CHAPTER 3
PURPA

In 1978 a flurry of energy-related legislation was enacted. Five individual pieces of legislation comprised the National Energy Act. One of those was the Public Utility Regulatory Policies Act of 1978 (PURPA). It was a controversial act, but almost all of the controversy surrounded Title I, specifically Section 133, of PURPA. This section of PURPA required large utilities to make public information showing their cost of serving different customer classes at different time periods. Every public service commission was required to hold hearings to evaluate specific rate changes for their impact on conservation. Section 133 requires commissions to examine time-of-day rates, seasonal rates, lifeline rates and inverted rates (where additional consumption is priced higher than initial consumption).

Title II, on the other hand, sneaked into the legislation almost unnoticed. Although many people now take credit for having authored this section, few people at the time were aware of its potential impact. Title II affects all public and private utilities of any size. It is mandatory. Thus its impact is much more substantial than that of Title I. Yet until the Federal Energy Regulatory Commission (FERC) issued its preliminary regulations to implement this section of PURPA, little notice was paid to its profound implications. When the FERC transformed the general goals of the legislation into hard-hitting regulations, the nation became aware of the act's dramatic implications.

PURPA Title II, Sections 201 and 210, perhaps more than any other piece of federal legislation, made energy efficiency a matter of national policy and opened the way for small power plants.

Prior to the enactment of PURPA, a cogenerator or small power producer had three problems. First, utilities would often refuse to buy electricity from these producers. A utility might allow the small producer to send electricity to it but it wouldn't pay for it. Or if a utility did pay, the price was often unfairly low. Second, utilities discouraged small power production by charging extremely high rates for back up or supplementary power. Third, selling electricity could subject the small power producer to complex and expensive state and federal utility regulation.

PURPA was a legislative attempt to overcome these three primary obstacles. The act directed the FERC, formerly the Federal Power Commission, to establish regulations to implement the law. Final rules implementing Sections 201 and 210 of Title II of PURPA were issued on 25 February and 20 March 1980.

These regulations aggressively promoted the Congressional goals. They ended the century-old monopoly utilities had held over electric power sales. After March 1981 all electric utilities in the nation, including rural electric cooperatives, municipal utilities, investor-owned utilities and federal power agencies were required to buy energy and capacity from qualifying small power producers using renewable resources or cogeneration. The renewable resources include wind power, hydropower, photovoltaics, wood and other biomass and even garbage. With these fuels a utility's customers can now become its suppliers as well.

PURPA sets forth the conditions for becoming a qualifying facility (QF). It describes the various ways the QF can sell its electricity to the utility and the basis upon which the price the utility pays must be calculated. It sets forth the data the utilities must provide to potential QFs on their avoided costs. QFs not only qualify to sell electricity to utilities (and buy supplementary or back-up power at nondiscriminatory rates) but are also exempted from state and federal utility regulations.

QFs can interconnect to a utility's grid system in two ways. They are entitled to use their power on-site and sell only surpluses to the utility. In some cases state regulatory commissions have let very small facilities literally run their regular watt-hour meter backward when power is sent to the utility. This is called *net billing*.

QFs can also choose to sell all the power they generate to the utility and buy all the power they consume from the utility. This procedure, called *simultaneous purchase and sale,* requires at least two meters.

The distinguishing factor between these two arrangements is the number of connections to the utility's system. Allowing simultaneous purchase and sale permits the QF to continue to be a regular customer while also selling electricity. Utilities have argued that a building that produces power sometimes and buys power at other times has a unique load configuration and should be charged higher prices for back-up or supplementary power. But a customer with two connections to the grid system in reality continues to buy all of its power just like a nongenerating customer. Thus, there is no cause for treating a generating customer differently from a nongenerating customer with respect to charges for back-up power. Indeed, in its preamble to the regulations, the FERC specifically states that a QF involved in simultaneous purchase and sale contracts has no need for back-up power.

To encourage investors, the FERC requires utilities to pay QFs a price for their electricity equal to the price the utility would otherwise have to pay to generate or to buy an additional kilowatt-hour or unit of added capacity. The FERC calls these the utility's *avoided costs*. Buyback rates constitute the most controversial and important part of PURPA, and much of this chapter is devoted to a full discussion of what avoided costs really are.

PURPA requires utilities to provide back-up power to QFs at nondiscriminatory rates. The QF cannot be charged any higher rate for back-up, standby or maintenance power than any other customer who doesn't generate power. The only exception is if the utility can prove that the cost of providing this service to the QF is higher than the cost of providing the equivalent service to a regular customer. This regulation is valuable not only to those who want to sell power. It also can prove immensely useful to those who produce only for their own use but want to use the utility as a backup. The homeowner who produces a portion of his or her own power cannot be treated differently from the next-door neighbor who is a regular utility customer.

Finally, PURPA exempts QFs from most federal and state financial, rate and organizational regulations that apply to electric utilities, although the act does not exempt them from federal, state or local environmental regulations.

PURPA has demonstrated the federal government's commitment to the generation of cost-effective electricity from renewable resources and high-efficiency cogeneration plants. During the law's passage and implementation, the following potential benefits of small-scale power production were noted:

1. Cogeneration uses fuels more efficiently than when thermal energy and electrical generation are accomplished separately.
2. Alternate energy sources diversify the utility's resource plan. By minimizing its dependence on any single source of generation, the system becomes more resilient, that is, less vulnerable to external supply disruptions (lapses in availability).
3. Electrical generation from biomass (including wood waste and refuse) or wind, water and sunlight makes the nation less dependent on foreign nations for fuels.
4. The development of many small power plants improves the total electrical system's reliability. The probability of many small plants failing simultaneously is far less than the proba-

bility of one or a few large central station plants suffering a forced outage.

5. The lead time required for construction of small facilities is several years shorter than that for a large central station power plant. Shorter lead times lessen the risks associated with construction cost overruns, rising interest rates and changing demand. Small facilities have also simplified licensing and siting requirements, as do cogeneration systems located at existing industrial facilities.
6. Many small power plants lessen the reserve margin that the total system requires. Large plants need equally large back-up plants. Because of their higher overall reliability, many small plants need proportionately smaller back-up plants for reserve capacity.
7. Independent power producers raise their own capital. The utility, therefore, does not have to raise the capital to construct the facility. The facility is not included in the utility's rate base and thus lessens the possibility of poor bond ratings and higher interest, leading to higher capital costs. The ratepayer does not have to bear the cost of unscheduled plant outages.
8. Electrical generation from many renewable resources promises to be more environmentally benign than generation from fossil fuels or nuclear power.

Sections 201 and 210 of PURPA apply to every utility in the nation—even those that do not generate electricity themselves. For regulated utilities, the state public service commissions have the responsibility for implementing the act. In those states in which the regulatory commissions have no authority over rural electric cooperatives or municipal utilities, the rural electric board and the city council must exercise this responsibility. State utility regulatory commissions and unregulated utilities were required by 20 March 1981 to have adopted rates or procedures for determining rates, or to have at least announced that they would entertain petitions from QFs for interconnection and rate determinations.

As it has turned out, several state legislatures have enacted mini-PURPA laws, putting these states on record as encouraging small power production. The first to do so was New Hampshire with its Limited Electrical Energy Production Act of 1979. Indiana, Minnesota, Oregon, New York, North Carolina and Montana followed New Hampshire's lead. These state laws became important when several law suits put key PURPA regulations in doubt. They gave a legal basis for public utility commissions or city councils to continue implementing the law.

Congress and the FERC gave states and unregulated utilities broad authority to provide even greater incentives to small power producers than did PURPA, which is essentially a minimum guideline. Thus, for example, North Carolina specifically required long-term contracts. Oregon required distribution utilities to pay a much higher price for QF energy than they would have had to pay under PURPA guidelines.

Most regulatory commissions and unregulated utilities have been slow to implement PURPA, in some cases because of reluctance or even hostility to the new law. But in most instances the delay was simply a matter of their entering unfamiliar territory. Not only was the field a new one, but the principal actors were given ground-breaking responsibilities. Attorney Peter Brown is a specialist in small-scale

TABLE 3–1

Required Data for Utilities' Avoided Cost of Energy

UTILITY SIZE	LEVEL OF PURCHASE FROM QUALIFYING FACILITY(IES)	UNIT OF COST	CONSUMPTION PERIODS	YEARS REPORTED
Each utility system with a peak demand of 1,000 Mw or greater	Blocks of not more than 100 Mw	¢/kwh	Daily peak off-peak Seasonal peak off-peak	Current calendar yr Each of the next 5 yrs
Each utility system with a peak demand of less than 1,000 Mw	Blocks of not more than 10% of system peak demand	¢/kwh	Daily peak off-peak Seasonal peak off-peak	Current calendar yr Each of the next 5 yrs

NOTES: From Randi Lornell, "A PURPA Primer," *Solar Law Reporter*, May/June 1981, p. 45.
The data in this table is required by PURPA Section 210 of all utilities with sales of at least 500 million kwh annually. Utilities with sales greater than 1 billion kwh annually must have reported these data by 1 November 1980. Utilities with annual sales of between 500 million kwh and 1 billion kwh must have reported by 30 June 1982.

TABLE 3–2
Required Data for Utilities' Plans and Cost

CAPACITY TYPE	AMOUNT	COST OF COMPLETION	ENERGY COSTS	FREQUENCY OF COST CALCULATIONS
Capacity additions	By individual generating units	\$/kwh	¢/kwh	Each yr for the next 10 yrs
Capacity purchases	By individual planned firm purchases	\$/kwh	¢/kwh	Each yr for the next 10 yrs
Capacity retirements	By individual generating units			Each yr for the next 10 yrs

NOTES: From Randi Lornell, "A PURPA Primer," *Solar Law Reporter*, May/June 1981, p. 45.
The data in this table is required by PURPA Section 210 of all utilities with sales of at least 500 million kwh annually. Utilities with sales greater than 1 billion kwh annually must have reported these data by 1 November 1980. Utilities with annual sales of between 500 million kwh and 1 billion kwh must have reported by 30 June 1982.

hydro at the Energy Law Institute in Concord, New Hampshire. He told Congress in hearings held a year after PURPA's legislated implementation date, "It is important to note that FERC, the state regulatory authorities, and unregulated utilities were, for the most part, unfamiliar with the process of implementation. In the first place, state regulatory authorities were setting wholesale rates and determining interconnection standards in an area where their regulatory authority had seldom, if ever, been exercised. Secondly, state regulatory authorities and unregulated utilities were setting rates for sales of power by qualifying facilities based on the marginal or, as FERC called it, the 'avoided' costs of the purchasing utility (something they also had never done before)."[1]

The FERC itself warned the nation that the PURPA implementation process would involve a giant learning experience. "The Commission continues to believe . . . that this rulemaking represents an effort to evolve concepts in a newly developing area within certain statutory constraints. The Commission recognizes that the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise, and one which, by definition, is based on estimation and forecasting of future occurrence. Accordingly, the Commission supports the recommendation made in the Staff Discussion Paper that it should leave to the state and nonregulated utilities 'flexibility' for experimentation and accommodation of special circumstances with regard to implementation of rates for purchases."[2]

In 1981 the Utah Public Service Commission agreed that the development of rules governing this new relationship between utility and customer must be an evolutionary one. "The concept of avoided cost-based rates is new to this commission," it noted, "and does present difficulties that are yet to be satisfactorily resolved. The Commission therefore intends this order to be a starting point for a process of change and refinement that will at some future point yield proper relationships between utilities and qualifying facilities."[3]

The utility industry's engineers also conceded their lack of experience and definitive knowledge. *Power* magazine, a trade journal for electrical engineers, counseled its readers that, when trying to protect the grid system and the new power producer, "right now, no one, including your utility, knows how much protection [from low-quality energy inputs] is prudent, and how much is overkill, in your specific interconnection situation."[4]

This lack of certainty has tranformed the nation into a giant laboratory. Thousands of experiments are going on simultaneously. Different states and even different utilities within states have widely varying buyback rates and interconnection standards. Sometimes the small power producer can shop around even within small geographic areas. One hydro developer in Oregon found that his property was bounded on one side by a rural electric cooperative (REC) and on another by an investor-owned utility (IOU). Each utility offered different contractual terms. The REC offered lower rates but a better long-term contract than the IOU. He was still deciding which utility to go with when this book went to press.

Qualifying for PURPA

PURPA recognizes two types of qualifying facilities: small power producers fueled by renewable sources of energy and cogenerators. No small power production facility can be larger than 80,000 kilowatts (kw). That includes the capacity of any other facilities owned by the same person and using the same energy source at the same site. (However, producers with between 30,000-kw and 80,000-kw capacity are subject to certain provisions of the Federal Power Act and must have their rates approved by the FERC.) At least 75 percent of the fuel a small power producer consumes in any calendar year must be from biomass; waste; renewable resources like sun, wind or water; or geothermal steam or any other combination thereof.

Cogenerators can be fueled by natural gas or oil as well as by such renewable resources as wood and alcohol produced from biomass. There is no size limitation on cogenerators. However, they must meet certain operating standards. Cogenerators are of two types: topping cycle and bottoming cycle. A *topping-cycle* cogeneration facility first produces electricity and then uses the waste heat from this process to provide useful thermal energy. A *bottoming-cycle* facility reverses the process. It first produces useful thermal energy and then uses the waste heat to produce electricity. Almost all the cogeneration equipment discussed in this book uses the topping cycle, because a bottoming-cycle facility that is under 200 kw is at this time uneconomical.

The useful thermal energy produced from a topping-cycle cogenerator must be no less than 5 percent of the total energy output in any calendar year. This is meant to prevent a person from installing a generator and only producing electricity, thereby not capturing the efficiencies of cogeneration.

If the topping-cycle facility uses any oil or natural gas and was installed on or after 13 March 1980, it must meet an additional efficiency standard. Once again the purpose is to encourage high efficiency. In this case, if the useful thermal output of the cogenerator is less than 15 percent of the total energy output, then the electric output plus one-half the useful heat recovered must be at least 45 percent of the total oil and gas consumed. This means if one recovers a relatively small proportion of the waste heat, the QF must convert a higher portion of the energy consumed into electricity than otherwise would be necessary. If only 10 percent of the energy consumed is recovered as heat, then the facility must convert at least 40 percent $(45 - 10 \div 2)$ of the oil or gas consumed into electricity. If the QF recovers at least 15 percent of the total energy consumed as useful heat, then the combination of electric output plus one-half of the useful thermal energy need only be 42.5 percent of the oil and gas consumed in the process.

A cogeneration facility can have a dual fuel capacity and still qualify for PURPA benefits. Such a facility can automatically switch from gas to oil or another fuel source.

Other provisions require that not more than 50 percent of either the small power producer or the cogenerator may be owned by an electric utility, electric utility holding company or a subsidiary thereof. Public utility holding companies that do not own electric utilities may own QFs, as may electric utility holding companies and subsidiaries that are not primarily involved in generating and selling electricity. If the primary fuel source of the QF is geothermal, 100 percent of the facility may be utility-owned.

Applying for qualifying status is essentially a simple process. Any facility that meets the criteria previously discussed can "self-qualify" (except for dual fuel cogenerators). Or, alternatively, the facility can request a formal certification by the FERC. The latter takes time but has certain legal and regulatory advantages. The utility knows you have contacted the FERC. It may presume you have a slightly higher level of sophistication than the self-certifier and may bargain with you accordingly. In the case of hydro developers, one is given certain powers of eminent domain to make small-scale hydroelectric systems viable, and a license gives you exclusive rights to develop a site for a certain period of time.

The FERC requires the following information:

1. The name and address of the applicant and location of the facility
2. A brief description of the facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility
3. The primary energy source used or to be used by the facility
4. The power production capacity of the facility
5. The percentage of ownership by any electric utility or by any public utility holding company
6. The location of the facility in relation to any other small power production facilities within one mile of the facility owned by the applicant, which uses the same energy source

Upon receiving an application, the FERC will issue an order granting or denying the application or scheduling consideration of the application. An order denying certification must identify which requirements were not met. If the FERC does not issue an order within 90 days of the filing of a complete application, qualifying status is deemed to have been granted by the FERC.

The FERC may revoke the qualifying status of a facility that fails to comply with the statement contained in its application. So, a qualifying facility planning to undertake substantial alteration or modification may choose to apply to the FERC for a determination that the proposed changes will not result in a revocation of its qualifying status.

As of December 1982 the FERC charged no significant fees for certifying projects. However, proposed fee schedules for various services were issued in late 1982 for comment. The FERC proposed to charge any QF $2,600 to have its project certified. Moreover, the FERC proposed to charge additionally if the QF appealed to it to gain approval to interconnect with and sell power to a utility. The charges range from a minimum of $6,200 to a maximum of $57,400 if the interconnection is contested by the utility and hearings are needed. Critics argue that such fees undermine the intent of PURPA to encourage cogeneration and renewable-based electric generation. Even if such fees were justified on the basis of the FERC's internal costs, critics maintain that they should not be levied on small producers. Those with projects of less than 100-kw capacities would delay or cancel investments in the face of such stiff charges. In early 1983 the FERC delayed its final decision on implementing these new regulations until late 1983.

Utility Avoided Cost Data

The heart of PURPA is the requirement that utilities pay QFs a price based on their own avoided costs. Much of the data upon which that price is set comes from the utilities themselves. The FERC requires utilities with retail sales of more than 500 million kilowatt-hours (kwh) to provide data at least every two years from which avoided costs can be derived. State utility commissions or publicly-owned utilities can ask for more frequent data submissions. Each regulated utility must give these data to the state commission. Both regulated and unregulated utilities must maintain them for public inspection.

Utilities must give the following data to state utility commissions:

1. The system's estimated avoided cost of energy for various levels of purchases from QFs. These levels must be given in blocks of not more than 10 percent of the system peak, or 100 megawatts (Mw), whichever is less. For example, a utility that has 50,000 kw of system peak might serve 5,000 people. It must determine its avoided costs if QFs displace 5,000 kw of capacity. The avoided cost must be stated in cents per kilowatt-hour during daily and seasonal peak and off-peak periods, by year for the current calendar year and for each of the next five years.
2. The utility's plan for the addition of capacity, the amount and type for purchases of firm energy and capacity it

has with other utilities and for capacity requirements for each year during the succeeding ten years.

3. Estimated capacity costs, at completion of the planned capacity additions and planned capacity firm purchases (purchases of capacity a seller must deliver at the buyer's request) in dollars per kilowatt and the associated energy costs of each unit, in cents per kilowatt-hour. These costs are to be expressed for individual generating units and purchases.

Appendix 5 presents cost-of-service data for several utilities. Acquiring this type of data is the first step in estimating buyback rates. Notice the difference not only in the estimated avoided costs but in the manner in which each utility presents the data. Seattle City Light indicates that some of its figures are in current dollars, but certain energy cost escalation rates are assumed. In other cases, the costs are in 1981 or 1972 dollars. Seattle City Light could not provide capacity costs, due to confusion over the FERC regulations. Houston Lighting and Power provides costs in current dollars. It gives no escalation rate. It gives a breakdown of avoided costs for 100 Mw, 500 Mw and 1,000 Mw.

The regulations do not specify a methodology for determining avoided costs. That is left up to the state regulatory agencies and the unregulated utilities (via their city councils) or rural electric cooperative boards. They do, however, provide guidelines, which are discussed below.

Utilities with retail sales of less than 500 million kwh, other than an all-requirements utility, must provide data comparable to those described in Appendix 5 upon request, so that QFs can estimate the utility's avoided cost. It is important to remember that, in most cases, the public utility commission does not establish actual rates. Rather, it establishes the methodology with which to calculate the actual rates. However, the utilities must develop a standard contract for QFs with capacities under 100 kw, and most commissions monitor this closely and will intervene to establish rates directly if the utility proves recalcitrant or is viewed as promoting inappropriate tariffs. An *all-requirements utility* is one that purchases all of its electricity from a bulk supplier. It may provide the data of its supplying utility and the rates at which it purchases energy and capacity.

Standard and Negotiated Contracts

To minimize the expense of negotiations, PURPA requires that utilities offer a standard contract to QFs with capacities under 100 kw.

The standard contract is a useful device to balance the inherently unequal bargaining power of the utility and the small power producer. As Paul Gipe, an adviser to small wind machine owners in Pennsylvania says, "Small power producers come to the utility hat in hand."

States can also require standard contracts for generators of more than 100 kw, although PURPA does not require this. New Jersey, for example, requires a standard contract for all QFs with a capacity of less than 1 Mw (1,000 kw). Montana requires a standard contract for all QFs regardless of size. The standard contract should contain the minimum provisions the regulatory commission believes necessary to attract the maximum number of QFs. Standard contract prices must reflect full avoided costs.

The owner of a power plant with less than 100-kw capacity (or the state minimum) can choose the standard contract or can negotiate individually for a better deal. QFs with capacities greater than the state minimum required for a standard contract must negotiate individually. PURPA still provides the guidelines for individual negotiations, but it is not the final word. As one handbook for small hydro producers advises, "Thus, while PURPA has become a vital 'silent partner' of private power producers, it is largely still up to the individual hydro developer to secure a satisfactory agreement through a process of negotiation with a purchasing utility. Following a thorough understanding of his own costs and requirements, as well as those of the prospective purchaser, the producer will, at an early point in his negotiating strategy, be confronted with the need to establish very precise terms and conditions with respect to the proposed transaction. For it is within the framework of these provisions that the most critical bargaining will take place."[5] One point to be stressed here is that it is legal under PURPA for a QF to negotiate any deal or set of contract terms with a utility. PURPA laws are not a limiting framework, and the QF is free to try to obtain the best contract terms possible.

QFs unhappy with specific contract provisions offered by the utility or who believe the utility is delaying the negotiation process have the right under PURPA to appeal to the regulatory commission or the FERC. Although no states have yet developed clear appeal procedures, some QFs have already used their regulatory commissions to good effect. Sometimes all it takes is a phone call to the commission staff, who then calls the utility to investigate the matter informally.

Introducing the Actors

Small power producers and cogenerators with capacities of less than 200 kw are the primary audience for this book. This size range embraces the 2-kw rooftop photovoltaic array as well as the medium-size motel cogeneration system. Potential power producers usually fall into one of three categories.

First is the producer who wants only to sell electricity. The owner of a 50-kw hydropower facility or wind farm has no purpose other than to sell electricity to the grid system. The project's cost-effectiveness depends on the buyback price and the cost of the interconnection equipment. If the buyback price is too low, the project will not be developed. This facility needs no back-up power. Many of these projects will be financed by outside investors who need long-term contracts and some certainty of future purchase prices to encourage their investment.

The second type of producer uses some of the electricity on-site and sells only the surpluses. For this person, the price of utility back-up power will become a very important factor. The size of the power plant may vary depending on the price the utility pays for the delivered power. This is especially true for cogeneration systems. The cogenerator can choose, if the buyback price is too low, to size the system to meet only the internal heat load, with the electricity viewed as an additional benefit. If the buyback rate were higher than the retail cost of electricity, the size of the system might be increased to take advantage of the additional revenue from sales to the grid. According to Richard Nelson of Cogenic Energy Systems, a major supplier of small-scale cogeneration systems (see Appendix 6), none of the more than 100 systems installed by his company were sized to deliver electricity back to the grid.

The third type of producer generates only for internal consumption. A 2-kw residential solar cell array could represent such a case. This producer may have no plans to sell electricity to the utility. The cost of two meters and certain interconnection equipment may outweigh the revenue possible from sales. This producer may not be interested in buyback rates but in the provisions of PURPA that prohibit high back-up or other service charges.

Major Negotiation Issues

Many QFs lack knowledge about their rights under PURPA. Sunday supplements carry heartwarming stories about the family that now owns a small hydroelectric plant, but they rarely give any detailed information about how the system fits into the overall electric system. While interviewing people for this book, we discovered many examples of ignorance being harmful to the independent producer. One owner of a photovoltaic array in California didn't know that she qualified for capacity payments under the standard contract even though sunlight is an intermittent source of fuel. A hydroelectric developer in Utah wasn't aware that even though his state's major utility had an excess capacity fired by coal, this didn't rule out a high avoided cost and therefore a high buyback rate.

In the bargaining process, the potential QF must be ready to deal with a wide variety of issues. Listed are the major ones in the form of questions. Each will be addressed in the course of this chapter.

What was the purchase price based on? How often could it be changed? Is net billing available? Are long-term contracts available? Do such contracts include provision for rising purchase prices if energy costs increase? Is there any protection against declines in future avoided costs? Are levelized payment schedules offered for long-term contracts?

Does the utility offer time-differentiated rates? Is the difference between peak and off-peak buyback prices sufficient to compensate for the additional cost of a time-of-day meter?

Are capacity credits available? How much are they worth? How are they estimated? How often can they be changed? What is the minimum length of contract the QF has to sign in order to qualify for capacity credits? Are capacity credits available on an "as available" basis or does the QF have to meet certain performance standards including availability during peak periods to earn capacity credits? Is a penalty attached to a QF failure to meet these standards?

Under what conditions can the utility cease purchasing power from a QF? In such instances what notice does the utility have to give the QF? What justification does the utility have to present to the regulatory commission?

Are customer service charges imposed on the QF in addition to those imposed on other customers in the same class who do not generate power? Are back-up or standby rates different for QFs than for other customers? Have utilities justified these differences on the basis of differences in their cost of service?

How often can the contract be renegotiated by the QF or the utility? When must notice of termination be given by either party?

Does the utility include QFs as part of its resource plan? What is the total capacity of QFs it plans to have on-line within the planning horizon?

How does one appeal to the public service commission or, in the case of the unregulated utilities, to the utility board or the city council? How long does an appeal take?

Does the utility require the QF to indemnify it for possible damages? Does indemnity work both ways? Must the QF take out an insurance policy to cover possible injuries sustained to the system or to other customers? Is a specific amount of insurance coverage indicated?

Are there provisions in the standard contract offered to applicants under 100 kw that are not in sample negotiated contracts?

What is the responsibility of the utility to wheel QF-generated electricity to a neighboring utility that might pay more for the electricity? What is the charge for such wheeling?

If this list of questions appears mind boggling, don't worry. In the beginning you will have a new jargon to learn. You will have to learn to think systematically. But eventually the answers to individual questions will form a picture. Most relate to others. You are discovering the relationship of the individual producer to the electric grid system. Remember, while you are going through the process, so are dozens, even hundreds of others. Several states have their own associations of independent power producers. Link up with them. Form your own. Share information. Piggyback on their experiences. You can do it.

Those who master the process may get their just rewards. In several states individuals who negotiated knowledgeably more than doubled the price they received for their electricity.

Although most of this book is devoted to providing technical information, one point cannot be stressed enough. The process of PURPA proceedings is a political one. Clearly there is a rational, technical, mathematical basis for the final decision. But the final decision can vary dramatically depending on the political clout of the small power producers. Examples of this abound. Utah Power and Light (UP&L) serves areas of Idaho as well as Utah. Most of the data upon which it based its avoided costs in both states was identical. Yet Idaho concluded that UP&L should pay 4.6¢ per kilowatt-hour and Utah concluded it should pay about 2.4¢. Needless to add, independent power producers intervened aggressively in Idaho's hearing process. Utah had little participation during its initial process.

The large issue of interconnection requirements has not been raised here. That issue is so complex that the entire next chapter is devoted to it.

Purchase Prices and Avoided Costs: A Brief History

For many small-scale power producers, the key to PURPA is the rate the utility must pay for independently produced electricity. PURPA requires utilities to buy energy from QFs at rates based on the utilities' incremental costs. Thus the purchase prices (or buyback rates) should be based on the cost of the next unit of energy or capacity that the utility would have to bring on-line. As discussed in the last chapter, the utility *sells* electricity at its *average* rather than its *marginal* cost. If it must buy electricity at its marginal or future costs, it may pay a QF a higher price than it charges. This is especially true if the QF can receive a capacity credit. This favorable situation depends greatly on aggressive public service commission involvement in rate structuring. In early 1983 this was the case in most parts of Oregon, Idaho, Montana, New Hampshire and Vermont.

To most QFs, no issue is more important than the buyback rate. Today these rates vary by more than 5:1 around the country. A 4-kw wind machine that generates 9,000 kwh a year in 12-miles-per-hour (MPH)-average wind would receive 1.2¢ per kilowatt-hour in mid-1982 in Nebraska and almost 8¢ per kilowatt-hour in Vermont. That represents a range in first-year revenue of $100 to $700. In the first instance, assuming a 10 percent annual increase in the buyback rate, the machine will still not repay its initial investment over its life. In the second case, it pays itself off in about seven years. PURPA itself does not establish a specific buyback rate. Congress said only that purchase prices (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) shall not discriminate against qualifying cogenerators or qualifying small power producers. In addition, "No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy." Congress simply defined "incremental cost of alternative electric energy" as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[6]

The Federal Energy Regulatory Commission translated this relatively broad mandate into specific regulations. Its regulations put meat on the bare legislative bones. The FERC redefined "incremental costs" as "avoided costs" and ordered utilities to pay 100 percent of their avoided costs to QFs. To the FERC, these represented those costs that "but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source."[7]

To the electric utilities, the FERC regulations constituted a declaration of war. The utility-QF relationship has been from the beginning an adversarial one. Most utilities view QFs as potential competitors. Utilities believe QFs even under ideal conditions can generate only insignificant quantities of power in the foreseeable future. Therefore they do not believe that QFs can actually displace a multi-megawatt power plant.

If this interpretation were accepted by utility commissions, it would become a self-fulfilling prophecy. The utility concludes that QFs can never produce sufficient power to displace a central power plant. Therefore it offers no capacity credit. As a result, few QFs enter the market because the economics of doing so are marginal. The FERC turned a deaf ear to the utilities' forecasts and ordered them to pay QFs a capacity credit in return for a contract for firm power (that is, power generated a certain fraction of the year) as if the individual QF were displacing a piece of a future generating plant because the aggregate class of a type of QF (e.g., all the wind-electric systems, all the hydroelectric systems and so forth) does itself provide some level of firm power.

Utilities also vigorously disputed the FERC's requirement that they pay QFs their full avoided costs. They argued that, if QFs could generate power at very low costs, the utilities should be given the ability to bargain flexibly so that a portion of the savings could go to their ratepayers. They argued further that by denying them the right to share in the immediate benefits of small power production, the FERC undermined any incentive they might have to encourage dispersed generation actively. In Congress, before state regulatory commissions and in federal courts, utilities consistently presented the case for full avoided costs as a ceiling rather than a floor.

To utilities, having to pay 100 percent of their avoided costs meant giving a windfall profit to QFs. They argued that the first QFs would install dispersed generation plants on the most attractive sites, harnessing the fastest flowing rivers equipped with existing dams, or the windiest terrains, or industrial cogeneration systems in businesses that could use a large portion of the waste heat. Utilities expressed chagrin that investors in dispersed generators could earn a return of 30 to 50 percent or more while they were restricted to a regulated return of 11 to 17 percent.

Utilities argued that high purchase prices were unnecessary since many dispersed generation facilities would be profitable even if they received a lower price. Why pay full avoided costs when the same amount of capacity could be brought on-line at a lesser cost to the ratepayers?

Finally, utilities argued that they should not be denied PURPA benefits. The FERC restricted utility ownership to no more than 50 percent of individual QFs. This restriction once again reduced the utilities' incentive to encourage small power production and cogeneration. If Congress really wanted to encourage electrical generation from such technologies it should allow utilities, who after all know the electric generation business better than anyone, the same incentives it does private unregulated industries.

The FERC denied each of these arguments. It admitted that paying full avoided costs might give those QFs that acquired the most attractive facilities a very high return on their investment. But the FERC argued that this rapid penetration was exactly what Congress intended, and that these pioneers were taking the risk of dealing with relatively new technologies and new regulatory and legal requirements, not to mention recalcitrant utilities.

The FERC further argued that to base the purchase price on the return the QF would be getting would require a detailed examination of the QF's production costs. Such an examination smacked of the kind of conventional utility regulatory investigations that were the sort of bureaucratic deterrent Congress wanted to avoid.

Finally the FERC argued that paying full avoided costs encourages not only those at the tip of the iceberg to invest in small power production and cogeneration but all of the iceberg that is below the avoided-cost waterline. Assume that a utility's next power plant would generate electricity at a cost of 9¢ per kilowatt hour. QFs that can generate electricity at a production cost of 3¢ per kilowatt hour might still invest even if they were paid a fraction of the full avoided cost. But investments in QFs that generated electricity at 6¢, 7¢ or 8¢ per kilowatt hour would not be profitable unless the investor received the full avoided cost. Yet these facilities would nonetheless have provided cheaper electricity than the utility's. It was to gain the active participation of this "second tier" of QFs that full avoided-cost payments were proposed.

Indeed, several state agencies argued that full avoided costs actually represented a conservative price. The California Public Utility Commission commented, "If anything, this Commission believes that the avoided cost signal to QFs is a conservative one, as it does not include the tangible but hard-to-quantify 'social costs' that are associated with new utility supplies and which are avoided through the purchase of QF power. These 'social costs' include the risks associated with imported energy supplies and environmental degradation related to conventional generation."[8] In short, at least one regulatory body saw in QFs a value beyond just the utility's avoided cost. Avoiding the pollution of a new coal plant or the waste problems and potential danger of a new nuclear facility were also of value.

Ironically, at the moment the commission issued this statement, one of its regulated utilities, Southern California Edison, was requesting permission to charge its ratepayers $3.15 million over six years for its share of the $760 million remaining cleanup cost of Three Mile Island. No more perfect example of the social costs of conventional electric generation could have been given.

In fact, the FERC does not prevent state regulatory commissions or unregulated utilities from establishing purchase prices that are higher than avoided costs. It prohibits only the setting of purchase prices lower than avoided costs. Both Montana's and New Hampshire's regulatory commissions have taken public note that their purchase prices may sometimes be higher than full avoided costs to encourage greater participation of QFs.

The FERC also denied the utilities' request that they be permitted to own QFs. It noted that nothing in PURPA prevents a utility from owning wind turbines or cogeneration facilities. PURPA only denies such facilities eligibility for the unique PURPA benefits. Utilities *should* be building wind turbines and hydro plants where they are cost-effective. Moreover, before 1981 and PURPA's implementation, utilities had shown *no* desire to build cogeneration plants or to install small hydro or wind facilities. The FERC believed that this lack of initiative demonstrated their lack of commitment. Finally, the FERC hoped and expected that the field of cogeneration and small power production would be highly competitive. Having operated in a highly regulated, monopolistic environment, the utilities probably had little expertise or inclination to operate in such a field. If a subsidiary of the utility owned a QF, there arose the additional possibility of collusion or at least favoritism.

To understand properly the PURPA negotiation process and the intense controversy surrounding the FERC's regulations, one must realize the extent to which PURPA reverses the conventional utility role. Traditionally the utility has exercised a monopoly over electric power generation and sales. Any monopoly tries to maximize the price it receives and the profit it makes. That is why regulatory commissions were established to represent the public interest and the ratepayer. PURPA eliminates the monopolistic role, but it replaces it with a *monopsonistic* one. PURPA does not allow QFs to sell at retail, preserving the monopoly by utilities over transmission and distribution and thus creating monopsony. A monopsony occurs when there is only one buyer. Before PURPA the utility was the only seller. Under PURPA it is the sole buyer but not the only seller. Under monopsony the buyer's objective is to pay the lowest price.

Thus one can expect an adversarial role even between the most progressive utility and the potential QF. Even when a utility wants to encourage QFs, it will still try to buy electricity on the best terms for itself. When a utility is anything less than sanguine about the rise of independent power producers, its negotiation position can be downright discouraging. A full discussion of negotiating strategies and examples is the focus of chapter 5. However, any QF should have a basic understanding of the economics of utility electric generation. Knowledge is your best ammunition. What follows is a discussion of the basic concept of avoided cost and the various ways that this cost is determined.

Calculating Avoided Costs

Dispersed electric generation allows the utility to avoid several kinds of expenditures. One is the expenditure for fuel to fire the plant that would ordinarily carry the top of the utility's load at the moment the QF is producing power. Another is a modest savings in the cost of the plant due to reductions in operation and maintenance expenses because of a decreased annual use. These types of savings are called *short-term avoided energy costs.* The second type of potential savings are *long-run energy costs.* These savings can also include a capital credit if, as is the case for most utilities, the management policy has been to substitute capital for fuel by building nuclear (low fuel cost, high capital cost) rather than oil-fired (higher fuel cost, lower capital cost) power plants. The third type of avoided cost is the savings in not having to construct new power plants. These are called *capacity credits.* Another avoided cost is in savings to the transmission and distribution system because the dispersed generator's output will be consumed nearby, thereby lessening the load on the utility's transformers, voltage regulators and lines.

To the FERC, "the costs which an electric utility can avoid by making such purchases generally can be classified as 'energy' costs or 'capacity costs.' Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel and some operating and maintenance expenses. *If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid.* Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital cost of facilities. If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to enable it to build a smaller, less expensive plant, or to purchase less-firm power from another utility, then the rates for such a purchase will be based on the net avoided capacity and energy costs."[9] (Emphasis added by author.)

Short-Run Avoided Energy Costs

Utilities operate several kinds of power plants that vary in construction cost and operating expense. Coal or nuclear-fired baseload plants might have an operating cost of between 1¢ and 2¢ per kilowatt-hour. Coal is cheap. In 1982 a ton cost $40.00, or about $1.35 per million Btu. Assuming a heat rate of 10,000 Btu per kilowatt-hour, the cost of electricity would be 1.3¢.

Oil, on the other hand, is expensive. Oil-fired peaking plants can cost 7¢ to 15¢ per kilowatt-hour to operate. Thirty-three dollars a barrel translates into $5.69 per million Btu. Assuming a heat rate of 12,250 Btu per kilowatt-hour, the kilowatt-hour cost is about 7.2¢ (Natural gas falls between coal and oil. In 1982 it cost 33¢ per cubic foot or $3.30 per million Btu. Deregulation should produce parity between oil and natural gas by the mid-1980s.)

Remember, *PURPA requires that the QF be paid a price equal to that of the most expensive plant operating when the QF generates electricity*. The QF is displacing the top of the load, the peak. New Hampshire's Public Service Commission, for example, concluded that even though its utilities rely heavily on nuclear power, the top of the load (demand) should almost always be supplied by oil-fired power plants. Thus the QFs are paid a high price based on the costs of operating oil-fired plants. (If the Commission had concluded that nuclear plants were able to meet 100 percent of the demand during a significant period of time, the utility would have had to pay QFs only about 1.5¢ per kilowatt-hour.)

Many states rely on sophisticated computer models to determine their avoided costs. Others choose a proxy, or stand-in power plant, to provide the data. New Hampshire used the Newington plant, the most efficient baseload, oil-fired plant operated by the Public Service Company of New Hampshire. Since it was oil-fired the fuel was expensive, but it was an efficient baseload plant, so it burned less fuel to produce the same amount of electricity than would a peaking plant.

The commission determined a base avoided fuel cost of 61.18 mills per kilowatt-hour. This assumed a heat rate of 10,250 Btu per kilowatt-hour and an oil price of $35 per barrel. The New Hampshire Commission used that as a starting point for estimating avoided costs. In response to a utility petition, the commission stated, "The position that avoided costs should be based solely on average fuel costs is rejected." The commission then raised the base fuel cost to account for the time the efficient Newington plant would not be available. When the Newington plant was not available (e.g., during periods of forced outage) or when the system load exceeded the total capacity of Newington to carry the top of the load, more expensive peaking plants would be used. These plants also burn oil but more inefficiently. Their higher heat rates mean that the cost of producing a kilowatt-hour rises. The commission increased the avoided costs by 17 percent to reflect "the unscheduled outage rate at Newington and the weighted cost of all units more expensive than Newington."[10]

The New Hampshire Commission was aggressive in searching out other savings gained from the inputs of QFs. For example, it increased the buyback rate 0.2¢ per kilowatt-hour to account for the displaced working capital that utilities would otherwise have had to use to pay for fuel inventory. Another 0.21¢ per kilowatt-hour was tacked on for reduced operation and maintenance costs. The lessened use of the Newington station meant reduced deterioration and therefore a longer useful life.

These additions increased the base fuel cost of 6.18¢ to a purchase price of 7.63¢ per kilowatt-hour.

New Hampshire's buyback rate does not vary throughout the year. Most commissions have rates that vary by time of day and season. California is one state that breaks down the day into three rating periods. Table 3–3 shows the incremental heat rate and energy purchase

TABLE 3–3

Calculation of PG&E's Energy Purchase Prices for November and December 1981 and January 1982

TIME PERIOD	AVERAGE INCREMENTAL HEAT RATE (BTU/KWH)	UNIT COST OF ENERGY CONTENT ($/10⁶ BTU)*	ENERGY PURCHASE PRICE (¢/KWH)†
On-peak	11,850	6.5193	7.725
Partial peak	11,200	6.5193	7.302
Off-peak	10,000	6.5193	6.519
Annual average	10,860	6.5193	7.080

SOURCE: PG&E, 1981.

* Cost of oil received ÷ energy content of oil received.

† Average incremental heat rate × unit cost of energy content.

price for Pacific Gas and Electric (PG&E) for each rating period and its annual heat rate and energy cost. To understand how PG&E derived the 7.725¢ per kilowatt-hour price it was willing to pay QFs during the summer peak hours, take 11,850 Btu per kilowatt-hour and multiply by the $6.5193 per million Btu cost of oil at the time ($32.86 per barrel). Then divide by a million and you get 7.725¢.

Table 3–3 displays the computation of energy purchase prices to be offered to qualifying facilities in November and December 1981 and January 1982. This table is based upon the unit cost of energy content value of $6.5193 per million Btu and the average incremental heat rates for various pricing periods.

California's system is complicated inasmuch as it has many different rating periods and is based on PROMOD, a highly sophisticated computer model that the utility industry uses for regional power pool dispatching. Some controversy has been generated about exactly what type of plant is carrying the top of the load curve at any given time period. Since the incremental heat rate varies by some 18 percent, from 10,000 Btu to 12,340 Btu per kilowatt-hour, the controversy is not trivial. A 100-kw cogenerator operating at a capacity factor of 80 percent would generate about 500,000 kwh a year. The 1.2¢ per kilowatt-hour difference in heat rates equals a difference of $6,000 in annual income to the QF. However, the difference will only be that great if the 1.2¢ variation occurs during the entire year. That is unlikely. It would probably occur only when peaking plants are operating during off-peak or mid-peak times. Thus only a fraction of the $6,000 is at stake.

Often utilities offer nonfirm energy purchase prices and time-differentiated energy prices. The nonfirm price is usually an average of peak and off-peak. In 1982 the Oregon-based Pacific Power and Light Company (PP&L) offered a price of 2.28¢ per kilowatt-hour, or a time-differentiated price of 2.76¢ on-peak, 6 A.M. to 10 P.M. Monday through Friday, and 1.84¢ at all other times. The individual QF in this case would benefit from the time-differentiated prices only if it can generate a great deal more power on-peak than off-peak. But the QF would have to install a meter for each time period. Thus in California a three-register meter must be installed. Each additional register costs $50. If the amount of power the QF can generate during peak periods is greater than the cost of installing extra meters, only then is the time-differentiated rate beneficial to the QF.

In some cases, the average price will not be midway between the off-peak and peak rate. The Omaha Public Utility District offered 1.6¢ at peak in 1982 and 1¢ at off-peak. The nonfirm rate was 1.1¢ per kilowatt-hour. Since a time-of-day meter costs $100 to $300, the QF must be able to deliver 2,000 kwh to 6,000 kwh annually on-peak just to balance the cost of the meter. (Typically there are 2,000 peak hours a year.) A 5-kw wind machine operating at 30 percent capacity would generate 13,140 kwh per year. If 20 to 50 percent of this output were generated during the utility's peak periods, the time-of-day meter would be a good investment.

Calculating short-term energy costs is relatively easy. The major arguments relate to which plant is carrying the top of the load curve and what associated costs (e.g., displaced working capital, line losses and so forth) the QF displaces.

Long-Run Avoided Energy Costs

The concept of long-run energy costs is more difficult to understand. Many utilities are "backing out" of oil-fired power plants by substituting coal and nuclear plants. That is, they are substituting baseload plants for peak load plants. Thus when the QF displaces the top (peak) of the load, it may be displacing inexpensive coal or uranium fuel rather than expensive oil or natural gas. The baseload plants are expensive compared to peaking plants, but coal and uranium are inexpensive fuels. Utilities argue that avoided energy cost is the cost of operating these plants and that they should be required to pay QFs only this amount. Since coal- or nuclear-powered baseload plants have very low operating costs, this interpretation of avoided costs would lead to very low buyback rates. Where this interpretation has been accepted by public utility commissions, as in Nebraska and Iowa, this has been the case.

If the utility argument is accepted, the QF is placed in a difficult situation. The utility that substitutes base load for peaking plants will tend to have an excess capacity, thereby reducing the availability of capacity credits to the QF. If the avoided energy costs are based on the price of coal or uranium, the QF will receive a low price for its electricity. As was mentioned before, some regulatory commissions designed an as available energy tariff under which the QF receives a higher kilowatt-hour rate for long-term firm power contracts. These as available rates reflect a certain amount of avoided capacity. If the QF wants to receive a higher capacity credit, then it must meet the higher performance standards set by the utility for these credits.

But other commissions located in states with coal-fired plants do not interpret the energy costs in so restricted a manner. They assume that by building more expensive coal and nuclear plants the utility is substituting capital for fuel. The plant is not being built to meet future growth in demand but rather to substitute for oil- or natural gas-fired plants. Thus the portion of the plant's cost that exceeds the cost of a combustion turbine ($300 per kilowatt in 1980) can be interpreted as an energy-related rather than a capacity-related investment.

If this is done, the long-run avoided energy cost for a typical $2,000-per-kilowatt coal plant is about 5.2¢ per kilowatt-hour. Assuming $1,700 of the plant's cost per kilowatt is related to energy and it operates at an 85 percent capacity factor and the fixed capital charge is 17 percent, the capital-related, energy-cost component alone would be 3.9¢ per kilowatt. A typical nuclear plant would have an even higher energy-related payment.

Montana's Public Service Commission has adopted this methodology. In return for gaining capital-related energy payments, the QF must sign a long-term contract but need not meet any reliability or operating standards that would be associated with capacity credits. In Montana in 1982, QFs with no contract received a short-term energy rate of 2.1¢ to 2.3¢ per kilowatt-hour, depending to which of the three Montana utilities they sold their electricity. For those QFs willing to sign a minimum four-year contract, both a long-term energy rate and a long-term capacity credit applied. Capacity credits will be discussed shortly.

The estimation of long-term energy rates requires the use of modest arithmetic. The Montana formula for the long-term energy rate (LTE) follows:

$$\text{LTE} = \frac{\left[\Big([a(c+e)] - [b(d+f)]\Big)(1+g)\right]}{(8{,}760 \times 0.70)} + \frac{[(h)(j)]}{i} + k$$

This formula will be explored in detail because the Montana methodology is a model that could very well be used by the entire country. The formula looks formidable, but once the letters are defined, the equation loses its mystery. The baseload capital costs are represented by *a*, and the baseload annual carrying charge by *c*. This is called the *fixed-charge rate*. When you take out a loan and want to know how much you must pay each year to repay the loan principal plus interest, you multiply the loan by the fixed capital charge rate. That rate varies depending on the interest and the term of the loan. The baseload fixed operation and maintenance cost are represented by *e*. Thus the first part of the formula calculates the annual costs of repaying the investment in a baseload plant plus the maintenance and fixed operating costs of that plant. The baseload plant will be expensive. In Montana the average cost is over $1,500 per kilowatt.

The next part of the formula deals with the annual costs of a combustion turbine. The capital cost of such a plant is *b*, and *d* is the fixed-charge rate. The rate is higher for this type of plant because the plant is estimated to last only 25 years versus 35 years for a baseload plant. Since the investment must be repaid over a shorter time, the fixed-charge rate is higher (assuming identical interest rates as Montana did). The fixed operation and maintenance costs for the combustion turbine are represented by *f*. The capital cost of the combustion turbine is low. In Montana it is slightly more than $325 per kilowatt.

The annual costs of the combustion turbine are then subtracted from the annual costs of the baseload plant. This then gives the energy-related capital cost. In other words, the assumption is made that a utility is substituting capital for energy by building a coal-fired baseload plant to meet future load. The energy-related capital costs are the additional costs of the baseload plant.

The rest of the formula is easy. The transmission line losses are represented by *g*. Montana assumes an 8.3 percent line loss so that costs determined by the first part of the formula are multiplied by 1.083. This entire figure is then divided by the number of hours in a year, 8,760 multiplied by 0.70, which is a typical capacity factor. This gives the cost in cents per kilowatt-hour for a typical year.

It remains to add the fuel cost and the baseload variable operation and maintenance. The fuel cost is figured out by taking the cost of a pound of coal (*h*) and multiplying it by the heat rate of a baseload plant (*j*) and then dividing this by the number of Btu in a pound of coal (*i*). In the case of Montana, the cost of coal is about $10 a ton or about 0.5¢ per pound. There are about 8,500 Btu in a pound of Montana coal, and the baseload plants have heat rates of slightly less than 11,000 Btu per kilowatt-hour. The fuel cost comes to about three-quarters of a penny. To this is added the baseload variable cost of operation and maintenance (*k*), which comes to about 0.25¢ per kilowatt-hour, and the formula is complete.

The result is a long-term energy rate of from 5.1¢ to 5.3¢ per kilowatt-hour depending on the utility. Thus any QF that signs a contract for a minimum of four years will receive this rate for any kilowatt-hour generated during the contract period.

The Montana case illustrates an important rule. *Long-term contracts allow a QF to receive higher prices for energy. However, in the majority of cases, the price is fixed. In return for certainty about future prices, the QF actually receives a price that decreases in real terms because of inflation.* If the QF can negotiate into the contract a clause that allows the buyback rate to rise with inflation, all the better. This is less a concern for those owning hydroelectric wind power facilities or photovoltaic systems because these are financed by fixed-rate loans. Therefore, the monthly payment is fixed and drops in real terms (because of inflation) as does the buyback price. But for cogenerators who are uncertain about future energy price increases, this can present a genuine problem and make a cogenerator less than enthusiastic about a long-term, fixed-rate contract.

There is always an exception to the rule. In this instance it is the rare utility that experiences no significant variations in daily demand over the course of a year. Economics would justify letting a baseload plant carry the top of the load all the time. There would be no substitution of capital for energy. This might be the case, for example, where there are local industries that operate around the clock or where there is no significant difference between summer and winter demand.

For example, the avoided energy costs would probably be quite low for a utility like Colorado-UTE. It relies entirely on coal-fired generation. The utility has "mine-mouth" coal plants; that is, coal is burned right where it is mined, reducing the cost of the coal by 75 percent (transportation is generally most of the cost of coal). Thus, provided the utility is not planning to build any new coal plants, it can realistically offer QFs only about 0.5 cents per kilowatt-hour for their electricity. (For those interested, the weekly publication *Energy User News* has periodic reports that break down coal costs into mine-mouth costs and transportation.)

Avoided Capacity Costs

No component of the buyback rate has been more controversial than that representing *avoided capacity costs*. This represents capital displaced by deferring or canceling future power plant construction. Utilities often argue that capacity credits are inappropriate for dispersed generators. Their arguments fall into three categories.

First, small power producers like wind machines or photovoltaic arrays produce electricity intermittently. Since they cannot realistically be depended upon to be producing at any specific time of the year, they should not be given credit for displacing capacity.

Second, dispersed generator owners do not hold the long-term public interest as a central consideration. They may abandon the plant 5 years down the line. If that is the case, how can it be said that they are displacing the need for a power plant to be built 10 years in the future and operate for an additional 30 to 40 years beyond that?

Third, dispersed generators are by their nature very small. How can a 10-kw hydroelectric plant be said to displace a 500,000-kw coal plant?

The first and third arguments can be answered together. One 10-kw hydro plant cannot displace a coal plant 50 times its size, but 500 hydro or small-scale power plants can. In the second argument the utility is saying that an individual QF is not motivated by a long-term public interest, which may or may not be true on a case-by-case basis, but the argument has the wrong focus. It is the aggregate class, all QFs taken together, that should be looked at. By virtue of its being a dispersed, growing entity, an aggregate class does in fact have a long-term interest. In its rules, the FERC indicated that rates for purchases shall take into account "the individual and aggregate value of energy and capacity from QFs on the electric utility's system."[11]

In the preamble to its final rules, the FERC notes that "an effective amount of capacity may be provided by dispersed small systems, even in the case where delivery of energy from any particular facility is stochastic."[12] Stochastic means probabilistic. One might not be able to predict how much electricity will come from a specific QF, but one can predict how much electricity will come from a statistical sample of QFs. Thus the wind might be said to be too unreliable to be able to displace any capacity. But many wind turbines located throughout the utility's service area will intercept a minimum amount of wind, and if there are many wind turbines, then the class of wind machines can be said to have a minimum capacity factor. The FERC also notes that "testimony at the Commission's public hearings indicated that effective amounts of firm capacity exist for dispersed wind systems, even though each machine, considered separately, could not provide capacity value. The aggregate capacity value of such facilities must be considered in the calculation of rates for purchases, and the payment distributed to the class providing the capacity."[13]

Measuring precisely the aggregate capacity value of a class of small generators requires that such a class already exists and can be monitored. Obviously, were such a class in existence, PURPA Sections 201 and 210 would be superfluous. Thus, in response to the utility argument that capacity payments be waived until such time as the class exists and proves itself, the FERC orders utilities to estimate the capacity value of technologies under different penetration scenarios. For example, if there were 50,000 10-kw wind machines operating over several hundred square miles, how much of that capacity could be considered firm? Today only an educated guess can be made. One report by Westinghouse concluded that multiple wind turbines should be credited with a 35 percent capacity value. If that figure were accepted and the utility were paying full capacity credits to a facility with a 70 percent capacity factor and the utility commission required partial payments, the wind turbine would qualify for 50 percent of the capacity credit. In five years there should be sufficient operating data to make a much more reliable estimate.

Different technologies have different operating characteristics and, therefore, a different likelihood of receiving capacity payments. Clearly, cogenerators have the best chance. They operate most like a utility power plant. Their forced outage rate is often lower than that of most utility plants. The greater the number, the more reliable they become on a class basis. Indeed, one could argue that, given their greater reliability, cogenerators should be receiving more than a 100 percent capacity credit, which will be discussed shortly.

Outages and breakdowns at one cogeneration plant are not linked in time or associated with a higher incidence of breakdowns at other cogeneration plants. This is not the case with small-scale solar-electric technologies. These technologies have a *correlated output*. All hydro plants operating off the same river and most in the same geographic vicinity will have similar seasonal variations in output due to variations in the river's flow. But these hydro plants will have a minimum firm capacity. If their maximum flow rates coincide with their utilities' maximum demand for power, they can actually be said to displace a higher amount of capacity than if they had a stable year-round output at a lower level.

The output from photovoltaics is clearly intermittent and weather dependent. But here the timing of that output can have substantial benefits. Solar energy is available only during the day; it is less available and less intense during the winter. Yet its availability coincides well with most utilities' peak and intermediate loads. The peak solar radiation in summer coincides with most American utilities' peak air-conditioning loads. Moreover, the output characteristics of solar cells can be shaped by varying the orientation of the arrays. Maximum generation occurs when a solar collector of any kind is at solar noon (between noon and 2 P.M.), but peak generation can be shifted in time at the expense of a reduced maximum overall daily output. The capacity value of solar electric generation can thus be increased to coordinate output to match the system load curve of a utility whose annual peak load occurs at 4 P.M., typical of a summer peaking system.

If the utility is paying a much higher price for peak power than for nonpeak power, or if it pays a good capacity credit for on-peak generation of electricity, it may be worth it for the photovoltaic owner to slope the panels more toward the west or somewhat higher than would be the case if he or she wanted to maximize annual production.

Wind speeds vary across the utility's service area. Some wind machines are likely to be producing power at any given time. However, wind power is not as closely coincident to utility demand peaks as are photovoltaics. Wind machines may generate more electricity in the afternoon in the spring and autumn months.

Collectively, even the most intermittent sources of electricity should qualify for some capacity credit. The California Public Utility Commission staff concluded that even "the nonfirm, surplus-only, short-term contracts with PG&E, providing for what may have appeared to be undependable supply without long-term commitment, have proven to have capacity value."[14] They recommended that small power producers receive a credit based on a 50 percent capacity value until experience justifies some other figure. The full commission overruled the recommendation and awarded intermittent producers 100 percent of the capacity credit firm producers would receive.

Utilities argue that capacity is actually displaced only if the QF meets certain minimum performance criteria. They tend to offer long-term contracts that contain minimum performance criteria. QFs must operate at 70 to 85 percent capacity factors either year-round or during the peak and intermediate-peak periods. Some utilities tried initially to impose a 100 percent capacity factor on QFs, until the commissions pointed out that their own plants rarely operate at better than 80 to 85 percent capacity factors. Often a commission will impose *availability* rather than capacity factor requirements, that is, require that the QF's plant be available for generation for a certain portion of the year or during peak periods. Most utilities do not offer partial payments for QFs that meet partial performance criteria. Some do. Most states give no bonus to a QF that operates more reliably than the utility. Montana is one exception. If the QF exceeds the standard capacity factor needed to gain capacity credits, it will receive a greater capacity payment.

Several states allow utilities to require a "dispatchability" test as part of the performance requirements for capacity credits. New Hampshire's utilities use the same dispatchability requirements as the New England Power Pool (NEPOOL) uses for its members. The QF capacity must be available on two hours notice during the November-through-February peaking period. Thus hydro sites are evaluated to test for minimum flow rates during this period. This is the basis for their capacity credits. New Jersey bases its dispatchability requirements on the Pennsylvania-New Jersey-Maryland (PJM) power pool requirements. PJM also requires its members to meet a two-hour advance notice dispatchability requirement, but, unlike NEPOOL, the PJM requirement must be met at any time during the year. Capacity credits for wind or photovoltaics will be extremely difficult or even impossible to receive under such performance criteria.

Although common, these terms probably undermine the intent of the FERC's requirement that the QF be treated as a class. As Colorado

Hearing Examiner Michael R. Homyak said, "The reliability adjustment calculations will be based upon the characteristics of the aggregate class of the small power producers in question, as it is then constituted, and not upon an individual qualifying facility."[15] The need for minimum performance criteria for individual plants will not be onerous for cogenerators. They have extremely reliable plants over which they have direct control. But it will prove debilitating to small solar electric facilities.

Often utilities try to impose severe penalties on the QF that does not achieve the expected capacity credits. They justify these because actually to displace future capacity, they must include QF capacity in their ten-year resource plan. If, five years down the road, the QF decides to go out of business, the utility will have inadequate capacity. Montana-Dakota Utilities, for example, proposed in August 1981 to pay capacity credits in any month where the QF delivers with at least 65 percent on-peak capacity factor. If the QF fails to meet this criterion, then no capacity payment is made at all and it receives only a nonfirm energy payment. If the QF terminates its service, the "Firm Energy Service" severance penalty payment due the company would be calculated as the average capacity compensation per month for QF power times the remaining months in the unexpired contract. Thus if the QF were on a ten-year contract and earned $100 per month for the first two years and then went out of business, it would have to pay a penalty of $9,600 to the utility! The Montana Public Service Commission disallowed the proposed tariff.

Utilities argue that to gain capacity credits, QFs must displace future generating capacity, and to accomplish this the QF must stay in operation at least as long as the conventional power plant. A QF that stops operations after 5 years cannot be said to displace a coal plant that operates for 30 years. The North Carolina Public Utility Commission explicitly rejected this argument. It noted that PURPA is intended to create a class of dispersed generators. Some QFs will undoubtedly cease operations, but others will enter the market to replace them. Given the ease of entry into this market, if the contractual terms encourage small power producers, utilities should be able to count on continued generation and, therefore, displaced capacity, even if an original producer goes out of business.

Remember, the utility's own power plants do not have 100 percent capacity factors. Nuclear plants operate nearer to 65 percent, and even large coal plants have an effective load-carrying capacity of only 70 to 75 percent of their nameplate rating. Even if we were to use the availability factor rather than the capacity factor, a coal-fired baseload plant does not have higher than an 85 percent factor. The availability factor tells the amount of time the plant is not operating through no conscious design, reflecting the random nature of forced outages. The 85 percent availability factor means 15 percent of the time, or almost five days a month, the plant will not be available to generate electricity even if it is needed for an emergency or to meet a system's peak. The capacity factor is an indicator of the amount of time the plant is actually used, not the amount of time it is available for use. Florida requires capacity credits only to QFs that provide 70 percent "equivalent availability." Montana uses both an 85 percent availability factor and a 70 percent capacity factor in determining its long-term energy and long-term capacity payments.

Small power producers actually displace *more* capacity than their nameplate ratings would indicate. In the language of the grid system, they are located "downstream." Those QFs with capacities under 200 kw will almost certainly be located at the distribution secondary. Thus they avoid transmission and distribution line energy losses. Several utilities have argued before public service commissions that they do not know their exact line losses. Preliminary data indicate that they are usually between 7 and 10 percent. Montana's regulatory commission used 8.3 percent as a first approximation in mid-1982. When questioned by several utilities to justify that figure, the commission conceded it had only preliminary data, but noted that their data provided some evidence of line losses approaching 30 percent in some parts of the state. In its final ruling, the commission requested all state utilities to develop a strong data base for a better estimate of line losses.

Taking line losses into account allows a QF to displace a load greater than its own generating capacity. Thus a 100-kw QF in Montana operating in the distribution secondary would displace, not 100 kw but 109 kw of central plant capacity. In other words, in the absence of the QF, the utility would have to install 109 kw of capacity in a central facility to deliver, after the 8.3 percent line loss, 100 kw at the load.

The line-loss factor is a two-edged sword, however, as it may work against some QFs. Those located in remote sites might have a line-loss percentage assessed against them if they are displacing a peak power facility located nearer the utility's load centers. Wind or hydro facilities might be in this category.

One final point on capacity credits. Many dispersed small power plants can displace more than an equivalent nameplate capacity of central power plants, even though they individually operate at the same capacity factors. As a class, the small power plants will have a greater reliability than the handful of large power plants. In addition, the presence of many dispersed plants can allow the utility to lower the reserve margin it needs. One large plant requires another equally large plant in reserve. Many smaller plants require a lower reserve margin. This increased reliability and decreased need for excess capacity should be taken into account in calculating capacity credits for QFs. This will only be done if they are viewed in the aggregate, as a uniform class, as the FERC's regulations require.

As Available Capacity Credits

Utilities award capacity credits in two ways. One is to require a long-term contract. In this the QF agrees to meet certain performance criteria and to supply a certain minimum amount of capacity. The QF makes the initial decision on how much capacity to commit and also selects the term of the contract. The longer the contract, the greater the capacity credit. Usually the utility estimates the cost of the future power plant and gives the QF a larger and larger portion of the actual kilowatt capital cost as the term of the contract approaches the life of the conventional power plant. Often the terms are linear. Thus, a contract for 5 years will get only one-sixth of the capacity credit paid to a QF willing to sign a 30-year contract.

The second method of disbursing capacity payments is on an as available basis. This method assumes that as a group, QFs will displace a certain amount of capacity. Thus, they should receive a portion of the long-term capacity credit so long as they generate electricity during peak or possibly intermediate-peak hours. The QF is required to meet no performance criteria. The capacity cost in dollars per kilowatt is translated into cents per kilowatt-hour and paid on that basis. As of mid-1982, as available capacity credits have been used in California, North Carolina, Montana, New York, Idaho and Colorado.

Sometimes as available capacity credits are paid only for electricity delivered during peak hours, as in North Carolina. Sometimes, as in New Hampshire, the capacity credits are available on a kilowatt-hour basis at all times. (This case is illustrative of the need for investigating differences in some detail. North Carolina pays, on the average, a penny a kilowatt-hour for electric capacity but only during the peak hours of its peak and off-peak months. New Hampshire pays on average only a half a penny but pays this for all hours of the year. Thus, if North Carolina's peak hours represent 50 percent of the total hours in a year, the capacity credits are identical, depending on the technology's capability of generating on-peak.

Avoided capacity costs are based on the cost of new capacity. The estimation of capacity costs is an arithmetic exercise fraught with controversy. Most states base capacity payments on the annual avoided cost of deferring the addition of a new combined cycle generating unit. To estimate capacity credits, they need to estimate the cost of a new generating unit. One would think this a simple task. They are not, after all, projecting future costs. Power plant list prices are available from manufacturers. But sometimes such a simple task generates varied answers. In 1982 San Diego Gas and Electric estimated a combustion turbine cost of $618 per kilowatt. Pacific Gas and Electric said it cost $777. Southern California Edison estimated $415. The California Public Utility Commission staff bemusedly commented, "We believe that a more consistent value of CT (combustion turbine) cost is called for and request all three utilities to reassess their determination of CT costs and report the results of this reassessment in these proceedings in sufficient detail to allow for comparison between utilities. Reassessment should be based on the value of a generic gas turbine."[16]

The proper value for the capital costs of a combustion turbine in 1982 is probably $350 per kilowatt. For a combined cycle power plant (one that takes the waste steam and uses it to generate more electricity, thereby increasing the efficiency of the plant) it is $650 per kilowatt. A nuclear plant will cost about $3,000 per kilowatt in 1982 dollars and a coal plant will cost $1,800 per kilowatt. The primary difficulty in estimating the costs of these plants is that their planning and construction takes place over several years. Therefore, the time value of money must be taken into account, and the inflation rate for future construction must also be included in the formula. For example, based on the last decade's costs of nuclear power plants, it can be safely predicted that those constructed in the 1980s and 1990s will have cost overruns that exceed the cost of inflation. Therefore, after excluding the impact of inflation, these plants will still cost more (in constant, uninflated dollars) than those being built today. Sometimes utilities underestimate the cost of new plants by not inflating the value of dollars spent on previous years of planning and engineering studies to equate with current dollars. Montana found this to be the case. Its utilities were underestimating the cost of a new baseload plant in this way. They were ignoring the time value of money. A dollar spent in 1973 was worth more than twice a 1983 dollar, assuming an average annual inflation rate of 9 percent. By ignoring the inflation factor, the Montana utilities were underestimating their capacity costs by 20 percent, and therefore underestimating their capacity credits to QFs by 20 percent.

The estimation process is nothing more than a series of guesses. The utility is providing cost data that may or may not be accurate. The New Hampshire Public Service Commission initially investigated the possibility of basing avoided costs on the cost of electricity from the soon-to-be-completed Seabrook Nuclear Power Plant but concluded that the cost estimates were so varied that it could not do so. Final construction costs for nuclear power plants have typically run 100 to 1,000 percent over their initial projections.

Once the flow of future construction investments is developed, the future dollars must be discounted back to their present value. The higher the discount rate (interest, or the cost of future money), the lower the present value of these future dollars and, therefore, the lower the capacity credit. Finally, it must be decided how often these plants will operate (capacity factor) to develop a cost per kilowatt-hour.

For example, New York State in 1982 concluded that Nine Mile Point 2, a 1,080-Mw nuclear power plant, would come on-line in 1986. The cost in 1981 dollars was estimated to be $2.3 billion. Assuming an annual fixed-charge rate of 17 percent to estimate the annual capital costs of the plant and an 80 percent capacity factor, the as available capacity credit for capital alone should be 5.15¢ in 1981 dollars, or almost 6¢ per kilowatt-hour in 1982 dollars. To get this figure, multiply $2.3 billion by the annual fixed charge rate to give the annual cost for the plant of $390 million. The 1,080-Mw plant operates 80 percent of the time, so it produces 7.57 billion kwh annually. Divide the amount of electricity generated into the annual cost of the plant. To this figure, slightly more than a penny in fuel and operating costs would be added. However, nuclear plants historically operate at 55 to 60 percent capacity factors, not 80 percent. Assuming this lower reliability, the capital-related cost would be almost 8¢ per kilowatt-hour in 1982 dollars.

This example illustrates one reason QFs should analyze in some detail the utility's assumptions. For much of the avoided cost data is assumptions. The utility assumes its cost of capital, future inflation rates, future cost of money, the availability and capacity factors of its plants as well as its future demand for electricity. Each of these assumptions must be examined carefully even if they are in the fine print in the appendices of most utility data offerings.

Case Study: Duke Power Company

Capacity credits are sometimes called *demand credits*. They are given for each kilowatt of demand replaced by the QF. Often they are only paid for power generated during the peak periods of the year, requiring a demand meter. Duke Power Company, for example, requires demand metering for customers operating under its Parallel Generation schedule PG. The service is available only to three-phase commercial customers. Peak periods are 7 A.M. to 11 P.M. Monday through Friday. Demand credits are based on the maximum integrated

30-minute demand, which is continuously supplied to the utility during the on-peak periods of June through September and December through March.

A customer desiring demand credits must enter into a contract for a minimum original term of five years. The utility may require a longer original contract term if circumstances indicate this. Thirty months notice of termination in writing is required. Penalties for early termination apply but are not spelled out in the rate schedule. The QF receives $5.12 per month for each kilowatt of capacity if connected to the transmission system and $5.29 per month for each kilowatt of capacity if connected to the distribution system. The annual payment of $60.00 for capacity indicates that a combustion peaking plant ("peaker") was used as the basis for the avoided capacity cost.

Duke Power Company has another tariff for residential as well as commercial customers. It provides for as available capacity credits. The credits vary slightly depending on the contract period. A variable rate contract is offered for a minimum of 5 years, and fixed-rate contracts are offered for 5, 10 and 15 years. Duke Power recognizes it has a secondary peak in the winter, so it provides capacity credits for peak hours during the on-peak months of 1.11¢ per kilowatt-hour and for peak hours during the off-peak months at a lower rate of 0.66¢ per kilowatt-hour. The variable-rate customer will have the rate changed as the fuel charge applicable to retail service is changed. The fixed-rate customer receives no change in the capacity credit.

For this rate class Duke Power also offers an energy credit. The payment varies significantly based on the length of the contract. A QF owner who contracts for the 5-year variable rate receives 2.399¢ per kilowatt-hour for all energy generated on-peak, which is from 7 A.M. to 11 P.M. Monday through Friday, all year. A 5-year fixed contract provides a 2.87¢ per kilowatt-hour payment, and this rises to 5.02¢ per kilowatt-hour for a fixed 15-year contract. The off-peak rate varies from 1.81¢ per kilowatt-hour for a variable-rate, 5-year contract to 3.78¢ for a fixed-rate, 15-year contract.

Case Study: Pacific Gas and Electric

PG&E uses a combined cycle generating plant to determine its cost of capacity. The capacity payment increases with the length of the contract. Table 3–4 presents the annual avoided-capacity costs from plant deferral over 20 years.

Payments are calculated from the schedule of avoided costs as follows: The annual avoided capacity cost for each year of a contract is discounted to its present value. Then the resulting present values are

TABLE 3–4
Annual Avoided Capacity Costs to PG&E of Deferring a Combined Cycle Unit Over 20 Years

YEAR	ANNUAL COST ($/KW/YR)
1980	49.69
1981	53.42
1982	57.42
1983	60.29
1984	63.31
1985	66.47
1986	69.80
1987	73.29
1988	76.95
1989	80.80
1990	84.84
1991	89.08
1992	89.08
1993	98.21
1994	103.12
1995	108.28
1996	113.69
1997	119.38
1998	125.35
1999	131.61

SOURCE: PG&E, *Derivation of PG&E's Full Avoided Costs,* table B, p. 6.

summed and *levelized* (expressed in terms of first-year dollars). The applicable discount rate is 11 percent. For example, consider a five-year contract beginning in 1980. Each of the first five values of table 3–4 is discounted to the 1979 present value (see table 3–5). The present values are summed and then multiplied by the appropriate factor to obtain a levelized payment per kilowatt per year. The result is an annual payment of $56 per kilowatt per year. Note: Discount rates and inflation rates are different. The inflation rate gives one a measure of the rate at which future purchasing power falls. The discount rate is also called the *opportunity cost of money*. It represents the return one might have received from an alternative investment. A great deal of important information can be buried in the footnotes to methodologies. Given that most capacity payments and even firm energy payments are

TABLE 3–5

Calculating Payments from Avoided Capacity Costs

YEAR	AVOIDED COST ($)	×	PRESENT WORTH FACTOR (YR)	=	PRESENT WORTH ($)
1980	49.69		0.9009 (1)		44.77
1981	53.42		0.8116 (2)		43.35
1982	57.42		0.7312 (3)		41.98
1983	60.29		0.6587 (4)		39.71
1984	63.31		0.5935 (5)		37.57

Total present worth = \$207.38

Present worth factor (11%, 5 yrs) = <u>0.27057</u>

Levelized capacity payment = (207.38) (0.27057)

= 56.11, rounded to 56¢/kw/yr

Annual Payments in Dollars per Kilowatt per Year

CONTRACT TERM (YRS)	YEAR OF INITIAL OPERATION 1980	1981	1982	1983	1984	1985
1				60	63	66
2			59	62	65	68
3		57	60	63	66	70
4	55	58	61	65	68	71
5	56	60	63	66	69	73
6	57	61	64	67	71	74
7	59	62	65	69	72	76
8	60	63	67	70	74	77
9	61	65	68	71	75	79
10	62	66	69	73	76	80
15	68	72	75	79	83	87
20	73	77	81	85	89	93
30	81	85	89	94	98	103

SOURCE: PG&E, *Power Sales Agreement*, table 1, p. C-5, 4 February 1980.

based on the costs of plants to be built far into the future, the assumed discount and inflation rates can make a very significant difference in the amount of money paid the QF.

Consider, for example, that the inflation rate was 15 percent a year in 1979 and 5 percent in 1982. Assume the QF is bargaining in 1983 and the local utility is building a plant that it estimates will cost $2 billion in 1990 dollars. If the 1990 dollar figure is discounted back to 1983 based on the 1979 inflation rate, it becomes $750 million in 1983 dollars. Based on the 1982 inflation rate, it is $1.42 billion. The higher the present value, the higher the current avoided cost rate will be.

Capacity payments are made only for contracts extending to or commencing from 1983, presumably the date from whence PG&E can defer capacity additions. The prices are subject to change when the state regulatory commission reviews PG&E's capacity costs in future rate applications.

In its Power Sales Agreement, PG&E stipulates a set of minimum performance requirements that must be satisfied by a QF before it qualifies for a capacity payment. The contract capacity for which capacity payments are made is not to exceed the minimum amount of capacity provided during any of the three peak months on PG&E's system (June, July and August). This simply acknowledges that PG&E needs capacity during its peak months. No matter how much capacity is made available during off-peak months, payment will be made only for the minimum amount provided during the peak season. The second criterion is that the contract capacity must be available for 80 percent of the on-peak hours in the three peak months on PG&E's system. The peak hours are 12:30 P.M. to 6:30 P.M. Monday through Friday except for holidays. PG&E, unfortunately, determines the availability factor on an individual or system-by-system basis, when the factor for the entire class of QFs would presumably be much higher.

PG&E defines availability as a percentage of hours, not as a percentage of contract capacity. In other words, the contract capacity may be a fraction of installed capacity that is actually available for 80 percent of the peak hours. For example, a 500-kw cogenerator might decide to commit 100 kw of capacity to be available for 80 percent of the peaking hours, or the owner of a 12-kw hydropower system might commit to a full 12 kw of availability if the stream site were known to be a reliable one.

The contract also indicates that the QF may have scheduled outages other than during the off-peak months only during its first month of operation, presumably to work out any bugs, or when otherwise permitted by PG&E. Capacity payments continue during the scheduled outage period for an annual limit of 35 days, at a daily rate equal to the daily average payment over the preceding month.

If a QF enters into a contract to sell capacity at a future scheduled operation date and the capacity price is revised upward prior to that date, the higher capacity price supersedes the original one.

TABLE 3–6
PG&E's Notice Requirements for Full or Partial Derating of Contract Capacity

CONTRACT CAPACITY (KW)	LENGTH OF NOTICE (YRS)
Under 25,000	1
25,001 to 50,000	3
50,001 to 100,000	4
Over 100,000	5

PG&E's contract also has penalty provisions. If a QF fails to meet the minimum capacity performance standard, PG&E will suspend capacity payments for a probationary period of up to 14 months. Should the QF demonstrate during that period an ability to meet the minimum obligations, PG&E will make a retroactive capacity payment for the probationary period and reinstate the regular capacity payments at the agreed-upon price. If the QF is unable to meet the minimum requirements during the probationary period, PG&E may either derate (reduce) the contract capacity or terminate capacity payments. Such downward revision in contract capacity will be considered termination without prescribed notice and subjects the QF to certain refund provisions.

PG&E's contract tries to balance the need for the QF to be able to count on future payments with the utility's need to be able to count on a certain future capacity displacement. PG&E requires prior notice in writing for a full or partial derating of contract capacity. Notice has to be given one to five years in advance, depending on the contract capacity. The larger the QF, the longer the prescribed advance notice.

If the QF fails to give advance notice in proportion to its size, it must agree to refund to PG&E the difference between (1) the total capacity payments to date based on the original contract capacity and the current capacity price and (2) the total capacity payments due to the QF over the period of actual previous performance at the adjusted capacity price.

In other words, the QF must pay the difference between what it received under the old contract and the amount it would have collected at the capacity price for as long as it actually performed under the old contract capacity. Interest based on the Bank of America's prime rate is then added. This adjusted capacity price, as PG&E calls it, forms the basis for future capacity payments.

The following example illustrates the result of this capacity derating:

An apartment complex installs a 200-kw, gas-fired cogeneration system to meet its space-heating, air-conditioning and hot water needs. It decides to engage in the simultaneous purchase and sale of electric energy and capacity to PG&E, commencing in 1980. The QF owner(s) enter into a contract capacity for ten years. Five years later, at the end of 1984, the owners notify PG&E that they plan to derate the contract capacity to 100 kw. How much does the QF collect, and how much must be refunded to PG&E?

Original capacity price	\$62/kw/yr
Annual payment, \$62 × 200	\$12,400/yr
Total payment through 1984	\$62,000
Adjusted capacity price, 5 yr, 1980	\$56/kw/yr
Adjusted contract capacity	100 kw
Adjusted annual payment, \$56 × 200 =	\$11,200
Annual overpayment, \$12,400 − \$11,200 =	\$1,200/yr
Total refund due PG&E, 5 × \$1,200 =	\$6,000

Under a complicated formula, the QF that fails to issue prescribed notice must also make a one-time payment to PG&E to cover the excess payments that might have been paid to the QF. For example, a levelized capacity payment might provide for higher payments up front. The utility agrees to this in the expectation of paying lower payments in later years, payments lower than the current capacity credits. If the QF terminates the agreement early, PG&E recaptures the early overpayments.

For example, suppose the same gas cogeneration apartment complex gave 1 month's notice (instead of the prescribed 12) that it wanted to reduce its committed capacity from 200 kw to 100 kw. The one-time penalty payment would be calculated as follows:

Capacity price beginning in 1985 for remaining 5-yr contract	\$73/kw/yr
Original contract price	\$56/kw/yr
Difference	\$17/kw/yr
Times contract capacity, \$17 × 200	\$3,400
Prorating factor, $1 - \frac{1}{12} = \frac{11}{12}$	0.9167
Total additional payment, \$3,400 × 0.9167	\$3,116

PG&E offers the QF three capacity credit options. The QF can choose to receive equal monthly payments. In this case the contracted capacity is multiplied by the contracted price and then divided by 12. The second option is to base the payment on the monthly delivered capacity, which means the payment would fluctuate. Or third, the payment can be made on a cents-per-kilowatt-hour basis for each time-differentiated kilowatt-hour. Thus PG&E offers an as available capacity credit but varies it by the time of day (peak or off-peak value).

Case Study: Montana

Montana has a long-term capacity credit (LTC). The formula for the LTC is simpler than the one for long-term energy (LTE), since the cost of one type of plant need not be subtracted from that of another. The LTC equals $[(b)(d) + f] \times (CF \div 0.85)$. The first part of the equation, $[(b)(d) + f]$, estimates the annual carrying charges of a combustion turbine. *CF* stands for capacity factor. This is divided by the availability factor of a combustion turbine. It assumes the turbine will be available for service 85 percent of the time. Its random outage rate, or forced outage rate (FOR), is 15 percent. If the QF has a capacity factor of 0.85, then the final equation will be equal to 1. If it has a lower capacity factor than 0.85, the amount of the long-term credit will go down. If it has a higher capacity factor than 0.85, the amount paid will increase. In 1982 the three Montana utilities paid $63.96 to $80.88 per kilowatt per year to QFs signing a minimum four-year contract to deliver capacity.

A QF in Montana willing to sign a minimum four-year contract will thus receive both a long-term energy and long-term capacity payment. The 100-kw, gas-fired cogenerator that operates 85 percent of the time will generate 744,600 kwh per year. It will receive about $38,000 in long-term energy payments and about $6,000 in long-term capacity payments. The 30-kw hydroelectric facility that operates 85 percent of the time will generate 223,380 kwh per year. It will receive $11,400 in long-term energy payments and $1,800 in long-term capacity payments.

This illustrates an important point. Capacity credits do not constitute a very significant portion of the total payments to the QF. However, as will be seen when the economics of small-scale power production are explored, the capacity credits can play a crucial role in changing a deficit into a surplus. They can make the difference between an investment being and not being profitable.

Estimating Base Rate for Firm Energy and Capacity

The following is the formula used by Oregon's Public Service Commission to estimate the base rate for firm energy and capacity. Notice that the associated costs of transmission and operation come to more than $16 million dollars, more than 25 percent of the annual carrying charge for constructing the plant. A 35-year contract gives the QF 100 percent of the firm energy price or firm capacity price. A 5-year contract would give the QF only one-seventh (14 percent) of that price. One could argue that the Oregon formula is quite conservative. It requires an extremely long-term contract before the QF can gain full capacity credits. Moreover, it uses as the cost of a new power plant the Boardman facility, which was already operational in 1982, rather than the cost of the next plant to come on-line.

Computation of Boardman-Based Rates

A = Levelized annual revenue requirement	$62,265,000
B = Coal inventory carrying cost	1,703,000
C = Oil inventory carrying cost	93,000
D = Materials and supplies inventory carrying cost	585,000
E = Operations expense	6,294,000
F = Maintenance expense	5,189,000
G = Transmission expense ($5.56/kw × 424 Mw)	$2,357,440
H = Fuel cost (22.42 mills/kwh)	
n = Number of years in the contract	Varies at the option of the qualifying facility

Firm energy price (mills/kwh) =
$$0.8577\ \frac{(B+C+D+E+F+G)}{424 \times 8{,}760 \times 0.75} + H + \frac{n}{35} \times \frac{A}{424 \times 8{,}760 \times 0.75}$$

This formula reduces to 24.22 + n × 0.5477

Capacity price ($/kw/mo) =
$$0.1423\ \frac{(B+C+D+E+F+G)}{424 \times 8{,}760 \times 0.75} + H + \frac{n}{35} \times \frac{A}{424 \times 8{,}760 \times 0.75} \times \frac{8760 \times 0.75}{12 \times 1000}$$

This formula reduces to $2.20 + n × 0.04975

SOURCE: Before the Public Utilities Commissioner, order no. 82–515, 20 July 1982.
NOTES: 0.8577 = Long-run incremental cost-based allocation of total cost to energy
0.1423 = Long-run incremental cost-based allocation of total cost to capacity

TABLE 3–7

NUMBER OF YEARS IN CONTRACT	CAPACITY PAYMENT ($/KW/MO)	FIRM ENERGY PAYMENT (MILLS/KWH)
1	2.25	24.77
2	2.30	25.32
3	2.35	25.87
4	2.40	26.41
5	2.45	26.96
6	2.50	27.51
7	2.55	28.06
8	2.60	28.60
9	2.65	29.15
10	2.70	29.70
11	2.75	30.24
12	2.80	30.79
13	2.85	31.34
14	2.90	31.89
15	2.95	32.44
16	2.99	32.99
17	3.04	33.54
18	3.10	34.08
19	3.14	34.63
20	3.20	35.17
21	3.25	35.72
22	3.30	36.27
23	3.35	36.82
24	3.39	37.37
25	3.44	37.92
26	3.49	38.46
27	3.54	39.01
28	3.59	39.56
29	3.64	40.11
30	3.70	40.65
31	3.74	41.20
32	3.79	41.75
33	3.84	42.29
34	3.89	42.84
35*	3.94	43.39

NOTE: Nonfirm energy is 22.42 mills/kwh. Base standard rate for facilities of 100 kw or less is 35.90 mills/kwh.

* If a qualifying facility enters into a 35-year contract for firm energy and capacity and operates at a 75 percent capacity factor (identical to the design capacity factor of the Boardman plant), the energy and capacity payments combined would equal 50.59 mills/kwh.

The Monopsonist Meets the Monopolist

PURPA creates an internal inconsistency within utilities. On the one hand, the utility is a monopolist who controls all electric sales within its service area. As with any monopoly, its goal is to maximize profits. A by-product of this goal is the tendency to increase rates. On the other hand, PURPA makes the utility the sole buyer of electricity. The monopsonist also tries to maximize profits, but in this case it means minimizing the price it has to pay for power.

The monopolist and the monopsonist should be operating with identical data. Both should be using construction and operating data on current and future power plants. Unfortunately, public service commissions have not yet demanded that both divisions of the utility make their cases at the same proceeding. Therefore, in one hearing the monopolist argues for high rates based on high costs. At another hearing, the monopsonist argues for low buyback rates based on low avoided costs.

For example, utilities treat a consumer of electricity differently from a producer of electricity. The utility does not treat equally a customer's demand for a kilowatt of power and the delivery of a kilowatt of power by the same customer. Utilities will deny avoided capacity payments to power-producing customers on the theory that the utility already had excess capacity, yet will turn around and impose demand charges on these same customers (as power consumers). In 1982 the Niagara Mohawk Power Company proposed to ignore completely the distribution cost savings in its response to a New York Public Service Commission order, but it also advocated a distribution demand charge of between 33¢ and 71¢ per kilowatt whenever the QF's service classification contract demand is exceeded. As Occidental Chemical Corporation (which wanted to sell power to Niagara) argued before the Public Service Commission, "Niagara Mohawk has proposed distribution-related charges for increased demand while not providing a credit for distribution capacity savings resulting from cogeneration. This is not justified if one is pursuing an avoided cost-based pricing system." [17]

The commission pointed out that this decentralized power generation is equivalent to not taking power during peak periods. Therefore it concluded "it would be inconsistent to charge back-up and supplementary customers, in particular, for transmission costs when they take service—as Con Edison proposes—but not credit those costs to them when they supply power." [18] The commission in that case concluded "the peak period delivery of power by on-site generators, in and of itself, can enable a utility to avoid transmission capacity costs." [19]

In the above example, Occidental Chemical Corporation argued for a higher avoided cost basis by relying heavily on testimony given by a utility representative in a different rate case. The arguments of the monopolist were given to undermine the arguments of the monopsonist. Based on the data from this other rate case, Occidental recommended avoided capacity costs for cogenerators during peak hours (representing 3,700 hours a year) or 2.35¢ to 4.31¢ per kilowatt-hour. This was four to seven times larger than the avoided capacity credit proposed by Niagara Mohawk in that case.

The war of the numbers continues. Owners of QFs would do well to read transcripts from recent rate cases to gather utility-generated data that could support high buyback rates.

Excess Capacity

The issue of excess capacity is already becoming a central one. Having grossly overestimated future demand, utilities persuaded regulatory commissions to allow them to build several dozen unnecessary plants. Given the 10- to 12-year lead time for large central plants, a decision to build in 1972 when demand was projected to continue to grow at 7 percent a year, doubling every 10 years, would lead to a plant generating electricity beginning in 1984, when demand growth dropped to 1 to 2 percent, or less, a doubling time of 35 to 75 years. Moreover, the economic decline in 1980 to 1983 reduced industrial demand even further. Thus utilities that in the 1970s argued for new plants to meet the needs of the 1980s now argue they need no new electricity for the '80s. But they still envision new plants in the '90s. QFs can legitimately respond that they are indeed displacing new capacity even though that new capacity may not come on-line for more than a decade.

Many utilities argue that they have, or soon will have, a substantial amount of excess capacity. Therefore they argue that they don't need additional QF capacity, at least for several years. The QF should resist that argument. It is a sound one only if these utilities are not planning to build any additional capacity that could be displaced by QFs. That includes any capacity to replace plants to be retired in the near future. Thus, for example, the Potomac Edison Electric Power Company (PEPCO), located in the Washington, D.C. area, argued before local regulatory commissions that it should pay no capacity credit because it has an excess capacity and has no plans to build additional power plants within its ten-year planning horizon. The commissions agreed not to require any capacity credit.

However, during the hearings PEPCO conceded that it was planning to construct a new power plant 11 years hence. By delaying the construction plans by 1 year, it put them outside its 10-year traditional planning horizon, which allowed it to argue that it could displace no future capacity. Understandably, potential QFs were furious. Vigorously, but unsuccessfully, they argued that many utilities could manipulate their resource plans and end up with no capacity payments in exactly the same manner. One way for QFs to respond to these allegations by their utilities is to persuade the city council, rural electric board or state regulatory commission to require the utility to integrate QFs into its 10-year resource planning. PEPCO, for example, estimated no significant QF generation within 10 years. Clearly that was the basis for its plan to construct additional generation capacity in 11 years. However, some commissions, such as in California, have established minimum goals of QF generation capacity that a utility must achieve by a predetermined time period.

The issue of excess capacity is becoming a central one as increasing numbers of utilities defer or cancel new power plants in the light of their overbuilding sprees of the 1970s and declining demand. Ironically, those environmentalists who fought against new power plants are being proven correct. But those plants that were built now represent an excess capacity that is used against small power producers.

However, the QF should remember that if a plant is planned in 1992 or even 1995, it has a value in current dollars. At a real discount rate of 3 percent, capacity worth $50 per kilowatt year in 1995 is still worth $37 per kilowatt year in 1985. The further one delays power plant construction, the lower the capacity credits.

Some public utility commissions not only require utilities to buy independently produced power but to promote it as well. California's public utility commission reduced the return that Pacific Gas and Electric could receive on its investments as a penalty for its lack of effective promotion of cogeneration. California has established quantitative goals for each utility. The commission expects the utility to encourage a specific minimum amount of independent power production before it comes up for another rate increase.

The New Jersey Board of Public Utilities overruled its staff's arguments that QF capacity had zero value because the regional power pool, PJM, had excess capacity. The staff had concluded that a future coal plant would displace oil and therefore no other capacity was necessary. The board found several problems with the staff analysis. First, it was based on quite a few assumptions about costs and inflation rates for the distant future. Second, the only reason a coal plant could be said to displace the need for capacity was because the New Jersey utilities had let themselves become dependent on oil-fired baseload plants. The board noted that "the value of zero for avoided capacity results from the suboptimal fuel mix of the New Jersey utilities. That is, the utilities are presently overly reliant on oil-fired capacity. This, however, will not always be the case. In addition, we are of the opinion that there is intrinsic value to smaller, decentralized cogeneration and small power production facilities." It went on to say that "while the board will not comment on the causes for the present suboptimal fuel mix, we do not want to penalize the development of cogeneration and small power production because of this condition." The board set capacity payments based on the cost of capacity when the electric utility is at an optimal fuel mix. "This results in a capacity value equal to that of a combustion turbine peaking plant."[20]

Given the mistakes in forecasting that most utilities made in the 1970s, the issue of excess capacity will be an increasingly important one in the mid-1980s. The issue has added importance (as well as added complexity) given interstate pooling arrangements. For example, in November 1980, Arkansas Power and Light (AP&L) and the other companies in the Middle South Utilities System entered into a Memorandum of Understanding whereby they would not count cogenerated electricity as capacity on the theory that to do so would jeopardize the massive Middle South construction program. Middle South plans capacity expansion on a systemwide basis. Through a procedure of capacity equalization payments among subsidiaries in four states, every subsidiary pays for its share of new plants regardless of where they are built on the system.

The Little Rock law firm of Nixon and Trotter explained the problem this Memorandum of Understanding presented to QFs in testimony before the Arkansas Public Service Commission. "Before November 1980 any source of capacity brought on-line by a given subsidiary could be counted to determine its capacity equalization payments. Not counting cogeneration capacity has allowed AP&L to argue that avoided capacity costs should not flow from the company to qualified cogenerators since it and Middle South have built excess capacity in the form of coal and nuclear plants to back out (reduce) oil generation." They conclude, "Herein lies the ultimate problem. Plants are not built in Arkansas to serve AP&L ratepayers alone; they are built to serve the Middle South system as a whole. Our experience indicates that the Middle South leadership will not back away from its construction program. Consequently few should be surprised at AP&L's cogeneration strategy."[21]

This problem is difficult and formidable. One of the problems is that state commissions have little or no authority over regional power pools. Indeed, in 1983 Middle South Utilities requested permission of the FERC to set its own PURPA rates, bypassing the state commissions. Independent power producers and the regulatory commissions protested against this usurpation of state authority. The FERC had not yet decided the issue as this book went to press, but it raises a delicate issue, and one that will continue to plague the potential power producer. Only if the FERC imposes the same tough guidelines on new capacity for regional power pools as state commissions have recently done for in-state systems can this problem be overcome. Yet the FERC under Reagan has been predisposed to favor utility interests.

The problem is prevalent throughout the nation. Southern California utilities, for example, plan to get future base load from coal-fired plants in Utah, Arizona and New Mexico. California utilities will own only a few peaking plants. Does this mean that when such construction programs are completed, the Utah, Arizona and New Mexico utilities will argue before their commissions that they have excess capacity and therefore should pay no capacity credits?

The relationship of regional power pools and joint ventures to a local utility's avoided costs is already proving crucial to capacity credits. Sometimes utilities use regional power pools in one way during PURPA proceedings and in another way when they are involved in rate cases. For example, in one rate case PEPCO argued that it could not rely on the PJM power pool for power, that it had to build its own power plants to meet future capacity. In the PURPA proceedings, on the other hand, it argued it should pay no capacity credits because PJM was building sufficient capacity to meet all its future needs. The argument is more difficult to unravel when there is a joint venture. Municipal utilities, for example, might own a small share in a coal or nuclear plant scheduled to come on-line in five or ten years. Generation and transmission (G&T) cooperatives sell shares to distribution cooperatives. In these cases the local utility could argue that it signed a letter of intent to buy into future capacity and cannot withdraw that intent even if QFs displace the need for such capacity. Regulatory commissions are taking an increasingly aggressive position with respect to this attitude. They may decide that the decision to buy future capacity was a management mistake based on erroneous load forecasting (QFs can be considered as load displacement the same as energy conservation). Therefore it could ask the utility to sell its share in the power plant. Montana's Public Service Commission has already warned its utilities that the commission's responsibility is to assure cost-effective power to the ratepayers, and if the utilities are recalcitrant in encouraging QFs, they may be viewed as irresponsible and the rate of return on their rate base can be decreased, thereby reducing their profits.

The Montana Public Service Commissioners are directly elected. Each commissioner represents a different part of the state. As a result, the commissioners are more responsive to the popular will, which brings us once again to the importance of politics in PURPA proceedings. Again and again those in favor of independent power production have successfully used politics to strengthen their bargaining position. In Indiana the state legislature overturned a public service commission's pro-utility PURPA decisions. In North Carolina the state legislature set minimum buyback rates. In Oregon the state legislature required the utility commissioner to develop a system that gave the highest possible buyback rate to independent producers despite the very low price for electricity paid by publicly owned systems.

Political pressure means organization. Even in California, where one might expect a sympathetic regulatory commission and state legislature, small power producers concluded in early 1982 that they could protect their interests only if they organized an independent coalition that could continually lobby.

When Utility Purchases Are Not Required

PURPA 210 allows utilities to stop buying energy or capacity from QFs whenever doing so would increase their operating or production costs. To many observers this section of the law is a potential escape hatch. The FERC requires utilities to give advance notice of such times and to prove to the satisfaction of the regulatory commission that its avoided costs are actually negative during that time.

The major problem with this section of the law is that it may actually make QFs vulnerable to the poor planning of utilities. For example, a utility's current avoided energy and capacity costs might be quite high, but it plans to bring a nuclear plant on-line in two or three years. That plant is expensive and also unnecessary because demand has softened to the point that added capacity is no longer needed in the projected time frame. However, once it comes on-line, it may be less expensive to run it than to leave it idle. As previously shown the fuel costs of a nuclear plant are the lowest of any steam electric plant. Nuclear plants must be operated at a certain load. If they dip below a certain load they must be shut down. Once shut down it takes a long time to start them up again. Therefore, the utility can argue that to purchase electricity from QFs when the nuclear plant is operating at partial load could displace sufficient energy to force a shut-down of the nuclear plant. The costs of shut-down and start-up would actually raise the overall operating costs. Therefore the utility need not buy QF energy during this time.

Most regulatory commissions specifically cite such a case as one that would allow utilities to cease purchases from QFs. The problem is that by allowing this, the regulatory commission makes the QF pay for planning errors by the utility that have led to excess capacity.

The best response by QFs is to ally themselves with those vigorously promoting conservation to fight against any expansion of central power plants. In several states, such as Kansas and Pennsylvania, the regulatory commissioners ruled that stockholders had to pay for cost overruns of nuclear plants and capacity that comes on-line but is unneeded. The more the costs of poor planning are imposed on stockholders rather than ratepayers, the greater will be the tendency of the utility to forecast cautiously. The more that happens, the less the QFs will be faced with a fait accompli, that is, an excess capacity due to previous poor projections that leads the utility to reduce its purchases of QF power.

In 1981 PG&E submitted a preliminary Power Sales Agreement to the California Public Utility Commission. The agreement contains the following section entitled "Continuity of Service."

> *PG&E shall not be obligated to accept, and may require Seller to curtail, interrupt or reduce deliveries of energy or energy and capacity (1) whenever PG&E can obtain energy from another source, other than a PG&E fossil-fueled plant, at a cost less than the price paid to Seller, (2) during any period when PG&E can generate or purchase an equivalent replacement amount of electric energy generated from renewable resources . . . or from plants designated for operation to minimize air pollution, or (3) during periods of minimum system operations.*

This contract says that PG&E could refuse all QF purchases whenever actual avoided costs fall below the stated buyback rate. This confuses the FERC directive that says utilities may refuse to accept QF output when such acceptance in itself would raise the overall cost of service to its customers. The FERC's intention was *not* to allow utilities to refuse purchases just because they miscalculated avoided costs prior to QF delivery. The FERC, for example, allows the QF the option of selling energy to the utility on an as available basis, the price for which is to equal the avoided costs at the time of delivery. But it also allows the QF to elect to sell energy on the basis of a contract that estimates future avoided costs. In the latter case, the utility must continue to pay the QF on the basis of the costs estimated when the obligation was made, even if avoided costs actually drop below that level.

Fortunately, PG&E qualifies the above provision with another that says, "PG&E shall take or be prepared to take energy or energy and capacity from Seller for not less than 8,160 hours of each calendar year." Thus PG&E has restricted its authority to invoke the no-purchase clause to about 7 percent of the year.

Most regulatory commissions have recognized that this provision of PURPA could be used as an escape hatch for utilities that are reluctant to buy from QFs. They strongly urge utilities not to do so, and they require utilities to present data to support their contention that negative avoided costs are present during those times. They also require advance notice. Nevertheless, the only guaranteed protection is a provision, as in the PG&E contract, that the no-purchase allowance is permissible for a limited number of hours a year.

All-Requirements Utilities and Wheeling

All-requirements utilities are those that buy all their power from other utilities. They often have what are called "take or pay" contracts, which say they must pay for a certain amount of electricity whether or not they use that amount. Also, they must buy all their electricity from a certain supplier. These utilities may try to use this contract as the basis for refusing to buy power from a QF. The FERC specifically notes however, that these all-requirements utilities have the same obligation to buy as do other utilities. PURPA Section 210 supersedes any existing take-or-pay contract. Thus the local utility must buy QF energy, which then displaces the purchase of energy from its wholesale supplier.

The owner of a QF should keep in mind that the avoided cost to the all-requirements utility is nothing more than its purchase price of electricity and capacity from the bulk supplier. This purchase price is based on embedded or historic costs, rather than marginal costs. Many all-requirements utilities purchase wholesale power for only a couple of cents a kilowatt-hour. Thus, for example, the Clark County, Washington, Public Utility District (PUD) was offering QFs their average system retail rate of 2¢ per kilowatt-hour in late 1981. At the same time Bonneville Power Administration (BPA), the supplier to Clark County, calculated its long-run incremental cost for energy at 6.18¢ per kilowatt-hour and the value of capacity at $55.32 per kilowatt. The advantages of selling to the supplier rather than to the local utility in this case are obvious.

The all-requirements utility has the right, subject to the approval of the QF, to wheel or transmit the QF's electricity to the bulk supplier. The bulk supplier must then purchase capacity and energy as if it were the original buyer. It must pay a price based on its cost of avoided power. Such a price should be much greater than its wholesale price to the all-requirements utility.

Most all-requirements utilities are publicly owned. Thus QFs can organize to influence decisions about wheeling. They can participate before city councils or in rural electric cooperative membership meetings. Or they can lobby the state legislature to direct the utilities to wheel the electricity to better-paying, more remote customers. This last strategy was successfully pursued in Oregon.

The Oregon legislature took an innovative approach to the profound difference between the avoided cost of power to its public utilities, which are largely customers of the BPA, and the avoided cost of power to BPA itself. In 1981 the legislature amended the law to give the Public Utility Commissioner jurisdiction over municipalities, cooperatives and people's utility districts for the purpose of PURPA Sections 201 and 210. The commissioner then ordered all utilities in Oregon to pay a QF its avoided cost of power or a base rate, whichever was higher. The commissioner noted that the base rate's "primary purpose was not to establish a new rate for electricity which was above any utility's avoided cost, but rather to provide an incentive for certain utilities to wheel power voluntarily, rather than pay a rate which exceeded their own avoided cost. Such a device was thought necessary by the Legislature because of a presumed inability of the state to mandate wheeling, in the light of the possibility of federal preemption [because wheeling is considered to be interstate commerce, under federal jurisdiction]."[22] Moreover, the establishment of a base rate would give prospective QFs a better idea of the minimum payment they could receive under the contract.

Oregon's investor-owned utilities had avoided costs of up to 6¢ per kilowatt-hour in 1982 for a long-term contract and 3¢ or more per kilowatt-hour for short-term firm power. The BPA maximum wholesale rate to preference customers at the time was 0.74¢ per kilowatt-hour for energy and $2.80 per kilowatt of billing demand. The Oregon commissioner established a base standard rate for facilities of 100 kw or less by using the lowest standard rate available to facilities interconnected with investor-owned utilities in Oregon. That rate was 3.59¢ per kilowatt-hour, which was adopted as the base standard rate.

For those wanting a variable rate for long-term contracts, the commissioner used as a basis the highest-cost permanent baseload plant serving Oregon consumers. It was an existing coal-fired electric plant owned by Portland General Electric (PGE). He assumed the cost of a publicly-owned plant would be only two-thirds that of the PGE plant due to the lower financing costs of publicly-owned facilities. He then established a table to estimate the base rate for varying contract terms. A 12-year contract at a 75 percent capacity factor would give 3.59¢ per kilowatt-hour, the same as the base standard rate. QFs who signed longer contracts received a higher rate.

The Problem of Falling Avoided Costs

The price of electricity can be expected to rise for the foreseeable future, but this does not necessarily apply to the price QFs will receive for their electricity. Avoided costs could decline for several reasons. California's utilities switched from expensive oil to less expensive natural gas for their peaking and intermediate peak plants in 1982. Their fuel costs dropped, and as a result they dramatically reduced the price they offered to QFs. This is a temporary situation because natural gas deregulation will raise its price to parity with oil by mid-1985. But this did not stop at least one QF from going bankrupt. He had counted on the 7¢ per kilowatt-hour price in 1981 and couldn't repay his investment with the offered 4.5¢ of 1982.

The declining price of oil between 1981 and 1983 reduced buy-back rates around the nation and emphasized the risky nature of small power production. PURPA guarantees the QF a market; but it does not guarantee a profit. The utility company is guaranteed a return on its investment, but the QF is at the mercy of external forces. Anyone entering the field would do well to carefully analyze future trends in electric demand and fuel prices.

A more permanent drop in avoided costs will take place when the top of the load curve is displaced by conservation or QF generation. Say, for example, that the top (peak) of the load curve is carried by 200 Mw of expensive, inefficient, oil-fired power plants. After 200 Mw of peak capacity is introduced by QFs or when 200 Mw of peak capacity is shaved through load leveling or other conservation efforts, this inefficient, high-cost plant will be displaced. As the peaks in the load curve get lower, less expensive plants will carry peak load, and avoided costs will drop.

Some states recognized this problem very early. They wanted to assure the first QFs coming on-line that they would not be penalized later when more QFs came on. That is, those who took the risk of being first should receive the highest return. Those who came five or six years afterward would receive a lower avoided cost rate, which would not be applied to the first QFs. New Hampshire's public service commission actually enacted a "grandfather" clause, which ordered that the purchase price of QF energy never drop below the initially-contracted avoided cost price. If avoided costs rose, the purchase price would also rise. If they dropped, the purchase price would remain at its original level. However, the New Hampshire State Supreme Court overturned this regulation. The court ruled that by enacting such a regulation, the commission was in effect restricting the authority of future commissions. This represented an inappropriate exercise of its own power.

New Jersey's Board of Public Utilities may be more successful in insulating its QFs from potentially declining avoided costs. It ordered utilities to pay an energy rate equal to 110 percent of the projected annual average *running rate* of the PJM. The running rate represents the average hourly cost of the marginal fuel plus variable operation and maintenance costs of dispatching PJM plants to serve an additional kilowatt-hour of demand. In 1982, on an individual hourly basis, this value ranges from a penny a kilowatt-hour for a coal plant to 11¢ a kilowatt-hour for a gas-fired jet turbine. The board selected this measure as the best estimate of electric utilities' avoided energy costs. It believed the estimate to be conservative and also wanted to encourage QF development, so it added the 10 percent premium.

In New Jersey the energy rate is subject to retroactive upward adjustment if the actual rates are higher than the projected rates. No downward adjustment is possible even where the projected avoided energy costs overstate actual costs. In 1980 the actual average running rate was 5.30¢ per kilowatt-hour. Keep in mind that, because of inflation, any long-term fixed-price contracts actually yield a declining real value of the money paid. A nickel ten years in the future will be worth considerably less than today's nickel. On the other hand, a long-term contract protects the QF against a dramatic decline in avoided costs, as occurred in California in the spring of 1982.

Service or Customer Charges to QFs

PURPA requires that QFs be charged no higher rates for back-up service, maintenance power, standby power or interruptible power than customers that have no generating capacity, unless the utility can prove it has a higher cost of serving QFs. Most regulatory commissions put the burden of proof on the utilities to document the increased cost of service.

However, most utilities do impose unique customer charges on QFs. Some are for repaying extra metering costs, and these are appropriate so long as the actual cost of the meter is based on the cost to the utility for bulk purchases and not the cost to the QF for purchasing a single meter. Thus Union Electric in Missouri in late 1981 required a $4-per-month charge for a single-phase energy meter and $6 for a three-phase energy meter. If the customer wanted to be paid for time-differentiated energy (peak and off-peak), the meter cost $13 per month for single-phase and $15 for three-phase.

Some utilities charge stiff customer service fees. Sulphur Springs Valley Electric Cooperative in Arizona, for example, charges $6.50 per month per meter for handling the QF's account. PEPCO charges $11 per month unless the QF's electricity is delivered at 13.2 kilovolt (kv). If it is, the customer charge becomes $80 per month and there is a reduced energy payment. The reduced energy payment is presumably a result of the QF delivering the power to the primary side of the distribution transformer. The QF avoids the line losses inherent in the transformer and thus receives a lower payment because the electricity will probably be consumed on the secondary side of the transformer. Several New York utilities submitted tariffs to the public service commission in mid-1982 that required $100 monthly customer charges for QFs. The QF can complain to the regulatory commission and ask that it request documentation from the utilities to show that serving a QF is so much more costly than serving a regular customer.

Some utilities have tried to charge higher rates to QFs for back-up power. This is conceivable when the QF operates so that it uses power internally and only buys from the utility irregularly. However, even in this case the FERC requires that utilities not assume that such downtimes will be coincident with their system peaks. For QFs that buy all their electricity from the utility and sell all they generate to the utility, discriminatory back-up charges should be easily denied by the regulatory commission.

Wheeling

Wheeling is defined in general terms as the transmission of power to a purchaser on behalf of a generating entity by a third party where the transmission facilities are owned by the third party.

The ability to wheel electricity across the nearest utility's lines to a remote utility opens up larger markets for the QFs power. PURPA allows, but doesn't require, wheeling if the utility and the QF agree to it. The FERC comments, "the commission notes that this transmission can only occur with the consent of the utility to which energy or capacity from the qualifying facility is made available. Thus no utility is forced to wheel."[23] The United States Supreme Court has concluded that the Federal Energy Regulatory Commission cannot order wheeling except when they can prove that the refusal of the utility to wheel electricity is part of a larger restraint of trade under the antitrust doctrine.[24] In the 1930s Congress debated including a "common carrier" provision making it the duty of every public utility to transmit energy for any person upon reasonable request. This is already the case for oil pipelines and railroads. These provisions were eliminated to preserve "the voluntary action of the utilities."[25] The Fifth Circuit Court concluded in 1981 that "the legislative history of the Federal Power Act makes clear that the commission lacks the authority to require electric utilities to provide wheeling even upon a reasonable request."[26]

A state's authority to order wheeling is circumscribed. Federal courts have held that states were preempted under Section 201 of the Federal Power Act from requiring the transmission of electric power and the sale of wholesale electric power in interstate commerce.[27] However, the wheeling issue may become a central one in the PURPA debate. As noted above, the Oregon legislature designed an innovative base rate structure designed to encourage public utilities to wheel electricity to investor-owned utilities or regional suppliers who would have a higher avoided cost rate. Two-thirds of all municipal utilities have no generating capacity. Their avoided costs are therefore based on their contracts with bulk suppliers. If the municipal utility purchases a QF's power, it pays that wholesale cost. The difference between that and the avoided cost to the bulk supplier may be two or even three to one.

New Hampshire's Limited Electrical Energy Producers Act of 1979 requires wheeling. To date it has not been tested. Several New Hampshire utilities have formally expressed their willingness to wheel any QF power to a remote supplier. California's Public Utility Commission noted in a decision in late 1980 that "we agree that wheeling is an important concept that can make a material contribution to cogeneration and small power production in California . . . this commission will view with disfavor any actions or inactions by a utility which will interfere with the signing of a contract between a neighboring utility and a cogenerator or small power producer located in its service territory."[28] Minnesota enacted legislation that requires, for all QFs with capacities less than 30 kw, that the utility "at the QF or the utility's request, provide wheeling or exchange agreements wherever practicable to sell the qualifying facility's output to any other Minnesota utility having generation expansion anticipated or planned for the ensuing ten years."[29]

Little investigation has occurred on appropriate wheeling charges. Testimony from two witnesses before the Board of Public Utilities in New Jersey indicates the differences of opinion. James Donald Hebson, Jr., manager of transmission planning of the Public Service Electric and

Gas Company (PSE&G), indicated that his methodology for estimating wheeling costs would be to set all of PSE&G's "loads and generator outputs . . . equal to zero."[30] He would treat the system as if it were virgin and estimate the costs of new electricity coming on-line. This would be terrible news to the independent power producer. Edward P. Kahn, a mathematician who has testified before many regulatory commissions, addressed the same issue by stating, "Since there are currently very substantial power flows in New Jersey relative to the size of QFs . . . it is a reasonable assumption that wheeling will impose no new costs and hence QFs should not be charged for this service."[31]

It is by now apparent that issues such as avoided costs, short- and long-term marginal rates, cost of peaking plants, length of contract, levelized payments and the like are complex. The reader is advised that they are also quite new. In the future the feedback from this first round of contracts and rates will generate a more sophisticated approach, and probably a simpler one. As more data is gathered, the relationship between rates and investments and the reliability data on solar electric systems will become clearer.

In this chapter the contractual price has been the primary focus. Chapter 4 discusses an equally important and complex topic: interconnection standards. How much does it cost to interconnect with the utility, and how can the quality of electricity sent into the system be maintained at a sufficiently high level?