Supply Capability

Target Electricity Demand for CSP Plants

The growth in peak demand projected by the SSG-WI team[11] until 2015 is about 34 GW.
The California goal for renewable deployment in the time frame under consideration is about 20% of its total load. Assuming the same 20% market penetration for the six Southwestern States analyzed here, **the total peak period target for renewables (which is the suitable time period for CSP generation) is projected to be about 7 GW.**

Estimated CSP Deployment by State

Consideration of the solar resources in each state, the optimal sites for CSP plants and the expected incremental growth in peak demand leads to a tentative deployment of CSP electricity generation by State. Such a deployment, while reasonable, is somewhat arbitrary at this point in time, and will be strongly influenced by State policies and business decisions of the industry stakeholders. The objective here was to allocate 4 GW of CSP generation capacity proposed to be in place within the WECC region by 2015. The growth in peak demand[13] in the Southwestern states is the governing criteria, given that siting constraints are minimal at these levels of deployment. Using this approach, the Solar Task Force projects the approximate deployment by State through 2015 to be:

Table I-1 Estimated CSP Deployment by State[14]

State	Peak Demand Growth (GW)	CSP Allocation (GW)
California	11,600	2.0
Arizona	6,100	1.0
Nevada	5,100	0.5
New Mexico	4,300	0.3
Colorado	5,300	0.1
Utah	1,700	0.1
Total	34,100	4.0

[13] Based on The Seams Steering Group of the Western Interconnection (SSG-WI) 2015 load projection for transmission reference case expansion studies and U.S. DOE Energy Information Administration 2005 load projection.
[14] Allocation of CSP resources was based on an analysis of peak demand growth and proximity to transmission in the western interconnect region. Significant solar resources also exist in Texas, most of which lies within the ERCOT system which is not part of the WECC and therefore has not been included in this analysis. Given these resources and the aggressive Texas RPS, the Solar Task Force believes that significant central station potential exists in the state.

CSP Industry Capacity

The accelerated industry growth needed for the expansion of CSP deployments will increase competition while allowing individual companies to achieve economies through large-scale production and materials procurement, all of which tend to lower product costs. Accelerated deployment is facilitated by the wide use of common materials in CSP plants. While the material requirements for CSP plants differ by technology, they mainly consist of low-cost, recyclable materials that are available worldwide: steel, glass and concrete. (Exceptions include minor use of plastics and of high-efficiency solar cells in CPV systems.) Local companies generally will construct the plants, and the modular structure of CSP systems facilitates entry into mass production with substantial potential for increased efficiency. The Luz development of the SEGS plants in California demonstrated a swift expansion to build larger and multiple plants at once, and the typical plant construction period was less than 12 months.

Independent of projected peak demand growth estimates, the companies in the CSP industry estimated their worldwide production capability under favorable financial conditions during the period from now until 2015. The totals of these estimates are shown in Table I-2. **The industry projections resulted in a cumulative 13.4 GW of additional peak period capacity**, exceeding the estimated 9.5 GW demand, but lower than the expected maximum target market for renewables of 47 GW. The parabolic trough industry estimate is based on experience with the 354 MW of solar electric plants operating in California; the other estimates are based on estimates of industry production capacity growth under favorable plant development conditions. The strong message here is that the CSP industry is in position to meet the potential market identified above.

Table I-2. CSP Industry Estimates for Capacity Production to 2015 under Favorable Financial Conditions

Year	Parabolic Trough MW		Power Tower MW		Dish-engine MW		Conc. PV MW			Total GW
	annual	cumul.	annual	cumul.	annual	cumul.	annual	cumul.		cumul.
2006	0	0	0	0	0	0	10	10		0.01
2007	150	150	0	0	0	0	25	35		0.2
2008	150	300	50	50	50	50	80	115		0.5
2009	300	600	50	100	150	200	100	215		1.1
2010	600	1200	150	250	300	500	150	365		2.3
2011	600	1800	150	400	600	1100	250	615		3.9
2012	900	2700	200	600	600	1700	350	965		6.0
2013	900	3600	200	800	600	2300	450	1415		8.1
2014	1200	4800	300	1100	600	2900	485	1900		10.7
2015	1200	6000	300	1400	600	3500	600	2500		13.4

Technology Description and Characteristics

Concentrating solar power plants produce electric power by using lenses or mirrors to efficiently convert the sun's energy either into high-temperature heat to drive turbines or engines or directly into electricity via high-efficiency photovoltaic (PV) cells. Two major subsystems come into play: first to collect and concentrate solar radiation, and then to convert the concentrated energy to electricity. CSP systems can be sized for distributed generation (10-35 kilowatts) or central grid-connected applications (up to several hundred megawatts).

Four concentrating solar technologies are shown in Figure I-1. Parabolic trough plants 30-80 MW in size are in commercial operation, with a total of 354 MW in the California Mojave Desert demonstrating reliable operation and excellent performance since 1985. An aerial view of five 30-MW trough plants is shown later in Figure I-5. Currently a 1-MW trough system is under construction in Arizona (for Arizona Public Service) and a 65-MW trough plant is under development in Nevada (for Nevada Power). At least two 50-MW trough plants with storage are being developed in Spain. Dish-Stirling systems are currently in an aggressive commercialization program by industry centered on a 25 kWe dish system unit for modular production of over-100 MW plants. Recently, Southern California Edison announced signing of a power purchase agreement for a 500-MW dish-Stirling project in the Mojave Desert with optional expansion to 850 MW. Separately, San Diego Gas & Electric also announced signing of a power purchase agreement for a 300-MW dish-Stirling project in the Imperial Valley with options to expand to a total of 900 MW by 2014.

A prototype 10 MW power tower that was successfully operated in California demonstrated efficient thermal energy storage and 24-hour per day electric production. Concentrating PV systems are in early commercial development at the 25 kW - 5 MW level. Flat plate photovoltaics can also be a source of utility-scale solar systems. Several systems under development in Germany are multi-megawatt power parks, and a system in excess of 60 MW has just been announced in Portugal. In Arizona, a 4.6 MW flat plate PV system has also been deployed at a utility power plant. While distributed markets may be most attractive today for PV, as the costs of this technology decline, additional opportunities will exist for central station deployments.

Dispatchability is a very important characteristic of several CSP technologies, allowing delivery of firm power during selected demand periods. Trough and tower plants can provide dispatchability by using thermal storage to store solar-produced thermal energy to generate power at a later time, by being integrated with supplemental fossil-fired components, or by being configured to share with a fossil plant the generation portion of a facility.

For example, high temperature thermal energy stored during the off-peak periods can be utilized during peak hours in the evening to generate electricity. These attributes, along with very high solar-to-electric conversion efficiencies, make CSP an attractive and viable renewable energy option in the Southwest and other sunbelt regions worldwide.

CSP systems can also be configured with auxiliary gas-fired equipment to supply thermal energy to achieve full power and remove intermittency from operation with insufficient sunlight. This is demonstrated by parabolic trough system performance at the Kramer Junction sites in California, which typifies the reliability of these systems. These plants are "hybrids" in which a gas-fired boiler can provide steam to augment solar-generated steam. In a proposed alternate hybrid configuration, heat gathered by a CSP system is fed to a larger fossil power plant to be converted to electricity. The solar heat energy can be used to increase the electric production or reduce the fuel consumption of the fossil plant.
Figure I-4 shows 16-year history of on-peak performance[15] at Kramer Junction broken down into solar production (yellow) and auxiliary boiler production (red). By design, the Kramer Junction plants have averaged about 80% of rated on-peak capacity from solar energy, with natural gas used to fill in to 100%. Note in the figure that solar output was low in 1991 and 1992 as a result of the eruption of the Mount Pinatubo volcano in the Philippines. Adding thermal storage would enable nearly 100% on-peak capacity without fossil hybridization. **The ability to dispatch power during peak demand periods makes CSP an ideal renewable energy technology for the Southwest.**

[15] On-peak for these plants occurs from 12pm to 6pm on weekday afternoons during June through September; capacity factor is the actual output divided by that possible with full-load nameplate turbine output during the on-peak period. Values over 100% are possible because the turbine can be driven (safely) higher than it nameplate rating.

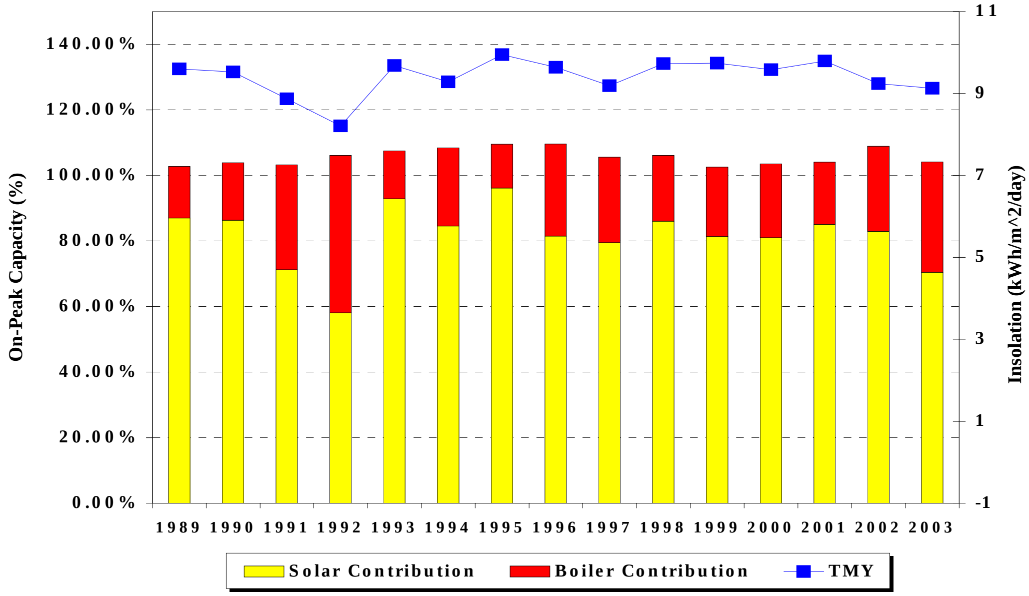

Figure I-4. Performance History of Parabolic Trough Plants at the Kramer Junction Site

Low Water Use Potential

Solar thermal electric systems can be designed for very low water requirements. Dish Stirling engines and PV systems are air-cooled by design, and the steam power plants driven by trough and tower systems can utilize dry cooling technology at a modest increase in electricity cost. The primary water uses at a Rankine steam solar power plant are for steam cycle condensate makeup, cooling for the condenser, and washing mirrors. Historically, parabolic trough plants have used wet cooling towers for cooling. With wet cooling, the cooling tower make-up represents approximately 90% of the raw water consumption. Steam cycle make-up represents approximately 8% of raw water consumption, and mirror washing represents the remaining 2%. Soiling-resistant glass is being explored to further reduce the mirror washing requirement. Still, availability of water is a significant issue in the desert SW regions.

Projected Costs and Competitive Position

Cost Reductions

Cost reductions in CSP systems will be driven by three factors – further technology development, volume production and scale-up in plant or project size. Technology development includes evolution in the performance and reliability of specific technology components, improvements in construction techniques and Operations and Maintenance (O&M) due to learning experience as more projects are installed. Volume production brings significant cost reductions with increased deployment due to decreases in manufacturing cost, material procurement costs, standardized engineering and project development costs. Large power plant sizes or multiple plants in a single project invoke economies of scale in equipment and systems.

The expected cost reduction is illustrated in Figure I-5. Estimates are given for 2015 deployment levels up to 4 GW. This represents a development and deployment plan for the relatively mature parabolic trough technology, which the Solar Task Force believes to also represent a reasonable scenario for the other CSP technologies (tower, dish and CPV). The starting costs are based on the SEGS plants, current costs for the conventional power unit technology, and current solar field estimates. The assumed levels of deployment are supported by expectations in demand growth and industry capacity. Both nominal and real levelized costs of energy are indicated in the figure. At a deployment of 4 GW, projected CSP costs are lowered to about 8 ¢/kWh (nominal) or 5 ¢/kWh (real) from today's plant status.

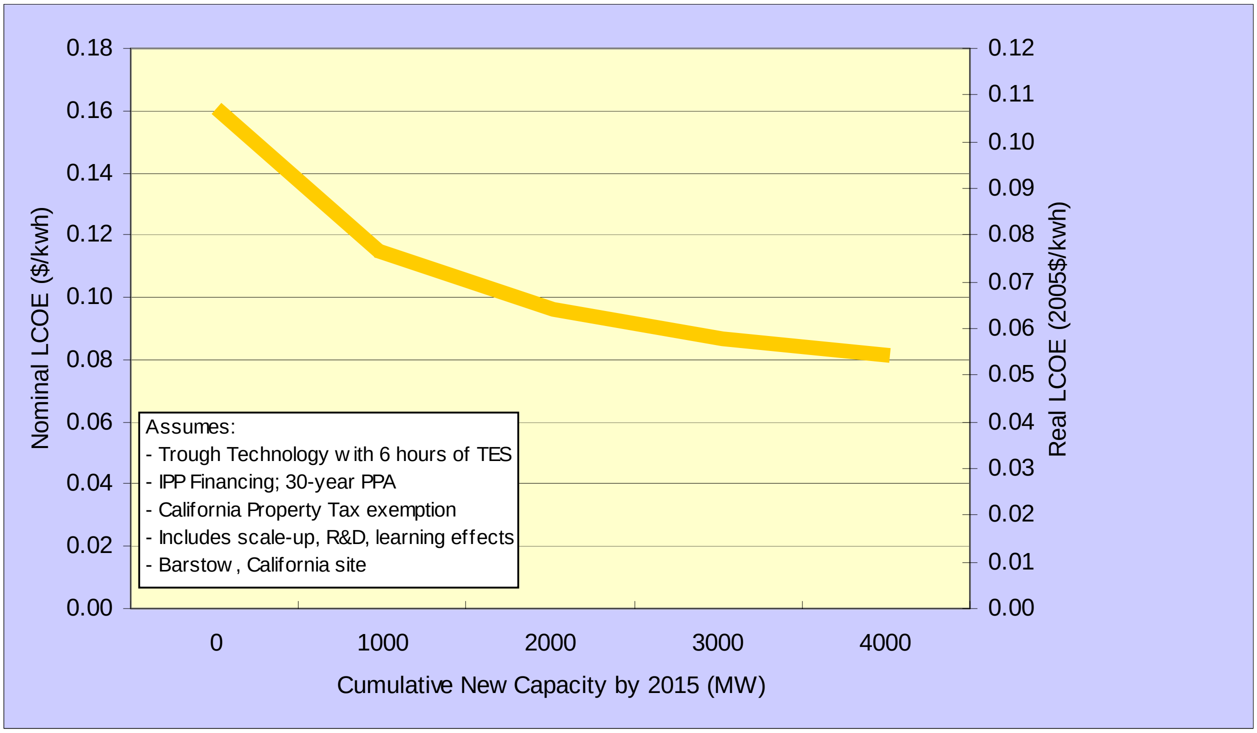

Figure I-5. Projected Cost Reduction Scenario for CSP (based on trough technology)

For reference, the assumptions used in the financial model that generated costs in Figure I-5 were provided by the Analytical Group and are:

- Independent Power Producer (IPP) project structure
- 30 year financial life, Internal Rate of Return (IRR) =15%, 3% fee
- 20-year debt, 6% interest rate, 1.4 Debt Service Coverage Ratio (DSCR), 2% fee
- California solar property tax exemption, but includes 7.75% sales tax (on equipment)
- 10% ITC and 5 year Modified Accelerated Cost Recovery System (MACRS) (see comments on 30% ITC later in this report)
- Optimized Levelized Cost of Electricity (LCOE), including debt/equity ratio, initial O&M cost and escalation, in 2005$
- Engineering, Procurement & Construction (EPC) cost includes 10% contingency, 7% contractor fee and 3% warranty fee

Scenarios to facilitate cost reductions from increased deployment are under discussion. Using troughs as an example, there could be a process by which a utility or consortium of utilities requests that industry submit large deployment bids in incremental phases, e.g., 500 MW each. The first 500-MW phase could be guaranteed at a negotiated rate; the second 500-MW phase might be built only if agreed-upon cost goals were met. If the first GW increment met the cost goals, the process could be repeated.

Competitive Target Price Point for CSP

The target price for CSP is that which utilities would find competitive with their alternatives. This target price should reflect the value of CSP during peak periods and adjust for natural gas prices. The California Public Utility Commission has used a Market Price Referent (MPR) methodology to provide an estimate of the long-term market price of electricity from baseload and peaking power plants. For a reference 100 MW CSP plant with 6-hours of thermal storage, the MPR methodology provides a "blended" electricity value based on the fraction of CSP generation falling into peak and non-peak periods.

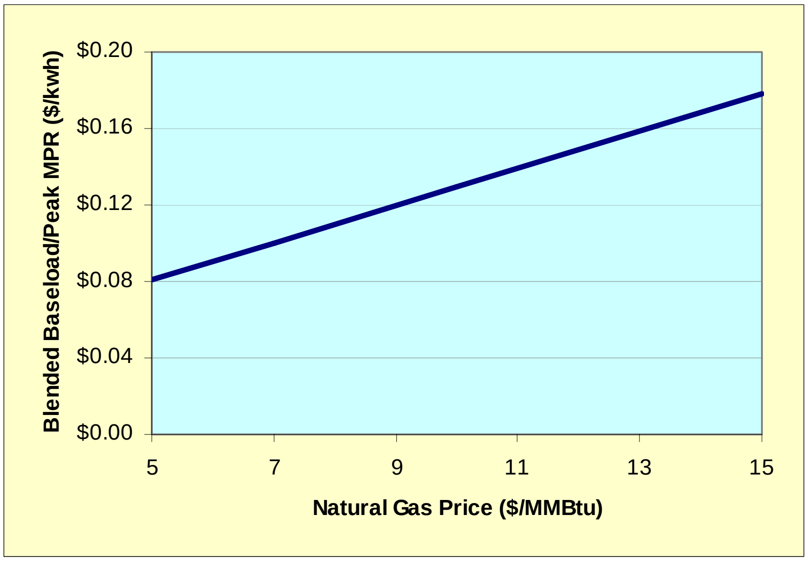

Figure I-6. Sensitivity of the blended value of peaking/ baseload electricity to the price of natural gas.

Figure I-6 depicts a blended value of peaking and baseload electricity as a function of natural gas price based on the PG&E time-of-use cost structure. This analysis considered 2005 natural gas prices between $5 and $15/MMBtu and is assumed to escalate at 2% per year beyond 2005. For a natural gas cost of $7/MMBtu, the analysis yields a blended baseload-peak value of 10¢/kWh. The utility participants on the Solar Task Force agreed that 10¢/kWh would represent a current competitive market price for a firm solar plant meeting the summer peak base on the proposed new resource adequacy rules. A natural gas cost of $15/MMBtu would drive the competitive price up to about 17.5¢/kWh[16].

Based on the current reference price, however, the predicted CSP technology cost projection as a function of deployment in **Figure I-5 show that the cost of CSP electricity could reach the 10¢/kWh target at a deployment of about 2 GW. Because of a normal spread in extrapolated estimates and other factors, the Solar Task Force suggests using a more conservative deployment goal of 4 GW.**

To summarize this argument, the following logic leads to a proposed deployment of 4 GW by 2015:

- Excellent site areas in the Southwest for CSP plants identified using GIS mapping techniques total to a least 200 GW of electrical generation (Fig. ES-2)
- The CSP industry estimates a manufacturing capacity to deploy 13.4 GW by 2015 (Table I-2)
- Growth in peak demand is estimated for six selected states to be 34 GW by 2015. Goal of 20% renewables gives market target of 7 GW. (Table I-1 and text)
- Cost estimates for the CSP technologies project cost competitiveness at a deployment of 2 GW for any single technology or, more conservatively, 4 GW for multiple technologies. (Fig. I-3)

[16] Natural gas prices are difficult to predict and various well-versed experts project differing scenarios, some with high prices and others with lower ones in the long term. The Solar Task Force observes, however, that $15/MMBtu has already been reached in August, 2005 on the spot market for natural gas.

Benefits to Ratepayers and Society at Large

Economic Impact

The social benefits accruing to all taxpayers are broad in scope. Construction and operation of CSP plants would bring significant economic impacts to the southwest States. Recent work[17] by Black & Veatch on the direct and indirect economic impact of CSP plants in California is the source of the data reported here. Direct economic impacts are the dollars directly spent by the project in the region for materials, equipment, and wages. Indirect economic impacts are also referred to as the "multiplier" impacts of each dollar spent in the region. When a dollar is spent in the region, a portion of that dollar goes to pay employees' salaries (earnings). Those dollars are then re-spent in the region to purchase goods and services. The following economic metrics can be used to measure the direct and indirect economic impact of dollars spent in a given region:

- Gross State Output--The total value of goods and services produced within the State.
- Earnings--The value of wages and benefits earned by workers in the region.
- Employment--Full and part-time jobs.

The economic impacts of a power generation project can be divided into the construction and operation periods. The fiscal impact of building CSP plants includes increased tax revenues to State and local governments. These would arrive as increased personal and corporate income taxes, increased gross receipts taxes, increased compensating taxes on imported equipment, increased property taxes, and other taxes specific to electric utilities.

Based on the result of a study focused on California, the net[18] economic benefits would be:

Table I-3. Economic Benefits of CSP in California

Deployment level	2 GW	4 GW
Increase in Gross State Output	**$11.7 billion**	**$22.2 billion**
Creation of construction jobs	**6,800**	**12,800**
Creation of permanent operations jobs	**500**	**1,100**
Increase in State Tax Revenues	**$1 billion**	**$2 billion**

The direct impact to other SW States would be comparable.

Avoided Emissions

With solar energy as the primary fuel, the use of natural gas, oil and coal will be reduced, with a coincident reduction in the production of greenhouse gases. The avoided emissions at several levels of deployment are shown in Table I-4. This is a conservative estimate of the emissions offset by the deployment of CSP because it is assumed here that CSP would displace emissions from new high-efficiency plants. CSP plants could offset generation from older less-efficient natural gas plants with an average heat rate of about 10,000 Btu per kWh, which would increase the emissions offset by about 30 percent. Furthermore, these plants are likely to have greater emissions per Btu of gas consumed, such that the emissions increase is likely to considerably exceed 30 percent. CSP plants may also offset some generation by coal plants, which generally have much higher emissions than natural gas plants.

The proxy Fossil Plant for Table I-4 is assumed to be a natural gas combined cycle with a heat rate of 7,000 Btu/kWh. The CSP plants are assumed to operate at 40 percent capacity factor.

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[17] "Economic Benefits of Concentrating Solar Power in California", Draft Final Report, Black & Veatch for NREL, August 2005.
[18] Compared to an alternative gas-fired power plant

Central solar energy plants also provide a hedge against electricity price fluctuations due to increases in fossil fuel costs or drought. Grid security will be enhanced by this lessened dependence on fossil fuels. A study of the power flows in the southern CA distribution system showed that adding about 1 GW of CSP in select areas would strengthen the grid reliability[19].

Table I-4 Emissions Reduction by CSP Plants

Pollutant	Proxy Fossil Plant Emissions Rate (lb/MBtu)	CSP Plant Capacity		
		100 MW (tons/year)	2,100 MW (tons/year)	4,000 MW (tons/year)
NO_x	0.0060	**7.4**	**156**	**297**
CO	0.0036	**4.5**	**95**	**181**
VOC	0.0021	**2.6**	**54**	**103**
CO_2	154	**191,000**	**4,000,000**	**7,600,000**

Risks and Barriers to Realizing CSP Potential

The key barriers to widespread implementation of concentrating solar power plants continue to be economic in nature. First costs are high compared to traditional fossil-fired plants, and this issue is judged by the Solar Task Force to be the major barrier at present. Deployment is a critically important factor in cost reduction, as shown earlier. New policy and regulatory measures will be essential in facilitating early CSP deployment in the WGA region. A related issue – the need for full cost recovery by utilities that purchase CSP power – was ranked by the Task Force to be the second major barrier. Rising natural gas and coal prices are narrowing the cost gap from below, and that trend is likely to continue.

There are no known major technical or materials barriers to widespread implementation of concentrating solar power plants. CSP plants predominately utilize common materials such as steel and glass, with minimal specialty materials required. To a large extent, accelerated deployment can occur rapidly with the requisite addition in manufacturing capability to meet the demand. There are particular components, however, where the necessary infrastructure must be established to match a growing deployment, such as high-performance PV cells, Stirling engines, and thermal receivers.

While no technology *barriers* are evident, further technology *advances* are still essential to achieving reductions in electricity costs from CSP plants. Inadequately funded R&D is therefore a significant potential barrier. R&D on advanced, more cost-effective systems to improve performance and lower costs will continue to be a very important cost reduction driver. Other barriers include the cost of capital required for financing, the need for access to transmission, and the risk of using a relatively new technology. For trough and tower technologies, the availability of cooling water for the power block is a potential barrier to flexibility in siting. Water is an issue only with trough and power tower plants, but they could be built to use dry cooling technologies and then also consume very little water.

Permitting and siting large power plants is a costly and time-consuming process. If possible, standardized, streamlined, fast-track permitting procedures should be implemented for CSP plants to implement clean, safe renewable energy systems while retaining the need to provide for public oversight and protection.

[19] "Strategic Value Analysis of Renewable Power Technologies for Concentrated Solar Generation," Davis Power Consulting, December 2004.

BLM has taken steps[20] in this regard to facilitate the application and permitting process, such as funding programmatic environmental impact statements to reduce the time and costs to prepare site specific environmental documents. A related concept is the creation of "solar development zones" as a policy mechanism. For example, states (or the Federal Government if on BLM land) could set aside tracts of land dedicated for solar projects. Broad EIRs, plant/animal surveys, geological, and/or weather studies could be done on the entire zone to expedite permitting and/or reduce project development time and cost (and risk).

Desert land is relatively abundant, but it is also environmentally sensitive. Siting power plants is never easy and can be a barrier to solar systems that have a high land use and are more cost effective if near a water supply and adequate transmission lines.

Case Studies

Central station technology and performance have been successfully demonstrated for over 15 years. Of the four CSP technologies demonstrated to date, parabolic trough technology has been the most broadly deployed, while others such as dish-engine systems are slated to increase. The trough technologies are well vetted, and have successful track records. MW-scale flat plate PV has been installed in prototype facilities. The following case studies are illustrative of some of the world's largest central station installations.

California SEGS plants demonstrate successful operation since 1985: Solar facilities comprised of 9 Solar Electric Generating Station (SEGS) plants in the California Mojave Desert, with a combined capacity of 354 MW have been successfully producing clean energy since 1985. The plants, utilizing parabolic trough solar fields to collect the sun's radiation to drive conventional steam turbines, have a design life of 30 years, and all are still in operation today. Still the world's largest single solar installation, the plants are owned today by independent power producers (IPPs), and their output is delivered through PPAs (Power Purchase Agreements). The plants were deemed Qualifying Facilities under PURPA. The successful launch of these plants was driven largely by some key policy incentives in place during the mid 1980s, including a 25% federal Investment Tax Credit (ITC), a 25%state ITC, property tax exemptions, and California PUC standard offer PPAs. The standard offers fixed rates, guaranteeing energy payments for 10 years at projected prices, energy payments for 20 years at utility avoided cost, and capacity payments for the full 30 years. Another key driver was the plants' ability to meet peak demand by utilizing fossil backup fuel to provide up to 25% of the heat for the steam turbines.

Figure I-5. 150 MW of SEGS trough power plants at Kramer Junction, California

Large CSP projects are underway in Arizona and Nevada: Renewable Portfolio Standards (RPS) in both Arizona and Nevada have been key drivers in the launch of a 1 MW solar plant by Arizona Public Service, and a 64 MW IPP plant in Nevada. Both plants will utilize parabolic trough technology, and are planned for start-up in years 2006 and 2007, respectively. APS will be the owner and operator of the Arizona plant, while Nevada Power will be the purchaser of the Nevada plant's output. In Nevada, another key driver to facilitate financing for the 64 MW plant was the passing of legislation that secured

Fig. I-6. Final stages of installation of trough solar field at the 1MW APS

[20] See: http://www.blm.gov/nhp/what/lands/realty/solar energy.htm for valuable information

payment of the PPA terms independent of the utility financial condition.

Spain will launch large CSP deployments in 2007: In September 2002, Spain was the first European country to introduce a "feed-in tariff" funding system for solar thermal power. The feed-in law created a premium for solar kWh production, which was increased to 18 € cents/kWh in 2004 under Spanish Royal Decree, and guaranteed for 25 years, with annual adaptation to the average electricity price increase. This removed the concerns of investors, banks and industrial suppliers and launched a race of the major Spanish power market players to be among the first 200 MW. Currently, a total of 795 MW of solar capacity additions are planned for southern Spain, consisting of both parabolic trough and power tower technologies. The first production is expected in 2007, with additions of approximately 100 MW per year thereafter. The plants are being developed by IPPs, and will be dispatchable via thermal storage.

California utilities have just signed PPAs for energy from the world's largest solar installation: Just this year, a Phoenix-based provider of dish-Stirling engine systems signed Power Purchase Agreements (PPAs) for two large solar power plants in Southern California. The first of these contracts is with Southern California Edison and purchases all the electricity generated from a 500 MW facility, with an option to purchase power from a 350 MW addition. The second is with San Diego Gas & Electric, for all the power from a 300 MW plant, with options for up to another 600 MW. The primary impetus behind these two contracts, which total up to 1,750 MW of solar power, is the 20% Renewable Portfolio Standard enacted in California. The requirement for such a large amount of renewable energy allowed the manufacturer to put together a large enough deployment program to achieve substantial economies of scale and automotive-scale mass-production efficiencies. The resulting bids for largely-peak power were deemed by the two utilities to provide the "Best Fit/Least Cost" renewable alternative offered under their RFP programs. Both projects are slated to start construction in 2008 or early 2009 and will start producing power soon thereafter.

The case studies above illustrate that CSP deployments can indeed allow the Western States Governors to meet their clean energy goals, while serving their economic growth needs and constraints, provided some key policies are in place. The key policies required to enable successful continuation of CSP deployments are recommended below. These measures are expected to have minimal impact on states' treasuries, requiring few to no state incentives. In fact, they will support investments that will provide the states with positive and significant economic gain. The recommended policies will enable CSP plants to be built and those plants will increase your state's tax revenues, create new jobs and increase your state's GSP.

Renewable energy portfolio requirements also stimulated the 4.6-MW utility-owned central station photovoltaic prototype installation at the Springerville Tucson Electric Power station in eastern Arizona: One of the largest PV systems in the world, it is still in the "distributed generator" size range in utility terms. Using conventional PV technologies, it powers the auxiliary loads at an existing fossil-fired generating station. The system consists of multiple independent arrays of about 2500 flat plate PV modules each. Their modularity allows PV generation plants to be purchased and built in phases, eliminating finance charges to significantly reduce their levelized cost of electricity. Tucson Electric plans to nearly double this system to 8 MW by 2010 and cites its pay-as-you-build aspect as a significant advantage. The Solar Task Force-recommended incentives for CSP technologies can also apply to such cash-financed PV systems.

Fig I-6. Springerville 4.6 MW flat plate PV plant

Policies and Incentives

Principles and Framework

As shown above, the cost of CSP electricity generation is expected to decline rapidly with increased deployment and a more favorable financial climate. In the near-term, however, Federal and State incentives are required to bridge the cost gap between CSP and competing technologies. In general there are a variety of incentives and policies that could be proposed to achieve closure. In order to identify the best incentives package, the Solar Task Force followed the following principles:

- The price point goal should be acceptable to the utilities, assuring the utilities of cost recovery and ensuring that CSP projects will be an attractive investment.
- Implementation of the proposed policies should be accomplished in a reasonable amount of time.
- The proposed policies should be structured to maximize their benefit to projects, ensuring their use and effectiveness.
- To the extent possible, and with insufficient time to implement new Federal policies, the proposals will build on existing Federal incentives and/or policies.
- Renewable Portfolio Standards and solar set-asides have strongly benefited CSP entry into the marketplace. This report, however, focuses on incentives, not mandates, to bring CSP to a fully commercial status.

Recommended Policies and Incentives

The full set of recommended policies and incentives includes:

Recommended Set of Policies/Incentives
• **Extend the 30% Federal ITC and expand its use to utilities** • **Exempt sales and property taxes on central solar plants** • **Allow longer-term Power Purchase Agreements and set equitable central solar price references** • **Encourage State PUC, utilities, and IPPs to seek means for aggregating plant orders and project bids to accelerate CSP scale-up cost reductions**

- **Extend the 30% Federal ITC and expand its use to utilities** – The present 2-year 30% federal ITC needs a 10-year term to allow time to design, permit, finance, and build central solar plants. This is extremely important because it gives about a 3¢/kWh price reduction for CSP plants. Allowing utilities to use the ITC would further reduce the price by 1-2¢/kWh.
- **Exempt sales and property taxes on central solar plants** – This apparent loss to the State treasury will be off set by new tax revenues from activities caused by the central solar plants. For

example, the increase to the New Mexico treasury as a result of CSP deployment was estimated to be about ten times larger than the forgone taxes. [21]

- **Allow longer-term Power Purchase Agreements and set equitable central solar price references** – Encourage State PUC to extend the allowed PPA term to 30 years because a central solar plant can be viewed as a power plant with a guaranteed 30-year fuel supply at a fixed price. The price of this 30-year guarantee is the advance purchase of fuel in the form of a solar field. Given the significant private capital investment required for a central solar plant, it is essential that the appropriate framework be in place to both value and protect the investment. This provides the market stability needed for capital-intensive central solar development. The State PUC and utilities also should consider adopting target tariffs that reflect the value of central solar for peak periods and adjust for natural gas price changes.
- **Encourage State PUCs, utilities, and project developers to seek means for aggregating plant orders and project bids to accelerate CSP scale-up cost reductions. –** Some California utilities can issue bids for large CSP plants in the 500 MW range, but others may need to form consortia, or coordinate otherwise[22], to aggregate CSP demand. Large orders are crucial to early-stage cost reductions. Without sufficient orders for CSP capacity, States may have to cover cost gaps with additional incentives, perhaps including a capital buy-down or a performance-based incentive such as a declining State production tax credit.
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Loan guarantees have the potential of reducing both the interest rate and the equity return on investment, and therefore warrant further study. Definitions of these and related policies and incentives can be found in Appendix I-2.

Impact of the Recommendations on the Cost of Electricity from CSP

The incremental effect of each policy is shown in Table I-5. The Nominal LCOE is the metric that should be compared to the Target Price from above. The Real LCOE is shown for information only, as it is typically used to compare technology options by Federal agencies such as DOE. The estimates presented here are for a high solar resource site. The starting point is the current baseline Federal incentives and a 20-year Power Purchase Agreement with a utility. The specific policy measures are in bold print.

Parabolic trough technology was used to evaluate the current market competitiveness of CSP. The cost and performance assumptions are based on the U.S. DOE 2007 parabolic trough technology baseline system[23]. The financial analysis was conducted by NREL and the results presented should be viewed as first order estimates of the cost of power and the relative effect of each policy presented. The analysis is based on NREL's current understanding of how each policy would be implemented into the financial proforma of a large commercial IPP or utility power project. The analysis begins with an IPP project and is later extended to utility financing.

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[21] "The Economic Impact of Concentrating Solar Power in New Mexico," University of New Mexico Bureau of Business and Economic Research, December 2004, comprising Chapter 7 in "New Mexico Concentrating Solar Plant Feasibility Study," Draft Final Report, Black & Veatch, for New Mexico Energy, Minerals and Natural Resources Department, February 2005.
2004 and (B&V NM report goes here when FHM finds it)

[22] For example, Renewable Energy Credit (REC) trading between States may provide an aggregation avenue. REC trading: (1) allows CSP plant siting at the most advantageous regional resources; (2) encourages joint development and ownership of larger, more economic projects; (3) reduces transmission constraints in delivering renewable energy; and (4) promotes scale efficiencies by allowing multiple owners of the attributes without having multiple owners of the physical plant.

[23] The DOE 2007 parabolic trough technology baseline system is a stand-alone 100-MW Rankine steam cycle power plant with 6-hours of thermal energy storage, located near Barstow, CA (7.65 kWh/m^2-day).

Table I-5. Financial Impact of Recommended Policies and Incentives

Nominal LCOE ¢/kWh	**Analysis for Basic Set of Policy Incentives**	Real LCOE 2005 ¢/kWh
18.3	(Baseline Federal Incentives, 20 yr PPA)[24]	13.3
17.5	Extend PPA to 30 Years	11.8
14.8	10-year Federal 30% ITC	10.0
13.3	Enact State Property Tax Exemption	8.9
12.8	Enact State Sales Tax Exemption	8.6
10.3	Extend Federal ITC to Utilities	7.0

It can be seen that after implementing the initial policy recommendations (30% ITC extension to 10 years, solar sales and property tax exclusions), the total cost (12.8¢/kWh) is still approximately 3¢/kWh above the desired price target (about 10¢/kWh). However, if utilities are able to take the 30% ITC and purchase and finance the plant directly, the cost of electricity is reduced to about 10.3¢/kWh. Utility purchase of power in large blocks, e.g., 500 MW, from project developers could bring similar reductions.

It remains, then, to evaluate the magnitude of the final two State incentives. This was carried out by assessing the level of solar firm capacity buy-down or the solar production tax credit that would be necessary to achieve the 10 ¢/kWh cost goal. The impact of the two tax credits is strongly influenced by plant ownership (project developer or utility) and deployment (early projects or after large deployment increments, e.g., 500 MW).

If any of the recommended set of Federal and State policies are not implemented, or the plants are developed in relatively small incremental builds, then the State will need to provide appropriate incentives such as a production tax credit or a buy-down. Either such incentive will decrease as CSP capacity grows, and disappear when up to 4 GW of additional CSP capacity have been installed.

Enabling Regulations and Actions

The following actions for the WGA region and States on regulatory and administrative steps are recommended to enable central solar plants after the incentives are in place.

- **Regional**
  1) Explore regional trading of renewable energy credits through the WREGIS system.
  2) Evaluate developing a standardized contract approach for central solar system procurement by utilities (perhaps through the WECC).
  3) Work with BLM more closely to standardize permitting on public lands.
  4) Evaluate standardization of other permitting requirements among States.
  5) Form via the WGA a CSP Task Force of utilities and State energy offices to address issues and approaches
  6) Create new education and awareness campaigns
- **States**
  1) Form Task Forces to evaluate in-state issues, benefits, and impacts of deploying CSP systems, including electric transmission
  2) Identify in-state incentive packages (such as mechanisms to allow above-market central solar plant PPAs) and work with regulators to identify implementation
  3) Develop policies and/or legislation to support the defined approach
  4) Create new education and awareness campaigns

[24] Baseline IPP Project with 20-year PPA, 10% Federal ITC, 5-year MACRS accelerated depreciation.

- **Federal**
  Significant opportunity appears to exist for cost reduction through continued research and development both nationally and in the western states. R&D conducted in the U.S. is more likely to address the needs of U.S. power markets and is more likely to develop U.S. industry. Experience has shown that European R&D has helped improve CSP technologies over the last 15 years, but tended to build European industrial capacity.
- **Development of Large Solar Power Projects (~500 MW)**
  As previously indicated, the cost of power from CSP technologies is expected to decline over time as more plants are built due to learning and project scale-up. One of the most effective ways to facilitate learning and benefit from scale-up is to encourage the development of large, multi-unit power plants. As an example, significant cost savings are believed to be possible by building, for example, five 100 MW plants over a period of five years at a single site instead of a single standalone 100 MW plant. The cost reduction occurs in all phases of the project from project development, common facilities and infrastructure, improved competitive procurements, labor learning, and O&M. The larger build will also have a more sustained positive economic impact on the local community. For example, for parabolic trough technology, a 5-year project of this size would potentially justify the building of a local factory for manufacture of receivers and mirrors, components currently imported from outside the US. For purpose of assessing the value of a solar power park development, it is estimated that a 10% reduction in the capital and O&M cost can be achieved over a single standalone power project.
- **Hybridization and Solar Co-firing**
  Hybridization of solar typically means that the plant can operate either from solar energy or from a backup fossil fuel source. Current Public Utility Regulatory Policy Act (PURPA) rules allow solar plants to use up to 25% fossil input to the plant. Hybridization provides the ability to dispatch power as needed, even with low solar radiation. The ability to hybridize a solar plant is seen as important to utilities participating on the Solar Task Force, although the current PURPA rules, which do not distinguish between the solar and fossil-fueled plant outputs, are problematic in times of relatively low-priced gas. Given the 9.6¢/kWh price target and the likely higher future cost of natural gas, it is unlikely that a hybrid solar plant would burn natural gas unless it was necessary to firm up on-peak generation.

  There are also existing fossil (or other) power plants that could be co-fired with solar energy. The solar contribution may range from a small to relatively large percent of the total electric generation. Often these solar co-firing opportunities represent some of the least expensive opportunities for increasing solar electric generation and offsetting conventional fossil generation. It is desirable that all incentives presented above are also made available to the solar co-fired portion of such plants and their output.

Conclusions for Central Solar Plants

- The solar resource in the Southwest is very large. Of particular note, the prime solar energy resource potential in the seven States is 200 GW, and there is ample highly suitable land to support large-scale CSP development.
- CSP technology is proven, and it can provide firm dispatchable power to meet peak power demands. The CSP industry estimates that a total plant capacity of 13.4 GW could be deployed for service by 2015, which equals about 30% of the growth in peak regional demand.
- The cost target for CSP, based on gas-fired plants, is slightly under 10¢/kWh in 2015. When up to 4 GW have been installed, the cost of electricity from future CSP plants is expected to be on a par with plants burning natural gas.
- The economic benefits that would accrue to the States from development of their CSP resources are large enough to add a significant new engine in those States' economies. Using California as an example, building 4 GW of CSP plants in that state will inject, relative to installation of gas-fired

plants, over $22 billion into the gross state output, approximately 13,000 construction jobs and 1,100 permanent operation jobs, and an additional $2 billion to tax revenues.

- The major barrier is current higher capital cost. Policy and regulatory measures create opportunities to reduce and/or remove barriers.
- The most important Federal policies for central solar are extension of the recently passed 30% Federal Investment Tax Credit to 10 years and allowing it to be used by the utilities.
- The most important State policies are property and sales tax exemptions for central solar plants and 30-year PPAs with a capacity payment. These actions are expected to have minimal net cost impact on the State treasuries. The apparent loss to the States will be offset by new tax revenues from activities caused by the CSP plants.
- If the above policies are enacted, and if CSP plants can be constructed in 500 MW increments, additional State incentives may not be required.

Part II. Distributed Solar

Summary

Distributed solar technologies present an opportunity to enroll businesses, schools, governments and millions of homeowners to contribute individually and collectively to the region's energy security and supply, taking actions that have the potential to benefit the entire West while helping to diversify and hedge the sources of supply needed to meet the West's energy needs.

If the region moves ahead aggressively implementing programs to promote solar, we estimate[25] that by 2015:

- An additional 4,000 MW of distributed solar PV could be installed[26]
- At least 500,000 solar thermal water heating systems could be installed, providing the equivalent of 2,000 MW_{th} of generating capacity and saving almost 15 billion cubic feet of natural gas per year
- Approximately 5 to 6 million megawatt-hours of electricity annually will be contributed to the region's energy needs, shaving approximately 5 percent off of the West's growth in peak energy demand over the next ten years
- Between 4 and 4.8 million metric tons of CO_2 emissions can be avoided annually, the equivalent of taking over a million cars off the road
- Between 2.2 and 5.0 million gallons of water per day would be saved depending on the type of power displaced, enough to supply between 7,000 and 14,000 homes
- 15,000 high-quality jobs will be added in the region
- And hundreds of thousands of homeowners and businesses will be provided with an important energy option.

Increased demand for solar systems can drive expanded manufacturing in the region, bringing with it thousands of high-paying jobs

No major physical or technical barriers stand in the way of widespread adoption of solar; the major impediments are in the realm of economic and public policies. One hurdle for consumers is that costs are heavily front-loaded – much like paying cash for a car all of the fuel needed to run it for 25 years included in the sticker price. A number of inconsistent public policies around interconnection and metering exist as well. As a result, while the number of installations has been rapidly growing in recent years, the industry is still very much in its infancy. Experience in the West and around the world has demonstrated that economic stimuli and policies that encourage easy adoption of solar can be effective in accelerating demand and driving down costs. Adoption of the right policy framework could create the environment where the investment in solar technologies will be one that is cost positive for consumers.

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[25] See Appendix II-1 for detailed description of the methodology behind these estimated benefits.

[26] The 4000 MW target was set based on growth in the WGA states averaging 32% annually over the next decade on the assumption that the WGA states take strong policy actions to encourage the growth of distributed solar technologies. However, it is a reasonable estimate of the capacity of the PV industry to grow in the WGA states over the next decade under solar-friendly policies and is in line with both historical growth rates of the PV industry during the past decade (see Strategies Unlimited, *Photovoltaic Manufacturer Shipments 2004/2005*. Report PM-57. 2005, and Maycock, Paul. 2005. *PV News.* Vol. 24, No. 3 and 4. PV Energy Systems, Warrenton, VA), and projected growth rates by the U.S. PV industry over the next decade (see Solar Energy Industries Association, *Our Solar Power Future: The U.S. Photovoltaic Industry Roadmap Through 2030 and Beyond,* 2004).

Central to our recommendations that the Governors should pursue is the extension of the 30 percent Federal tax credit for a total of ten years. Congress should also be encouraged to lift the $2000 credit cap on residential systems, providing homeowners with the same incentive as businesses to size systems appropriate to their energy needs. These modifications provide an unprecedented opportunity for the Governors to leverage state solar incentive funds. Though the Federal tax credit is not sufficient to drive solar on its own, it can greatly reduce the allocation of state or ratepayer funds necessary to ensure a rapidly expanding solar market. In addition, while individual homeowners and businesses can take advantage of this credit in 2006 and 2007, the lack of a long-term program is a major disincentive for suppliers to invest in expanded manufacturing capacity. These investments are necessary to ensure continued cost reductions that will eventually eliminate the need for subsides while providing a source of high-paying jobs in the region. Finally, Federal and state recognition of the value of renewable technologies through the establishment of programs and incentives has proven to be a powerful stimulus for prospective purchasers of solar systems.

Beyond the Federal tax credit, this report covers a wide range of policy and program options from which the Governors can select the ones most appropriate for their states' circumstances. All are based on programs already in operation in one or more WGA states. To date, the most effective programs to stimulate solar installations have been to:

- Use **economic incentives** to mitigate the capital-intensive nature of solar, encouraging homeowners and businesses to invest their capital in systems, driving demand that ultimately results in increased production and lower costs. The most popular programs are:
  - Declining up-front rebates to underwrite the cost of installing systems
  - Ongoing performance-based incentives, paying system owners only for the electricity they actually generate
  - Access to low-cost capital, enabling building owners to repay loans out of the savings on their electricity bills
  - Exemption from state and local sales and property taxes, further reducing the upfront capital costs and ongoing expenses associated with these systems.

Solar systems can be installed on homes in aesthetically pleasing ways, particularly in new home construction

- Adopt policies to **remove barriers** to the easy installation of solar. These simple initiatives can pave the way for individual action by homeowners and businesses:
  - Simplified interconnection standards that enable easy access to the grid.
  - Solar access laws that ensure that local governments and homeowners associations can't enact rules that restrict the installation of solar systems.

- Enact programs that encourage solar system owner-generators to **optimize** their **solar energy production**:
  - Encourage utilities and/or regulatory bodies to offer optional time-of-use electricity rates that reward generators for maximizing the output of their solar systems during high-value peak periods.
  - Provide net metering, a simple way to account for the net amount of electricity generated and used by building owners with solar electricity systems.
  - Facilitate ownership of Renewable Energy Credits (RECs) as well as the ability of owner-generators to exchange these RECs in open markets to help states meet renewable or environmental portfolio standards.

- Demonstrate leadership through **state purchases** of solar energy and **public education:**
  - States can send a clear signal to their citizens about the long-term economic and environmental benefits of distributed solar by purchasing systems for state buildings.
  - Use public education and awareness program to inform homeowners and businesses about the costs, benefits and technology options available to them.

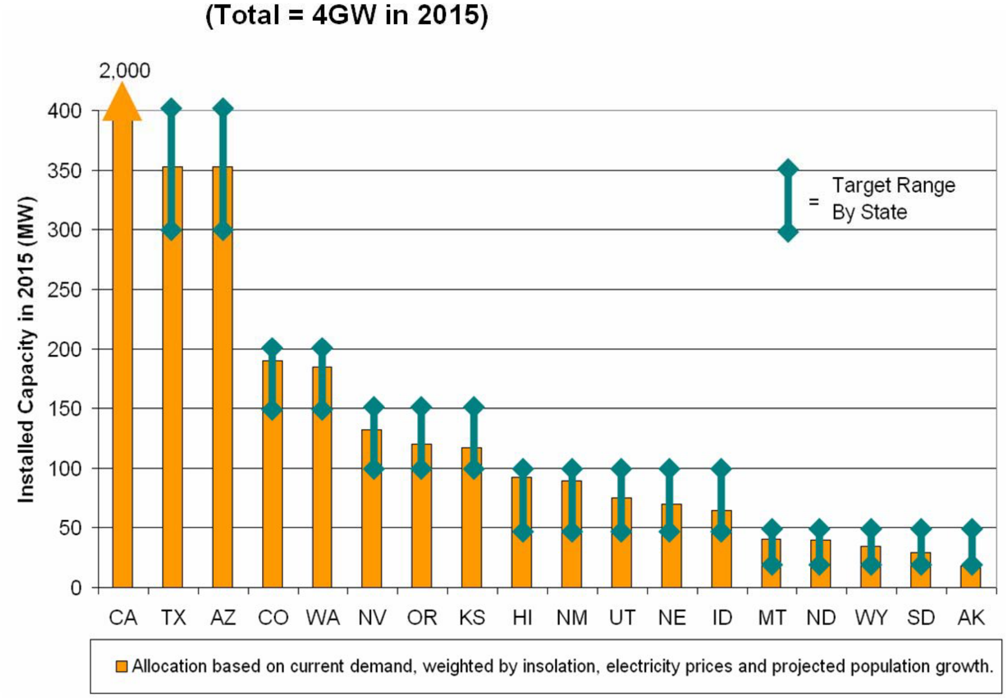
Solar parking lot canopies, such as this one at Cal State Northridge, are highly visible signals to consumers about the benefits of solar

Solar Works in Every WGA State

One of the greatest attributes of distributed solar is that every state can take advantage of its benefits. While the Southwestern states and Hawaii clearly enjoy greater solar resources than states farther north, solar electricity, solar water heating systems and solar space heating and cooling systems will deliver valuable renewable energy throughout the West. While the solar resource in Portland and Seattle is 60% of the solar resource in Phoenix, two-thirds of the Northwest receives as much or more direct sunlight as Florida. Even the rainforests of the Olympic peninsula receive as much sunlight as many areas in Germany and Japan – the two countries with the vast majority of the world's solar photovoltaic installations and among the world's leaders in solar thermal (water and space heating) installations. Over 20,000 solar water heating systems have been installed in Oregon since 1978, for example, showing that solar can thrive in any climate when barriers are removed and the right level of incentives is used to drive demand. That demand, in turn, can fuel a cycle of declining prices and expanding markets.

Based on current demand, weighted by the amount of sunshine, electricity prices and projected population growth, we believe that each state will be able to make a meaningful contribution to the region's energy needs through the installation of distributed solar systems.

Figure II-1. Weighted Allocation of Installed Capacity in WGA States (Total = 4GW in 2015)



*Source: **NREL***

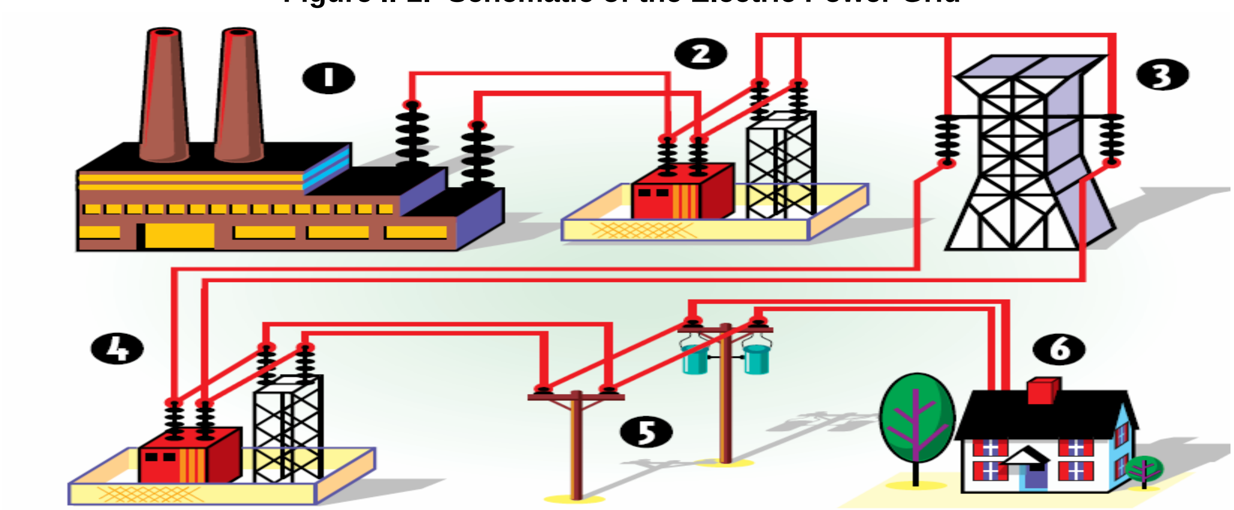
Distributed Solar Benefits All Ratepayers

- **Power is most often produced during critical peak hours**
- **Power is produced on-site, avoiding line losses, reducing the strain on the transmission and distribution systems, and potentially deferring the need for new distribution and transmission investments**

Distributed solar offers many unique and valuable contributions to the economic health of the region and to the stability of the electricity and natural gas distribution systems. However, two broad categories stand out. First and foremost, while each state may have different peak load and system performance characteristics, solar PV systems are often most productive during peak hours – including the time when demands on the electrical grid can be the greatest.[27] This reduces peak electricity demands, resulting in lower peak energy costs and lower price volatility for all consumers. Furthermore, reducing demand for peaking power lowers demand for natural gas, keeping gas procurement costs down. Second, because generation is located at or close to the point of use, a number of benefits can accrue to the entire grid. Reduced line losses help the grid to operate more efficiently, security concerns are lessened, and over time upgrades to the transmission and distribution systems may be mitigated, potentially deferring investment capital.

Figure II-2 demonstrates the steps involved in transmitting power generated at a traditional power plant to the end user. When PV systems are operating, typically during peak electricity demand periods, they provide electricity on site for the PV owner and bypass stages 1 to 5. Although these stages cannot be eliminated since most residents and businesses require electricity 24 hours a day, the strain on these systems during peak periods could be reduced substantially with widespread PV application.

Figure II-2. Schematic of the Electric Power Grid



When electricity leaves a power plant (1), its voltage is increased at a "step-up" substation (2). Next, the energy travels along a transmission line to the area where the power is needed (3). Once there, the voltage is decreased or "stepped-down," at another substation (4), and a distribution power line (5) carries the electricity until it reaches a home or business (6).

Source: Edison Electric Institute, *Key Facts: A Look at the Electric Power Industry*

[27] See Appendix II-1 for a more detailed description by NREL of the region's effective load-carrying capacity (ELCC) – the relationship between the load shape and the resource availability (insolation) in a particular area.

Distributed solar thermal systems also reduce electricity or natural gas consumption at the point of use. Reduced electricity consumption through the use of solar thermal systems is functionally identical to the production of electricity during those same periods, and this potential is further available through the newer solar space heating and solar cooling technologies coming to market. Reduced natural gas consumption translates into more natural gas available for electricity generation and industrial use.

There is a wide range of economic and environmental benefits from distributed solar photovoltaics. The most significant of these are in avoided costs for natural gas for electricity generation and for capital costs to build new plants. Recent studies of the California market indicate a potential for a variety of other benefits, including the value of avoided T&D losses, avoided CO_2 and NOx emissions, avoided water usage, and many others.[28] The California Public Utilities Commission is currently considering which of these are appropriate to include in a formal cost-benefit analysis of its existing subsidy program and how best to calculate the impact of those that are included. Regardless of which are ultimately deemed appropriate to include and at what level, enacting programs that have the effect of reducing costs will ultimately improve net benefits.

Similarly, small-scale solar thermal technologies have both environmental and economic benefits, particularly when systems are used to offset the consumption of electricity or natural gas[29], which along with propane are the primary water heating energy sources used in the WGA states. In many areas in the West, natural gas is used almost exclusively for water heating applications in new construction.

Society Benefits from Distributed Solar Energy

- **Jobs**
- **Healthier environment**
- **Keeps money in region**
- **No water is consumed**

In addition to ratepayer benefits, there are a series of advantages that accrue to society at large. First, developing a distributed solar industry can help to build local and regional economies by creating high-paying local manufacturing and installation jobs, thereby increasing state and local tax revenues. A healthy, growing solar industry, installing solar products that convert indigenous solar resources into usable energy, can have the added advantage of converting into local contracting and manufacturing jobs those dollars that would otherwise be sent out of state or out of the country for the importation of fossil fuels. According to a recent study by researchers at the University of California, Berkeley, the solar industry currently supports 33.25 installation and manufacturing jobs for every megawatt installed[30] – more local jobs per MW than any other energy technology[31] – so the employment leverage offered by an expanded solar market can be substantial. In addition, there is a wide range of environmental benefits, such as reduced use of scarce water resources and avoided emissions of greenhouse gases and other pollutants that further contribute toward the WGA's objectives in its energy program.[32]

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[28] Severin Borenstein, *Valuing the Time-Varying Electricity Production of Solar Photovoltaic Cells*, Center for the Study of Energy Markets, University of California Energy Institute, March 2005; and Ed Smeloff, *Quantifying the Benefits of Solar Power for California*, The Vote Solar Initiative, December 2004

[29] US Department of Energy, Energy Efficiency and Renewable Energy Solar Energy Technologies Program, *Solar and Efficient Water Heating*, 2005.

[30] Virinder Singh, *The Work That Goes Into Renewable Energy*, Renewable Energy Policy Project, 2001.

[31] Daniel M. Kammen, *Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate?*, Goldman School of Public Policy, UC Berkeley, 2005

[32] See Appendix II-1 for NREL's detailed analysis on reduced water use and greenhouse gas emissions.

What Will It Take to Enable Solar Technologies to Make a Meaningful Contribution to the Region's Energy Needs?

There is a common misconception that solar is too immature to make a meaningful contribution to the region's energy needs. In fact, both the solar photovoltaics and the solar thermal (space and water heating) markets are already substantial. In 2004, over $7 billion of PV systems were sold worldwide, and solar thermal sales are approaching $5 billion per year. PV industry leaders include multinational corporations from traditional energy (BP Solar, Shell) and electronics (Sharp, Kyocera) industries, many of whom have manufacturing facilities in the U.S. Growth in the industry has also been enviable by most industries' standards. Over the past eight years, sales of PV systems have grown an average of 31% annually and solar thermal systems 20% annually, and most analysts expect these rates to continue for the foreseeable future. Solar heating and cooling, although new to the U.S. market, is prevalent in the European Union and is projected to continue to grow. The European Renewable Energy Council is predicting that, for the European Union, renewable thermal cooling and heating can achieve 25% of the total cooling and heating demand by 2020.

Despite this phenomenal growth, the industry still represents less than one-tenth of 1% of the electricity generated in the West, and the US share of those robust global markets is declining markedly. Many thoughtful observers have noted that solar is an industry ready to explode. So what can the current programs in the West and around the world tell us about what we need to do to make that happen? What are the roadblocks we need to clear and the catalysts we can employ to encourage energy consumers to make the levels of private investments in distributed solar needed to help meet the Governors' goal of 30,000 MW of clean energy?

There are No Physical or Technical Barriers to Market Entry

- **Plenty of sunshine**
- **Plenty of roof space**
- **New technologies are providing competition that will ensure continuing decline of average system prices**

Much of what we need to make this happen is largely in place. First, there are no physical barriers to achieving our goals. We have an abundant natural resource in sunlight – indeed some of the best in the world. The maps below[33] indicate the amount of solar radiation in the US annually (left) and during August (right). The annual map indicates the potential for significant year-round contributions from at least ten WGA states. However, in the height of summer, when the grid is straining to meet regional

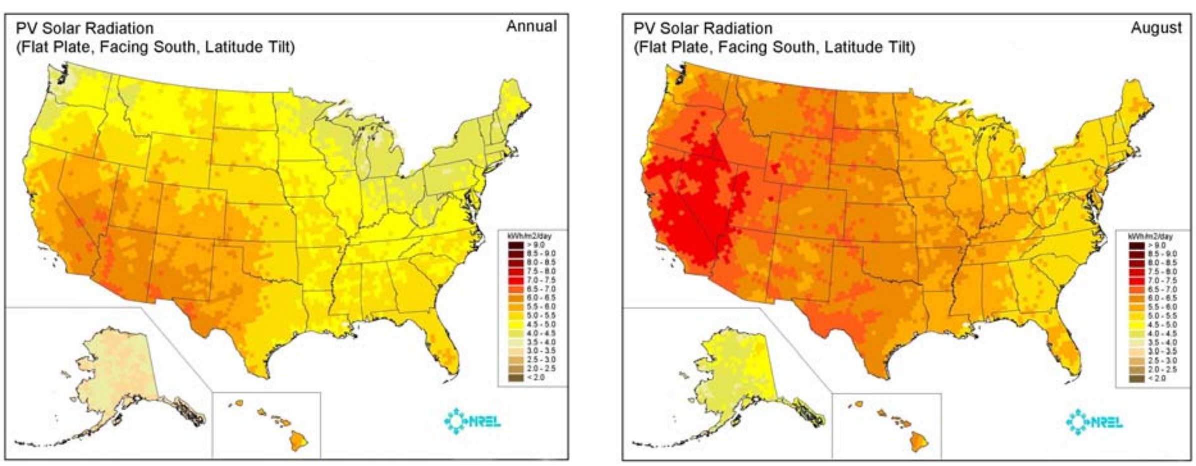

Figure II-3. Solar radiation in the US annually (left) and during August (right).

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[33] See http://www.nrel.gov/gis/solar_maps.html for detailed maps and an explanation of how they were derived.

electricity needs, every WGA state is in a great position to contribute to the total requirements through distributed solar. By comparison, if one were to plot on this same scale the solar resource in Germany and Japan (which together are home to the vast majority of the world's solar PV installations), their maps would look like the northwest corner of Washington State in most areas of their respective countries.

There is also ample roof space available for distributed solar installations. In September, 2004, the Energy Foundation and Navigant Consulting released a detailed study estimating by state and building sector (residential, commercial, etc.) the amount of roof area appropriate for installing solar.[34] Even after eliminating 78% of residential roofs for such factors as steep angles or improper orientation and 35% of commercial roofs for structural inadequacy, shading and the like, approximately 22 *billion* square feet of roof space in the WGA states appear appropriate for use by solar systems. Although neither recommended nor even realistic, it is interesting to note that the entire 30,000 MW of clean generating capacity sought by the Governors could be generated by less than 18 percent of the available and appropriate roof space. Clearly lack of spots to site solar systems will not be a constraining factor.

In addition, in most areas of the West there appear to be no major technical barriers to success. While additional R&D, largely through federal and private investment, will be needed to uncover the technical advancements that will further drive the industry, existing technologies are ready for market now. Current PV systems already work exceptionally well. Panel failures are extremely low (nearly all manufacturers guarantee their products for 25 years), and the inverters that convert DC power from the panel to usable AC power usually last five to ten years before needing replacement. Given that most of these systems have not been in the field for anything close to their expected lifetimes, many utilities and industry groups are watching the performance of panels and inverters carefully and may have further recommendations for improvements in the coming years.

Solar water heating systems are also typically reliable. The Solar Rating & Certification Corporation and the Florida Solar Energy Center have equipment certification protocols that address collector and system design and performance. Several electric utilities are involved in highly successful solar water heating programs, demonstrating that properly designed programs lead to highly reliable solar energy systems. The Utility Solar Water Heating Initiative (USH_2O) is an electric utility/solar industry collaborative which now counts nearly 30 utility members from across the US, as well as 45 other solar industry, state government and utility commission members, all of whom are working towards developing additional effective and reliable utility-based solar water heating programs.[35] As an example, Hawaiian Electric Company's Energy Solutions Solar Water Heating Program has grown to over 3,000 systems per year since its inception in 1996.[36]

In recent months, there has been a worldwide shortage of PV panels due to the dramatic increase in demand from Germany, leading to a modest reversal of the decades-long trend of declining prices of modules. Exacerbating the problem has been revived growth in the semiconductor industry, which relies on the same highly pure silicon feedstock as its base semiconducting material. There is consensus among manufacturers, however, that these shortages are temporary, and every major manufacturer is bringing on new production lines and/or expanding capacity at existing facilities over the next year. Despite these increases in module costs, overall system costs have continued to decline, according to rebate applications filed with the California Energy Commission's Emerging Renewables Program[37].

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[34] Maya Chaudhari, Lisa Frantzis, and Tom Hoff, *PV Grid Connected Market Potential Under a Cost Breakthrough Scenario*, The Energy Foundation and Navigant Consulting, September 2004. Report can be downloaded at http://www.ef.org/documents/EF-Final-Final2.pdf. Also, see Appendix II-1 for NREL's detailed analysis on rooftop PV potential in the WGA region.
[35] See: http://www.eere.energy.gov/solar/ush2o/
[36] http://www.heco.com/CDA/frontDoor/
[37] See http://www.energy.ca.gov/renewables/emerging_renewables/2005-11-02_post_1_1_2005_update.xls

Further, there are a number of new PV technologies recently on or soon to be introduced to the market that are designed to provide competition for the traditional, silicon-based PV cells and modules. This competition has come from two basic directions. The first group of companies is developing new semiconducting materials to replace or expand on the silicon in PV cells. In addition to the considerable expense of the silicon feedstock itself, the manufacturing process that turns it into a PV cell is difficult and expensive. There are two paths being pursued. One involves somewhat less efficient but substantially less expensive PV material not based in silicon wafers, such as thin-film PV (so called because ultra-thin photovoltaic material is deposited on an inexpensive material such as glass or plastic) and other new materials.[38] The other involves somewhat more expensive but substantially more efficient semiconductors, such as multi-junction cells (named as such because they involve layering of different materials, each of which responds to a different wavelength of light, into a single cell). Products based on these materials are already on the market, and new designs are emerging on a regular basis.

New thin-film PV material is incorporated into panels and installed atop the City of San Diego Miramar Operation Center

Rooftop solar concentrator eliminates 95% of the silicon-based PV material required to produce a given amount of energy

The second group is focused on more mechanical solutions. Here again, there are two distinct areas of effort. One involves process improvements in manufacturing PV cells that would result in less semiconductor stock (often silicon) being used. The other is to find clever approaches to concentrating light that would enable a lot less of the expensive PV material, silicon or otherwise, to be used for a given amount of electrical output.

All of these new efforts have the ultimate goal of dramatically reducing the cost of power generated by PV systems. There are trade-offs, to be sure. For example, many of the new-materials technologies such as thin film PV are currently less "area efficient" than silicon PV (meaning they take up more roof space to produce the same amount of output). For many building owners, however, trading additional roof space for a lower price and quicker payback is a worthwhile compromise. For others, the traditional systems are more suited to their needs.

This growing number of options, which are emerging precisely because of the various market-stimulating incentives being offered around the world, can be expected to produce at least two major market effects. At minimum, these new technologies can reduce the pressure on silicon-based photovoltaics to meet the entire growth in demand for distributed solar electricity systems. That in turn will lessen demand for the underlying silicon feedstock and reduce upward pressure on silicon prices. The advent of new module technologies will also ensure that there are sufficient modules available for programs like the ones proposed here, no matter how substantially the PV market grows as a result of its widespread adoption. Even more importantly, new options will provide intense competitive pressure to ensure that prices for all systems will continue to decline and reach ambitious competitive cost levels as the market matures.

This emerging market in new, clean energy technologies has also caught the attention of the mainstream venture capital community. In the first nine months of 2005 alone, over $100 million in investment capital[39] has poured into early-stage companies pursuing thin-film, nanomaterial, solar concentrator and

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[38] For an analysis of the costs, efficiencies and potential for thin-film PV to meet energy needs, see Ken Zweibel, *The Terawatt Challenge for Thin-film PV,* NREL Technical Report NREL/TP-520-38350, August 2005, http://www.nrel.gov/docs/fy05osti/38350.pdf

[39] CleanEdge, Venture Power, Dow Jones' *Venture Wire* and other industry reports.

manufacturing technologies, among many others. Several solar companies have also gone or are in the process of going public in 2005. Major financial analysts, including CLSA Asia-Pacific Markets and Piper Jaffray, regularly issue extensive reports covering the solar industry and its key players. Clearly the industry – and the financial community's interest in it – is expanding rapidly.

Additionally, given high rates of growth in many areas in the West, home developers who are building zero-energy homes and/or integrating solar systems into new home construction can make a meaningful contribution to reducing overall growth in demand for new generation capacity. Builders can take advantage of cost efficiencies inherent in designing solar electric and solar water heating systems into new developments, and home buyers can finance these improvements through minimal increases in their home mortgages offset by lower utility bills, yielding a net reduction in their living expenses from the moment they move in. Indeed, many top builders and developers, including KB Home, Pardee Homes, and Ladera Ranch, among others, are integrating solar systems into their offerings in response to consumer demand.

Public Policies Around Solar Economics Make the Difference

The remaining challenges are all in the realm of economics and public policy, representing major opportunities for the Governors to take a lead in recommending and adopting the programs that will clear the way for solar to make a powerful contribution to the region's energy supply. In this regard, much can be learned from successful programs in other countries as well as throughout the Western states. Most of these were designed to get over the one significant hurdle standing in the way of widespread adoption of solar – its current economics. In various ways these countries or states provided sufficient financial incentives to homeowners or businesses to enable their investments in solar to be cost-effective. In the process, they created vibrant economies around manufacturing and installing systems and drove down the cost of systems as a result of increased manufacturing and installation efficiencies and the impact of competition.

The first major set of policies designed to stimulate the development of a solar PV industry was initiated in Japan. Starting in 1994, consumers were provided up-front subsidies to purchase systems for their homes. Incentives were specified over a ten-year period and on a declining scale, providing manufacturers with the market certainty they needed to make investments in plants and equipment. The program was by all accounts successful in meeting its objective. Today, Japanese manufacturers dominate the industry with a 48% worldwide market share in modules, and the Japanese market was until 2004 the largest in the world. The result is a self-sustaining solar energy industry that continues to add clean energy to the grid through the private investment of home and business owners. It is noteworthy that while the federal government is ending the residential subsidy program this year, it is considering embarking on a new program to encourage broader commercial adoption of solar.

Germany took a different but no less successful approach. Motivated by both environmental and economic-development considerations, the government established a "feed-in tariff," guaranteeing the purchase of whatever energy was produced from a PV system over a twenty-year period at a substantial premium. With that level of certainty and incentive, the market has exploded. In 2004 alone, over 350 MW of solar were installed, edging out Japan for the first time.

California, the third-largest solar PV market in the world, adopted a program similar to Japan's. Combining net-metering laws and interconnection standards with up-front incentives and waivers from a number of costs have encouraged homeowners and businesses to respond in ever-growing numbers. Indeed, during 2005 the various incentive programs offered by the California Energy Commission and the California Public Utilities Commission have been fully subscribed and in some cases vastly over-subscribed. Realizing the latent demand for and potential benefits of solar, Gov. Schwarzenegger has proposed a series of initiatives designed to stimulate 3,000 MW of distributed solar over the next 13 years (through 2018) and has supported legislative and regulatory initiatives to reach this goal.

European countries have also instituted a series of very successful incentive programs for solar water and space heating systems, enabling them to make significant progress and poising them for continued growth. Incentive programs are quite modest in countries with the most active solar water heating programs with rebates ranging from $300 to $1400 per system depending on size. Many of these countries have substantially less solar resource than that available in the Western US, yet they have more aggressive solar thermal programs. A subset of seven European Union countries[40] together installed approximately 250,000 solar thermal systems in 2003, or 875 MW_{th} equivalent.[41] Austria alone (population of 8.1 million) has an existing installed solar thermal generating capacity of 1,469 MW_{th}, equal to all of the installed solar thermal capacity in the entire US (population 294 million). Israel, with the population roughly equivalent to Arizona, is home to 5 percent of the world's solar water heating deployments. By contrast, the US solar thermal market for water heating has been stagnant for a number of years at around 8,000 systems.

WGA States Have Already Taken the Lead

California's efforts have already resulted in over 93[42] megawatts of grid-connected solar PV installations throughout the state, but it's not alone. Other Western states have also taken the lead in identifying and eliminating barriers to solar utilization and have adopted programs to provide financial support for solar technologies. Arizona, New Mexico and Nevada have provided system owners with up-front help in the purchase of solar systems similar to successful programs in Japan and California, and the State of Washington recently passed a feed-in tariff akin to the one that worked so well in Germany. Hawaii and Oregon have in place tax incentives that are similar in nature to the Federal incentive.

About half of the Western states – representing far more than half of the population in the West – have adopted Renewable Portfolio Standards (RPSs) in which targets are set for the amount of electricity generated by a given date that must come from renewable sources. A number of Western states have enacted specific policies to use RPSs to advance solar. While most often associated with encouraging utilities to contract for the output of large-scale central-station solar facilities, several states have also used their RPSs to promote distributed generation as well. Nevada has a set-aside requiring that a minimum subset of the total RPS come from solar and a 2.4 multiplier for distributed applications. Arizona is revising its Environmental Portfolio Standard to include a 30 percent distributed resources set-aside. In Colorado, the voters recently passed a ballot initiative enacting an RPS. It requires that a certain percentage come from distributed solar and includes a minimum rebate ($2 per watt) to help accomplish this. New Mexico's RPS includes triple credits to advance solar technologies. One utility in California (SDG&E) has a separate solicitation to advance distributed PV. And the California Public Utilities Commission has indicated that solar renewable energy credits (RECs) belong to the owner operator, which provides another avenue for distributed solar system owners to participate in RPS programs. Several of these individual states have adopted mechanisms for the inclusion of solar thermal technologies in their RPS programs as well.

The following table, prepared by NREL, catalogs the many efforts underway throughout the WGA states. The full document detailing each of these programs is included in Appendix II-1.

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[40] Austria, France, Germany, Greece, Italy the Netherlands and Spain
[41] Solar Heating Worldwide; Markets and Contribution to the Energy Supply 2003 IEA Solar Heating and Cooling Programme, May 2005; Appendix 6, pg. 25 "Annual Installed Capacity"
[42] 46 MW installed under the CEC's program and 26 MW under the CPUC's SGIP program. Remainder installed by Sacramento Municipal Utility District, Los Angeles Departrment of Water and Power, and other small municipal utilities. Internal CEC document provided by Bill Blackburn.

Table II-1. Overview of PV Related Policies in the WGA States.

State	Net Metering	RPS	Rebate/ Buy-down Program	Production Incentive	Low-interest Loans	Tax Incentives	System Benefit Charge	Total
CA						Pe, Pr, C		8
OR						Pe, Pr, C		8
MT						Pe, Pr, C		7
NV		+++				Pr, S		6
AZ		+++				Pe, S		5
TX						Pr, C		5
WA						S		5
CO		+++						4
HI						Pe, C		4
ID						Pe, S		4
UT						Pe, C, S		4
ND						Pe, Pr, C		4
NM								3
WY						S		3
AK								1
NE								1
KS						Pr		1
SD						Pr		1
Total	12	7	5	5	5	29	3	

Notes:
Tax Incentive Abbreviations: Pe=Personal Pr=Property C=Corporate S=Sales.
Policy and Incentive data is based on DSIRE as of August 2005 (http://www.dsireusa.org/). Income tax credit in California expires at the end of 2005.
Production Incentives do not include the Federal Conservation Security Program which applies to all states.
Not implemented state-wide.
+++ Solar set-aside included within RPS.

Key Policies and Programs to Enable Solar to Succeed

- **Provide financial incentives to encourage private investment in solar systems**
- **Remove barriers to the easy installation of solar**
- **Implement programs that encourage solar system owner-generators to optimize their solar energy production**
- **Demonstrate leadership through state purchasing and public education programs**

From among the successful programs throughout the West, we have identified a number of policies, programs and operating principles that have proven invaluable in cultivating a viable and growing market. In many cases, these can be accomplished through executive or administrative actions and have little or no impact on state revenues. Each state is unique in its needs and interests, and each Governor will undoubtedly find some more appropriate than others for his or her state. Further, by leveraging the new federal solar tax credit of 30 percent of system costs, many of these programs are now highly affordable. The most critical programs to consider are covered below. A more detailed table of options can be found in Appendix II-1.

Provide Financial Incentives to Stimulate the Market

Once the path has been cleared for easy installation of solar technologies, consumers often face a substantial economic hurdle to purchasing these systems. While the price of solar PV has come down substantially in recent years, the payback period is still long in most areas, making it difficult for most homeowners and businesses to justify the investment. The Federal government has done its part to reduce the cost of solar technologies by enacting a 30 percent tax credit for commercial and residential applications starting in 2006. For those states that wish to leverage the federal tax credit and stimulate local markets – to develop local manufacturing and installation industries and to accelerate experience that further drives down prices – incentive programs may be appropriate. General state revenues can be used to underwrite these programs, or they can be funded through public benefits charges on utility bills or small increases in tariffs to cover the expense of these incentives.

The single most significant collective action that the Governors should pursue is the extension of the 30 percent Federal tax credit for a total of ten years. Congress should also be encouraged to lift the $2000 credit cap on residential systems, providing homeowners with the same incentive as businesses. While individual homeowners and businesses can take advantage of this credit in 2006 and 2007, the lack of a long-term program is a major disincentive for suppliers to invest in expanded manufacturing capacity. These investments are not only necessary to ensure continued cost reductions that will eventually eliminate the need for subsides, they are also the source of high-paying jobs in the region. While Federal support is vital to the overall success of the solar effort in the West, state leadership is equally important, if not more so. The following programs should be considered as part of that effort.

Newest-generation residential solar hot-water systems can be tightly integrated into building design.

- **Provide modest incentives for residential solar thermal technologies** that reduce the consumption of electricity or natural gas. Natural gas price and availability will continue to be volatile, and electricity prices in the West are closely tied to natural gas fundamentals. The reduction of electricity or natural gas consumption via the use of solar thermal technologies is indistinguishable from energy efficiency and on-site electricity generation. Solar water heating can be both cost-effective and attractive to consumers with minimal incentives. Public indifference can be turned into strong demand with modest financial incentives in the range of $750 to $1000 per system that strongly communicates the importance of investing in this energy-saving technology. Further, where homeowners with existing electric water heaters want to take advantage of incentives for PV, they should be encouraged to install solar water heaters first or alongside a PV system to increase the effectiveness of whatever incentives are provided.

- **Incorporate solar thermal cooling , heating, domestic hot water and process heat in commercial and industrial applications into the incentive system for renewable energy** in order to allow this technology to quickly achieve cost reduction and market penetration in the U.S. These systems, which incorporate flat-plate, trough and vacuum tube collectors, can provide buildings with space heating, space cooling, domestic hot water and process heat, depending on need. Because buildings in many of the WGA states experience high cooling loads, the use of solar thermal technologies to replace electrically driven air conditioners is very attractive. In addition, this is a firm technology, allowing for permanent displacement of load from the grid.

  Programs that incorporate either a buy-down or a performance-based incentive would be an effective approach to stimulating commercial and industrial (C&I) solar thermal projects. The industry is currently working with utilities and regulators to establish the basis for appropriate incentive levels and

Commercial buildings can incorporate solar thermal heating, cooling and hot water systems to reduce both electricity and natural gas usage.

contract lengths (typically 10-15 years) required for this technology in the U.S. as well as to enable the formation of Renewable Energy Service Companies (RESCos) to install, own and operate systems on customer sites.

Incentive programs must be designed in a way that recognizes that the economics of C&I solar thermal applications will vary from state to state, depending on such variables as type of fuel used, primary application (e.g. cooling, cooling/heating, domestic hot water, etc.), and solar radiation. The first step for each State is to include C&I solar thermal technologies in its RPS or other equivalent program and work with industry, regulators, and utilities to establish appropriate incentive levels. States will benefit from these actions by making a proven, cost-effective solar technology available to address the needs of commercial and industrial customers. Given that the use of C&I solar thermal is in its infancy in the U.S., a significant decline in system price by 2015 is not unreasonable if proper incentive programs are put in place now.

- **Build smart incentive programs that leverage private investment to drive the PV market**. Incentive programs will necessarily vary from one state to the next, driven largely by available solar resources and the cost of electricity – the two most critical variables to a cost-effective installation beyond the price of the system itself. In order to be effective, incentives should be structured so that distributed PV is economically attractive for electricity consumers, enabling private investment by homeowners and businesses to drive the market. Current industry experience is that the tipping point for demand is reached when the payback on an investment in a solar system falls below ten years for homeowners and five years for businesses. (Businesses enjoy greater federal incentives than homeowners such that these critical payback points may be reached with equal programmatic support for these two groups at the state level.) Additionally, states should consider special incentives to ensure that low-income families can participate in these programs. As noted previously, this collective demand will in turn allow PV system providers to gain additional levels of experience that have proven effective in driving down the cost of systems, eventually eliminating the need for incentives altogether.

  Direct incentives form the heart of all of the world's successful PV programs. Each state should consider adopting at least one of the following types of incentives – if not providing homeowners and businesses the option of choosing whichever of the two best suits their particular situation. Regardless of which is adopted, it is critical to commit to the program over a substantial period of time, typically ten years. This commitment provides suppliers with the market assurance they need to invest their capital in local infrastructure and plant expansion, R&D and other programs that will ultimately drive down costs for consumers.

Wide swaths of unobstructed commercial roof space are prime targets for solar PV systems.

  - **Up-front incentives to purchase** – These incentives are typified by the successful programs in California and elsewhere that underwrite the initial purchase of a system, reducing up-front capital costs. Often called "buy-down programs," these incentives should be structured so that they decline over time, eventually zeroing out.

- **Performance-based incentives** – More philosophically appealing, particularly for large commercial installations, are programs in which system owners are paid only for the electricity they produce, not the capacity they install. These typically involve a modest per-kWh payment spread over a fairly long period of time, ensuring the continued production of energy and continued benefit to the grid. The key to the success of such an effort lies in selecting the appropriate per-kWh payment and time period such that business owners can achieve an adequate return on their investment in the system. Performance-based incentives can be easily incorporated into RPS requirements for distributed solar.

The costs of incentive programs have been the subject of much debate, particularly with regard to capping total program costs to limit the impact on ratepayers. For example, recent discussions in California on the costs of implementing the (3GW) Million Solar Roofs Initiative focused on limiting the cost of direct incentives over ten years to $2.5-$3 billion. To put that figure in context, if spread over all ratepayers in that state over ten years, an additional charge of approximately $0.001 (one-tenth of one cent) per kWh would be required to fund the direct incentive portion of the program.

The benefits to consumers of a sustained set of incentives have been demonstrated around the world. Every industry has its experience curve in which additional volumes of production yield reductions in costs, and solar is no exception. It has been widely observed that for every doubling of cumulative global production in megawatts, the cost of PV modules drops by roughly 20%[43]. Where markets have been robust, such as in Japan and Germany, similar reductions have been seen in installation costs, and balance-of-system costs (inverters, mounting hardware, etc.) have begun similar declines[44]. It is important to note that while increasing worldwide production of PV modules helps drive down costs for everyone, modules are only half of the equation. As shown in Figure II-4, the non-module portion of the total installed system cost for systems installed in California during 2004 were over 56 percent. Unless the WGA states grow their local markets, the anticipated cost reductions related to increased experience and installation efficiency are not likely to occur. However, assuming that WGA states adopt the recommendations in this report and are successful in growing their local markets, we anticipate that through a combination of global learning and local progress average installed system costs will drop from around $8 per watt today – equivalent to 15 to 30 cents per kWh over 25 years depending on how sunny the location is – to roughly half that amount by 2015 in the WGA region.[45]

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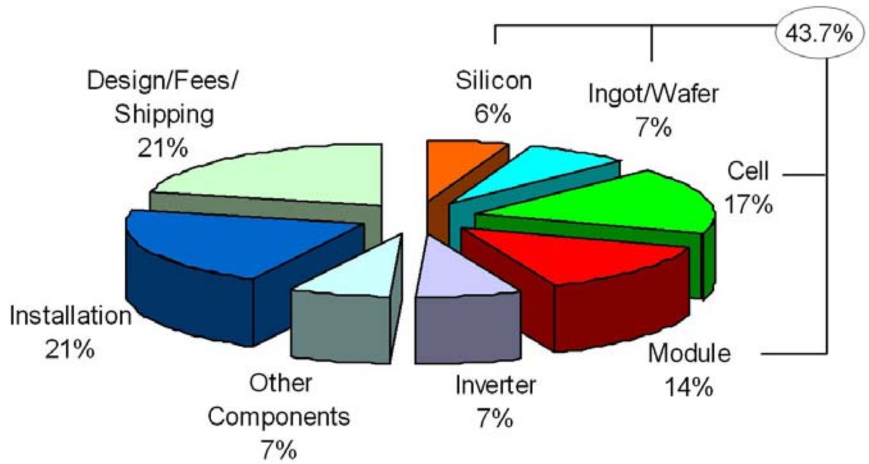
[43] Nemet, Gregory F., *Technical Change in Photovoltaics and the Applicability of the Learning Curve Model.* International Institute of Applied Systems Analysis, Laxenburg, Austria. Report IR-05029, 2005.
[44] Ikki, Osamu, *PV Activities in Japan*. RTS Corporation, Tokyo, Japan (May)., Jager-Waldau. 2004. *PV Status Report 2004*. Joint Research Centre, European Commission, Ispra, Italy. Report EUR 21390 EN, 2005.
[45] This assumes a combination of global learning and local progress in which states are successful in growing their local markets. The range of expected price reduction is based on different levels of insolation occurring between states. All LCOE calculations anticipate a system lifetime of 25 years.

Figure II-4. Breakdown of average PV system costs[46]



A recent unexpected surge in demand from Germany has temporarily halted and in some cases reversed this downward price trend, but the consensus among manufacturers is that investments in expanded capacity already underway will enable the PV industry to continue down the traditional cost-volume curve within the next year or two. Indeed, this reduction in costs, which is aimed at creating an industry able to continue on its own without incentives, is precisely the point of a declining incentive schedule recommended above.

Any incentive program needs to be designed like any investment program – the goals should be attainable, the incentive designed so that the goal can be reached, the costs and impacts should be transparent and fully accounted for, and progress toward the goal should be monitored. Further, a large percentage of customers in some states receive power from publicly owned utilities or other energy service providers, and these entities should be encouraged to participate in incentive programs so that they are available to all customers.

Removing Barriers to Easy Installation of Solar

In many areas of the West, when homeowners or businesses want to invest in a solar system for their buildings, they often face obstacles that have nothing to do with the challenges of financing a capital-intensive system. Simple improvements can pave the way for broader adoption of this important technology. Among the most critical are:

- **Adopt common and simplified small generator interconnection standards.** Make it easy and inexpensive for consumers and businesses to connect solar systems to the grid with standardized policies, streamlined procedures and simplified standard form contracts. Fast and easy interconnection is absolutely necessary for developing a robust distributed solar market, and stakeholder working groups have demonstrated success in streamlining this process. Residential and commercial solar customers in most cases must be able to easily plug their solar system into the grid, consistent with applicable system protection, reliability and safety standards, without undue cost or hardship imposed by utilities or state regulations. The most effective interconnection standards:

[46] Source: Energy Innovations, Inc. calculated based on worldwide gross spending by component industries, global revenue pool of component industries, prices in key world markets, and wholesale component costs in the US.

- Allow for the interconnection of pre-certified systems
- Establish reasonable timelines for utility responses to interconnection applications
- Eliminate undue fees or insurance requirements on interconnecting customers
- Have a pre-determined dispute-resolution process
- Provide for transparency and consistency among different utilities and states, consistent with safety requirements

FERC has recently released the Standard Interconnection Agreements & Procedures for Small Generators, Order No. 2006[47], which will apply to utilities across the country and is substantially similar to rules adopted in California, New Jersey and other leading solar states. In addition, the recently enacted 2005 federal energy bill requires all states to consider adopting uniform interconnection rules based on IEEE Standard 1547.

- **Ensure access to the sun**. Throughout the Western states, there are numerous examples of home and business owners who have had to resort to battling restrictive zoning ordinances and homeowner association rules in the courts to enable them to install solar panels on their rooftops. Invariably the building owners win the right to install, but the process is daunting even for the most ardent solar advocate. California[48] and other states have taken a lead in this area with solar rights laws, but much work remains to be done. The Governors need to develop policies that ensure that homes and businesses are presumed to have the right of access to the sun unless there are extraordinary mitigating circumstances.

Implement programs that encourage system owners to optimize their energy production.

The third category of policy that can make the difference between an investment in a solar system being appealing or not is the ongoing benefits that accrue to the system owner. In one way or another, it is important for the homeowner or business contributing to the region's energy needs to be encouraged to optimize the amount of electricity generated. Several approaches have been taken that acknowledge the strong correlation that in many areas occurs between solar production and peak energy needs, attempting to align the payment or reimbursement schemes to actual avoided costs. As with other incentive programs, publicly owned utilities and other energy service providers should be encouraged to participate in these types of programs for them to be optimally effective.

- **Provide net metering**. Net metering is the simplest way to value the electricity generated on site by a home or business. The term is derived from the way in which electricity production and usage is measured at the meter. When a building uses energy from the grid, the meter records consumption in the usual fashion. When on-site energy production exceeds usage, it is exported to the grid, and the meter spins backwards. Because the customer's meter "nets" the differences between two over the billing period, the term "net metering" is used. The effect of net metering is to compensate system owners at retail rates in effect when they generate electricity – often during critical peak hours. The recently enacted 2005 Federal energy bill requires all states that have not already done so to consider enacting net metering programs within the next two years.

  Retail electricity rates are established with a variety of components including generation, transmission and distribution, and various mandated surcharges. It is generally agreed that PV-generated energy from an individual home or business and delivered to the grid eliminates the utility-delivered generation of those same kilowatt-hours. There is some debate, however, on how to appropriately value the other benefits to the transmission and distribution system portion of the costs. Regardless, net

[47] FERC Order No. 2006: http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp
[48] See California Civil Code Section 714; California Government Code Sec. 65850.5; and California Health & Safety Code Sec. 17959.1 at www.leginfo.ca.gov

metering policies, when structured appropriately, can incentivize the solar generator to continue to operate its solar systems effectively.

- **Encourage solar-friendly rate structures**. Another critical factor in valuing any distributed resource or energy efficiency improvement is the current rate structure used by the electric or gas utility. It is important to keep in mind that utilities are entitled under the law to earn a fair return on their investments to provide electricity. However, there is great flexibility in designing rate structures that both ensure that rates adequately compensate utilities yet at the same time provide significant encouragement for greater conservation and use of distributed resources. Cost-based fixed charges (often called customer charges) that are kept to a minimum would provide such encouragement. Declining block rates, which charge a lower per unit cost based on greater consumption, can undermine efforts to encourage efficiency. Commercial customers in particular could be offered the option of converting to a tariff that eliminates demand charges but includes very high per-unit charges, providing strong incentives to keep distributed solar systems working at their maximum. One Western utility, Pacific Gas & Electric Company, provides an optional tariff to small businesses that encourages conservation and distributed solar installations. PG&E's A-6 tariff rolls all transmission and distribution costs into a single energy charge that is dependant on the time and season of consumption, providing a strong incentive for solar owners to keep systems operating at peak efficiencies. This tariff is one factor that has contributed to the large number of PV installations in PG&E's service territory. Similar tariffs would encourage distributed solar installations throughout the WGA states.

- **Facilitate REC ownership and exchanges**. The Western Renewable Energy Generation Information System, established by the WGA, is being designed to accurately measure and track renewable energy credits (RECs) so that a market for the specific financial benefits associated with renewable energy can be sustained. Governors should encourage policies that allow REC owners to fully realize the benefits of these markets.

Demonstrate Leadership Through State Purchases and Public Education

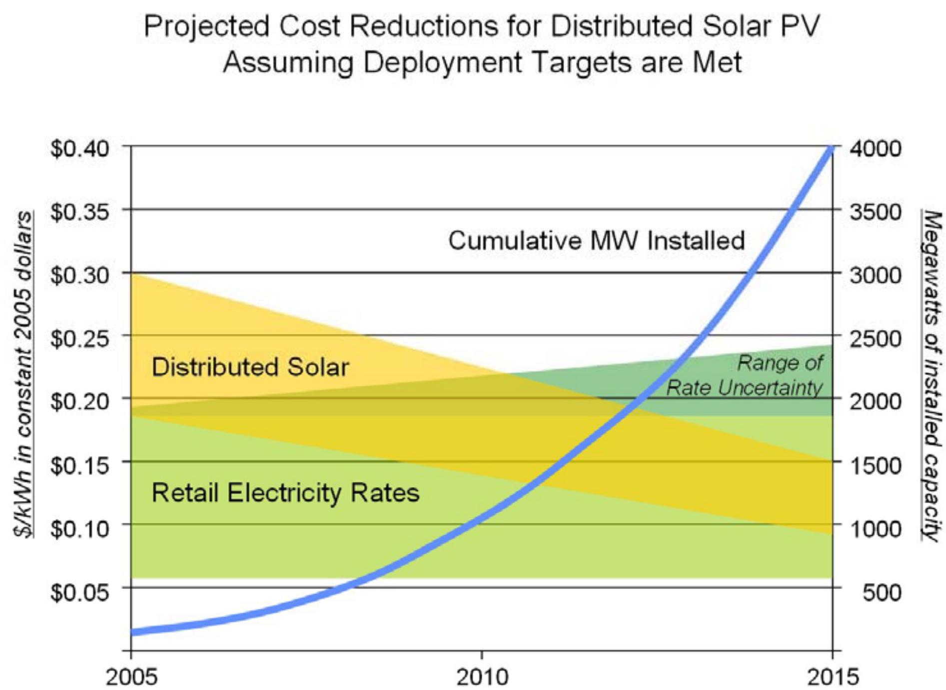
Finally, each Governor has an opportunity to take a strong leadership position through actions that demonstrate a firm commitment to deploying his or her state's solar resources toward meeting the region's growing energy needs. The public at large – homeowners, businesses, nonprofit organizations, schools and other public institutions – take their cues from state initiatives.

- **Purchase solar electricity for state buildings**. One high-profile initiative that can have a strong ripple effect throughout the region is to purchase solar electricity systems for key state buildings. These installations can also serve to demonstrate the economic viability of solar electricity and can provide Governors with an opportunity to show real savings to taxpayers on electricity costs over time. Governor Napolitano's Executive Order is an excellent model. It requires that 10 percent of the energy usage in new state-funded buildings in Arizona to come from renewable resources. The new Federal renewable purchase requirement contained in the Federal Energy Policy Act of 2005 is another useful model. The Act also requires that a certain percentage of a government building's energy use be derived from renewables, and double credits are provided for on-site generation.

- **Encourage adoption through public education and awareness programs.** In many instances solar systems are already cost-effective, and yet few home or business owners know it. This is particularly true of solar thermal systems for heating water and air. By using the pulpit of the Governor's office and through state publications and outreach programs, building owners can learn how to adopt these technologies to save money on their energy bills and contribute to the region's economic and environmental health.

Conclusion: Distributed Solar Can Contribute 4,000 MW of Generation and $2GW_{th}$ of Solar Thermal Power by 2015

With these programs implemented throughout the region over the next few years, we estimate that distributed PV solar can contribute 4,000 MW of the Governor's objective of 30,000 MW of clean, diversified energy. In addition, 500,000 solar thermal systems could be installed, providing the equivalent of $2GW_{th}$ of energy and saving 15 billion cubic feet of natural gas per year.



Source: NREL and industry data

This will add over 15,000 high-quality jobs in the West and contribute up to 6 million megawatt-hours of electricity annually to the region by 2015 – the equivalent of the electricity consumed during peak hours by Portland, Seattle and Denver each year *combined*. Ten years of growth could also drive down the cost of solar systems by approximately 50%, resulting in an industry that should be able to thrive without financial subsidies. These estimates are based on continuing the existing industry growth rate in the Western US of approximately 32% per year. After 2015, assuming growth in the distributed PV industry slows to an average of 20% annually, by 2025 another 30GW of systems could be installed without subsidies at prices below retail electricity rates in most states. Much of this growth is driven currently by incentive programs in California, and the overall goal cannot be reached without those programs continuing in one form or another, whether through Governor Schwarzenegger's Million Solar Roofs Initiative (targeting 3,000 MW of solar by 2018) or equivalent programs adopted by the California Public Utilities Commission. In addition, however, the efforts of every state in the WGA will be needed to reach the 2015 goal of 4,000 MW of distributed PV and $2GW_{th}$ of solar thermal systems, and we encourage the Governors to adopt programs from among the myriad options that best suit their individual states' circumstances.

Appendices

- Section I – Central Station Solar
    1. Supply Curves
    2. Definitions and Discussions of Incentives, Policies and Other Factors

- Section II – Distributed Solar
    1. "Status of Distributed PV Policies in the WGA States," Robert Margolis and Michael Wheeler, National Renewable Energy Laboratory, November 15, 2005
    2. Background on Installing 500,000 Solar Water Heating Systems Over 10 Years
    3. Policy Options to Encourage Widespread Adoption of Distributed Solar

APPENDIX I-1 – Supply Curves

Capacity supply curves provide a means for describing the relative cost of generation for a particular technology (renewable or conventional) and the generating capacity coincident with the cost. For renewable technologies, costs are driven primarily by two factors, resource availability and proximity to available transmission. For this analysis “busbar costs” (technology costs exclusive of transmission, that is, those costs accumulated within the perimeter of the plant site, up to and including the point of delivery to a transmission system, or “busbar”) were based on a fixed charge rate (FCR) methodology supplied by the WGA Quantitative Working Group (QWG). While the FCR methodology provides a simple determination of the relative cost of generation for a given resource, it over-estimates the real and nominal levelized cost of energy when compared to the more detailed cash flow model used for cost analyses performed for the Central Solar WG.

One of the supply curve sets that were requested by the QWG is shown in Figure A1-1. This supply curve assumes, per QWG guidance, 20% transmission capacity availability to the nearest load center(s). Where the solar resource is located adjacent to a load center, 20% of city demand is assumed to be available to off-take the solar generation without the need for new transmission. The supply curve in Figure A1-2 assumes that once the 20% capacity is allocated, new transmission must be built to carry additional supply to the nearest load center. New transmission cost is assumed to be $1000 per MW-mile. The final supply curve, to be supplied, assumes 0% transmission capacity availability to nearest load center(s). That is, the supply curve must include new transmission and associated costs.

As new capacity is deployed, it may be further from transmission lines or require new transmission because the existing line capacity is filled. The cost is constrained to rise, but at a rate determined by line capacities and plant locations. **These curves show by their relative flatness that the solar resource and transmission infrastructure impose minimal constraints on development, and that most of the SW states can build significant CSP capacity before the costs of power increase. In this case the curves go to 10 GW, but this is also the case for much higher deployment levels.**

The supply curves described in the figures are essentially a snapshot in time and do not account for cost reductions due to levels of deployment commensurate with the capacity depicted on the supply curves. As such the supply curves, while providing an important qualitative assessment of the magnitude of the resource and proximity to transmission, are impractical and incapable of depicting actual costs, and should not be used as the source of information on the current or projected future cost of the technology. Cost reductions as a function of deployment are shown later in this report.

Figure A1-1

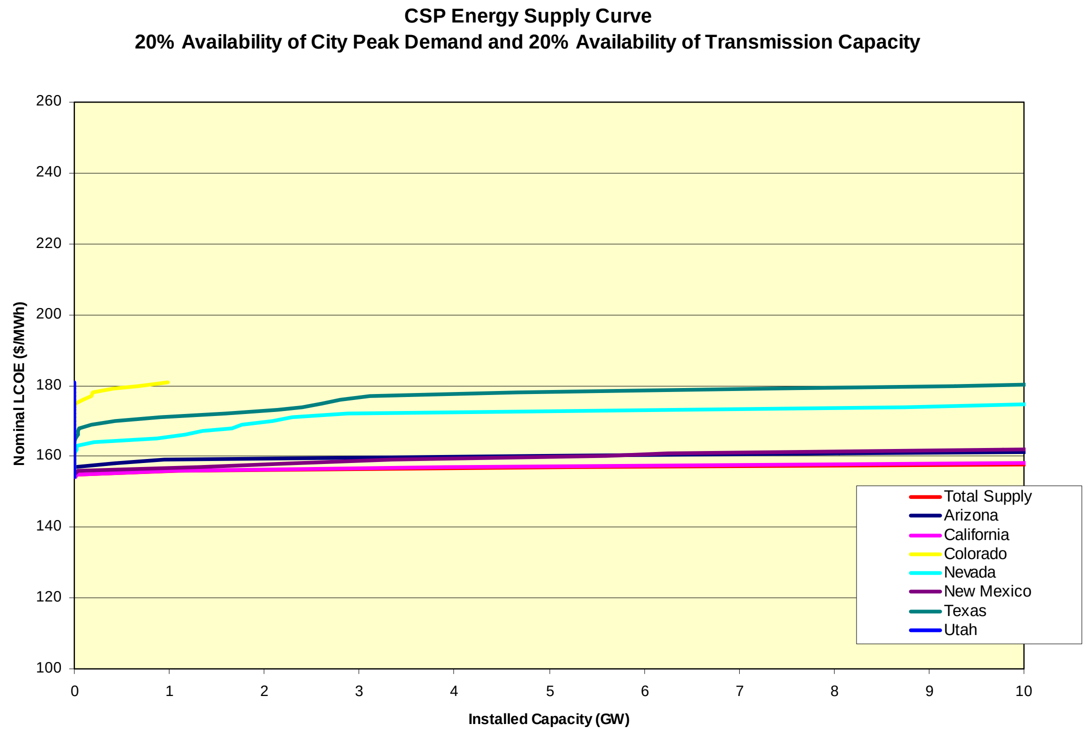
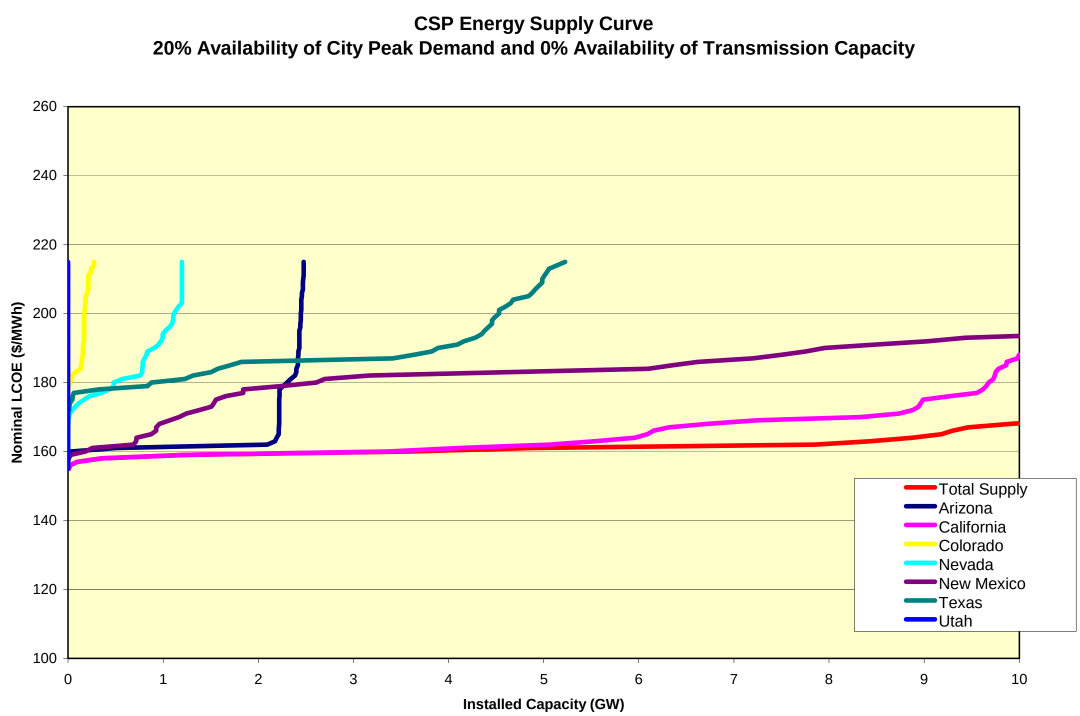


Figure A1-2



APPENDIX I-2 – Definitions and Discussions of Incentives, Policies and Other Factors

Extend PPA to 30 Years	It is important that a fair methodology be put in place to value the energy, capacity, fuel price stability, energy diversity, and environmental benefits of the power produced. The California PUC has developed the Market Price Referent methodology that is a step in the right direction. However, this approach should be extended to a 30-year lifetime. A 30-year power purchase agreement (PPA) will reduce the (real) levelized electricity cost by approximately 11% compare to a 20-year contract. Also it is essential that regulations be changed so that utilities are able to rate base the costs for large scale solar power plants, whether in the form of a 30-year PPA or by ownership of the plant. It is also essential that the creditworthiness of payments be assured to ensure financeability of the project (as has been achieved in Nevada). Since utilities are moving toward a "Resource Adequacy" planning approach, CSP plants should be given credit for the firm capacity that they provide.
Include $60 Capacity Credit	Quantification of the capacity credit for firm power operation. Justified by the inherent characteristics of CSP solar thermal plants, and the performance experience at the SEGS facilities.
Extend Federal 30% ITC to 10-year window.	The Federal solar Investment Tax Credit (ITC) was recently increased from 10% to 30% in the federal energy bill for a period of 2 years, reducing the LCOE by about 20%. The current 2-year timeframe will only benefit plants currently in the development pipeline and is ineffective to encourage development of new projects that will lead to significant cost reductions. New projects can require 3 to 4 years for siting, permitting, procurement, construction and plant start-up. Extension to 10 years of this important incentive would allow CSP technology to develop in a sustained manner and lead to cost reduction from higher deployments.
Extend Federal ITC to Utilities	The Federal ITC currently cannot be taken by utilities. Utility ownership of CSP plants reduces financing since utilities often have access to capital at lower interest rates than independent power projects (IPPs). Allowing utilities to take the ITC will encourage utility ownership, and could reduce the cost of solar power by 10% or more.
Exempt Solar Equipment from State Property and Sales Taxes	Current tax law does not place a meaningful tax on conventional fossil fuels (natural gas and coal). Although there are some minor excise taxes, fuel cost is expensed and written off the taxes. However, because solar fuel is the solar field itself, sales taxes and property taxes are in effect paid on solar fuel. In fact, a solar plant must pay sales taxes on the equivalent of a 30-year fuel supply up front, and then must pay property taxes each year on the 30-year fuel supply. To better achieve tax equity for solar electricity, sales taxes and property taxes on solar equipment should be

	eliminated. California already waives property taxes on the entire solar plant. It is in the states' interest in minimizing the cost of energy to ratepayers to eliminate these taxes. This tax burden is just transferred to the electric ratepayers in the form of increase PPA costs or utility rates. Exempting property and sales taxes will reduce the cost of solar power by about 10% and 5%, respectively.
Solar Firm Capacity Buy Down	Many states already use a cost buy down incentive to encourage the implementation of solar technologies. This is typically used for photovoltaic systems in the form of dollars per peak watt installed. One of the concerns with this type of incentive is that the incentive is not tied directly to the performance of the system, thus two systems could receive the same amount of incentive but deliver significantly different levels of energy. The solar firm capacity buy down would be different in that it is an incentive for dispatchable solar technologies. The incentive would be used to buy down solar technologies with a firm capacity capability using thermal energy storage or fossil backup to assure that the solar plant will meet the plant rated capacity during the system peak on sunny summer days. The incentive is an upfront payment at the point commercial operation that would be based on the plant rated capacity as defined by the power purchase agreement with the utility.
Solar Production Tax Credit (PTC) **CSP Performance-based Incentive (PBI)**	The Federal production tax credit has been used to encourage the development of wind power. The production tax credit is generally favored over an investment tax credit because it is a performance-based incentive. The credit is paid based on the actual electricity delivered over some period of time, typically the first 5 or 10 years of a project's operation. The state could provide a similar electric generation based tax incentive that would be used to bridge the cost gap. For purpose of this analysis a flat state PTC is assumed for a 10-year period. However, more analysis should be conducted to determine if 10 years is the best duration, and whether the incentive should be flat, has some inflation over time, or has rate tiers that change over time. In any case, the incentive should be available to IPPs or investor owned utilities. If the initial policy recommendations of a 30% federal ITC extended to 10 years, solar sales and property tax exemption, provision of a 30 year PPA with a \$60/kW-yr capacity payment, there will be about a 3 ¢/kWh gap between the CSP cost and the 9.6 ¢/kWh price target. This gap could be addressed with a CSP performance-based incentive that will require the utilities to pay 11 cents for each kWh generated by the CSP plant for the term of the PPA. As the utilities can recover the target price of 9.6 ¢/kWh in their rate base, the impact of the PBI is to add another 3 ¢/kWh to their rate base. The CSP PBI could be capped at 1 GW and a lower PBI be determined for the next GW.

Loan Guarantees	The recent federal energy bill put in place the structure for federal loan guarantees on clean energy technologies. This type of loan guarantee provides a lenders protection against loan defaults due to technology risk, and could enable a project to get debt financing for demonstration of new technologies that otherwise would be unable to. The primary disadvantage of the federal loan guarantee is that it must be appropriated by congress in its annual appropriations process. One of the primary differences between IPP and utility financing is that the loan on the IPP project is entirely secured by the revenues generated by the project itself. The loan on a utility project is secured by the overall credit worthiness of the utility as a whole. As a result, utilities can obtain longer term debt financing and do not require the same debt service coverage requirements that an IPP project does. For capital intensive solar power projects, this can significantly lower the cost of debt service on the project. In principle it is possible that a State loan performance guarantee would allow the cost of power from IPP projects to be reduced to that of a utility owned project. In this approach, the state would need to guarantee that the loan would be repaid no matter how the project actually performed. A detailed analysis of this approach needs to be verified with the financial lending industry to be assured that this approach will in fact have the desired effect on the resulting cost of electricity, and to determine what form the loan guarantee would take.

Appendix II-1: Status of Distributed PV Policies in the WGA States and Additional Technical Detail[1]

November 15, 2005

In this appendix we review PV related policies, provide a baseline projection for distributed PV in the WGA states, and provide additional technical detail. First, we present two tables that provide an overview of policies, and then compare policies in place with installed PV capacity, average electricity prices, and available solar resources by state. Second, we present a set of tables that provide considerably more detail on the PV related policies in place in the WGA states. From these tables one thing is clear: the WGA states are pursing a very diverse set of policies aimed at facilitating investments in distributed PV technology. Third, we present a table with detailed information on policies currently under consideration in the WGA states. Fourth, we present a set of baseline projections. These baseline projections take into account both existing policies and a reasonable expansion of existing policies given what is currently on the table. These projections are provided to WGA Solar Task Force as a benchmark against which to evaluate the impact of additional policies focused on distributed PV in the WGA States. Finally, we provide additional technical detail on the following topics: rooftop availability and potential installed capacity in the WGA states, projected solar jobs in the WGA states, effective load carrying capacity (ELCC) in the WGA states, projected avoided CO2 emissions in the WGA states, projected avoided water use in the WGA states, projected levelized cost of electricity in residential and commercial systems, and a state by state allocation of the 2015 installed PV target.

1. Overview of Existing PV Policies

As shown in Table 1, there is considerable variation across the WGA states in terms of how policies and market incentives have been used to encourage deployment of PV technology. There are three basic types of policy tools that are currently being employed: regulatory levers (net metering and Renewable Portfolio Standards), direct incentives (rebates/buy-downs and production incentives) and tax incentives. While there are some policies that appear to be implemented widely, for example some form of net metering exists in 14 of the 18 WGA states, there are important differences across states in how policies have been implemented.

As shown in Table 2, the top five WGA states in terms of PV installations are CA, AZ, HI, TX and CO. CA is the clear leader accounting for at least 90% of total installed grid-connected distributed PV capacity in the WGA states through 2004.[2] CA's lead is not surprising given its use of aggressive PV policies such as net metering, consumer-friendly interconnection standards, various consumer rebates, and solar friendly rate structures[3] combined with high electricity prices and very good solar resources. Four out of five offer significant rebates at state, local, or

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[1] This appendix was prepared by Robert M. Margolis (NREL) and Michael Wheeler (NREL) for the WGA Solar Energy Task Force. Paul Denholm (NREL) provided input to the section on rooftop availability, and Bruce Ellestad (SEIA) provided assistance in gathering data on pending legislation.

[2] This estimate excludes central PV in AZ.

[3] The impact of various rate structures on the value of output from PV systems will be examined in a separate paper currently under preparation by NREL for the WGA Solar Task Force.

utility levels. In addition, the top four all have multiple tax incentives. Through a combination of policy tools states can implement strategies that incorporate both regulatory and market-based elements and create a push and pull effect on the market for distributed PV.

Understanding how policies influence market development requires that states learn from each other about how various tools work best together. In the next section we present detailed tables for each of the policy options shown in Table 1.

Table 1. Overview of PV Related Policies in the WGA States.

State	Net Metering	RPS	Rebate/ Buy down Program	Production Incentive	Low Interest Loans	Tax Incentives	System Benefit Charge	Total
CA	X	X	X	X		Pe, Pr, C	X	8
OR	X		X	*	X	Pe, Pr, C	X	8
MT	X	X			X	Pe, Pr, C	X	7
NV	X	X*	X	X		Pr, S		6
AZ	X	X*	*			Pe, S		5
TX	X	X	*			Pr, C		5
WA	X		*	X	*	S		5
CO	X	X*	X		*			4
HI	X	X				Pe, C		4
ID	*				X	Pe, S		4
UT	X					Pe, C, S		4
ND	X					Pe, Pr, C		4
NM	X	X		X				3
WY	X		X			S		3
AK					X			1
NE					X			1
KS						Pr		1
SD						Pr		1
Total	12	7	5	5	5	29	3	

Notes:
Tax Incentive Abbreviations: Pe=Personal Pr=Property C=Corporate S=Sales.
Policy and Incentive data is based on DSIRE as of November 2005 (http://www.dsireusa.org/). Income tax credit in California expires at the end of 2005.
Production Incentives do not include the Federal Conservation Security Program which applies to all states.
* Not implemented state-wide.
X* Soar Set Aside included within RPS.

Table 2. PV Policies and Installed Capacity in the WGA States.

State	Total PV-Related Policies	PV Installed (kW)[a]	Average Electricity Price (¢/kWh)[b]	Solar Resource (kWh/kW)		
				Low	High	Average
NM	3	82	7	1,840	2,102	1,971
NV	6	112	8.3	1,752	2,102	1,927
AZ	5	5,000	7.3	1,752	2,015	1,883
HI	4	1,014	14.5	1,752	1,840	1,796
CO	5	775	6.8	1,577	1,927	1,752
CA	8	93,000	11.6	1,577	1,840	1,708
TX	5	980	7.5	1,577	1,752	1,664
WY	2	46	4.8	1,489	1,840	1,664
ID	4	140	5.2	1,489	1,752	1,621
UT	4	1	5.4	1,489	1,752	1,621
MT	6	157	6.2	1,402	1,664	1,533
NE	1	4	5.6	1,402	1,664	1,533
KS	1	0	6.4	1,402	1,664	1,533
SD	1	0	6.4	1,402	1,664	1,533
ND	4	0	5.5	1,314	1,577	1,445
OR	7	74	6.2	1,139	1,314	1,226
WA	5	75	5.9	1,051	1,226	1,139
AK	1	21	10.5	788	964	876

Notes:
a. PV Installation data is as of January 2005 for:
CA; 46 MW installed under the CEC's program and 26 MW under the CPUC's SGIP program. Remainder installed by Sacramento Municipal Utility District, Los Angeles Departrment of Water and Power, and other small municipal utilities. Data received from Bill Blackburn of the CEC.
AZ; 5.0 MW represents only distributed PV installations installed through MSR and other programs. In addition, APS has installed nearly 5 MW of utility scale arrays around the state, TEP has completed a 4.6 MW facility, and SRP has a total of 525 kW.
All other state data is through 2002 from the NREL's Renewable Electric Plant Information System. REPiS data is for both stand-alone and grid-connected systems.
Web address: http://www.nrel.gov/analysis/repis/index.

b. Average price data in ¢/kWh for all customer classes in 2003. EIA Electricity Publications Sales and Revenue Data Tables 2003. Web address: http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html

c. Solar Resource data was calculated from the capacity factors derived using NREL's PVWatts PV simulation program. For each state, a representative city was chosen, based on the availability of data near the state's largest population center. Three cities were chosen in California. This limited data set will result in some errors, particularly in larger states, or in states with greatly varied solar resources such as Washington and Oregon.
PV Watts Web address: http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/

2. Detailed Tables on Existing Policies

Net Metering

Net Metering allows for the flow of electricity both to and from the customer through a single, bi-directional meter. With net metering, during times when the customer's generation exceeds his or her use, electricity produced by the customer offsets electricity consumed from the utility at another time. In effect, the customer is credited for this excess generation at the retail rather than wholesale rate. Under most state rules, residential, commercial, and industrial customers are eligible for net metering, but some states restrict eligibility to particular customer classes. In practice, net metering has emerged as a key policy to promote distributed PV. The rationale for instituting net metering is based on the fact that distributed PV provides energy at the point of use, thus distributed PV can help avoid the cost of T&D upgrades, the capital cost of increased peaking capacity, and the associated losses of centralized generation.[4] As shown in Table 3, 14 out of the 18 WGA states have enacted net metering legislation. Of the top five states listed in Table 3, CA and HI have set statewide limits on net metered generation at .5% of peak demand. The other states either allow utilities to set their own rules or plan to revisit the issue once a certain threshold of participation is reached.[5]

Table 3. Net Metering Policies in the WGA States

State	State-wide/ Utility	Residential/ Commercial	System Size	Enrollment Limit	Net Excess
AZ	Salt River Project	Residential	10 kWp	None	Purchased monthly with price adjustment of .017¢
	Tucson Electric Power	Res. & Comm.	10 kWp	500 kWp	Credit to following month's bill. EOY net excess credited to TEP
CA	State-wide	Res. & Comm.	1 MWp	.5% utility peak	Credit to following month's bill. EOY net excess to utility
CO	Xcel Energy	Res. & Comm.	10 kWp	None	Credit to following month’s bill
	Holy Cross Electric	Res. & Comm.	Not specified	50 kWp	Full retail credit
	Aspen Electric	Res. & Comm.	Not specified	50 kWp	Full retail credit
	Gunnison Co. Electric	Res. & Comm.	10 kWp	50 customers	Full retail credit
	Fort Collins Electric	Residential	10 kWp	25 customers	Credit to following month’s bill
HI	All utilities	Res. & Comm.	50 kW	.5% utility peak	Granted to utility monthly

[4] Smeloff, Ed. 2005. “Quantifying the Benefits of Solar Power for California” Vote Solar; E3 Consulting. 2004. “Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs”. Energy and Environmental Economics Inc.; Schell, Laurie & Shirly Neff. 2005. “Testimony Before the Public Utilities Commission of the State of California”. Docket # R.04-03-017
[5] Solar Flare. March 2005. Issue 2005.1

Table 3 (cont.)

ID	Alvista Utilities	Res. & Comm.	25 kWp	.1% 1996 peak or 1.52 MWp	Credit to following month's bill. EOY net excess to utility
	Idaho Power	Res. & Comm.	25-100 kWp	.1% 2000 peak or 2.9 MWp	Res. and Small Com.: Full retail credit – monthly. Large Com.: 85% of Mid-Columbia rates – monthly.
	Utah Power & Light	Res. & Comm.	25-100 kWp	.1% 2002 peak or 714 kWp	Res.and Small Com.: Full retail credit – monthly. Large com.: 85% of Dow Jones index for non-firm energy rates – monthly
MT	Investor-owned utilities only	Res. & Comm.	50 kWp	None	Credit to following month's bill. EOY net excess to utility
	Montana Electric Cooperatives	Res. & Comm.	10 kWp	None	Credit to following month's bill. EOY net excess to utility
ND	IOUs only	Res. & Comm.	100 kWp	None	Purchased at avoided cost
NM	IOUs and Co-ops	Res. & Comm	10 kWp	None	Purchased at avoided cost or credited to following month
NV	IOUs only	Res. & Comm.	30 kWp	None	Credited to utility
OR	All utilities	Res. & Comm.	25 kWp	.5% utility peak	Purchased at avoided cost or credited to following month. EOY net excess to utility.
	Ashland	Res. & Comm.	None	None	Full retail credit up to 1,000 kWh purchased monthly.
TX	State-wide	Res. & Comm.	50 kWp	None	Purchased at avoided cost
	Austin Energy	Res. & Comm.	20 kWp	Re-evaluate at 1% of load	Monthly credit to customer, calculated by multiplying the net kWh fed into grid by current fuel charge or by appropriate Green Power Charge
	San Antonio	Res. & Comm.	25 kWp	None	Credit of 1.65¢ /kWh Oct.-May and 2.02¢ /kWh June-Sept.
UT	All electric utilities and coops(munis excluded)	Res. & Comm.	25kWp	0.1% of 2001 peak	Credit to following month's bill. EOY net excess to utility
WA	All utilities	Res. & Comm.	25 kWp	0.1% of 1996 peak demand	Credit to following month's bill. EOY net excess to utility
	Grays Harbor PUD	Res. & Comm.	26 kWp		Purchased at EOY for 50% retail rate
WY	All utilities	Res. & Comm.	27 kWp	None	Credited to the following month, then purchased at avoided cost by the utility at the end of the annual period

Source: Data is based on DSIRE as of November 2005 (http://www.dsireusa.org/).

Interconnection Standards

The ability to sell distributed PV power to the grid through net metering requires that a physical interconnection be created. In order to insure a safe and reliable grid most utilities treat small-scale PV systems similar to the way they treat large-scale PURPA facilities. Engineers must review system designs and engineering diagrams on a one-system-at-a-time basis. As state policies promoting distributed PV increase, both utilities and their customers will save time and money by adopting uniform interconnection standards that speed the process. As shown in Table 4 the WGA states address interconnection at varying degrees from lack of awareness at the utility level to state-wide standards. At a minimum, utility-level standard agreements give the customer knowledge up front about what the utility will require and costs that can be expected. When these vary from one utility to another, customer confusion and frustration can arise. Issuing state-wide interconnection standards helps to reduce the barriers associated with distributed PV. However, a state-wide interconnection standard can still present barriers to the customer such as requiring insurance or providing the same requirements of small generators (< 50 kW) as large generators (up to 20 MW).

Table 4. Interconnection Standards

State	Authority	Applicable Sectors[1]	System Size/ Enrollment Limit	Standard Agreement	Insurance Required	External Disconnect Required
AZ	Varies by Utility	R, C, I	No	Varies by Utility	Varies by Utility	No
CA	Varies by Utility	R, C, I	10MW-max, 10 kW-simplified/ no limit	Yes	No	Yes > 1 kW
CO	Varies by Utility	R, C, I	10 kW (Varies by Utility)	Varies by Utility	Varies by Utility	Yes
HI	State-wide	R, C, I	.5% of peak	Yes	No	Yes
ID	Varies by Utility	R, C, I	Varies by Utility	Varies by Utility	No	Yes
KS	State-wide	R, C, I	25kW – Res 100 kW – Com/Ind	No	No	Yes
MT	State-wide	R, C, I	50 kW	Yes	No	Yes
NV	State-wide	R, C, I	20 MW	Yes	No	No
NM	State-wide	R, C, I	10 kW	Yes	Yes	Yes
OR	State-wide	R, C, I	25 kW	No	No	No
TX	State-wide	R, C, I	10 MW	Yes	No	Yes
UT	State-wide	R, C, I	25 kW/ .1% of 2001peak	No	No	No
WA	State-wide	R, C, I	25 kW/ .1% of 1996 peak	Yes	Yes	No
WY	State-wide	R, C, I	25 kW	Yes[2]	No	Yes

[1] Applicable Sectors: R=Residential; C=Commercial; I=Industrial.
[2] Only applies to PacifiCorp
Sources: DSIRE as of November 2005 (http://www.dsireusa.org/), Strategies Unlimited, 2004. "Global Analysis of PV Markets and Application Factors"

Renewable Portfolio Standards and Solar Set Asides

A Renewable Portfolio Standard (RPS) requires that a certain percentage of a utility's overall or new generating capacity or energy sales must be derived from renewable resources, i.e., 1% of electric sales must be from renewable energy in the year 20xx. Portfolio Standards most commonly refer to electric sales measured in megawatt-hours (MWh), as opposed to electric capacity measured in megawatts (MW). An RPS with a solar set aside adds a requirement that a certain percentage of a utility's overall energy sales or generating capacity must be derived from solar installations (may included distributed and central generation). As shown in Table 5, seven of the WGA's eighteen states currently have an RPS. Of those seven, three have a specific solar set aside.

Table 5. Renewable Portfolio Standards in WGA States

State	Title	Standard	Solar Technology Set Aside	Credit Trading
With Solar Set Aside				
AZ	Environmental Portfolio Standard	0.2% in 2001, 1.1% in 2007-2012	50% (of 0.2%) in 2001-2003 60% (of 1.1%) in 2004-2012	
CO	Renewable Energy Requirement	3% by 2007; 6% by 2011; 10% by 2015	4% of total renewable kWh 1/2 of this 4% must be from distributed PV	Yes
NV	Renewable Energy Portfolio Standard	5% in 2003, 15% by 2013	5% of total renewable kWh (includes both PV or CSP) PV kWhs get 2.4 multiplier	Yes
TX	Renewable Generation Requirement	5,880 MW in 2015	Solar and biomass must account for 500 MW	Yes
Without Solar Set Aside				
CA	Renewable Portfolio Standard	Increase 1% per year beginning in 2003 to reach at least 20% by end of 2017		
HI	Renewable Portfolio Standard	7% by 2004; 8% by 2006, 10% by 2011, 15% by 2016, 20% by 2021 (includes existing renewables)		No
MT	Renewable Portfolio Standard	5% in 2008, 10% in 2010, 15% in 2015		Yes
NM	Renewable Portfolio Standard	5% in 2006, 10% in 2011	Some sources have higher "value" credit	Yes

Source: Data is based on DSIRE as of November 2005 (http://www.dsireusa.org/).

Rebate Programs

A wide range of rebate programs are offered at the state, local, and utility levels to promote the installation of renewable energy equipment. The majority of rebate programs are available from state agencies and municipally owned utilities and support solar water heating and/or photovoltaic systems. Eligible sectors usually include residents and businesses, although some programs are available to industry, institutions, and government agencies as well. In some cases, rebate programs are combined with low or no-interest loans. As shown in Table 6, seven WGA states currently have PV specific rebates in place. In comparison the typical installed cost of a residential PV system in CA during 2004 was $8-9/Wac. High initial rebates may be required to spur the development of local PV market infrastructure.

Table 6. PV Related Rebates in WGA States

State	Title	Amount	Maximum Incentive	Eligible System Size	Installation Requirements	REC Ownership
AZ	APS Utilty SRP Utility TEP Utility UES Utility	$4/Wdc $3/Wp $2/Wp $3/Wdc	No Limit $9,000 $20,000 $15,000	No limit No limit >= 10 kWp >= 5 kWdc	Grid-connected Grid-connected Grid-connected Grid-connected	Customer SRP(util) Customer Customer
CA	Self-Generation Incentive Program (SGIP)	$3.50/W	1 MW	30 kW – 5 MW based on customer demand	Grid connected	Customer/ producer
	Emerging Renewables Program	$2.80/W	$400,000[1]	<30 kW	Grid connected	Customer/ producer
CO	Utility PV Rebate	$2/W (min)	TBA	TBA	TBA	TBA
NV	SolarGenerations PV Rebate Program	Year 1: $5/Wp Year 2: $4/Wp Year 3: $3/Wp	Residential/Schools Year 1: $25,000 Year 2: $20,000 Year 3: $15,000 Comm./Public Year 1: $150,000 Year 2: $120,000 Year 3: $90,000	5 kWp (Res/ Schools) 30 kWp (Comm)	Grid-connected & net-metered	Nevada Power Company, Sierra Pacific Power Company
OR	Solar Electric Buy-down Program	$3/Wdc	Res: $6,000	Maximum of 10 kW	Grid-connected & net-metered	Customer/ producer
TX	Austin Energy Utility	$5-6.25/W	80% or $15,000	No limit	Grid-connected & net-metered	Austin Energy (Utility)
WA	Clallam PUD Klikitat PUD Orcas Power Puget Sound Energy	$.45/W $.40/W $1.5/Wp $.525-$.6/W	Not Determined $1,200 $4,500 No limit	No limit 3 kW >100 kW No limit	Grid connected Grid connected Grid connected Grid connected	Customer Customer Utility Customer

[1] This figure represents the maximum available in the Emerging Renewables Performance Based Incentive program. See Table 7 for more details.
Source: Data is based on DSIRE as of November 2005 (http://www.dsireusa.org/).

Production Incentives

Production incentives (or feed-in tariffs) provide project owners with cash payments based on electricity production on a $/kWh basis for a fixed number of years. By paying for performance rather than capital investments production incentives provide an effective mechanism for ensuring quality projects. A number of European countries (most notably Germany and Spain) have implemented very aggressive production incentives. As shown in Table 7, five WGA states have some form of production incentive for PV, the most aggressive being the recently implemented feed-in tariff in WA.

Table 7. PV Related Production Incentives in WGA States

State	Title	Amount	Max. Limit	Terms
CA	Supplemental Energy Payments (SEPs)	For above market costs as compared to a market price referent		3 - 10 year contracts
CA	Emerging Renewables (Rebate) Program	$0.50/kWh for 3 years.	$400,000	Must be grid-connected
NV	Renewable Energy Credits	1 kWh of PV = 2.4 kWh REC sold to utilities at market price	None	Must be grid-connected
WA	Feed-in Tarrif	15-54 cents per kWh	10 years	Must be grid-connected
NM	Renewable Energy Production Tax Credit	$0.01/kWh	Minimum of 10 MW capacity. Total annual generation > 2 million MWh/year	10 years
CO	Aspen Solar Pioneer Program	$.25/kWh	$1,000	4 years

Source: Data is based on DSIRE as of November 2005 (http://www.dsireusa.org/).

Low-Interest Loan Programs

Loan programs offer financing for the purchase of renewable energy equipment. Low-interest or no-interest loans for energy efficiency are a very common strategy for demand-side management by utilities. State governments also offer loans to assist in the purchase of renewable energy equipment. As shown in Table 8, seven WGA states currently have low interest loan programs that apply to distributed PV technology. In many states, loans are available to residential, commercial, industrial, transportation, public, and nonprofit sectors. Repayment schedules vary; while most are determined on an individual project basis, some offer a 5-10 year loan term.

Table 8. PV Related Low Interest Loans in WGA States

State	Program_Name	Amount	Terms
AK	Power Project Loan Fund	>$1 million	Repayment to match term of municipal bonds
CO	Aspen Solar Pioneer Program Gunnison County Electric	NA $25k	0% interest 5 year term Fixed for 10 years
ID	Low-Interest Loans for Renewable Energy Resource Program	Res: $1k - $10k Com: $1k - $100k	4% interest, 5-year term
MT	Alternative Energy Revolving Loan Program	$10k	5 years; 5% for 2004
NE	Dollar and Energy Savings Loans	5% or less	
OR	Small Scale Energy Loan Program (SELP)	$20k - $20 million	Repayment to match term of municipal bonds
WA	Franklin PUD Energy Loans	$400 - $10k	0% interest

Source: Data is based on DSIRE as of November 2005 (http://www.dsireusa.org/).

Personal Tax Incentives

Many states offer personal income tax credits or deductions to cover a portion of the expense of purchasing and installing renewable energy equipment. The allowable credit may be limited to a certain number of years following the purchase or installation or renewable energy equipment. As shown in Table 9, seven WGA states currently offer personal tax incentives for PV systems.

Table 9. PV Related Personal Tax Incentives in WGA States

State	Title	Amount	Maximum Incentive	Carryover Provisions	Eligible System Size
AZ	Solar and Wind Energy Systems Credit	25%	$1,000	5 year carryover	Not specified
CA	Solar or Wind Energy System Credit – Personal	7.5%	Not specified	7 year carryover	200 kW
HI	Residential Solar and Wind Energy Credit	35%	Varies by technology and property owner	Indefinite carryover.	Not specified
ID	Solar, Wind, and Geothermal Deduction	40% 1st year 20% next 3 years	$5,000 per year; up to $20,000	Not specified	
MT	Residential Alternative Energy Tax Credit	100%	$500	4 year carryover	Not specified
ND	Geothermal, Solar and Wind Personal Credit	15% (3%/ yr for 5 years)	Not specified	Credit is taken in installments of 3% per year, over five years.	Not specified
OR	Residential Energy Tax Credit	$3.00/W	$6,000	10 year carryover	Not specified
UT	Renewable Energy Systems Tax Credit – Personal	25%	$2,000	4 year carryover	Not specified

Source: Data is based on DSIRE as of November 2005 (http://www.dsireusa.org/).

Property Tax Incentives

Property tax incentives typically follow one of three basic structures: exemptions, exclusions, and credits. The majority of the property tax provisions for renewable energy follow a simple model that provides the added value of the renewable device is not included in the valuation of the property for taxation purposes. As shown in Table 10, eight WGA states currently have property tax incentives that apply to PV systems.

Table 10. PV Related Property Tax Incentives in WGA States

State	Title	Amount	Limit	Terms
CA	California Property Tax Exemption for Solar Systems	100% of project value	No limit	
KS	Renewable Energy Property Tax Exemption	100%		
MT	Renewable Energy Systems Exemption		$20,000 for single family, $100,000 multi-family & commercial	10 years
NV	Renewable Energy Systems Exemption	100%	None	
NV	Renewable Energy Producers Property Tax Exemption	50%		10 years
ND	Geothermal, Solar, and Wind Property Exemption	100%	None	5 years
OR	Renewable Energy Systems Exemption	100%		
SD	Renewable Energy Systems Exemption	50% commercial; 100% residential		For 3 years
TX	Solar and Wind-Powered Energy Systems Exemption	100%	None	

Source: Data is based on DSIRE as of November 2005 (http://www.dsireusa.org/).

Corporate Tax Incentives

Corporate tax incentives allow corporations to receive credits or deductions ranging from 10% to 35% against the cost of equipment or installation to promote renewable energy equipment. In some cases, the incentive decreases over time. Some states allow the tax credit only if a corporation has invested a certain dollar amount into a given renewable energy project. In most cases, there is no maximum limit imposed on the amount of the deductible or credit. As shown in Table 11, seven WGA states currently offer corporate tax incentives that can be applied to PV systems.

Table 11. PV Related Corporate Tax Incentives in WGA States

State	Title	Amount:	Maximum Incentive	Carryover Provisions	Eligible Size
CA	Solar or Wind Energy System Credit - Corporate	7.5%	Not specified	7 year carryover	> = 200 kW
HI	Corporate Solar and Wind Energy Credit	Solar Thermal and PV 35%	Varies	Unlimited carryover	Not specified
MT	Alternative Energy Investment Corporate Tax Credit	35% customer investment >= $5000	Not specified	7 year carryover	Not specified
ND	Geothermal, Solar, and Wind Corporate Credit	15% (3% per year, for five years)	Not specified	5 year carryover	Not specified
OR	Business Energy Tax Credit	35%, distributed over five years	$10 million	8 year carryover; 10% in 1st-2nd years, 5% in each year thereafter;	Not specified
TX	Solar Energy Device Franchise Tax Deduction	100% capital or 10% profit	None	1 year	Not specified
UT	Renewable Energy Systems Tax Credit - Corporate	10%	$50,000	4 year carryover	Not specified

Source: Data is based on DSIRE as of November 2005 (http://www.dsireusa.org/).

Sales Tax Incentives

Sales tax incentives typically provide an exemption from the state sales tax for the cost of renewable energy equipment. As shown in Table 12, six WGA states currently provide sales tax incentives for PV systems.

Table 12. PV Related Sales Tax Incentives in WGA States

State	Title	Amount	Limit	Terms
AZ	Solar and Wind Equipment Sales Tax Exemption	100%	$5,000 /system for retailers $5,000 /contract for contractors	Retailer or contractor must register with the AZ Dept. of Revenue
ID	Renewable Energy Equipment Sales Tax Refund	100%	Not specified	> 25 kW
NV	Renewable Energy/Solar Sales Tax Exemption	100% local sales taxes. State sales tax reduced to 2%	Not specified	Not specified
UT	Renewable Energy Sales Tax Exemption	100%	Not specified	Systems >20 kW
WA	Sales and Use Tax Exemption	100%	200W minimum	Not specified
WY	Renewable Energy Sales Tax Exemption	100%	Not specified	Not specified

Source: Data is based on DSIRE as of November 2005 (http://www.dsireusa.org/).

System Benefit Charge

System Benefit Charges (SBC) are typically state-level programs created as part of the electric utility restructuring process as a measure to assure continued support for renewable energy resources, energy efficiency initiatives, and low-income support programs. Such a charge is usually unavoidable and applied to all customers based on electricity consumption, e.g., 0.2 cents/kWh. In a number of states funds raised through a SBC have been used to support rebates on renewable energy systems; funding for renewable energy R&D; and development of renewable energy education programs. As shown in Table 13, three WGA states currently have SBCs in place.

Table 13. System Benefits Charges in WGA States

State	Title	Uses	Fund Size	Customer Charge
CA	Renewable Resources Trust Fund	Renewables	$135 million/year	2-3 mills/kWh ($.002/kWh - $.003/kWh)
MT	Universal System Benefits Program	Efficiency, renewable energy, low-income assistance	$14.9 million annually	Electricity suppliers will annually contribute 2.4%
OR	Public Benefits Funds	Renewables, efficiency, low income, schools	$10 million for renewables/year	3% from high demand customers

Source: Data is based on DSIRE as of November 2005 (http://www.dsireusa.org/).

3. Review of PV Policies Currently Under Consideration

Proposed legislation and rule changes under consideration that may affect the incentives and rates of installation of new PV are listed in Table 13. The incentives applicable to individual consumers may include tax credits, buy-downs and rebates. Mandatory regulations for utilities, such as Renewable Portfolio Standards, may create opportunities for individual and corporate installations of PV. The actions listed below were under consideration of November 2005.

Table 13. Proposed Renewable Energy Legislation and Rule Changes by State

State	Policy	Proposed Action
AZ[1]	EPS (RPS) Rule Changes	The Arizona Corporation Commission recommended (on 1/21/05) that the RPS be increased from 1% to 5% by 2015 and 15% by 2025, and the distributed generation requirement would be set at 25% of the RPS.
CA[2]	California Solar Initiative	Following the demise of SB 1 (Murray/Campbell), the Governor is pursuing a California Solar Initiative that would nearly replicate SB1 through the state PUC. It is likely that the CSI would aim for 3,000 MW of solar PV, by 2018.
	RPS	AB 1585 (Blakeslee) - Would increase the RPS target to achieve 20% by 2010, 33% by 2020.
	RPS	AB 1009 (Richman) - Would utilize time-of-use pricing. Includes a provision for time of use valuation of PV.
HI[3]	Net Metering	HB 1018 – Would increase individual generation capacity limit to 500 kW.
OR[4]	Net Metering	SB 84 – Would enable the PUC to increase the system size of net metered systems.
	Solar on Public Buildings	HB 3001- Would set aside 1% of appropriations for public buildings to be used for solar.
SD[5]	RPS	HB 1217 (Dennert) – Would require all utilities to add renewable energy equal to 50% of new electricity sold.

Sources:
1. http://www.cc.state.az.us/utility/electric/EPS-StaffRpt-01-21-05.pdf
2. http://www.calseia.org/currentstate0819.htm
3. http://www.forsolar.org/?q=taxonomy/term/11
4. http://www.oregonseia.org/legislation.htm
5. http://legis.state.sd.us/sessions/2005/bills/HB1217p.htm

4. A Baseline Projection for Distributed PV in the WGA States

In this section we present - a high baseline projection and a low baseline projection for distributed PV in the WGA states. These projections are based on (1) the implementation of existing solar set asides (SSA) in CO, NV, and AZ, and (2) continued growth in CA (with and without the implementation of the California Solar Initiative).

Our high and low baseline assumptions related to SSA implementation are shown in Table 14.[6] In CO and NV the only difference between the low and high cases is the assumed share of the SSA from PV. In AZ all three factors are assumed to change between the low and high cases: that multiplier declines, the share of the SSA from PV increases, and the RPS compliance rate increases. The result, as shown in Figures 1 and 2, is that in our baseline projection we expect between 100 and 280 MW of PV to be installed in CO, NV, and AZ by 2015 due to existing SSA legislation.

Table 14. Solar Set Aside High and Low Baseline Assumptions

	Low			High		
State	**PV Credit Multiplier**	**PV Share of SSA**	**RPS Compliance**	**PV Credit Multiplier**	**PV Share of SSA**	**RPS Compliance**
CO	1.25	60%	100%	1.25	100%	100%
NV	2.4	30%	100%	2.4	80%	100%
AZ	2.5	75%	40%	1.75	100%	100%

Because of its leadership role to date, and pending legislation, CA holds a unique position within the WGA states with respect PV. Thus we will treat it separately in projecting PV capacity additions. As of the end of 2004, a total of 93 MW of PV were installed in CA primarily under the CEC and CPUC programs.[7] A majority of the systems in CA were installed during the past 2 years (36 MW in 2003 and roughly 40 MW in 2004). In our low baseline projection we assume that the CA market continues at its current level without any growth (i.e. at 40 MW per year). Even under this very conservative assumption CA continues to be the dominant force in the WGA states with respect to PV. As shown in Figure 1, in the low baseline scenario, CA is projected to have a total installed PV capacity of 500MW in 2015 and 700MW in 2020.

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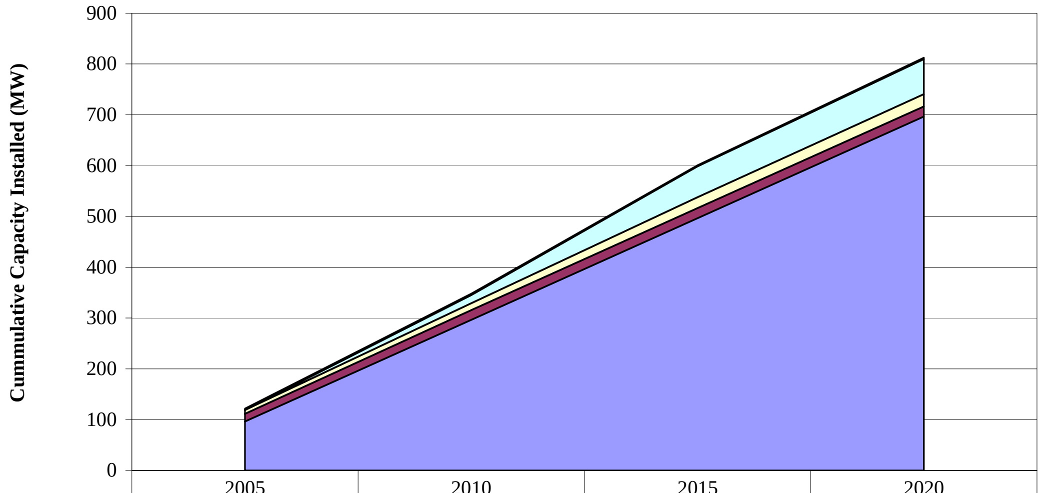
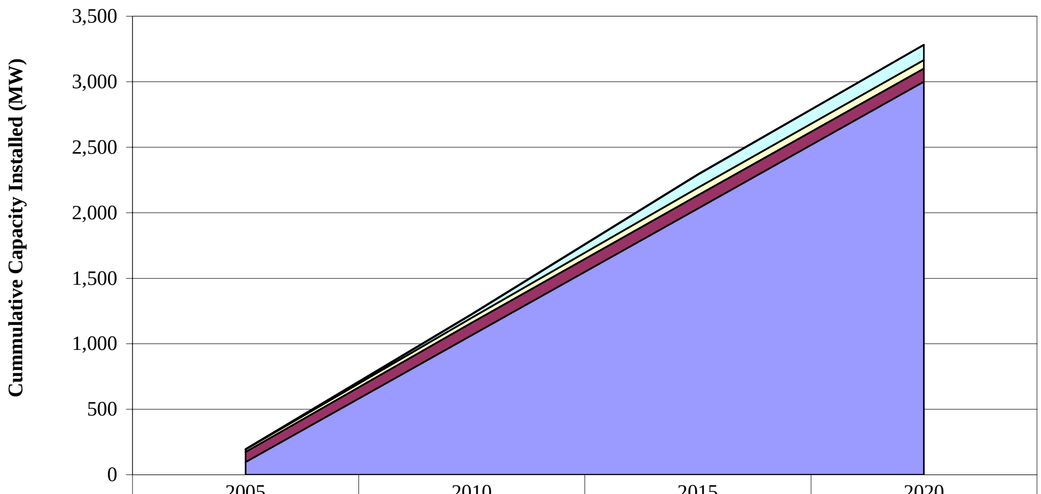
[6] Here we have followed the methodology in used in Wiser, R. and M. Bolinger. 2005. “Projecting the Impact of State Portfolio Standards on Solar Installations” Presentation prepared for the California Energy Commission (January 20).
[7] Internal CEC record of annual installations by utility and program provided by Bill Blackburn.

Figure 1. Projected PV Installations in the WGA States – Low Baseline Scenario



	2005	2010	2015	2020
Other WGA States	3	3	3	3
CO	0	16	61	69
NV	8	14	21	24
AZ	15	19	20	20
CA	97	297	497	697

Figure 2. Projected PV Installations in the WGA States – High Baseline Scenario



	2005	2010	2015	2020
Other WGA States	3	3	3	3
CO	0	27	101	115
NV	21	37	57	65
AZ	77	96	101	101
CA	97	1,064	2,032	3,000

In contrast, if the CSI moves forward the CA market is expected to expand dramatically and will likely dwarf all other markets in the US over the next decade. Thus, in our high baseline projection, as shown in Figure 2, we have assumed that the CSI is implemented and that the CSI goal of installing 3,000 MW by 2018 will be fully achieved by 2020. Here the total installed PV capacity in WGA states reaches 2,300 MW in 2015 and 3,300 MW in 2020.

As shown in Figures 1 and 2, CA dominates PV installation in the WGA states in both the low and high baseline scenarios, accounting for 86% and 91% respectively of total cumulative installations in 2020. In terms of the WGA goal of installing 30,000 MW of clean energy in the West by 2015, we expect PV to deliver 2-8% (600-2,300 MW) of this goal under exiting SSA and CA policies, i.e., in our baseline projections. This baseline is a reasonable benchmark against which to evaluate the impact of additional distributed PV related policies in the WGA states.

5. Rooftop Availability and Resulting Capacity in the WGA States

Lack of potential rooftop area is not a barrier for distributed PV in the WGA states. In fact, distributed PV is unique among renewable technologies because of its modular ability to make use of rooftop space. Several PV studies have attempted to assess the availability of this rooftop space,[8] the most recent being the Navigant Consulting study written for The Energy Foundation.[9] The Navigant study assesses the market potential for grid connected rooftop PV and identifies current market barriers. It also provides an analysis of resource adequacy and energy policy for all 50 states and selects 10 top performers. This analysis presented here builds on the Navigant estimates of rooftop availability for the WGA area and evaluates the potential of rooftop PV to provide a significant fraction of the region's electricity demand. The following tables indicate that there is an extremely large resource for solar PV on rooftops.

Rooftop Availability

To estimate suitable US rooftop space, the Navigant study calculated total rooftop area from building survey data using type of building, floor-space, and number of floors as key inputs. Multiple screens were applied to this estimate to consider shading and orientation issues.[10] Structural adequacy and material compatibility were also taken into consideration but were not found to pose any significant issue. Table 1 provides estimates based on Navigant of total rooftop availability on residential and commercial buildings in the WGA states. The data from the Navigant document was adjusted to estimate the building stock totals in year 2005. Industrial and non-occupied buildings such as parking structures are not included here.

Overall, the Navigant study estimated the area available for PV on Residential and Commercial buildings to be 22% and 65% respectively of their sector's total roof area. It should be noted that these fractions are based on estimates for the national average. This value might be higher or lower for western states due to lower shading impacts or larger than average HVAC requirements. This issue will be a concern only if extremely large PV deployment is projected.

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[8] Arthur D. Little. 1995 "Building-Integrated Photovoltaics (BI-PV) Analysis and US Market Potential", Prepared by Arthur D. Little, Inc. for the US Department of Energy Office of Building Technologies, NREL/TP-472-7850, DE95004055

[9] Chaudhari, Maya, Lisa Frantzis, Tom Hoff.. 2005. "PV Grid Connected Market Potential in 2010 under a Cost Breakthrough Scenario." Prepared by Navigant Consulting for The Energy Foundation.

[10] The Navigant study uses floor space data from the U.S. EIA's 2001 Residential Energy Consumption Survey and the 1999 Commercial Buildings Energy Consumption Survey. The floor space is adjusted to roof space considering number of floors, and PV available rooftop is estimated using estimates of rooftop structural compatibility, shading, and orientation. Description of screens is found on p.78-79 of the Navigant study.

Table 1: Estimated Rooftop Area Available for PV in 2005 (million feet^2)

State	Residential Total	Commercial Total	State Total
AK	80	83	163
AZ	657	504	1,161
CA	4,055	3,387	7,442
CO	590	569	1,160
HA	128	119	248
ID	176	220	396
KS	343	359	703
MT	133	179	312
NE	219	231	450
NV	268	268	536
NM	237	254	491
ND	87	90	177
OR	498	457	956
SD	99	98	197
TX	3,174	2,490	5,663
UT	249	202	452
WA	845	617	1,462
WY	73	116	188
	11,911	**10,244**	**22,156**

Data is provided only for U.S. states due to data availability limitations for Pacific Islands.

Potential Rooftop Capacity

Table 2 provides an estimate for the total capacity of PV systems installed on all available rooftops in the WGA area. The capacity of commercial buildings is presented in two ways. Flat Orientation assumes that all suitable commercial rooftops are completely covered with PV. Tilted Orientation increases PV performance by optimizing energy production, but reduces the area available due to shading effects. Tilted Orientation therefore assumes a 25% decreases in available rooftop area.

Table 2: Estimated 2005 Available PV Capacity (Peak MWAC)

State	Residential Total	Commercial Total		State Total	
		Flat Orientation	Tilted Orientation	Flat Orientation	Tilted Orientation
AK	696	724	543	1,419	1,238
AZ	5,718	4,382	3,286	10,100	9,004
CA	35,279	29,467	22,100	64,746	57,379
CO	5,136	4,953	3,715	10,088	8,850
HA	1,116	1,037	778	2,153	1,894
ID	1,529	1,914	1,435	3,442	2,964
KS	2,984	3,128	2,346	6,112	5,330
MT	1,157	1,560	1,170	2,716	2,326
NE	1,909	2,010	1,508	3,919	3,416
NV	2,329	2,332	1,749	4,661	4,078
NM	2,062	2,211	1,658	4,273	3,721
ND	760	780	585	1,540	1,345
OR	4,335	3,980	2,985	8,315	7,320
SD	857	852	639	1,710	1,497
TX	27,612	21,660	16,245	49,272	43,857
UT	2,168	1,761	1,321	3,928	3,488
WA	7,352	5,371	4,028	12,723	11,380
WY	631	1,005	754	1,636	1,385
State Total	**103,629**	**89,125**	**66,844**	**192,754**	**170,473**

Data is provided only for U.S. states due to data availability limitations for Pacific Islands.

Potential Energy Production

The potential PV energy production can be calculated with the Table 2 estimate of rooftop capacity by applying typical solar PV capacity factors.[11] Capacity factors for each state were selected based on a representative city with preference for the state's population center. The use of a single capacity factor for each state may result in some errors.[12] This estimate does not include the potential application of PV to parking lot awnings or other non-occupied structures.

Table 3: Estimated Technical Potential for Rooftop PV Energy Production in 2005

State	City	Capacity Factor	Annual Potential (TWh)	Estimated Electricity Demand - 2005 (TWh)	Potential Fraction of Total Electricity from PV in 2005(%)
AK	Anchorage	9-11%	1.1-1.3	5.7	19-22
AZ	Phoenix	20-23%	16.9-19.4	65.4	26-30
CA	Long Beach, Sacramento, San Francisco	18-21%	95.3-109.8	243.5	39-45
CO	Colorado Springs	18-22%	15.1-17.6	47.4	32-37
HA	Honolulu	20-21%	3.4-3.9	10.6	32-36
ID	Boise	17-20%	4.7-5.4	21.6	22-25
KS	Topeka	16-19%	8.1-9.3	37.5	22-25
MT	Billings	16-19%	3.5-4.1	12.9	27-31
NE	Omaha	16-19%	5.1-6.0	26.4	20-23
NV	Las Vegas	20-24%	7.8-9.0	30.7	25-29
NM	Albuquerque	21-24%	7.2-8.4	19.7	37-43
ND	Fargo	15-18%	1.9-2.2	10.7	18-21
OR	Portland	13-15%	8.8-10.1	46.1	19-22
SD	Sioux Falls	16-19%	2.2-2.6	9.3	24-28
TX	Fort Worth	18-20%	72.3-83.0	329.1	22-25
UT	Salt Lake City	17-20%	5.66.5	24.3	23-27
WA	Seattle	12-14%	12.9-14.8	79.7	16-19
WY	Cheyenne	17-21%	2.32.7	13.5	17-19
Total			**274.3-316.0**	**1034.2**	**27-31**

These estimates indicate that existing rooftop space is not a significant limitation to large-scale distributed PV deployment in the Western States and could provide nearly one-third of electricity demand. Assuming building stock grows at the same rate as electricity demand, this fraction could be expected to remain nearly constant. However, if PV efficiency increases at a rate faster than building energy intensity, this fraction could significantly increase. Use of rooftop resources such as parking lot awnings and bus stops could extend PV's contribution to the western state's electricity demand well beyond one-third.

[11] The capacity factors were derived by using NREL's PVWatts PV simulation program: http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/

[12] The highest probability of error will exist in states that are large; (CA, TX) or with varied insolation (WA, OR).

6. Projecting PV Related Jobs in the WGA States

In projecting the growth of PV related jobs in the WGA states we started with the most recent estimate of jobs involved in manufacturing and installing PV systems (based on production and installation in a given year), and O&M for PV systems (based on total installed capacity in a given year). Theses two factors were drawn from a report published by the Renewable Energy Policy Project (REPP) in 2001. This report estimated that for PV systems there are 33 jobs per MW involved in production and installation, and 0.25 jobs per MW involved in O&M (actual estimate was 2.5 jobs/MW over 10 years, we divided this number by 10 to create an annual O&M number). We then used the cost reductions projected for PV systems over the next 10 years to create a jobs index. This index reflects the fact that as costs decline jobs will also decline. In other words, labor productivity is assumed to increase in proportion to overall systems cost reductions, resulting in a one-to-one correspondence between declining cost and job intensity. We then used this jobs index to scale down the projected production and installation jobs per MW and the O&M jobs per MW. The resulting PV related employment projection is shown in Table 1.

Table 1: Projected PV Related Jobs in the WGA States

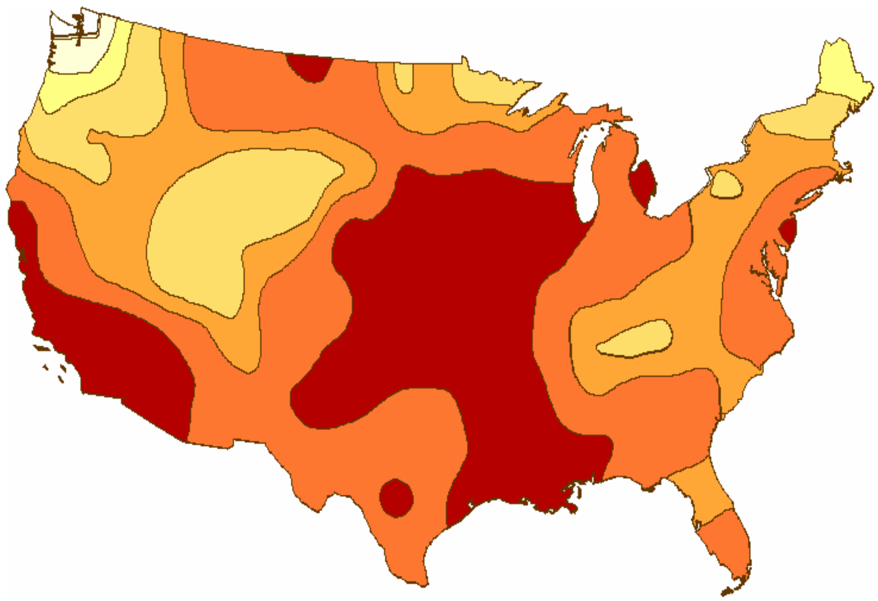
	2005	**2010**	**2015**
Ave. Installed Cost ($/kW)	8.00	5.50	4.00
Jobs Index	1	0.69	0.50
Annual Installed Capacity (MW)	64	250	1,000
Cumulative Installed Capacity (MW)	170[1]	1,000	4,000
Manufact/Install Jobs per MW[2]	33	22.7	16.5
O&M Jobs per MW	.25	.2	.1
Total Industry Jobs (thousands)	2.1	5.7	17.5

[1]Estimated cumulative capacity includes sum of end year 2004 WGA installations in Appendix 1, Table 2 plus estimated 2005 additions.
[2]A typical full time job includes 1,960 hours of work per year assuming a 40-hour work week and two weeks vacation. This remains constant throughout the timeframe of the analysis.

7. Effective Load Carrying Capacity (ELCC) in the WGA States

Effective Load Carrying Capacity (ELCC) represents the relationship between load shape and resource availability (insolation) in a particular area. Specifically, it describes the fraction of nameplate capacity that can be expected to be available during peak demand. ELCC is greatest in areas with intense summer heat waves (where heavy cooling loads drive peak demand), high daytime commercial demand, and/or small electric-heating demand. Such areas with high daytime loads allow PV to provide maximum support to the grid when it is most constrained. Areas with high ELCC include not only the Southwest, but also areas in the Mid-West and Deep South as shown in Figure 1[13].

Figure 1: Effective Load Carrying Capacity (ELCC) Map.



As evident in Figure 1, the majority of WGA states have an ELCC greater than 60% on average. In the mountainous areas of Washington, Oregon, Idaho, Utah, and Colorado, ELCC averages around 50%. Assuming an average ELCC of 60% would imply that achieving the task force's 4,000 MW goal for distributed PV, could offset roughly 5% of the WGA region's projected growth in peak demand. [14]

[13] Herig, Christy, et al. 1996. "Photovoltaics Can Add Capacity to the Utility Grid". National Renewable Energy Laboratory, Golden, CO. Report DOE/GO-10096-262.

[14] Specifically, EIA forecasts growth in peak demand for the WECC and ERCOT subregions of about 2.4% between 2004-2008. We extended EIA's forecast for the WECC and ERCOT subregions to 2015, which results in additional demand of about 50 GW by 2015 (from a starting point of 189 GW in 2005). These two subregions represent over 85% of the WGA's total demand. Source: http://www.eia.doe.gov/cneaf/electricity/epa/epat3p1.html

8. Avoided CO2 Emissions

Grid-connected photovoltaics offset fossil fuel generators and avoid the emission of CO2 during daytime hours. Within the WGA region, 4,000 MW of PV can be expected to avoid the emission of 4 - 4.8 million metric tons of CO2 annually. This estimate is based on the assumption that PV offsets fossil fuel generators comprised of 75% natural gas and 25% coal.[15] In addition, it is conservatively estimated that the annual generation from PV would be within a range of 5 to 6 billion kilowatt hours.

Fossil fuel generators burning coal emit CO2 at a higher rate than those burning natural gas. In the US in 2002, the rate of CO2 emission was nearly twice as great for coal as natural gas as illustrated in Table 1.

Table 1: US Emissions of CO2 by Fuel

	Natural Gas	**Coal**
2002 CO2 Emissions (Million Metric Tons of CO2)	299.1	1,874.7
2002 Electricity Generation (Billion kWh)	607.7	1910.6
CO2 Emission Rate (kg CO2/kWh)	0.492	0.981

EIA Annual Energy Review 2003, Tables 8.2b and 12.3

A 75% natural gas and 25% coal fuel mix would result in a CO2 emission rate of 0.614 kG/kWh. Based on this emission rate, between 4 and 4.8 million metric tons of CO2 emissions would be avoided. This range is illustrated in Table 2.

Table 2: Avoided CO2 Emissions in WGA Region

	Low (5 billion kWh)	**High (6 billion kWh)**
Avoided Emission Rate kg/kWh	0.614	0.614
Million metric tons CO2	4.0	4.8
Million metric tons carbon	1.1	1.3

The factors governing the CO2 emissions avoided by PV are primarily 1) the type of fossil fuel displaced in regional power plants, and 2) how closely the time, amount and duration of electrical demand coincides with electricity generation by PV.

[15] Locally, measuring the quantity of avoided CO2 emissions requires knowledge of the emission rates of the displaced fossil fuels as well as the average capacity factor of the PV. Each state in the WGA territory has a different average capacity factor for PV and a different mixture of power plants each with a unique profile of CO2 emissions based upon its fuel, efficiency, and time of operation.

9. Avoided Water Use

PV offsets the use of conventional energy generation sources and avoids the use of water for cooling and other processes. 4,000 MW of PV installed within the WGA territory will reduce the quantity of water lost to evaporation by between 2.5 and 5 million gallons per day. This is illustrated in Table 1.

Table 1: Daily Avoided use of Water from 4,000MW of PV

	Low	**High**	**Units**
PV Installed	4000	4000	MW
PV Generation	5	6	Billion kWh
Conventional Water Use Rate	0.18*	0.3**	Gallons/kWh
Annual Avoided Water Use by PV	2.5	4.9	Million Gallons/Day

*Equals the average consumption of water by a natural gas combined cycle plant with recirculating cooling system
**Equal to a 75-25 ratio of the technology representing the low end of the range and a steam cycle coal fired plant with recirculating cooling.[16]

According to the American Water Works Association (AWWA),[17] the average household use of water in the US is 350 gallons per day. The water savings from 4,000MW of PV would supply enough water to supply between 7,000 and 14,000 households.

Large water demands in arid regions have begun to be sighted as reasons for not issuing construction permits to power plant developers. The ability for PV to offset the need for water as cooling of conventional power plants is coincident with peak water demand in most of the WGA region. Water storage, distribution, and consumption is nearly analogous to the modern energy system. Prices fluctuate as each resource and its transport become constrained. Peak demand for water by power plants (for cooling purposes during hot summer months) is coincident with peak demand for power to pump water to customers. The avoided use of water is as only as valuable as the market for water determines. However, water is a finite resource and scarcity only increases its value.

[16] Clean Air Task Force. 2003. “The Last Straw: Water Use by Power Plants in the Arid West" Hewlett Foundation
[17] http://www.awwa.org/Advocacy/learn/conserve/resources/ConservationInfo.cfm

10. Calculating/Projecting the Levelized Cost of Energy for PV Systems

In calculating the levelized cost of energy (LCOE) for PV systems it is important to state one's assumptions and methodology. For example, factors such as system costs, system performance, financing and policies can have a significant impact on the calculated LCOE. In estimating the current and projected range of LCOE for distributed PV we included estimates for both commercial and residential systems. In Table 1 we show a simplified set of assumptions for projecting LCOE in the residential and commercial sectors. The assumptions shown in Table 1 represent systems that are installed well in a good location at aggressive but well documented prices. These estimates are in line with the recently published PV industry roadmap[18] and draft DOE Solar Energy Technologies Program Multi-Year Program Plan[19]. They include the permanent federal 10% ITC and accelerated depreciation for commercial systems, but do not include any incentives (state or federal) for residential systems.

Table 1. Current and Projected Levelized Cost of Energy for PV Systems

	Residential Systems (no incentives)			**Commercial Systems (w/ ITC and MACRS)**		
Year	2005	2010	2015	2005	2010	2015
Interest Rate (real) (i) *	4.0%	4.0%	4.0%	5.0%	5.0%	5.0%
System Lifetime (n)	25	30	30	25	30	30
Capital Recovery Factor (CRF)	0.064	0.058	0.058	0.071	0.065	0.065
System Selling Price ($/Wdc)	7.30	5.17	3.89	6.00	4.41	3.60
AC-DC Conversion Efficiency (%)	91%	94%	97%	93%	95%	97%
AC Equiv. System Price ($/Wac)	8.02	5.50	4.01	6.45	4.64	3.71
Fed ITC Rate (at permanent 10% level)	-	-	-	10%	10%	10%
Value of Fed ITC	-	-	-	0.65	0.46	0.37
Sys Cost after Fed ITC	-	-	-	5.81	4.18	3.34
Fed Accelerated Depreciation (Net Present Value)**	-	-	-	34%	34%	34%
Value of Fed Acc Dep. (basis = .95*system cost)	-	-	-	2.08	1.50	1.20
Final Cost ($/Wac) (ICC)	8.02	5.50	4.01	3.72	2.68	2.14
Capacity Factor (CF)	21%	21%	21%	18.5%	18.5%	18.5%
O&M	0.02	0.01	0.005	0.02	0.01	0.005
Levelized Cost of Energy (LCOE) (cents/kWh)* **	**29.9**	**18.3**	**13.1**	**18.3**	**11.8**	**9.1**

* These are real interest rates (i.e., adjusted for inflation and tax benefits) not nominal interest rates.
** Based on MACRS rates from IRS Publication 946, Table A-2 (assuming investment is made in 1st quarter of the year).
*** The LCOE values were calculated using the standard formula for amortization of cost over time, assuming the system is financed through a loan matched to the lifetime of the system.
LEC = (ICCx1000xCRF)/(CFx8760)+O&M, where
ICC = Installed Capacity Cost ($/Wp),
CRF = Capital Recovery Factor = (i*(i+1)^n)/((i+1)^n-1),
CF = Capacity Factor,
O&M = Operation and Maintenance ($/kWh),
i = interest rate,
n = system lifetime (i.e, how many years to amortize cost of system over).

[18] Solar Energy Industries Association. 2004. *Our Solar Power Future: The U.S. Photovoltaic Industry Roadmap Through 2030 and Beyond*. Solar Energy Industries Association, Washington, DC.
[19] U.S. Department of Energy. 2005 (Draft). *Solar Energy Technologies Program Multi-Year Program Plan 2007-2011*. Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, Washington, DC.

11. State-by-State Allocation of the Distributed PV Target

There are a number of ways once could define a state-by-state allocation of the solar task force's 4,000 MW target for distributed PV in 2015. We chose to use electricity demand weighted by average insolation, average electricity prices, and projected population growth. Table 1 shows the data used in this weighting process and the resulting targets for each state. Note that the targets for CA and TX were set separately – CA was set at 2,000 MW in 2015 to reflect the goals of the California Solar Initiative (likely to be implemented through the California Public Utilities Commission) and TX was set at 350 MW based on input from task force members (this was viewed a reasonable target given current discussions in TX on expanding its RPS).

We also experimented with other initial allocation and weighting schemes, but felt that the approach adopted in Table 1 was the most intuitive and easiest to understand. This approach captures the notion that each state should contribute towards the task force's 2015 target in proportion to its size (reflected in demand), but that resource availability, cost of electricity (which is related to the value of the PV output), and projected population growth (which is a reasonable proxy for demand growth) are also important. The values shown in the last column of Table 1 were used to rank the states and to set target ranges for groups of states as follows:

1) 300-400 MW - AZ and TX ,
2) 100-200 MW - CO, WA, NV, OR, and KS,
3) 50-100 MW - HI, NM, UT, NE, and ID,
4) 25-50 MW - MT, ND, WY, SD, and AK.

With these ranges a majority of the WGA states, but not all of the WGA states, would need take action to meet the task force's 4,000 MW target for distributed PV in 2015.

Table 1. State-by-State Targets for Distributed PV in 2015

State	Electricity Demand (TWh)[1]	Initial Share	Solar Insolation (kWh/kW)[2]	Insolation Multiplier	Average Electricity Price 2003 (¢/kWh)[3]	Electricity Price Multiplier 2003	Population 2005 (million)[4]	Population 2015 (million)[4]	10 Year Population Growth Index	Population Growth Multiplier	Final Share[5]	Final Allocation (MW)
CA	*243.5*	*na*	*1,708*	*na*	*11.6*	*Na*	*36.039*	*40.123*	1.11	*na*	*na*	2000
TX	*329.1*	*na*	*1664*	*na*	*7.5*	*Na*	*22.775*	*24.649*	1.08	*na*	*na*	353
AZ	65.4	14.2%	1,883	1.19	7.3	1.16	5.868	7.495	1.28	1.17	21%	353
CO	47.4	10.3%	1752	1.11	6.8	1.08	4.618	5.049	1.09	1.00	12%	190
WA	79.7	17.3%	1139	0.72	5.9	0.94	6.205	6.951	1.12	1.03	11%	184
NV	30.7	6.7%	1927	1.22	5.6	0.89	2.352	3.058	1.30	1.19	8%	132
OR	46.1	10.0%	1226	0.78	6.2	0.98	3.596	4.013	1.12	1.02	7%	120
KS	37.5	8.1%	1533	0.97	6.4	1.02	2.752	2.853	1.04	0.95	7%	117
HI	10.6	2.3%	1796	1.14	14.5	2.30	1.277	1.386	1.09	1.00	6%	92
NM	19.7	4.3%	1971	1.25	7.0	1.11	1.902	2.042	1.07	0.99	5%	90
UT	24.3	5.3%	1621	1.03	5.4	0.86	2.418	2.783	1.15	1.06	5%	75
NE	26.4	5.7%	1533	0.97	5.5	0.87	1.744	1.789	1.03	0.94	4%	70
ID	21.6	4.7%	1621	1.03	5.2	0.83	1.407	1.630	1.16	1.06	4%	65
MT	12.9	2.8%	1533	0.97	6.2	0.98	0.933	0.999	1.07	0.98	2%	40
ND	10.7	2.3%	1445	0.92	8.3	1.32	0.635	0.635	1.00	0.92	2%	39
WY	13.5	2.9%	1664	1.06	4.8	0.76	0.507	0.528	1.04	0.96	2%	34
SD	9.3	2.0%	1533	0.97	6.4	1.02	0.772	0.797	1.03	0.95	2%	29
AK	5.7	1.2%	876	0.56	10.5	1.67	0.661	0.733	1.11	1.02	1%	18
Median			1,577		6.3				1.09			

Notes:

1. Electricity demand: U.S. Department of Energy. 2004 (December). *Electric Power Annual 2003*, Energy Information Administration, U.S. Department of Energy, Washington, DC.
2. Solar insolation: Data was calculated from capacity factors derived using NREL's PVWatts PV simulation program. For each state, a representative city was chosen, based on the availability of data near the state's largest population center. Three cities were chosen in California. This limited data set will result in some errors, particularly in larger states, or in states with greatly varied solar resources such as Washington and Oregon. PV Watts Web address: http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/
3. Average electricity prices: U.S. Department of Energy. 2004 (December). *Electric Power Annual 2003*, Energy Information Administration, U.S. Department of Energy, Washington, DC.
4. Population in 2005 and 2015: US Census Bureau http://www.census.gov/population/www/projections/projectionsagesex.html
5. The insolation, electricity price and population growth multipliers were calculated relative to the median value for each variable. After multiplying the initial shares by the three multipliers, the final shares were re-normalized to sum to 100%.

Appendix II-2. Background on Installing 500,000 Solar Water Heating Systems Over 10 Years

The 2,000 MW_{th} target is based on worldwide growth in the solar thermal industry. Many of the European Union and the other countries listed have incentive programs or standing policies similar to what is being proposed for the WGA Solar Initiative, which have led to significant growth in the market for solar thermal systems. Considering the subset of European Union countries listed below where solar thermal activity is occurring, their population of 380 million citizens are installing over half a million solar water heating systems per year, whereas with a population of over 297 million in the United States, just over 10,000 systems per year are being installed.

With the advent of the federal tax credit set to take effect in 2006, with the prospect of incentives stemming from this WGA incentive phasing in over the next several years, with the cost of natural gas and electricity poised to rise, and with numerous foreign solar thermal equipment manufacturers beginning to enter the US market, a significant ramp-up in solar thermal system sales appears inevitable. The western US should be easily able to accomplish in ten years what the European Union countries alone are achieving in less than two.

	MWth 1999[1]	MWth 2003[2]	% Increase (Decrease)	# Systems Installed
European Union[3]				
• Austria (EUR)	98.81	116.8	18	33,288
• Belgium (EUR)	1.05	6.3	600	1,796
• Denmark	10.78	5.6	(49)	1,596
• Finland (EUR)	1.12	1.1	(1)	314
• France (EUR)	16.80	58.7	249	16,730
• Germany (EUR)	294.00	504.0	71	143,640
• Greece (EUR)	112.78	88.2	(22)	25,137
• Ireland (EUR)		0.7		200
• Italy (EUR)	33.6	39.9	18	11,371
• Netherlands (EUR)	19.6	19.4	(1)	5,529
• Portugal (EUR)	5.95	6.4	8	1,824
• Spain (EUR)	15.11	48.5	221	13,823
• Sweden	6.65	13.5	103	3,848
• United Kingdom of Great Britain and Northern Ireland	6.3	15.4	144	4,389
	Total MW_{th} 2003	**924.5**	**Total Systems 2003**	**263,575**
Other				
• Japan	214.73	196.3	(9)	55,946
• Australia		93.8		26,733
• China		7,980.00		2,274,300
• India		70.0		19,950
• Israel		280.0		79,800
• Turkey		560.0		159,600
• **United States**	**27.31**	**36.4**	**33**	**10,374**

[1] Solar Heating Worldwide; Markets and Contribution to the Energy Supply 2003 IEA Solar Heating and Cooling Programme, May 2005; Appendix 6, pg. 25 "Annual Installed Capacity"
[2] Ibid., pg. 29
[3] Population of European Union countries below (not all listed) – 380,270,826 (2005 Estimated)

Expressing Solar Thermal Energy Production in terms of Electrical Energy Production Equivalent

In September 2004, stakeholders from Austria, Canada, Germany, the Netherlands, Sweden and the USA, as well as the European Solar Thermal Industry Federation (ESTIF) and the International Energy Agency's Solar Heating and Cooling Programme, agreed to use a factor of 0.7 kW_{th}/m^2 to derive the nominal equivalent electrical generation capacity from the area of installed solar thermal collectors. Until then, installed solar thermal capacity had traditionally been counted by numerous countries and other entities in terms of square meters of collector area, a unit not comparable with other renewable energy technology statistics, which are usually based on peak generation capacity under an accepted set of ambient conditions. Prior to the European decision, in 2003 the US-based Solar Rating & Certification Corporation reached a similar conclusion, reporting on its website:
http://www.solar-rating.org/solarfacts/energyproduction20011017.pdf
that a square meter of solar thermal collector had an equivalency factor of 0.71 kW_{th}/m^2 or approximately 4 kW per 64 square foot solar water heating system.

Since solar water heating systems will vary in size in the WGA states based on climatic conditions, an average system size of 52.5 square feet (5 m^2) net aperture is used here to reflect a single residential system with a 3.5 kW_{th} capacity. Thus, 500,000 systems totalling 2,500,000 m^2 at 0.7 kW_{th}/m^2 is equivalent to 1,750 MW_{th} equivalent generating capacity.

Reference the attached document: Technical Note on the Conversion Factor provided by ESTIF:
http://www.estif.org/143.0.html

APPENDIX II-3. POLICY OPTIONS TO ENCOURAGE WIDESPREAD ADOPTION OF DISTRIBUTED SOLAR

Objectives	Strategies	Tactics	Policy & Program Options
Provide financial incentives to stimulate market	Provide tax incentives	▪ Federal incentives	▪ Extend 30% ITC (including IOUs) for 10 years ▪ Continued support for accelerated treatment of depreciation
		▪ State incentives	▪ Sales and property tax exemption ▪ Tax credit for distributed generation investments ▪ Manufacturing tax credits
	Provide direct incentives	▪ Capital cost subsidies	▪ Up-front, declining buy-downs for PV and thermal that attain targeted payback periods for system owners
		▪ Production-based subsidies	▪ Performance-based incentives such as per-kWh payments over guaranteed period of time
Facilitate easy access to solar	Maximize availability of solar resource	▪ Solar access	▪ Solar enterprise zones ▪ Statewide solar access rules/solar "rights" policies
	Expedite development	▪ Permits & approvals	▪ Streamline siting, permitting, zoning
		▪ Common interconnection standards	▪ Allow for the connection of pre-certified systems ▪ Establish reasonable timelines for utility responses to applications ▪ Eliminate undue fees and insurance requirements ▪ Establish dispute-resolution process ▪ Transparency & consistency among utilities and states
Provide ongoing support	Demonstrate leadership	▪ Advocacy	▪ Encourage "Zero Energy Buildings" ▪ Public education programs to promote efficiency, alt. energy
		▪ Public purchasing	▪ Purchase distributed solar for public buildings ▪ Purchase solar under long term power purchase agreements
		▪ Regulatory & market stability	▪ Establish stable, long-term programs (minimum 10 years) ▪ Structure incentive programs to attract investment (e.g, 10-year payback for residential, 5 years for businesses) ▪ Design programs to support self-sustaining markets ▪ Encourage participation by publicly owned utilities
		▪ Low-cost capital	▪ Tax-free solar bonds for public projects ▪ Long-term debt financing ▪ Government guarantees (loan or performance) ▪ Public-private partnerships
	Encourage optimized production	▪ Net metering	▪ Credit customer for excess energy generated and supplied to the grid
		▪ Alternative rates	▪ Encourage optional rate structures that incentivize PV including time-of-use tariffs
		▪ Create revenue stream	▪ REC trading and ownership