APPENDIX D – SOLAR ENERGY TECHNOLOGIES PROGRAM INPUTS FOR FY 2008 BENEFITS ESTIMATES

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Introduction

The President's Solar America Initiative (SAI) was launched January 2006, as part of the Administration's Advanced Energy Initiative, and is being led by the U.S. Department of Energy's (DOE) Solar Energy Technologies Program (SETP). The primary mission of the SAI is to reduce the cost of photovoltaic (PV) technologies so that PV-generated electricity is cost-competitive with conventional electricity sources by 2015.

The SAI enhances DOE's business strategy of partnering with U.S. industry to accelerate commercialization of improved PV systems that can meet aggressive cost and installed capacity goals. Complementing the core R&D and engineering activity of the SAI are technology-acceptance activities aimed at reducing market barriers and promoting market expansion of solar energy technologies through non-R&D activities.

The SAI will drive toward accelerated commercialization of solar photovoltaic systems to a milestone in 2015, at which time they will be competitive with conventional sources of electricity in all domestic grid-tied market sectors: residential, commercial, and utility-scale markets. The main goals of this nine-year mission are:

- Substantively accelerate development of U.S.-produced PV systems so that PV-produced electricity reaches parity with the cost of electricity in select grid-tied target markets across the nation (identified in **Table D-1**).
- Expand the U.S.-installed domestic capacity of PV systems to 5-10 gigawatts (GW) by 2015.

Because the cost basis of electric energy in the target markets is cents per kilowatt-hour, SETP has established targets for PV systems based on the levelized cost of energy (LCOE) delivered by these systems. LCOE is a measure of total lifetime costs of a PV system divided by expected lifetime energy output, with appropriate adjustments for time value of money, etc. The overall cost goals for SAI are shown in **Table D-1**. These targets are based on Energy Information Administration (EIA) projections of relatively flat electricity prices (in real terms) over this time period, based on current conventional fuels. The 2005 Benchmark LCOEs of PV systems and target projections are based on SETP internal analyses and the U.S. PV Industry Roadmap (SEIA 2004). With the ultimate goal for SAI being cost parity with grid-generated electricity, SETP will revise these targets over time as new information warrants.

To implement the SAI, the SETP will pursue an R&D strategy that is segmented into three manageable three-year phases. These phases will progressively reduce the cost of commercially available PV systems and components, and will ultimately yield commercial products and production processes that achieve the LCOE targets and support installed capacity targets by 2015. The first three-year phase is scheduled to run from early CY 2007 through early CY 2010; the second three-year phase is expected to run from early CY 2010 through early CY 2013; and the third three-year phase is expected to run from early CY 2013 through the end of CY 2015.

Table D-1. Cost Targets for Grid-Connected PV Systems in Key Market Sectors

Market Sector	Current U.S. Market Range (c/kWh)[a,b]	Solar Electricity Cost – Current and Projected (c/kWh)[1]		
		Benchmark	Target	
		2005	2010	2015
Residential[c]	5.8-16.7	23-32	13-18	8-10
Commercial[c]	5.4-15.0	18-22	9-12	6-8
Utility[d]	4.0-7.6	15-22	10-15	5-7

[a] Costs are based on constant 2005 dollars.
[b] Current costs are based on electric-generation with conventional sources.
[c] Cost to customer (customer side of meter)
[d] Cost of generation (utility side of meter)

Achieving the goals in **Table D-1** will require reducing installed PV system costs by 50%–60% between 2005 and 2015, from $5.50–$8.50/Wp to $2.25–$3.50/Wp.[1] These targets are reflected in the GPRA08 Solar Program Scenario presented below.

This appendix provides detailed information on the assumptions and methods employed to estimate the benefits of EERE's Solar Energy Technologies Program. The benefits analysis for the Solar Program utilized both NEMS and MARKAL as the analytical tools for estimating the program's benefits. As will be discussed below, a number of assumptions and structural modifications to the models were made in to represent the suite of solar technologies funded by the program as accurately as possible [Photovoltaics and Concentrating Solar Power (CSP)].

Significant Changes from Previous Analysis

Most of the assumptions used in the FY08 analysis are the same as or very similar to those employed in the FY07 analysis. As in the FY07 analysis, the FY08 analysis reflects changes in the Solar Program's structure and funding implemented in FY07 as included in the President's Solar America Initiative.

[1] All monetary figures in this report are in 2005 U.S. dollars unless otherwise specified. Wp is the peak output of a PV module or system measured in wtts.

GPRA08 Solar Program Baseline Assumptions

The primary driving factor in both NEMS and MARKAL for solar technology adoption is cost. For PV technology, the Solar Program Baseline (No DOE R&D Case) cost projections are very similar to the projections in the *AEO2006* reference case, which were based on the "Baseline" scenario in the U.S. PV industry roadmap (SEIA 2004). While the PV industry roadmap "Baseline" scenario included the PV program funded at the pre-SAI level, i.e., roughly one-half the SAI funding level, the U.S. and global PV industry has gained considerable momentum during the past couple of years. Thus, our GPRA08 Baseline cost projections take this momentum into account: Based on the program's benchmarked estimates, we assume that the cost of PV in 2005 is higher than in the *AEO2006*; however, by 2015, the projected GPRA08 baseline costs are roughly equivalent to the *AEO2006* projections. The overlap remains relatively close through 2030. Beyond 2030, the costs continue to decline, but at a relatively modest rate through 2050, ending slightly below the baseline PV industry roadmap projection. Thus, our baseline cost projection is consistent with the *AEO2006* Reference Case and PV industry roadmap Baseline Scenario.

For CSP technology, the Solar Program Baseline simply used the *AEO2006* Reference Case projection for CSP systems characteristics and costs.

To generate the Solar Program Baseline, a number of other changes were made to the *AEO2006* Reference Case related to system size, incentives, etc. Before discussing these adjustments in detail, the target markets for solar technologies will be briefly described.

Target Markets for Solar

During the past decade, the global PV market has been experiencing explosive growth. For example, during the past decade (1996-2005), the average annual growth rate of the global PV industry was 35% (Navigant 2006). The fastest-growing PV market segments during this period were the grid-connected residential and grid-connected commercial segments. Such rapid growth has created tremendous excitement about PV technology around the world within governments (EC 2004), industry (SEIA 2004, NEDO 2004, EPIA 2004) and the investment community (Rogol et al. 2006). During 2005, the global PV industry had 1.7 GW of annual production and a revenue pool of $12 billion (Rogol et al. 2006). At this point in time, the global PV industry is truly beginning to move into large-scale production and deployment.

The rapid growth in the global PV market during the past decade was driven largely by government subsidy programs—particularly in Japan, Germany, and a few states within the United States (California, New Jersey, Arizona, and New York). During the coming decades, as costs continue to decline and subsidies are phased out, industry analysts expect that the distributed grid-connected residential and grid-connected commercial markets will continue to expand rapidly and will become self-sustaining (Rogol 2006). Thus, the grid-connected residential and commercial markets have emerged as key markets for developing and expanding the use of PV technology.

The SETP is focused on developing new solar solutions for the residential, commercial, and utility market sectors of grid-tied electric power. These are described as follows:

Residential Rooftop Market: Typically mounted on rooftops and ranging in size from less than 1kW to 10kW, most commonly in the 3–4 kW range. These systems are connected to the grid on the retail (customer) side of the utility meter. These systems can be retrofitted onto existing homes or integrated into new construction through building-integrated PV (BIPV) designs.

Commercial Rooftop Market: Typically mounted on the large, flat roofs of commercial, institutional, and industrial buildings, ranging in size from less than 10kW to more than 500kW. These systems are connected on the retail side of the utility meter. Retrofits and BIPV are possible applications in this market as well.

Utility Market: Large-scale (multi-megawatt) systems that displace conventional utility-generated intermediate load electricity (e.g., natural gas combined-cycle CCT plants) on a wholesale basis. Typically, utility PV systems are ground-mounted and range in size from 1MW to10MW, while much larger systems are currently under development. Designs include both fixed and tracking configurations. The utility market is also the target market for concentrating solar power (CSP) systems.

Baseline Adjustments to the AEO2006 Reference Case

Several changes from the *AEO2006* Reference Case were incorporated into the GPRA08 Baseline. These changes include the following:

Revising projected PV cost. The residential and commercial PV system characteristics in the *AEO2006* reference case were based on the "baseline" scenario provided in the U.S. PV Industry Roadmap (SEIA 2004). As shown in **Figure D-1**, the projected PV system costs in the GPRA08 Solar Program Baseline are very similar to the projection in the *AEO2006* reference case. This Baseline was developed assuming that private industry would continue to improve first-generation PV (crystalline silicon) technology, that the entry into the marketplace of substantial quantities of second-generation PV (thin-films) technology would begin to occur around 2015, and that third-generation PV (organic, dye cells, etc.) technologies would continue to be locked out of the marketplace. This approach captures the notion of technological lock-in, i.e., when early use of a technology (i.e., crystalline silicon) creates a snowballing effect that enables it to become dominant in the marketplace for an extended period of time (Cowan and Kline 1996). In the GRPA08 Baseline, continuing incremental improvements in crystalline silicon technology—which is currently the dominant PV technology in the marketplace—enable it to maintain an extended lock-in. Also, as shown in **Figure D-1** and discussed below, changes in the program's structure and funding levels under the SAI are expected to result in accelerated cost reductions through 2015 under the GPRA08 Program case.

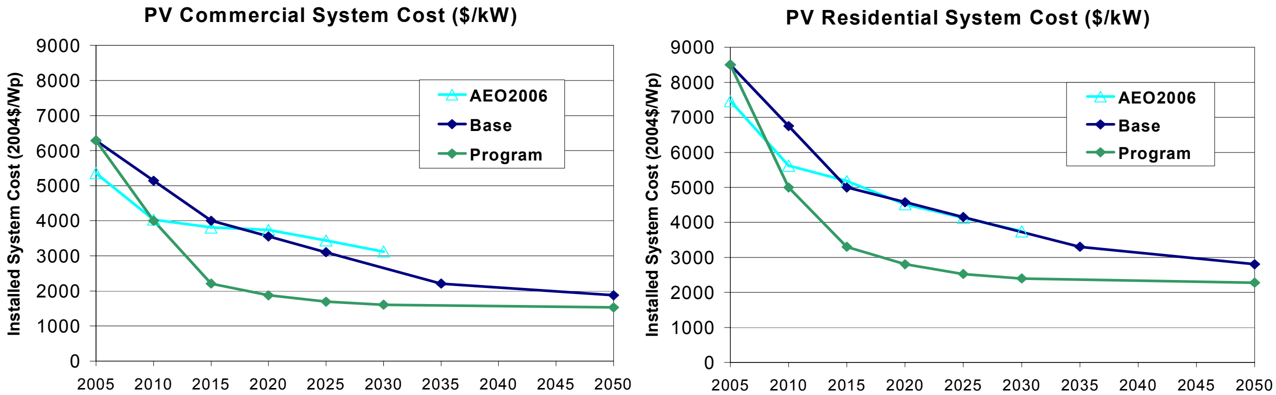

Figure D-1. Projected PV System Costs

Increasing the average commercial building system size. The *AEO2006* assumes that the size of commercial PV systems starts at 20 kW and increases to 45 kW over the projection period. This range of system sizes is much smaller than typical commercial systems being installed in the United States. Thus, in the GPRA08 cases, the average size of commercial PV systems is assumed to be 100kW today, and to increase to 150 kW by 2015 and 200 kW by 2030.

The 100kW average starting size is in-line with what is happening in the marketplace today. For example, during 2005, under the California Public Utility Commission's Self-Generation Incentive Program, a total of 24.6 MW of PV were installed on 207 commercial buildings. This translates into an average system size of 119 kW per installation. The largest system integrator, PowerLight, installed 4.6 MW on 17 buildings, i.e., an average system size of 269 kW per installation (PV News October 2006). Clearly, the 100 kW per system starting size is reasonable for California. It is also reasonable for the rest of the United States, based on typical commercial roof sizes and PV packing density requirements, as described below.

To gain a better understanding of how much PV commercial buildings in the United States can accommodate, on average, a sample of data from 14 PV systems installed by PowerLight was examined. As shown in **Table D-2**, the average PV packing density for these systems was 10 W/sq. ft. Given that commercially available PV modules are 13%-17% efficient, this is a reasonable packing density allowing for module spacing, stringing, etc.

Table D-2. Commercial System Size and Surface-Area Requirements

PowerLight System Installation Location	Date Completed	System Peak Capacity (kW)	PV Surface Area (sq. ft.)	W/sq.ft.
Santa Rita Jail - Alameda County, California	Apr-02	1,180	130,680	9.0
Cypress Semiconductor - San Jose, California	Jul-02	335	26,100	12.8
Fala Direct Marketing - Farmingdale, New York	Nov-02	1,010	102,700	9.8
Fetzer Vineyards, Hopland, California	Jul-99	41	3,750	10.9
Franchise Tax Board, Sacramento, California	Aug-02	470	50,000	9.4
Greenpoint Manufacturing – Brooklyn, New York	Mar-03	115	11,500	10.0
Mauna Lani Resort – Kohala Coast, Hawaii	Jan-02	528	43,330	12.2

Naval Base Coronado, California	Sep-02	924	81,470	11.3
Neutrogena Corporation - Los Angeles, California	Aug-01	229	30,154	7.6
Parker Ranch – Kameula, Hawaii	Jan-01	209	20,000	10.5
PSGA/Ortho-McNeil Facility - Pennsylvania	Apr-02	75	17,500	4.3
U.S. Coast Guard – Boston, Massachusetts	Sep-99	37	3,800	9.7
U.S. Postal Service - Marina del Rey, California	Nov-01	127	15,000	8.5
Yosemite National Park - Yosemite, California	Oct-01	47	4,500	10.4
Total		5,327	540,484	
Average		381	38,606	**10**

Source: PowerLight Case Study data sheets, downloaded from www.powerlight.com, 5/21/03.
Note: Some of the locations shown in this table have multiple installations. In these cases, the total installed capacity is shown above and the most recent installation date is shown in the Date Completed column.

Using this packing density, the average commercial building size, and the average ratio of usable roof space to floor space, one can estimate the amount of PV that could be placed on average on commercial buildings. EIA estimates that the average U.S. commercial building size in 2000 was 14,700 square feet (EIA 2006b), and the International Energy Agency (IEA) estimates that a reasonable ratio of usable roof space to floor space is 0.7 (IEA 2001). Using these estimates, the average commercial building could easily accommodate a 100 kW PV system, i.e., with available roof space for PV at 0.7*14,700 sq. ft. = 10,150 sq. ft. Thus, setting the average system size at 100kW is a conservative assumption based on industry trends, as well as the available roof space on a large share (50+%) of the commercial building stock.

The average commercial PV system size is likely to increase over time as cell efficiencies increase enabling larger systems to be installed on the same amount of square feet. In addition, as system costs decline, facades and other spaces (such as parking lots) could also be utilized for PV systems. Thus, a 200kW average system size on commercial buildings in 2030 is a reasonably conservative estimate.

Increasing the maximum share of commercial buildings with solar access. The *AEO2006* assumes that up to 30% of commercial buildings have solar access (i.e., limited due to shading, roof type, etc.). In the GRPA08 cases, the maximum share of buildings with solar access was increased to 55%. Similar to the assumptions described above regarding the ratio of usable roof space to floor space, the share of roof space suitable for PV installations was based on the published IEA report on integrated photovoltaics in buildings (IEA 2001). This report indicates that a reasonable estimate for the share of roofs suitable for PV installations is 55%. This estimate includes shading and other factors that would limit the use of roofs for PV systems (IEA 2001).

Increasing the average residential building system size. The *AEO2006* assumes that the average size of a residential PV system is currently 2kW and increases to 4kW over the projection period. However, residential rooftop systems being installed in the United States during the past couple of years have been averaging 3.5-4.5 kW. [2] In fact, 4.4 kW is the average

[2] Based on data from the California Energy Commission's Emerging Renewables Program, downloaded on October 13, 2006, from www.energy.ca.gov/renewables/emerging_renewables/index.html.

size of residential PV systems installed under the California Energy Commission's Emerging Renewables Program during 2005. [3]

Thus, in the GPRA08 cases, the average residential PV system size is assumed to be 4kW. Note that the average home in the United States has 1,700 square feet of floor space, and this is expected to increase in the future (EIA 2006a, Table A4). Using data from EIA's residential energy-consumption survey (EIA 2001, Table HC1-2a) one can estimate a floor- to roof-space ratio of 0.7 (based on distribution of one-story, two-story, and three-story single-family homes). This is a conservative estimate—most homes have pitched roofs, which would increase the total available roof space (yet may make a significant portion of the roof oriented away from the sun). If a typical system can accommodate 10 W/sq.ft. (as above), then a 4kW system would require roughly 400 square feet of roof space, which is well below the average available space allowing for multiple floors and pitched roofs. Thus, roof space is not a constraint for installing residential rooftop PV systems in the 4kW range. Because the efficiency of PV cells is likely to improve, a trend toward larger systems on rooftops is likely to continue. Thus, based on available roof space and what is happening in the marketplace, setting the average system size at 4kW is a conservative assumption.

Increasing the maximum share of residential buildings with solar access. The *AEO2006* assumes that up to 30% of residential buildings have solar access (i.e., limited due to shading, roof type, etc.). In the GRPA08 cases, the maximum share of residential buildings with solar access was increased to 60%. This estimate accounts for the fact that some homes will not be suitable for PV systems due to shading, building orientation, roof construction, or other factors. This value was calculated from a combination of single-family homes (70%) and multifamily homes (30%), using a 75%–25% split between single-family and multifamily homes (EIA 2006a, Table A4). Thus, the average maximum share was set at 0.7*0.75 + 0.3*0.25 = 0.6—this is a national average. Clearly the maximum share of homes suitable for PV will vary considerably across the United States.

Including a declining PV buy-down program in California. This baseline is constructed under the assumption that the PV buy-down currently available in California will continue to decline over time as defined in the recently passed California Solar Initiative (CSI). As shown in **Table D-3**, under the CSI, one of two events can trigger an incentive reduction: when an incremental level of installed PV (in MW) is achieved under the CSI, or the end of the calendar year, whichever occurs first.

Table D-3: Triggers for Reductions in Rebate Levels

	Rebates would change at the earliest of:		Starting at $2.80/watt equivalent in 2006	
"Bin" or Year	**Date**	Incremental MW	**Rebate Level ($/watt)**	Total $ (million $)
0	**1/1/06**		**2.8**	
1	**1/1/07**	50	**2.5**	125
2	**1/1/08**	70	**2.25**	157.5
3	**1/1/09**	100	**2.0**	200

[3] Also based on CEC data (source cited in note 2). For example, during 2005, a total of 17.2 MW of PV was installed in 3,881 PV systems under the CEC program, with an average system size of 4.4 kW.

4	**1/1/10**	130	**1.75**	227.5
5	**1/1/11**	170	**1.5**	255
6	**1/1/12**	230	**1.25**	287.5
7	**1/1/13**	300	**1.0**	300
8	**1/1/14**	400	**0.75**	300
9	**1/1/15**	500	**0.5**	250
10	**1/1/16**	650	**0.25**	162.5
Totals:		**2640MW**		**$2.3 billion**

Source: http://www.cpuc.ca.gov/PUBLISHED/COMMENT_DECISION/51994.htm

As shown in **Table D-3**, the CSI incentives are automatically scheduled to be reduced each year by 10%, and faster if program participation exceeds a predetermined capacity level. If costs decline and demand increases faster than expected, this structure lowers rebates earlier than on an annual basis. In the Baseline Scenario, the buy-down schedule was specified by date as shown in the table. This credit was included for the entire Pacific region. Given that a number of other state/local credits were not included in the GPRA Baseline (i.e., in Hawaii, Oregon, and Washington State), applying the California state-level credit to the whole Pacific region is likely to be a reasonable approximation.

Modifying the adoption rate of distributed generation technologies. The modification to the adoption rate was based on information provided by DOE's Distributed Energy Resources Program (**Figure D-2**). The adoption rate shown in the figure applies to PV as well as gas-fired CHP technologies. The AEO assumes that only relatively large buildings are suitable for distributed generation (DG) technologies, i.e., buildings that are at least four times the average size building. Because PV technology is more broadly applicable than CHP (PV system size can be easily scaled), the constraint on average building size for commercial installations was modified from being four times the average size, as in the AEO, to being only twice as large. This means that, in the model, only half of the commercial buildings are available for PV installations; and that, on average, these commercial buildings will have sufficient load to absorb the production from their PV system internally (even as the average PV system size increases to 200kW by 2030).

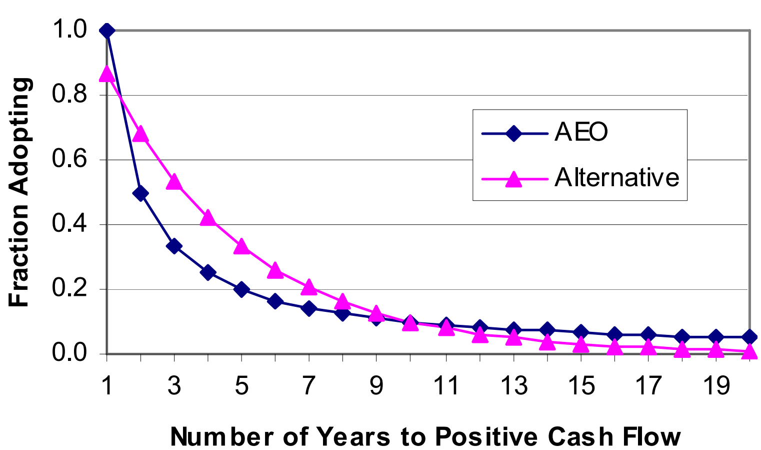

Figure D-2. Commercial-Sector DG Adoption Rates

These changes lead to increased adoption of PV systems in the baseline. The *AEO2006* assumptions about PV installations through the Million Solar Roofs or other programs were removed; however, as mentioned above, the subsidies available under the California Solar Initiative were included.

GPRA08 Solar Program Scenario Assumptions

Two key sets of assumptions related to technology characteristics were modified to generate the GPRA08 Solar Program Scenario. More aggressive technology targets were used for the range of solar technologies funded by the Solar Program: PV (distributed and central systems), and concentrating solar power (CSP). Both sets of technology characteristics were based on anticipated changes in the program's structure and funding to be implemented during FY07 under the SAI.

PV Technology Characteristics. To define a consistent set of long-term targets going out to 2050, a multilab, multitechnology team was assembled in 2003. This team produced a range of technology cost projections for use in NEMS under different funding and policy assumptions (for details, see Margolis and Wood 2004). In setting the targets used for PV technology in the GPRA08 analysis, we drew on the results from this team, as well as cost projections under various funding/policy assumptions in the U.S. PV Industry Roadmap (SEIA 2004). The targets shown in **Table D-4** are consistent with expected funding for the program (Margolis and Wood 2004 and SEIA 2004). It is important to note that, beyond 2015, the targets are increasingly uncertain and are likely to be revised as the Solar Program continues to analyze the long-term prospects for technology cost reductions. Note that, on an annual basis, costs are assumed to decline linearly between the years shown in the tables below.

While the technology assumptions for commercial rooftop PV systems are shown above in **Figure D-1**, detailed data for PV systems in the three markets modeled are provided in **Table D-4**. Although the costs shown below are for specific years, the costs decline annually between the years shown. Note that in both the GPRA Baseline and Program scenarios, the *AEO2006* Reference Case assumptions for solar insolation and capacity factors were used.

CSP Technology Characteristics. The data for CSP technology shown in **Table D-5** are for California. The CSP costs are up to 13% higher in other regions that have less solar insolation to account for greater capacity and storage requirements. The annual capacity factors by 2020 range from 49% in the Upper Midwest to 74% in the Southwest. The capacity factors by time period were computed by Sandia analysts to optimize the timing of solar output for each region within the bounds of the storage potential. Note that the *AEO2006* Reference Case assumptions include lower-cost CSP systems, but with significantly less storage and, therefore, lower electrical output.

The cost targets for CSP technology in the Solar Program scenario are based on a funding level consistent with the FY07 budget request and a funding level commensurate with those outlined in the Draft CSP Technology Transition Plan for years beyond FY07 (DOE 2005).

Table D-4. PV Systems for Solar Program Case

	Central Generation		Residential Buildings		Commercial Buildings	
Year	Installed Price (2003$/kW)	O&M (2003$/kW)	Installed Price (2003$/kW)	O&M (2003$/kW)	Installed Price (2003$/kW)	O&M (2003$/kW)
2005	5,500	20	8,500	100	6,290	40
2010	3,900	10	5,000	40	4,000	20
2015	2,580	6	3,300	20	2,210	10
2020	2,193	5	2,805	17	1,879	9
2025	1,974	5	2,525	15	1,691	8
2030	1,875	4	2,398	15	1,606	7
2050	1,781	4	2,278	14	1,526	7

Note: Installed costs do not include the impact of the existing investment tax credit. The O&M costs shown in the table are annual O&M costs.

Table D-5. Concentrating Solar Power for Solar Program Case

Year	Installed Price (2003$/kW)	O&M (2003mills/kWh)	Capacity Factor
2010	3,510	7.8	65%
2020	2,462	4.0	72%
2025	2,199	3.6	72%
2030	1,993	3.2	72%
2035	1,879	3.1	72%
2040	1,826	3.0	72%
2050	1,797	2.9	72%

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