SERI/TP-211-2041
UC Category: 63d

# PURPA and Photovoltaics: A Status Report

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November 1983

Published in *Photovoltaics International*
August/September 1983

Prepared under Task No. 1471.10
WPA No. 424-83

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A Division of Midwest Research Institute

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Prepared for the
**U.S. Department of Energy**
Contract No. DE-AC02-83CH10093

# PURPA and Photovoltaics:

## A STATUS REPORT

**On May 16, 1983, the U.S. Supreme Court struck down the last major challenge to the Public Utility Regulatory Policies Act (PURPA) and its implementing regulations. In so doing, the Supreme Court upheld the right of photovoltaic and other qualifying investors to interconnect with electric utilities and to sell power at rates equal to the utility's full avoided cost. To appreciate the significance of this event, for U.S. markets, it is necessary to review the recent five-year history of PURPA-related events (see inset).**

by Theresa Flaim

PURPA was passed by Congress in November of 1978, and had a broad, ambitious goal: to encourage efficiency, conservation and the use of renewable energy in the utility sector. Sections 201 and 210 of PURPA were aimed specifically at encouraging cogeneration and small power production.

The Federal Energy Regulatory Commission (FERC) issued its rules implementing Sections 201 and 210 of PURPA in March and February of 1980 respectively. The 201 rule specifies the technology and ownership requirements necessary for a facility to achieve qualifying status. The ownership requirement is that a utility cannot own more than a 50% interest in the facility. Photovoltaic systems no larger than 80 MW in size qualify for the rate benefits specified in the 210 rule. Photovoltaic systems smaller than 30 MW are also exempt from a variety of state and federal regulations governing electric utilities.

The FERC's 210 rule requires electric utilities to interconnect with, buy power from, and sell power to qualifying facilities. Qualifying facilities are explicitly protected from rate discrimination in their purchases of back-up power from utilities, and utilities must buy power from qualifying facilities at rates equal to the utility's full avoided cost.

The PURPA 201 and 210 rules were major milestones in the development of a large market for distributed power systems. Before PURPA was passed, the rate and regulatory barriers to small power production were virtually insurmountable and would have undoubtedly limited the market for distributed power systems to stand-alone applications. PURPA eliminated the major barriers to grid-connected markets. In the process, it also appeared to have the potential for inducing sweeping changes in the utility industry. Some observers even began speculating that the 210 rule was the first step along the path to total deregulation of the electric power industry.

Like any major institutional change, PURPA was not without its critics. Shortly after PURPA was passed, opposition became visible and organized. Two lawsuits in particular have clouded the future of cogeneration and small power production for the past several years.

In April of 1979, the State of Mississippi and the Mississippi Public Service Commission filed suit against the FERC and the Secretary of Energy. One month before states were to have begun implementing the FERC's 210 regulations, Judge Cox of the Mississippi Federal District Court declared that Titles I, III and Section 210 of PURPA were unconstitutional. Judge Cox's decision was based on an interpretation of state sovereignty. States have traditionally had the power to regulate utilities on matters related to intrastate sales of electricity, and Judge Cox argued that the United States did not have the constitutional authority to displace or usurp that power. On June 1, 1982 the U.S. Supreme Court reversed the Mississippi decision, and held that the U.S. Congress had the power to enact PURPA under the Commerce Clause of the Constitution.

Unlike the Mississippi decision – which was an attack against the law – the second case was aimed at the FERC's regulations. American Electric Power, Consolidation Edison Co. of New York, and Colorado Ute Electric Association, filed suit asking the U.S. Court of Appeals in Washington D.C. to review the FERC's regulations. They attacked on two fronts. First, they argued that the FERC had gone beyond the intent of Congress by requiring that rates for utility purchases must *equal* full avoided cost when the statute only says that rates should not *exceed* avoided costs. Second, they argued that the FERC had exceeded its authority in requiring utilities to interconnect with qualifying facilities without going through the procedures required by the Federal Power Act, which include an opportunity for a public hearing. Judge Malcomb Wilkey agreed, and on January 22, 1982 – four months before the U.S. Supreme Court struck down the Mississippi decision – the Washington D.C. Court of Appeals vacated the full avoided cost and interconnection provisions in the 210 rule.

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Given the litigation involving the

*This work was supported by the U.S. Department of Energy, Division of Photovoltaic Energy Systems.*

law and regulations, what is the status of PURPA implementation activities? Technically, the FERC's 201 and 210 rules have been in effect since they were issued in 1980, and states have been obligated to begin implementation. In practice, however, even though all states have made some progress toward implementation, many states have been in a holding pattern. Because the recent Supreme Court ruling resolves the legal uncertainties associated with PURPA, we can expect all states to begin full implementation of procedures designed to encourage cogeneration and small power production.

How do these recent developments affect the market outlook for distributed photovoltaic (PV) systems? The most obvious implication is that a grid-connected market clearly exists: PV systems meeting the size and ownership criteria now have all the rights and benefits specified in the FERC's rule implementing Section 210 of PURPA. Before we can say anything more about the market, however, it is necessary to examine avoided costs in some detail.

Viewed in basic terms, avoided costs are simply savings. If a utility buys power from a qualifying facility, it will have to generate less power itself, or purchase less power from another utility. The FERC defines avoided costs as the incremental "costs to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source."

Avoided costs are generation costs only, because transmission and distribution costs cannot generally be avoided through customer generation. Avoided costs are analogous to marginal costs in that they are forward-looking, and they are distinctly different from average costs which are historically based. Since current rates that customers pay utilities are usually based on average rather than marginal costs, any resemblance between customer rates and the avoided cost rates utilities must pay qualifying facilities will be coincidental. Avoided cost rates may be higher or lower than customer rates, depending upon the utility's particular circumstances. Thus, current customer rates are not a good general indicator of whether avoided cost rates will be attractive to the qualifying facility.

Throughout this article, we assume that avoided cost rates -- not customer tariffs – will largely determine the value of photovoltaic systems for three reasons. First, if the avoided cost rate is higher than the customer rate (the rate the customer must pay the utility for electricity), it will clearly be to the advantage of the qualifying facility to engage in a simultaneous purchase and sale arrangement, i.e., to sell all PV power production to the utility and to buy all the electricity it needs for its own use at the lower customer rate. Second, a recent study has shown that, without storage, PV systems will probably be unable to match more than 50% of the customer's load at least for residential applications.

Third, if the customer rate is higher than the avoided cost rate, there will definitely be an incentive for the customer to use as much power on-site as possible. However, customer rates include transmission and distribution costs which are not reduced when the customer installs his own generating equipment. If many PV customers try to maximize on-site use to take advantage of the higher customer rate, a rate adjustment is inevitable. (Under the FERC's 210 rule, an electric utility can charge qualifying facilities different rates if it can show that the costs of providing backup service to qualifying facilities differ from the costs of serving its non-generating customers.) Stated simply, avoided generation costs are all that distributed power producers can displace. If we are going to achieve significant numbers of grid-connected PV systems, they will have to be competitive relative to the actual costs they allow the utility to avoid.

Although specific methods can vary widely, avoided costs are estimated using a basic three-step procedure. First, total costs are estimated for a base case. This involves standard utility planning activities — forecasting future loads and analyzing the total costs (capacity plus energy) needed to serve that load and maintain reliability. Second, the utility's costs are recalculated after accounting for purchases from qualifying facilities. For photovoltaic systems, this can involve several intermediate steps: (1) the timing and quantity of energy produced by the PV system must be estimated based on available insolation; (2) If some of the PV generation will be used by the customer, then the customer's load must also be forecast to determine the timing and quantity of power that will be sold back to the utility; (3) The amount of power sold back to the grid must be subtracted from the utility's base load forecast; (4) The total costs needed to serve the reduced or residual load while maintaining reliability must be calculated.

The third basic step is to calculate avoided costs, which are the differences between the total costs for the base case, and the total costs for the case that includes PV generation.

To our knowledge, no utilities have estimated avoided cost rates for photovoltaic systems as a separate class of qualifying facilities. However, the Department of Energy (DOE) and the Electric Power Research Institute (EPRI) have funded a number of studies that assess the economic value of photovoltaic generation to electric utilities. Economic value as defined and estimated in these studies is identical to avoided cost. The results of these studies indicate the following: the most important factor affecting avoided electricity cost is the utility's generation mix which determines the type and cost of fuel and capacity displaced. The most important factor affecting the quantity of PV generation is available insolation. The higher the avoided cost and the greater the amount of power produced, the more the user can afford to pay for the photovoltaic system. Finally, savings associated with displaced capacity are relatively small compared to the value of displaced oil.

These results mean that photovoltaic manufacturers need only consider three factors to determine the best near-term (5- to 15-year) grid-connected markets: the amount of oil capacity in the utility's generation mix, insolation availability, and state tax credits. Per capita income, the regional housing stock, and utility attitudes are also relevant, but are definitely secondary in importance, provided that they do not pose significant market constraints.

It is also worth noting that utilities with large amounts of gas capacity could be as attractive a market as those with oil, but gas introduces the additional complications of supply contracts and price regulations. Under current regulations, about half of all natural gas production will be deregulated by 1985. However, many utilities obtain gas through long-term contracts. Even if all gas is completely deregulated, these long-term contracts could hold the utility's cost of gas below its value as an oil substitute well beyond the time that gas prices are deregulated.

If oil and gas prices combined with insolation will drive near-term markets, what will determine the best long-term markets for grid-connected applications? Insolation availability will always be important for obvious reasons. What will change over time is the utility's avoided cost. Right now utilities with large amounts of oil capacity have plans to add new coal or nuclear units that will back out oil. If the cost of oil continues to remain high relative to other fuels, we can expect this oil displacement trend to continue — sooner or later, utilities will achieve a more optimal capacity mix.

This change in generation mix will directly affect avoided costs, and has two important implications for photovoltaics. First, in order to compete with the lower avoided costs, photovoltaic system costs will have to come down by at least a factor of 10 over current costs which are estimated to be $12 per Wp for the Sacramento Municipal Utility District project. Second, capacity credits will become increasingly important. Recent analyses have shown that the savings associated with displaced capacity can be 20% to 70% of total avoided costs in utility systems with little oil or gas capacity.

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A critical question for the long-term market for grid-connected photovoltaic systems is this: Can a technology whose output is only available intermittently actually improve utility system reliability, and therefore be entitled to payment for avoided capacity costs? The conventional wisdom — based on the DOE and EPRI studies cited earlier — used to be that photovoltaic systems do have some capacity displacement potential. More recent analyses of the impact of intermittent generation on the real-time operation of utility systems cast some doubt on the previous estimates of PV capacity credits, at least for higher penetration levels. To understand why, we need to describe how capacity credits have been estimated in the past, and then explain how operating impacts could alter those results.

A useful place to start is by making a clear distinction among three separate concepts: reliability (measured as a probability), capacity displacement (measured in kW), and capacity credit or avoided capacity costs (measured in dollars).

There are several different measures of utility system reliability, but loss-of-load probability (LOLP) is commonly used in utility planning studies. LOLP is the probability that available capacity will be unable to serve the utility's load, and is calculated from the difference in the load and the available generating units.

In the past, capacity credits for PV systems have been calculated as follows: (1) LOLP is calculated for the base case; (2) PV generation is estimated (usually on an hourly basis) and then subtracted from the base case load data; (3) LOLP is recalculated for the PV case. Because the load that the conventional units must meet is reduced, reliability improves (i.e., LOLP declines). (4) From the difference in LOLPs for the two cases, the effective load carrying capability (ELCC)

## SYNOPSIS OF PURPA-RELATED EVENTS

| Event | Date |
|---|---|
| President Carter signed PURPA into law | Nov. 9, 1978 |
| Federal Energy Regulatory Commission (FERC) issued its final rules implementing Sections 201 and 210 of PURPA. | Feb., Mar. 1980 |
| Judge Cox of the Mississippi Federal District Court declared Titles I, III, and Section 210 of PURPA unconstitutional. | Feb. 20, 1981 |
| States were to have begun implementing the FERC's rules by | Mar. 20, 1981 |
| Judge Wilkey of the Washington D.C. District Court of Appeals struck down the FERC's full avoided cost and interconnection provisions. | Jan. 22, 1982 |
| U.S. Supreme Court overturned the Mississippi decision. | June 1, 1982 |
| U.S. Supreme Court overturned the Washington D.C. Court of Appeals ruling. | May 16, 1983 |

associated with PV capacity is estimated.

ELCC is the allowable increase in system peak load (in kW) that could be met and still maintain the base case level of reliability. Intuitively, ELCC can be thought of as how much PV generation reduces the utility's peak load. The capacity displacement potential of PV is often expressed as a percentage – ELCC as a percentage of the rated capacity of the PV systems. We normally expect ELCC to be 80% to 90% of the rated capacity of conventional units. ELCC has been estimated to be 20% to 50% of the rated capacity of PV units, depending upon the utility system, the correlation between the utility's load and available insolation, and the penetration level.

Translating the reliability improvement into dollar savings or credits is the least obvious step in avoided cost estimation, and confusion almost always arises when people try to estimate avoided energy and avoided capacity costs separately. For example, if reliability improves, a utility might be able to retire, cancel, or postpone a unit or it might cancel one type of unit and build another type. Each of these options will have different cost savings associated with them, and will directly affect fuel savings. Only by analyzing the change in total costs (capacity plus fuel) will the utility be able to determine which option is optimal.

Conversely, if a utility has excess generating capacity, units very near completion, or too much oil and gas capacity, changing its expansion plans could be neither feasible nor desirable. We can see this by examining the "negative capacity credit" phenomenon. If a utility has more oil capacity than is optimal, it will probably have new baseload coal or nuclear units planned or under construction. If these units are deferred, then the utility will have to burn more oil for a longer period of time. The capacity savings are usually less than the higher fuel costs, and in this sense, capacity credits are said to be "negative."

For all these reasons, avoided capacity costs are extremely utility-specific and must be based on an analysis of what is feasible as well as optimal. To eliminate ambiguous or counter-intuitive results, avoided costs should be calculated as the change in total costs. Finally, investors in the best near-term markets for grid-connected PV systems need not worry too much about whether they are receiving a separate payment for avoided capacity costs. Capacity payments will be small relative to avoided energy costs based on oil, and if they are calculated correctly, they could actually reduce the total revenues that the qualifying facility receives.

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In summary, the previous studies have shown that PV systems have some capacity displacement potential, but that the savings associated with that displacement vary widely by utility. To understand why there is now some doubt about these results, we have to look at one of the steps in the analysis procedure in more detail.

In previous studies, photovoltaic generation has been estimated using hourly average insolation data, and then the PV production is simply subtracted – hour by hour – from the utility's base case load data. This procedure implies some strong assumptions: (1) insolation, and therefore PV generation, remains constant over the hour; (2) available isolation is known with certainty and, therefore; (3) PV capacity will not cause a change in a utility's short-term load following requirements. To maintain reliability during system operation, utilities must be able to respond within minutes to sudden changes in the load. For example, to meet sudden increases in the load, utilities will commit spinning reserve capacity, which might be in the form of units that are operating at less than their rated capacity so they can be ramped up quickly if needed.

It is the implied assumption that PV output will not change suddenly, and therefore will not require an increase in spinning reserve capacity that makes the previous results suspect. In reality, the weather can change quickly and unpredictably – leading, of course, to changes in photovoltaic power production. The critical unknown is "How much and how fast can output from photovoltaic systems change?" If output could drop from 100% to 0% of capacity within ten minutes, then the utility system would have to back up all of the PV capacity. For every kW of PV capacity added, an additional kW of spinning reserve capacity would have to be committed, and photovoltaic systems could have no capacity displacement potential.

Ongoing research is attempting to analyze the probable impact of photovoltaic capacity on the operation of utility systems. A complete understanding of this issue will probably require extensive experience with PV systems operating in a grid-interactive mode. For the time being we can only conclude that the capacity displacement potential for photovoltaic systems is indeterminate, at least for penetration levels above a few percent of total system capacity, and that operating impacts will place a limit on the total amount of intermittent capacity that can be installed in a given utility system.

In summary, the recent Supreme Court ruling makes it clear that a grid-connected market for photovoltaic systems exists and that qualifying facilities are entitled to full avoided cost rates. Assuming that oil prices remain high relative to the cost of other fuels, the best near-term markets for grid-connected systems will be in oil- and possibly gas-dominated regions with good insolation. In the near-term, especially if solar tax credits are continued, PV systems will be marketable in grid-connected markets at prices higher than those that will be required in the longer term. In the long run, as oil capacity is removed, avoided costs will decline. Photovoltaic system costs will have to come down by at least a factor of 10 over current levels, and capacity displacement will increasingly affect the economics of photovoltaics. If photovoltaic systems cannot displace conventional capacity, longer-term grid-connected markets will be harder to penetrate. Viewed another way, photovoltaic electricity costs will have to be even lower than the ten-fold cost reduction we now think will be competitive. Happily, capacity credit is not a major factor affecting the near-term market for photovoltaic systems in oil-dominated regions, which should allow industry to begin selling systems in grid-connected markets before the capacity credit issue is resolved. Having some photovoltaic systems operating in a grid-interactive mode should then help provide the experience we need to understand the utility system operating impacts and the capacity displacement potential of photovoltaic systems. +

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