Business & Money

PV vs. Solar Thermal

Distributed solar modules are gaining ground on concentrated solar thermal plants.

BY JONATHAN LESSER AND NICOLAS PUGA

Like an ever-receding mirage, solar power has for decades been viewed as the future of electric generation. It always seemed to offer virtually unlimited potential, yet always was just out of reach. Now, it is closer than ever.

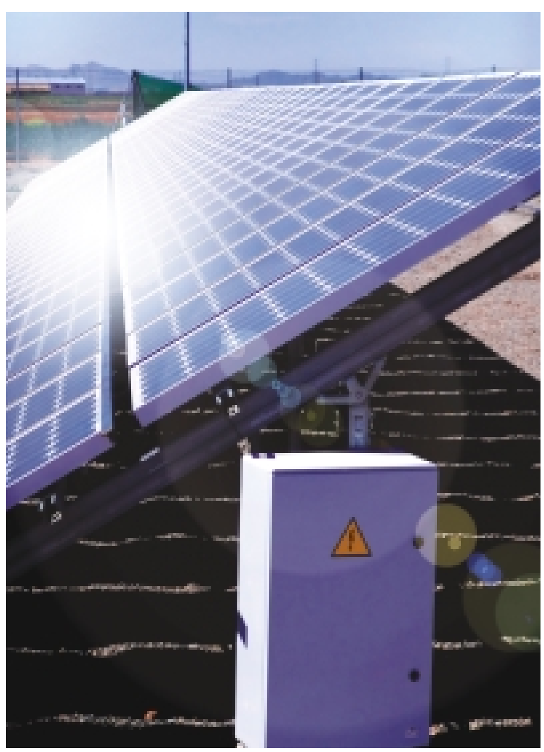
With soaring prices for fossil fuel and intensifying concerns about climate change, many state legislatures have adopted increasingly ambitious mandates for developing renewable resources through instruments such as renewable portfolio standards, feed-in tariffs, so-called green tags and net-metering standards (*See "Net Metering in the States," p.22*). These mandates, along with dollops of federal and state subsidies, are now turning the solar mirage into a reality.

As the industry approaches the new solar oasis, companies and regulators will take a closer look at the differences in prices to be paid for different solar technologies, and will compare them to other options—most notably windpower. While all of the solar technologies promise abundant and competitively priced electricity, for the long-term future the most economically viable options might not be the ones utilities have embraced in the past. Namely, photovoltaic technologies (PV) are appearing more attractive than concentrated solar thermal plants.

Wind Settles Down

The primary beneficiaries of government support for renewable energy projects have been windpower developers. Wind resources currently account for the majority of new renewable resources. Thousands of megawatts of capacity dot the landscape, especially across the sparsely populated expanses of the West and Midwest. Wind manufacturers have made great strides in exploiting scale economies. The generating capacity of individual turbines has increased many times over (with generating capacities today of over 1.5 MW) and so has the scale of individual wind farms. These typically contain dozens or even hundreds of turbines.

For a while, it seemed as if windpower would yield electricity at prices able to compete favorably even with the most efficient natural gas-fired facilities. But all has not gone smoothly with windpower, which has, to some extent, become a victim of its own success. Growth in manufacturing capacity for wind turbines has not kept pace with demand—to some degree stymied by the on-again, off-again status of federal tax credits for wind development. This has resulted in increased prices for turbines and multi-year queues.



Moreover, the full cost of providing needed transmission infrastructure for these wind developments hasn't always been accounted for in valuing the net benefit of wind-generation additions. The best sites for wind developments tend to be far from existing transmission infrastructure. Some states have responded to the lack of transmission infrastructure by forming government organizations to identify the necessary infrastructure and the mechanisms to encourage and subsidize its development.

Another concern is the inherent variability of windpower. Integrating wind generation with the high-voltage transmission grid caused only minor concern when there wasn't much of it, but now, with thousands of generators installed, transmission planners and operators face the challenge of how to integrate rapidly expanding windpower resources into the grid without jeopardizing transmission security and reliability.[1]

The transmission system operators of California and Texas, two of the states with the largest windpower potential, have carried out studies on the cost of the infrastructure and ancillary services necessary to integrate wind with their generation resource portfolios. The studies have shown that, while feasible, the integration of large amounts of » wind (perhaps as much as one-third of total installed capacity), especially where concentrated in a specific geographic area, comes at a cost—and that cost must be added to the direct cost of wind generation and interconnection.[2, 3]

Solar on the Rise

As windpower continues growing toward its full potential, and transmission planners and regulators address integration issues, policymakers increasingly are focusing on solar power.

In the United States, the power industry has focused on solar thermal technology because it was perceived as more economically competitive than solar PV technologies. Parabolic-trough collector fields with oil-based heat transfer fluids have been successfully used to drive steam-turbine generating plants since the 1980s. The collector technology painstakingly has been improved and O&M costs dramatically reduced over 20-plus years of operational experience, and the lion's share of proposed solar electric generation in the United States is based on this technology.

By contrast, policymakers in Europe made a significant commitment to solar power years ago, including PV. That commitment is especially apparent in Germany, where 20-year contracts and supportive feed-in tariff rates have signaled a long-term commitment to PV manufacturers, project developers, and the entire PV-plant supply chain. This has led to hundreds of megawatts of installed PV, and also allowed some PV manufacturers to improve their manufacturing processes and reap economies of scale by producing modules at declining prices. This in turn has produced a new model of grid-connected utility-scale solar PV—distributed central solar (DCS).

Additionally, DCS has benefited from the increasing efficiencies achieved by thin-film PV manufacturers, as well as realized economies of scale never achieved before.

For example, thin-film PV technologies based on cadmium-telluride (Cd-Te) have become much less costly than their better-known, silicon-based brethren. Although Cd-Te cells have lower conversion efficiencies than silicon-based cells, their costs are much lower. Some manufacturers of this PV technology already have committed to sales contracts with levelized costs around 12 cents/kWh over a 20-year term in the desert Southwest.[4]

> Building the latest solar thermal plants will require the manufacturer to move straight into commercial operation, skipping optimization and pilot plant stages.

As a result of these innovations, solar power appears to be becoming a viable, large-scale source of renewable generation, after so many years of being considered the technology of the future. A recent article in *Scientific American* presented a vision of the solar future in which thousands of megawatts of concentrated solar power (CSP) and PV would meet almost 70 percent of the United States' electric needs by 2050.[5]

Just as with windpower, however, a number of economic questions must be addressed, because solar technologies present challenges and risks that must be factored into the vision in order to be truly attainable.

Solar Thermal Chills Out

Solar thermal technology has dominated the market for utility-scale solar power for decades. Although it still faces technical and economic challenges, interest in this technology remains strong as the industry searches for climate friendly energy sources.

In February 2008, Arizona Public Service (APS) announced plans to build a 280-MW parabolic-trough solar-thermal generating facility near Gila Bend, Ariz., with a levelized cost of 14.4 cents per kilowatt hour over the plant's estimated 30-year lifetime. APS also plans to issue a second joint solicitation, with other Arizona utilities, to build another 250-MW plant using the same technology. These announcements coincided with the release of several studies of the generation potential for CSP across the southwest United States.[6]

The Gila Bend plant will be built by the Spanish firm Abengoa, and it will draw on that firm's experience with similar technology in Spain. Tracking, concentrating, parabolic-trough collectors will heat synthetic oil, and a two-tank molten salt-storage system will store the heat and allow the plant to generate electricity at near capacity during the long APS summer peak-demand period. The plant will generate electricity using a medium pressure steam turbine with wet cooling towers.

The project's collector-field technology results from more than 20 years of European and U.S. experiences, most notably the Luz International Solar Electric Generating System (SEGS) projects built in the Mojave dessert in California beginning in 1984. The same cannot be said for the molten salt-storage technology, which never before has been built or operated on this scale. (Smaller similar systems have been tested in the United States and are under construction by Abengoa in Spain.) Given the lack of commercial operating experience, the Electric Power Research Institute (EPRI) declined to include such storage in a recent study of the potential for parabolic-trough electric plants in the southwest United States.[7]

Irrespective of molten salt-storage technology, CSP development faces some more mundane challenges.

CSP plants are basically steam turbines that rely on the sun, rather than fossil or nuclear fuel, to make steam. Like most steam-turbine plants, economies of scale dictate that a parabolic-trough CSP plant must be sized in the 100-MW to 300-MW capacity range. The size of the collector field for such a plant, particularly one designed to provide hours of storage is enormous. For example, the Gila Bend plant will require a contiguous 1,900-acre site to build its collector field. (For comparison, a 21-MW thin-film PV plant to be built near Blythe, CA, would require less than 150 contiguous acres.) The size of Gila Bend's collector field will, in turn, require a detailed environmental impact review, perhaps spanning several jurisdictional boundaries.

The sheer amount of real estate required increases the likelihood of concerns about negative impacts on plant and animal species. Moreover, plants this size likely will require dedicated high-voltage transmission lines that will need to be permitted. These permitting requirements will increase the regulatory risk of the project and potentially lead to construction delays and higher costs.

Another critical issue is water, or rather a lack of water. The steam turbines used at CSP plants require water for cooling; using wet cooling towers, the proposed APS/Abengoa 280-MW CSP generating facility can be expected to consume between 600 million and 700 million gallons of water, roughly 1,900 acre-feet, per year. But in the desert Southwest, available water resources are becoming more scarce, as populations continue to grow. There are virtually no additional surface water supplies available and groundwater recharge rates are so slow as to make groundwater supplies effectively fixed.[8]

While several conventional thermal-generating facilities use treated wastewater from nearby urban areas, it is doubtful that this approach could be adopted for all of the proposed CSP generating plants in the desert Southwest. Moreover, treating and piping wastewater to far-flung CSP plants in the desert will add significant costs. As a result, CSP plants likely will require dry-condenser cooling—which minimizes water use, but does so at a significant cost, in the order of $200/kW by some estimates.[9] Furthermore, dry-cooling reduces both net generation and thermal efficiency, especially on the hottest days of the year, when summer-peaking utilities most need power. The loss of efficiency in a steam plant with a state-of-the-art dry-cooled condenser can be as high as 25 percent on very hot Southwest summer days. This reality will affect the economics of CSP plants as Black & Veatch recognized in a report prepared for the Renewable Energy Transmission Initiative (RETI) in California.[10]

> *Scientific American* presented a vision in which solar energy would meet almost 70 percent of U.S. electric needs by 2050.

Black & Veatch estimates that if the Gila Bend plant were dry-cooled, it could cost between $50 million and $60 million more to build, and would produce less electricity at a higher cost than currently expected. And a recent EPRI feasibility study for central-station solar power estimates power from a utility-owned 125-MW dry-cooled solar-trough plant (located in New Mexico and without molten salt storage) will cost between 24 and 26 cents/kWh, including the 30-percent federal investment tax credit.[11]

CSP technologies (including central solar receiver, linear Fresnel concentrator, and parabolic dish Stirling cycle) pose a number of other technical and financial risks. For example, parabolic dish Stirling engine technology lacks manufacturing capacity or commercial operation experience, although a leading manufacturer has signed between 800 MW and 1,750 MW in long-term power purchase agreements for commercial development. This suggests that building these plants will require the manufacturer to abbreviate the technology development stage and move straight into manufacturing and commercial operation, skipping manufacturing optimization or operational pilot-plant stages. How such a strategy will work in practice remains uncertain, but the effort likely will show the strengths and weaknesses of the latest CSP technologies.

PV Catches Up

PV technology also is advancing as a result of significant utility commitments.

Although announced with much less fanfare, Southern California Edison plans to install 250 MW of commercial rooftop PV at an estimated cost of $3,500/kilowatt (2008 dollars). This figure reflects an accelerating price differentiation between PV technologies. Some types of thin-film technology rapidly have gained ground in both efficiency and price relative to traditional silicon PV, where costs per watt actually have increased slightly since 2004. As a result, thin-film PV has become competitive with utility-scale solar-thermal generation, and also can provide additional benefits in the form of modular development, lower transmission-system interconnection costs, fewer technical uncertainties, and no need for copious

quantities of cooling water.

For example, First Solar, the largest manufacturer of thin film Cd-Te technology, reports that process improvements and growing manufacturing capacity has allowed it to increase the efficiency of its panels to 10.5 percent, while reducing module production costs from $2,940/kW in 2004 to $1,120/kW for the fourth quarter of 2007.[12]

First Solar is supplying PV panels for a 40-MW solar PV facility in Brandis, near Leipzig, Germany. When completed, the Brandis facility, which currently has 12.5 MW commissioned and 20 MW installed, will be the largest PV generating facility in the world. The project development arm of the same manufacturer also recently signed a contract with SCE to develop a 7.5-MW to 21-MW facility, at a price lower than the 20-year, 2007 California Market Price Referent.[13] The facility is expected to be interconnected to an existing 34.5 kV line near Blythe, Calif., and thus won't require any transmission-system upgrades.

While not as impressive in sheer scale as 200-plus MW solar thermal plants, modular DCS PV facilities with 20 MW to 50 MW of installed capacity can be placed closer to load centers and can interconnect to existing 69-kV or 115-kV transmission lines. This avoids the need for large-scale transmission investment (and the all-too-common permitting delays) and increases both the potential cost advantage and the likelihood of completing a DCS PV facility, compared to its much larger solar thermal brethren.

Solar-Life Cycle

As with all generating resources, renewable or not, a number of tradeoffs must be evaluated in order to identify the most suitable generating resources with the lowest life-cycle costs. Today, CSP technologies are perceived as having lower life-cycle costs than PV, and policymakers in the Southwest are incorporating greater quantities of CSP into their RPS portfolios. However, CSP technologies also pose a number of risks that affect life-cycle costs in ways that haven't always been fully accounted. These risks include:

- Potentially significant cost increases due to protracted and risky site-specific development cycles. This can affect regulatory approval if proposed facilities are to be rate-based;
- Reliance on technologies that are not commercially proven;
- Reliance on technologies in limited production that may not be sufficiently available when demand suddenly increases, as has happened with wind resources. This might drive prices higher and cause schedule delays. As a related matter, maintenance costs might be higher than projected, as is typical of commercially immature technologies and one-off designs.
- Environmental risks, especially reliance on scarce—and currently underpriced—water supplies.
- O&M complexities, with each facility requiring miles of pipe and thousands of joints and seals to circulate heated fluid. In the early years of operation of the parabolic-trough CSP plants in the U.S., built between 1985 and 1991, the loss of heat transfer oil through leaks was a significant problem.[14] Although much has been learned through the operation and maintenance of existing parabolic-trough plants, it is unlikely that technological improvements will eliminate the risks of leaks or the associated impact on performance and cost.

By comparison, the technological and operating *(Cont. on p. 27)*

> Lazard projects a levelized cost of $90/MWh for thin-film PV technology, with capital costs of $2,750/kW and fixed O&M costs of $25.00/kW-yr.

Net Metering in the States

Net-metering standards play an important role in the growth of distributed renewable energy. Some of the most important factors affecting utilities and facility owners involve enrollment limitations, compensation schemes and interconnection standards.

Various U.S. states and territories have differing rules on net metering, creating policy inconsistencies and confusion for proponents of distributed energy projects. The following provides a cross section of some of the most important factors in net-metering standards. More details are available from individual state regulatory commissions.

The following states were found to have no standards related to net metering in existence or under proposal: AL, AK, KS, MS, NE, SD and TN.

Abbreviations: calendar ("cal."); credited ("cred."); retail ("ret."); residential ("res"); non-residential ("non-res"); investor-owned utilities ("IOUs"); cooperatives ("co-ops"); municipal utilities ("munis"); net excess generation ("NEG"); not applicable ("N/A"); individual ("indiv").

State	Statute/ Rules	Utilities Involved	Limit on Size for Eligible Systems	Compensation/ Net Meter scheme	Interconnection Standardized
Arizona	No current rule; new rules proposed; tariffs imposed by indiv utilities.	Arizona Public Service, Salt River Project, Tucson Electric Power	APS: 100 kW SRP: 10 kW TEP: 10 kW	Cred. customer's next bill @ util. ret. rate; granted to utility at end of cal. year.	Interconnection guideline only; Rules under development; see indiv utility for standards.
Arkansas	Rules	All IOUs, munis and co-ops.	25 kW: res. systems. 300 kW: nonres. systems.	Cred. customer's next bill @ ret rate; granted to utility at end 12-mo bill cycle.	Yes
California	Rules	All utilities; IOUs. Publicly owned. electric utilities with 750,000+ customers that also provide water are exempt.	1 MW (10 MW for as many as three biogas digesters).	Cred. to customer's next bill; granted to utility at end of 12-mo billing cycle.	Yes
Colorado	Rules	All IOUs and Co-ops; munis with more than 5,000 customers.	IOUs: 2 MW. Co-ops and munis: 10 kW for res; 25 kW for commercial and industrial.	Cred. customer's next bill; IOUs: utility pays customer at end of cal year for excess kWh credits (at the ave. hourly incremental cost for that year) Co-ops and Munis: Reconciled annually at rate deemed appropriate by the utility.	Yes. By 10/01/08 the PUC must initiate a new rule for co-ops. Rules for munis must be "functionally similar" to PUC rules for IOUs.
Connecticut	Statute	IOUs	2 MW	Cred. customer's next bill at ret rate; usually purchased by utility at avoided-cost rate at end of 12-mo billing cycle.	Yes
Delaware	Rules	All utilities; applies to co-ops only if they opt to compete outside their service territories.	Res: 25 kW; Non-res: customers of DP&L: 2 MW; Non-res. customers of DEC and municipal utilities: 500 kW.	Cred. customer's next bill at retail rate; at end of 12-mo period; remaining NEG is granted at the utility's avoided-cost rate to Delaware's Green Energy Fund.	Yes, under revision
Florida	Rules	IOUs.	2 MW	Cred. customer's next bill at ret. rate; purchased by utility at avoided-cost rate at end of 12-mo billing cycle.	Yes
Georgia	Rules	All utilities.	10 kW for res. systems; 100 kW for commercial systems	Cred. customer's next bill; granted to utility at end of 12-mo billing cycle.	Yes
Hawaii	Rules	All utilities.	HECO, MECO and HELCO: 100 kW. KIUC: 50 kW.	Cred. customer's next bill; granted to utility at end of 12-mo billing cycle.	Yes
Idaho	No statewide metering rules; Tariffs apply	Idaho Power, Avista and Rocky Mtn.		See individual companies' tariffs.	No
Illinois	Rules	IOUs.	40 kW	Cred. to customer's next bill at utility's ret. rate; granted to utility at end of 12-mo billing cycle..	Yes; under revision; final rule by 08/29/08
Indiana	Rules	IOUs.	10 kW	Credited to customer's next bill.	Yes

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Source: Fortnightly Research, Courtney Barry

State	Statute/ Rules	Utilities Involved	Limit on Size for Eligible Systems	Compensation/ Net Meter scheme	Interconnection Standardized
Iowa	Rules	IOUs (MidAmerican Energy, Interstate Power and Light).	500 kW	Credited to customer's next bill.	No
Kentucky	Rules	IOUs and co-ops.	30 kW	Cred. to customer's next bill (no expiration).	Yes
Louisiana	Rules	All utilities.	25 kW for res. systems; 100 kW for commercial and agricultural systems.	Cred. to customer's next bill at utility's ret. rate; carried over indefinitely. (At termination of electric service, the net-metering customer shall receive payment for the balance of any credits due.)	Yes
Maine	Rules	All utilities, munis, and co-ops.	100 kw	Cred. to customer's next bill; granted to utility at end of 12-mo billing cycle.	No; but standards currently are being considered.
Maryland	Rules	All utilities.	2 MW	Cred. at ret. rate and carried over to customer's next bill; granted to utility at end of 12-mo period with no compensation for the customer.	Yes
Massachusetts	Statutes/Rules (pending legis- lative changes)	IOUs.	60 kW	Credited to customer's next bill at average monthly market rate.	Yes
Michigan	Rules; enacted 3/29/05, will expire 3/29/10; PSC to review.	Most major utilities; check with PSC for list.	Less than 30 kW	Cred. to customer's next bill; granted to utility at end of 12-mo billing cycle.	Yes
Minnesota	Rules	All utilities.	40 kW	Customer receives check for NEG at end of month, calculated at the "average retail utility energy rate."	Yes
Missouri	Rules	All utilities.	100 kW	Cred. to customer's next bill at utility's avoided-cost rate; granted to utility at end of 12-mo period.	Currently being developed
Montana	Rules	IOUs (separate rule for electric co-ops)	50 kw	Cred. to customer's next bill; granted to utility at end of 12-mo billing cycle.	Yes
Nevada	Rules	IOUs.	1 MW (utilities may impose fees on systems greater than 100 kW).	Carried over to customer's next bill indefinitely (kilowatt-hour credit).	Yes; tariff rule of Nevada Power and Sierra Pacific
New Hampshire	Rules	All utilities.	100 kW	Cred. to customer's next bill.	Yes
New Jersey	Rules; Re- adopted: Effec- tive 05/19/08	Electric distribution companies (excludes munis and co-ops).	2 MW	Cred. to customer's next bill at ret. rate; purchased by utility at avoided- cost rate at end of 12-mo billing cycle.	Yes; Re-adopted: Effective 05/19/08
New Mexico	Rules	IOUs and co-ops.	80 MW	Cred. to customer's next bill at utility's avoided-cost rate or purchased by utility at avoided-cost rate monthly.	Yes; under revision
New York	Statute/Rules	All major utilities.	10 kW for res. solar; 25 kW for res. wind; 125 kW for wind systems for res. farms; 400 kW for farm-based biogas.	Cred. monthly at ret. rate, except for wind greater than 10 kW, which is credited monthly at avoided-cost rate. Accounts reconciled annually at avoided-cost rate.	Yes
North Carolina	Rules	IOUs (Progress Energy, Duke Energy, Dominion North Carolina Power).	20 kW for res. systems; 100 kW for non-res systems.	Cred. to customer's next bill at ret .rate; granted to utility (annually) at beginning of each summer season.	Yes
Ohio	Rules	All electric distribution utilities and competi- tive retail electric service providers.	No limit specified (system must be sized to match some or all of customer's load).	Cred. at utility's unbundled gen. rate to customer's next bill; customer may request refund of NEG credits accumulated over a 12-mo period.	Yes

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State	Statute/ Rules	Utilities Involved	Limit on Size for Eligible Systems	Compensation/ Net Meter scheme	Interconnection Standardized
Oklahoma	Rules	IOUs, co-ops regulated by the OCC.	Lesser of 100 kW or 25,000 kWh/year.	Granted to utility monthly or cred. to customer's next bill (varies by utility).	No
Oregon	Rules	All utilities (except Idaho Power).	Res: 25 kW; Non-res customers of PGE and PacifiCorp: 2 MW; Non-res. customers of munis, co-ops, public utility districts: 25 kW.	Varies by utility (75% of the state offers annualized net metering; 25% of the state offers monthly net metering .	Yes
Pennsylvania	Rules	IOUs.	50 kW for Res; 3 MW for Non-res. Customers with systems that are part of microgrids or are available for emergency use: 5 MW.	Cred. to customer's next bill at ret. rate; PUC to address treatment of NEG remaining at end of 12-mo period.	Yes
Rhode Island	Rules (under revision)	Narragansett Electric (National Grid).	1.65 MW for systems owned by cities, towns or Narragansett Bay Comm.; 1 MW for all other customers.	Credited at utility's avoided-cost rate to customer's next bill; granted to utility at end of 12-mo period.	No (Narragansett Electric has informal standards).
South Carolina	No set rules				Yes
Texas	Rules- (modifications underway for another ruling for ERCOT and statewide IOUs).	Currently applies to integrated IOUs that have not unbundled in accordance with Public Utility Regulatory Act § 39.05; excludes munis, river authorities and co-ops	100 kW for qualifying facilities; 50 kW for renewables.	Purchased by utility for a given billing period at avoided-cost rate.	Yes
Utah	Rules	IOUs; certain electric co-ops (excludes munis).	25 kW for residential systems; 2 MW for non-residential systems.	Cred.to customer's next bill at utility's avoided-cost rate; granted to utility at end of 12-mo billing cycle.	Yes
Vermont	Statute	All utilities.	250 kW (farm systems and "group net metering" systems may be larger; net meterin.g applies only up to 250 kW	Cred. to customer's next bill at utility's ret. rate; granted to utility at end of 12-mo billing cycle.	Yes
Virginia	Rules	IOUs and certain co-ops.	Non-res: 500 kW; Res: 10 kW.	Cred. to following month at utility's ret rate; either granted to utility annually or cred. to following month.	Yes
Washington	Rules	All utilities.	100 kW	Cred. to customer's next bill; granted to utility at end of 12-mo billing cycle.	Yes
West Virginia	Rules	All utilities.	25 kW	Cred. to customer's next bill at utility's ret. rate.	Yes
Wisconsin	Rules	IOUs and munis.	20 kW (We Energies permits net metering for wind-energy systems up to 100 kW).	Varies by utility. Generally cred. at ret. rate for renewables; generally cred. at avoided cost for non-renewables.	Yes
Wyoming	Rules	IOUs and co-ops	25 kW	Credited to customer's next bill; purchased by utility at avoided-cost rate at end of 12-mo billing cycle.	Yes
D.C.	Rules	All utilities	100 kW	Cred. to customer's next bill at utility's ret. rate	Yes
Guam	Rules	Guam Power Authority	25 kW	Unknown (determined by Guam PUC).	No
Puerto Rico	Rules	Puerto Rico Electric Power Authority	25 kW for residential systems; 1 MW for non-residential systems.	Cred. to customer's next bill at utility's ret. rate (with limits); at end of 12-mo bill cycle, utility buys 75% of outstanding NEG credits at minimum rate of $0.10/kWh; other 25% credits donated to public schools	No

(Cont. from p. 20)

risks of utility-scale PV are small compared to those of CSP plants. PV facilities face far fewer challenges for siting and permitting—largely because they are modular and don't need to be installed in several hundred megawatt increments to achieve economies of scale. Moreover, that modularity allows DCS to be installed in dispersed locations, and this can improve availability by reducing the impact of a site-specific weather patterns. Additionally, DCS has little or no need for water, no air- or water-borne pollutant emissions, and uses no environmentally hazardous working fluids such as oil and molten salt.

O&M costs likewise are much smaller for state-of-the-art PV arrays than they are for parabolic trough fields. Non-tracking, ground-mounted PV arrays have no moving parts, and today's thin film Cd-Te modules exhibit both low failure and low performance degradation rates. [15]

Finally, the manufacturing supply chain for thin film Cd-Te equipment is well established and is growing quickly. First Solar, which today has a manufacturing capacity of 300 MW a year, plans to more than triple its capacity by the end of 2009. Other thin-film manufacturers also are increasing their production capacity, and this is resulting in significant reductions in equipment prices.

A recent presentation by Lazard projects a levelized cost of energy of $90/MWh for First Solar thin-film technology, based on total project capital costs of $2,750/kW and fixed O&M costs of $25.00/kW-yr. [16] If those cost estimates hold true, or are even close, then Cd-Te DCS represents a significant advance over the projected costs of CSP and of competing PV technologies. And, given the modular nature of DCS installations, those installations can more closely track load growth and can even be developed in conjunction with planned residential, commercial, and industrial growth centers.

Given today's relatively limited PV manufacturing capacity and the momentum of CSP development, the industry likely will continue to invest in parabolic trough CSP plants. However, thin-film PV technology already is knocking at the generation developer's door. In the long run, DCS plants likely will gain a strong foothold in the market as economic forces drive the industry toward the most efficient, cost-effective, and environmentally benign solar electric technologies.

> **In the long run, distributed central solar (DCS) plants likely will gain a strong foothold in the market.**

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