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An Analysis of PURPA and Solar Energy

Michael Rice

SERI

Solar Energy Research Institute
A Division of Midwest Research Institute

1617 Cole Boulevard
Golden, Colorado 80401

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FOREWORD

This paper on PURPA and its impact on the development of solar energy was prepared by the Solar Energy Research Institute (SERI) to fulfill, in part, SERI's solar information dissemination function. The paper is part of the Market Development Branch Law Program, which is in turn part of the overall program of the Commercialization Division. The function of the SERI Law Program is to identify and analyze significant legal issues affecting the development of solar technologies.

This paper was written as part of the Law Program's 1979 Summer Law Intern Program. The Program provided an opportunity for law students to research and address topics relating to law's impact on solar energy. The 1979 Program resulted in eight papers that discussed primary legal issues that are, or will be, generated by the commercialization of solar technologies.

The author of this paper, Michael Rice, was a law student at Northeastern University School of Law while he was participating in the Program. He is now a second-year student at the Northeastern University Law School. The Law Program is supervised by Jan G. Laitos, SERI Senior Legal Specialist.

David L. Feasby
David L. Feasby, Chief
Market Development Branch

Approved for:

SOLAR ENERGY RESEARCH INSTITUTE

Robert Odland for
Jon M. Veigel, Assistant Director
Commercialization Division

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SUMMARY

Solar and other renewable resources can be harnessed to generate electricity by small, decentralized, independently-owned facilities. Such facilities are flexible and may be better suited to innovation than are public utilities; however, they often depend on intermittently available energy resources and lack the size and consumer diversity that enable public utilities to match output to a variable demand. The advantages of small, independent facilities can be combined with the advantages of large public utilities by interconnection between them. Such interconnection allows the sale of excess electricity from independent facilities to public utilities and the sale of backup energy from utilities to independent facilities whenever the independent facilities' output falls below demand. Interconnection saves:

- the fuel that would be expended by the utility to generate the equivalent amount of energy;
- an amount of utility generation capacity expansion equal to the increased demand that can be met by the independent facilities interconnected with the utility; and
- the cost of the duplicate generating equipment or of the storage capability that would be required to make the independent facility self-sufficient.

The national goals of energy conservation and development of renewable energy resources are both met by encouraging independent small power production. Interconnection and suitable rates for the exchange of energy between such facilities and public utilities are essential incentives to such development.

The Public Utility Regulatory Policies Act of 1978 (PURPA) is designed to promote energy conservation, the efficient use of utility resources, and equitable rates. PURPA specifically requires the Federal Energy Regulatory Commission (FERC) to encourage small power production from renewable resources (and also cogeneration of electric energy as well as heat) by setting standards under which facilities qualify for interconnection, and guidelines for sales between utilities and independent facilities. The way FERC carries out this mandate may critically affect the development of solar alternatives to electric power production from fossil and nuclear resources. This report comments on proposed FERC regulations and suggests possible ways to encourage small power production within the PURPA mandate. In addition, some internal strains within PURPA are analyzed that seem to limit the effectiveness with which FERC can encourage independent facilities, and possible modifications to PURPA are discussed.

The effectiveness of the proposed rules under § 201 of PURPA, setting standards that small power production and cogeneration facilities must meet to qualify for interconnection and certain exemptions, could be enhanced if:

- The process of qualification were by generic rule rather than by case-by-case adjudication.
- There were no minimum size for qualification.
- The allowed fossil fuel use by small power production facilities were increased, particularly for solar thermal facilities.
- The status of facilities that are a hybrid of cogeneration and small power production were clarified, subject to a liberal interpretation favoring qualification.

In addition, the report notes a statutory inconsistency between the maximum size of 80 MW for qualifying small power production facilities, 30 MW for exemption, and a threshold of 500 million kWh annual sales which subjects utilities to reporting requirements in Title I of PURPA. The report suggests that the references in Title II to 80 MW and 30 MW be replaced by an annual production criterion of 500 million kWh (which is equivalent to an 80 MW facility operating at 70% capacity).

Section 210 of PURPA requires FERC to establish rates, or guidelines for rates, for the exchange of energy between utilities and interconnected qualifying facilities. The present report finds that standard ratemaking principles and a policy of energy conservation are best satisfied by rates based on a sharply time-differentiated energy charge that subsumes a demand charge. The predicament of the self-generator, that is, the small power production facility designed to meet a portion of its own electric needs, is a poignant illustration of the inequity of conventional demand/energy rate structures. A separate demand charge based on the monthly noncoincident peak demand ignores the statistical nature of the backup demand by self-generators and treats such producer-consumers discriminatorily relative to other consumers.

If demand/energy rates are nevertheless used, this report suggests:

- that a capacity credit be calculated for each qualifying facility—even for intermittent producers such as wind energy conversion systems;
- that capacity credit be based on the same statistical methods that would be used to calculate the effective load carrying capability of equivalent facilities owned by the utility; and
- that energy sales to qualifying facilities be priced on a flat or an inverted-block basis, with the facility considered to be a member of the consumer class in which it would be but for the self-generation.

It is noteworthy that the solution suggested here, a time-differentiated energy rate that subsumes demand charges, is simpler and results in about the same charge.

The report suggests that exchanges between public utilities and qualifying cogeneration and small power production facilities are more properly modeled on pooling arrangements among public utilities than on wholesale and retail transactions. In particular the report suggests an experimental rate to residential self-generators based on the net of the energy used less the energy supplied back to the utility. Such a rate can serve as a major incentive to solar development and does not harm the interests of the remaining rate payers at least until more than one percent of the residential energy consumption in a utility is supplied by self-generation. The report finds that utilities can absorb a significant amount of variable electric energy from independent facilities without adverse effects—relative to small independent facilities, public utilities behave as "infinite reservoirs" of power production.

This report suggests that modifications to PURPA allow:

- qualifying facilities to make final sales and to obtain orders from FERC requiring utilities to wheel power to subsidiaries or to other private consumers;
- energy sales from qualifying facilities to utilities to be credited against purchases, thus providing for net energy purchases by self-generators; and
- generation capacity subsidies by utilities to qualifying facilities.

Finally, the report suggests that public utilities be required to frame expansion plans with due regard to conservation of nonrenewable energy resources and economy of investment. Load management techniques, including incentive pricing, could be used to shift energy use away from times of peak demand and thus minimize the need for expansion. Even off peak, however, the use of electric energy for purposes which are more efficiently served by direct use of fossil fuels or renewable resources should be strongly discouraged. Expansion plans should take into account independent as well as utility-owned facilities that generate electricity from renewable energy sources—both in assessing the total need for expansion, and in assessing the optimal mix of generation and storage capability.

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SECTION 1.0

INTRODUCTION

In PURPA [1], Congress endorses two unconventional modes of electric power production. The act requires FERC [2] to "prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production"[3]. A cogeneration facility is one that produces both electric energy and "steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes" [4]. A "small power production facility" is defined as one that produces electric energy from biomass, waste, or renewable resources, and has no more than 80 MW of generating capacity [5].

PURPA exempts "qualifying" cogeneration and small power production facilities from certain laws governing other electricity producers [6], and requires FERC to design rules under which such facilities can sell excess electric energy and buy backup energy from public utilities at nondiscriminatory rates [7]. The act defines a "qualifying" cogeneration or small power production facility as one that is "owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities)" and "which the Commission determines, by rule, meets such other requirements . . . as the Commission may, by rule, prescribe" [8].

The subject of this study is the interconnection of small power production and cogeneration facilities with electric utilities, and the regulation of the rates at which the utility buys excess energy from such independent facilities and sells backup energy to them. Such interconnection is vital to the independent producers, for it would in most cases be prohibitively expensive for them to be self-sufficient. This interconnection is also useful in two ways. First, it makes the decentralized production of electricity from solar resources an economic possibility. Second, interconnection decreases the amount of fossil fuel that is used to generate electricity. PURPA is a constant theme throughout this report. It is the basic legal document that establishes and regulates small power production facilities and cogeneration facilities and governs their interconnection with utilities.

1.1 SMALL POWER PRODUCTION FACILITIES

Small power production facilities (SPPFs) conserve conventional fuel. They must use renewable solar energy sources except for limited quantities of oil or gas for startup and flame stabilization [9]. Each unit of electric energy generated by renewable resources saves or displaces more than three units of fossil fuel energy, for it takes over three units of fuel to produce one unit of electric energy in a steam generator plant [10].

SPPFs will use a variety of technologies: forest or agricultural biomass specially harvested as fuel, waste wood, other industrial or municipal waste, wind energy, sunlight directly converted to electric energy in photovoltaic cells, sunlight concentrated onto steam boilers using conventional steam turbine generators, and hydroelectric plants reactivated or installed at existing dam sites [11]. Energy from the ocean (currents, waves, tides, or thermal gradients) could be used but is not considered since it is unlikely that this can be done on a "small" scale [12]. This report is concerned with interconnection issues and will use biomass, wind energy, photovoltaic systems, and small hydroelectric projects as primary examples.

The use of solar resources not only conserves nonrenewable resources, but also is far less damaging to the environment than the use of fossil and nuclear fuels. This report will not deal directly with the environmental impact of extraction, transportation, and dispersal of combustion or waste products into the environment. However, the cost of providing electric service is analyzed, and the hidden costs of conventional power are briefly examined.

"Small power production" is limited by PURPA to under 80 MW, and is considered decentralized or distributed production. It lends itself to use by individual industrial plants, commercial parks, communities, and individuals. Decentralized production located near the point of end use minimizes transmission losses, which represent about 10% of all electric production [13]. Decentralized production is flexible in its ability to match the best available local source of solar energy to the particular end use. Small facilities require less lead time to plan and build and hence are less subject to inflation [14]. They provide additional local employment opportunities and increased state income through taxes and (in the case of biomass) vehicle registrations [15]. Small, decentralized facilities are less vulnerable to disruption or failure compared to centralized facilities and the consequences of system failure are less dire [16]. Perhaps most important for the long-run saving of energy resources, small locally owned facilities are consistent with values of self-reliance and entrepreneurship and are thus more innovative in unconventional power production than are public utilities [17].

1.2 COGENERATION FACILITIES

Energy resources can be conserved, in the production of electric energy, if all the fuel's energy is put to use. Only about one-third of the heat energy input is transformed into electric energy [18]. The other two-thirds is largely exhaust heat that is usually wasted and often the source of heat pollution of streams. In the typical steam generating plant the exhaust heat is spent steam, low pressure, and low temperature. Ordinarily this steam must be condensed in order to be returned to the boiler to make new high pressure steam. But, there is no physical reason not to use the spent steam for space heating or industrial purposes. Systems designed to use both electric energy and exhaust heat are called cogeneration systems. Thus, cogeneration facilities (CFs) conserve energy resources even if they use conventional fuels.

PURPA does not require of CFs, as it does of SPPFs, that the primary energy source be solar. Even if they use fossil fuel, cogeneration facilities obtain at least twice as much usable energy from one unit of fuel energy as conventional power plants can, for the fuel in CFs provides usable heat energy as well as electric energy [19]. Nonetheless, CFs can conserve energy more effectively if they generate steam from solar sources. The spent steam from solar thermal installations (using concentrated sunlight to heat the boilers) can be used for industrial process heat, after it has provided the mechanical energy to turn the steam turbine. Biomass fuel, such as waste wood in the forest products industry, can also be used to produce steam. Some of the largest industrial cogeneration facilities use such waste; a detailed example is provided in Section 5.1.1 [20].

1.3 INTERCONNECTION OF SPPFS AND CFS WITH PUBLIC UTILITIES

Cogeneration and small power production facilities—especially those using intermittent energy sources such as wind or sunlight—have one major disadvantage relative to public utilities: they cannot readily match their instantaneous power output to the instantaneous demand.

Public utilities have large numbers of customers whose aggregate demand tends to smooth out extreme fluctuations; that is, demand peaks of individual customers do not often coincide. Most demand fluctuations are predictable. The basic need is often met by baseload generation in nuclear and coal-fired plants, where fuel is relatively inexpensive and response time is sluggish. Peaks are met by more responsive, less cost-effective gas turbine generators, but only a small fraction of the total electric energy is so produced. Moreover, many utilities have pumped hydro energy storage facilities to further compensate for demand fluctuations. Finally, electric utilities have wholesale and pooling agreements whereby utilities whose demand peaks do not coincide can exchange electric energy.

It may be possible for a small solar or cogeneration facility to make itself energy independent by installing enough energy storage capacity; however, energy storage is expensive and not very efficient. For example, for every three units of electric energy used to pump water into an upper reservoir, only two units of electric energy become available when the water is returned to the lower reservoir [21]. Moreover, even CFs and biomass SPPFs, which are less vulnerable to energy supply problems than facilities depending on wind or sunlight, must face the problems of forced outages and planned shutdowns for periodic maintenance. Unless users are prepared to do without electric power or to install duplicate equipment, they will need backup energy from external sources [22].

The most cost-effective way to match the generating capability of CFs and SPPFs to the demand upon them is interconnection with public utilities. Interconnection permits CFs and SPPFs to sell energy to the utility whenever the rate of production exceeds that of consumption, and to buy backup energy when needed. Section 210 of PURPA requires FERC to encourage CFs and SPPFs by setting standards requiring utilities to buy excess energy and to sell backup energy to qualifying CFs and SPPFs at nondiscriminatory rates.

1.4 PERTINENT PROVISIONS OF PURPA

Title II of PURPA is directly relevant to the principal theme of this report—the interconnection of public utilities with independently owned facilities for cogeneration or electric power production from solar sources. Parts of Title II are summarized in Section 1.4.1. Title I of PURPA generally addresses ratemaking standards and seeks to encourage or discourage various utility operating practices. The ratemaking standards are important in the implementation by FERC of the interconnection mandate of section 210. Title I is discussed briefly, following the exploration of Title II.

1.4.1 Title II of PURPA: Cogeneration and Small Power Production

Section 210(a) of PURPA requires FERC to prescribe rules that require utilities to sell electric energy to qualifying* cogeneration and small power production facilities and to purchase electric energy from them. The rules must include provisions respecting minimum reliability** of such facilities and may not authorize a qualifying facility (QF) to make any sale for purposes other than resale.

*Defined in § 201.

**Reliability is a technical term of the greatest importance to this study and is explained in Section 2.2.

The rules prescribed by FERC concerning the purchase by utilities of excess energy from QFs must assure that rates are just and reasonable to the electric customers of the utility and may not discriminate against QFs [23]. No rule shall provide for a rate that exceeds the incremental cost to the utility of alternative electric energy [24]. "Incremental cost to the utility of alternative electric energy" is defined as the cost to the utility of the electric energy which, but for the purchase from the QF, the utility would have to generate or purchase from another source [25]. The rules prescribed by FERC concerning the sale of backup electric energy by the utility to the QF must assure that the rates are just and reasonable and in the public interest and do not discriminate against the QF [26]. Rules pursuant to § 201 of PURPA have yet to be proposed, but FERC has issued a Staff Paper that outlines the approach FERC expects to take [27].

Section 201 of PURPA defines small power production facilities and cogeneration facilities, and, in addition, requires FERC to issue rules that state the requirements that must be met by qualifying SPPFs and CFs. FERC has issued Proposed Rules pursuant to § 201 [28].

Section 210(e) requires FERC to issue rules under which QFs are exempt in whole or in part from the Federal Power Act, the Public Utility Holding Company Act, and state laws and regulations respecting the rates or the financial or organizational regulation of electric utilities. FERC's Staff Paper indicates its intention relative to exemption rules [29].

The regulations to be issued by FERC relative to the definition of qualifying facilities, and those relative to exemption and rates for the sale and purchase of electric energy from QFs by utilities, will have a major impact on the commercialization of solar production of electric energy and cogeneration. This report examines how these rules might be formulated to provide the maximum encouragement of cogeneration and independent solar production of electricity. To the extent that restrictions in PURPA itself serve as barriers to such encouragement, modifications will be proposed. To the extent that FERC's proposed rules or announced approach to rate structures for sales between utilities and QFs are less favorable towards solar commercialization than would be permitted by PURPA, comments regarding FERC rulemaking will be offered.

The issue of fairness—"just and reasonable and in the public interest"—permeates the language of §§ 210(b) and 210(c). These two sections govern the rates to be regulated by FERC regarding the purchase of electric energy by utilities from QFs and the sale of electric energy by utilities to QFs. The Conference Report [30] and Title I of PURPA make it possible to discern the congressional intent behind "just and reasonable." The Conference Report states that § 210 is "not intended to require the rate payers of an electric utility to subsidize cogenerators or small power producers" [31]. The interpretation of "just and reasonable" in Title I is discussed in Section 1.4.2.

1.4.2 Title I of PURPA: Ratemaking Standards

Title I sets federal standards for electric utility ratemaking and practices. The entire title serves the purposes of conservation of energy, efficiency of use of facilities and resources by utilities, and equitable rates to consumers [32]. The ratemaking standards call for:

- rates based on cost of service to each class of customers,
- an end to declining block rates for the energy component of the rate,

- time-of-day rates, where cost effective,
- seasonal rates,
- interruptible rates to be offered to commercial and industrial users, and
- load management techniques to be offered to consumers where it will be cost effective [33].*

The operational standards are not directly relevant to the subject of this report. They concern master metering, automatic adjustment clauses, information to consumers, procedures for terminating electric service, and advertising [34].

The federal standards are not obligatory to the state regulatory authorities. Section 111(a) requires state regulatory authorities to consider each standard, "and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title." In addition, § 111(b) sets procedural requirements for consideration and determination and § 111(c) requires the state regulatory authority to make a public statement in writing of reasons for rejecting any standard not adopted. Even though the standards are not to be imposed upon the states, they do suggest the intent of Congress with respect to which rate structures are just and reasonable.

The pressure on states to conform to federal standards is considerable, and it seems likely that most states will conform to a majority of the standards. Section 112(b) requires state regulatory authorities to complete consideration of the federal standards within three years of the enactment of PURPA (i.e., by 9 Nov. 81). The Secretary of Energy as well as "any electric consumer of an affected electric utility may intervene and participate <u>as a matter of right</u>" in such consideration (emphasis added) [35]. In the event of noncompliance by a state regulatory authority, the authority "shall undertake the consideration, and make the determination . . . in the first rate proceeding commenced 3 years after the date of enactment" [36]. Noncompliance with this last, highly specific requirement would seem to render the outcome of any rate hearing begun after 9 Nov. 81 vulnerable to court challenge. This virtually guarantees that each state regulatory authority will consider the federal standards and make a determination. The requirement of a written public statement of the reasons for rejecting any standard not adopted represents considerable pressure to conform.

1.4.2.1 The Constitutionality of PURPA

The state of Mississippi has filed a constitutional challenge to PURPA on the grounds that PURPA established federal standards regarding intrastate utility regulation [37]. The Mississippi complaint recognizes that

> [e]nforcement [of PURPA] requires the State . . . to show cause why federal regulatory standards should not be adopted in contravention of the sovereign [sic] right of the State . . . to exercise its own policies and jurisdiction as to retail electric . . . rates. [38]

The act is likely to withstand constitutional attack. In the first place, the act is an effort to deal with an area of split jurisdiction. Before PURPA, FERC had jurisdiction

*The meaning and significance of these standards will be explained in greater detail in the body of this report.

over the sales of energy from producers (because, in most cases, the energy is subject to resale in interstate commerce) while the states had authority over retail purchases by the same producers. FERC expects to implement the federal mandate by setting guidelines and leaving to the state regulatory authorities the day-to-day regulation of both sales and purchases by CFs and SPPFs [39]. The interconnection of qualifying facilities and their sales into interstate commerce of excess electricity would seem to bring their regulation within the purview of the commerce clause [40]. In the second place, PURPA is expressly based on the congressional "finding" that the provisions of the act are required for the "protection of the public health, safety, and welfare, the preservation of national security, and the proper exercise of congressional authority under the Constitution to regulate interstate commerce" [41]. Third, the doctrine of federal preemption is well established and especially likely to be upheld in areas of legislation where a clearly national problem, such as the "energy crisis," is confronted [42].

1.4.2.2 Cost of Service

The predominant emphasis of the PURPA ratemaking standards is on having the rates reflect the cost of service.* There is, however, a dearth of information upon which the actual cost of electrical service can be based. Accordingly, § 133 of PURPA requires FERC to formulate rules under which information can be gathered that will facilitate the determination of the cost of service to each consumer class. FERC has issued rules for the gathering of this information [43].

The gathering of data pursuant to §133 and FERC regulation Subchapter K, Part 290 will yield a more accurate calculation of the cost of electric service. An accurate value for the cost of service does not, however, resolve one major conflict of ratemaking: should cost-of-service computations be based on accounting costs or on marginal costs? Accounting costs are historical (or embedded) costs—the financing of past capital expenditures—plus operating costs. Marginal costs are the incremental costs of producing one more unit of something.

Marginal cost analysis is important because it leads to an economically efficient allocation of resources among the whole spectrum of choices available to a consumer. Applied to electric utilities, marginal cost analysis makes possible an economically accurate choice among different sources of energy (including the choice that a particular energy-consuming activity is not economic). As applied to electric service, marginal costs are usually taken to be Long Range Incremental Costs (LRIC). LRIC are the increments of cost incurred by one additional unit of demand for energy and power, over a prospective 10-yr period. This complex problem is explored in greater detail in Section 4.0. Marginal cost analysis may serve as a better measure of the social usefulness of solar energy than accounting cost analysis.

1.5 THE SCOPE AND ORGANIZATION OF THIS REPORT

The subject of this report is the interconnection with utilities of independently owned facilities for cogeneration (of electricity and usable heat energy) and for the generation

*PURPA does not set a cost-of-service rate as an absolute goal. Section 114 authorizes state regulatory authorities to allow lifeline rates—lower rates than those permitted by the standards of § 111(d). In fact, § 114(b) requires state regulatory authorities to consider whether lifeline rates should be implemented.

of electricity from solar resources. The principal legal issue addressed is the implementation of PURPA by FERC. Regulation at the state level is not addressed directly, even though it is likely that FERC will leave much regulatory detail to state regulatory authorities [44]. The report discusses regulation approaches under PURPA that would provide the largest possible encouragement to the commercialization of solar technologies for electric power production. Insofar as PURPA itself restricts encouragement, the report proposes modification of PURPA. Insofar as FERC regulation may fall short of the incentives proposed in this report, the proposals may nevertheless be adopted by state regulatory authorities; in that sense this report addresses itself to state regulation.*

Section 2.0 of this report describes the technical function of the electric utility—its role as producer of energy and supplier of power, its reliability, and load management. A clear understanding of the way utilities function is fundamental to the discussion of their interconnection with external generation facilities. Reliability and load management are technical concepts that play an important role relative to interconnection, and both are extensively addressed in PURPA.

Section 3.0 is an analysis of FERC's Proposed Rules under § 201 of PURPA, setting standards for qualifying small power production facilities and qualifying cogeneration facilities. Four changes in FERC's proposed rules are suggested, relating to proposed certification procedures, minimum size limitations, maximum fossil fuel consumption by SPPFs, and a needed clarification of the status of facilities that could qualify in part as CFs and in part as SPPFs. In addition, a definition in PURPA that limits the capacity of SPPFs and represents the threshold of qualification is discussed and a modification is suggested.

Section 4.0 is a discussion of the principles of utility ratemaking with special emphasis on marginal cost pricing. Section 210 of PURPA requires FERC to establish rules regarding rates for the purchase of backup energy from utilities by qualifying CFs and SPPFs and for the sale of excess energy to utilities by such facilities.

The rates for such exchange of energy will have a profound effect on the commercialization of solar production of electricity and cogeneration. The function of Section 4.0 is to provide a framework for the subsequent discussion of FERC regulation under § 210.

Section 5.0 presents a case study of an inadequate rate structure for interconnected facilities. The section then recommends rates for sales and purchases by utilities to and from qualifying facilities. Finally, two special problems are addressed—that of very small (residential) generation facilities and that of energy storage—in the context of the issue of cross-subsidization among electric utility ratepayers.

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*An example of disjunction between FERC and state regulation is built into PURPA at § 210(a): "[FERC] rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale." This limitation on FERC's authority is not intended by the House and Senate conferees to "limit the States from allowing such sales to take place. The cogenerator or small power producer may be permitted to make retail sales pursuant to State law" [45]. Thus, state regulation may be more encouraging to solar commercialization than FERC regulation.

SECTION 2.0

THE OPERATION OF ELECTRIC UTILITIES

The interconnection of an independent solar or cogeneration facility with a public utility modifies, to some degree, the operation of the utility. Since interconnection necessarily infringes upon the autonomous operation of the utility, it invites utility opposition. The legal issues concerned with the interconnection required by PURPA, §§ 202, 210, cannot be understood without a rudimentary understanding of the way a utility operates. The basic concepts that must be understood are energy (kilowatt-hours), power (kilowatts), and the related ideas of demand, capacity, and load management. This section attempts to provide that understanding.

A knowledgeable reading of Titles I and II of PURPA and an understanding of interconnection issues require acquaintance with the technical concepts of reliability and load management. Section 2.2 begins with a brief technical description of reliability, the cost-effectiveness of various levels of reliability, and different ways to achieve system reliability. The discussion then notes that the PURPA treatment of reliability could be construed and implemented in ways that would provide a disincentive to solar production of electricity. A proposal is made that the reliability be determined not of the individual independent facility but rather of the composite system, consisting of the utility plus the interconnected independent facility.

The subject of Section 2.3 is load management—a variety of techniques to minimize fluctuations in the load or power demand made on the utility. Cost-effective management of an electric utility requires that the generating capacity of a utility be used as fully and uniformly as possible. The unmanaged demand for electric energy varies with the time of day and season. The irregular demand cannot be met by a uniform rate of production of electric energy, because electric energy cannot be generated at one time for use at another [46]. It is possible to smooth the fluctuations in demand, however, by wheeling and pooling among utilities with noncoincident demand peaks, the reversible conversion of electric energy into storable forms of energy, and providing incentives to change consumer demand patterns. These techniques are discussed in Section 2.3, including a comparative evaluation of storage methods.

2.1 THE PUBLIC UTILITY AS SUPPLIER OF ENERGY AND POWER

2.1.1 Kilowatt-hours: Electric Energy and Fuel

When the consumer of electricity connects a load to the entering transmission lines (e.g., turns on a light), electric current flows through the transmission lines. When electric current flows through the lines, they deliver electric energy proportional to the amount of current. Electric energy is measured by a watt-hour meter in kilowatt-hours (kWh) and cannot be stored, as is mechanical energy in a flywheel or thermal energy in a hot water tank. Electric energy is only a transitional stage between the source energy at the power plant and the end-use energy on the consumer's premises.

The immediate source of energy at the power plant is the mechanical energy of the turbine that turns the electric generator. This may be derived from the decrease of the gravitational energy of water as it descends from behind a dam; high pressure, high temperature steam as it expands through the turbine; or a variety of other sources.

Steam may have obtained its thermal energy from the chemical energy stored in coal or biomass [47]. At the consumer's end, electric energy is instantly transformed into thermal energy in the filament of a light bulb, for example, or into mechanical energy by a motor. The motor in turn may run the compressor of a refrigerator, which operates as a heat pump, "pumping" heat from a cooler place (inside the refrigerator) to a warmer place (the kitchen).

2.1.1.1 Units of Energy Measurement

The consumer buys energy, measured in kWh. The more kWh of energy the consumer uses, the more kWh of mechanical energy must be transformed into electric energy by the utility. If the utility uses steam generation, it must use about 3 kWh of chemical energy in fuel to generate 1 kWh of electric energy [48].

The chemical energy in biomass and fossil fuels and the heat released in their combustion is generally expressed in calories or Btus (British thermal units). Mechanical energy and electrical energy transfers are often expressed in joules (J). (Since J is defined as 1 Watt-second, 1 kWh = 1000 W x 3600 sec = 3,600,000 J.) Table 2-1 is a conversion table among these energy units.

Table 2-1. ENERGY UNIT CONVERSION TABLE

joule	calorie	Btu	kWh
1	0.239	$.948 \times 10^{-3}$	2.78×10^{-6}
4.184	1	3.97×10^{-3}	1.16×10^{-6}
1.05×10^{3}	252	1	$.293 \times 10^{-3}$
3.6×10^{6}	$.86 \times 10^{6}$	3.42×10^{3}	1

National energy consumption is often reported in quads (1 quad = 1 quadrillion Btu = 10^{15} Btu) and runs to almost 80 quads annually [49]. To express quads in terms of the other energy units, multiply the numbers in the third row of Table 2-1 by 10^{15}.

2.1.1.2 The Size of Energy Units

The following list is intended to help the reader visualize the size of these energy units. The numbers are approximate.

1 kWh of energy:

- raises the temperature of one gallon of water from 0°C to 100°C,
- lights ten 100-W light bulbs for one hour,
- runs a 1/2-hp motor for three hours, and
- lifts 200 gal. of water from a 150-ft well.

2 kWh (about 7000 Btu) is available from one pound of dry wood.

2.8 kWh (about 2400 kilocalories) is a typical day's food intake of an adult.

45 kWh (about 150,000 Btu) is available from one gallon of fuel oil.

720 kWh is a typical residential electric consumption in one month (not an electrically heated home).

960 kWh is available per month from a 4-kW wind turbine generator in a good location (assuming 1/3 maximum energy output).

1800 kWh or 5,800,000 Btu is available from one barrel of crude oil.

2.036487 trillion kWh or 6.96 quads is the nation's electric production for 1976.

21.4 quads is the resource energy spent to produce electric energy in the United States in 1976.

2.1.2 Kilowatts: Electric Power and Capital Expenditures

A typical residential consumer who does not use electricity for space heating may use about 720 kWh/month. Since there are 720 hours in one month, consumption of 720 kWh/month is an average of 1 kWh each hour—enough to light ten 100-W bulbs continuously. A hypothetical consumer who uses ten 100-W bulbs continuously and no other electricity, utilizes electric energy at the rate of 1 kWh/hour, or makes a continuous power demand of 1 kW. Power is the rate of transforming energy.

A second hypothetical consumer might use the same amount of energy each month, but at a variable rate. Suppose this consumer uses no energy 16 hours each day, but uses 3 kWh during each of the other 8 hours. Such a consumer makes a power demand of 3 kW during those 8 hours and of zero during the other 16 hours.

The effect on the utility of these two patterns of energy use is drastically different, even though both hypothetical consumers use the same total energy. The point is dramatically illustrated if one million such consumers are hypothesized. In both cases the utility sells 720 million kWh or 720,000 MWh (megawatt-hours) each month. In the first case the utility must have the capacity to produce 1000 MWh each hour, a 1000-MW capacity. (One thousand MW is the approximate capacity of a typical nuclear power plant, such as Three Mile Island.) In the second case, making the further hypothesis that the 8-hr period of 3-kW demand coincides for all consumers, the utility must have a 3000-MW capacity. It would have to build three 1000-MW plants which would be idle two-thirds of the time, when none of the hypothetical consumers used electricity.

2.1.2.1 Capacity Factor

The capacity factor of a power plant is the ratio of the energy produced to the energy that would have been produced at full capacity operation. In the two highly artificial examples cited previously, the capacity factors are 100% and 33%, respectively. Typical utility system capacity factors average 50-55% [50]. A low capacity factor arises when excessive capacity is idle a large part of the time. The lower the capacity factor, the higher the capital (fixed) cost in relation to the variable (operating and fuel) cost, since the capital costs of idle capacity are not offset by income.

2.1.2.2 Load Factor

A quantity related to the capacity factor is the daily load factor. The load factor is the ratio of the average power output (which is equivalent to the average demand) to the peak output (or peak load). Average annual utility load factors have ranged from 60-65% in recent years [51]. A schematic daily load profile for a utility with a 70% daily load factor is shown in Fig. 2-1 [52]. Demand varies not only in a daily cycle, but on an annual cycle as well. Depending on the ratio between air conditioning and space heating demands, utilities are either summer peaking or winter peaking, and usually have a secondary peak in the opposite season. Fig. 2-2 shows a yearly load profile for a typical winter peaking utility [53].

2.1.2.3 Reserve Margin

The generation capacity of a utility must exceed the largest peak load imposed on it.* A reserve margin is required because any given generating unit has a certain "forced outage rate," a certain probability of being unexpectedly out of service.** Reserve margin is also required to compensate for errors in annual forecasts of peak load demands as long as 10 years into the future. However, projections of future needs have been systematically too high for the past five or more years. As a result, the reserve margin of total generation capacity over noncoincident peak demand reached 38% in 1978 [54]. This is regarded by the electrical industry itself as "much too high" a reserve margin [55]. Long-range industry projections call for a reserve margin of 18%, equal to the average for the years 1967-70 [56].

2.1.2.4 Operating Reserve; Spinning Reserve

It is not sufficient for a utility merely to possess reserve generating capacity. Some of the reserve generating capacity must be available for immediate dispatch, as a physician might be needed "on call." As many as three or four hours may be required to bring a coal-fired steam generating unit on line from a cold start [57]. For this reason, a portion of the reserve capacity is kept fired up and spinning and is available within 10-30 minutes. For example, a 300-MW oil-fired boiler might be used to produce only 200 MW of electric power, leaving an additional 100 MW of power immediately available by increasing the combustion rate of the oil. The additional available capacity from a unit already producing power is called the spinning reserve.

It is industry practice to maintain an operating reserve equal to the largest single generating unit (or transmission line) in use plus an additional margin. A portion of the operating reserve is instantly available ("spinning reserve"); an amount equal to the largest generating unit may be available on "ten-minute reserve;" additional capacity may be available on 30-min reserve to replace 10-min reserve when used in case of a forced outage [58].

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*For the purpose of this discussion, generation capacity includes firm wholesale contracts by which other utilities guarantee fixed amounts of power at times of peak load.

**Equipment maintenance is performed at off-peak times and involves scheduled outages as distinct from forced outages.

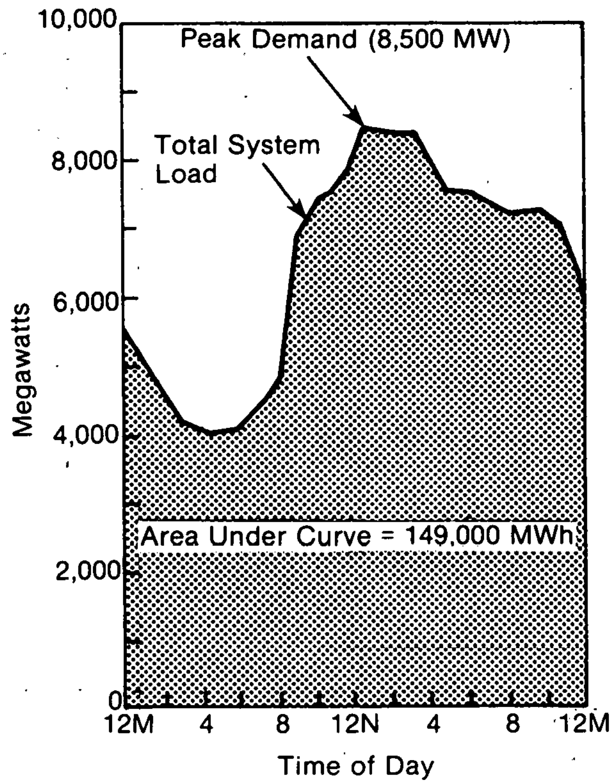

Figure 2-1. Schematic Daily Load Profile

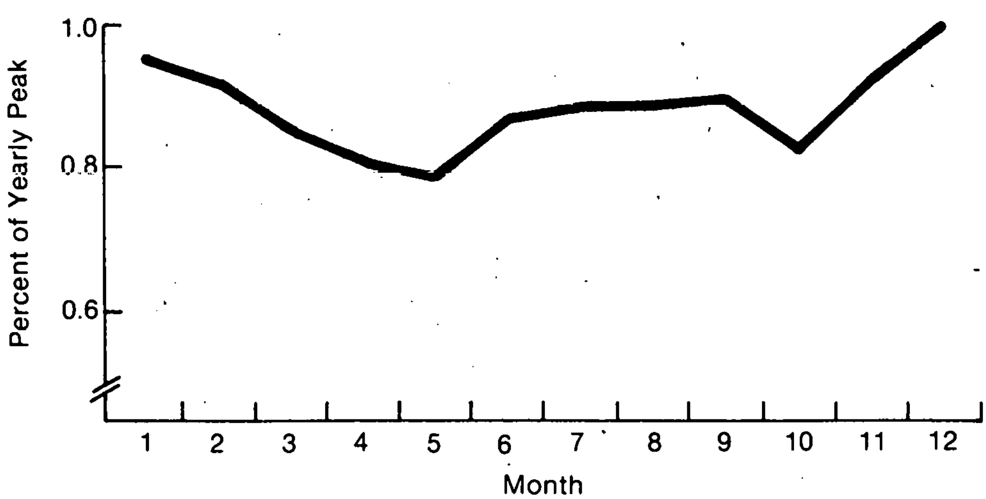

Figure 2-2. Yearly Load Profile

2.1.2.5 Load Swing

The load of a utility may have short-term variations, called the load swing, of as much as 3-5% [59]. These variations do not show up on Fig. 2-1 and 2-2 because daily load curves are based on 1-hr averages. The 3-5% variations from the load curve are fluctuations that occur in several minutes and represent random departures of the instantaneous output of particular generating units from the 1-hr averages [60].

Each generating unit is equipped with an automatic control of its output level. A typical intermediate steam generating unit (150-580 MW) can follow load variations; i.e., change its output at a rate of 1-1/2% per minute [61]. Fluctuations in the demand of less than 1% per minute are followed automatically by the generators on-line. Additional or more sudden fluctuations may require some of the spinning reserve.

The ability of a utility to follow substantial load swings is of the utmost importance to interconnection. For example, a 4000-MW utility can readily follow 120 MW (3%) fluctuations. Such a utility can readily "absorb" a 120-MW fluctuation from interconnected solar facilities that produce electricity intermittently. A fuller discussion of this important point follows in Section 5.4.1.

2.1.3 Transmission and Distribution of Electricity

The transmission and distribution of electricity raise economic and operational problems. The economic problems involve the proper allocation of the costs associated with transmission and distribution and are discussed in Section 2.4. The operational problems result from the energy losses associated with transmission. One-tenth of all electricity produced in the United States is lost in transmission [62]. To minimize long-distance transmission losses, ultrahigh voltages are used; this raises environmental and public acceptability problems of ultrahigh voltage transmission lines.

The capital costs of the transmission and distribution system are a significant fraction of the total fixed costs [63]. Transmission lines are sized to the peak power required. As is true of generation capacity, the capital cost of transmission is proportional to peak power. The size of the distribution system, on the other hand, is only partially dependent on peak demand; to a large extent it is a customer cost that is associated with providing service to a given customer [64]. Typical distribution costs are electric meters and transformers.

Transmission costs can be reduced relative to generation costs, if the generation of electricity is more decentralized. For example, if an industry that requires 30 MW produces this amount for itself and can hold its backup demand below 5 MW, the industry would require only a 5-MW transmission and distribution system instead of a 30-MW system. The possible saving in transmission and distribution costs constitutes one of the reasons for the encouragement of decentralized production by CFs and SPPFs [65].

The savings in transmission and distribution costs that result from decentralized production of electricity should be reflected in rates paid by utilities to CFs and SPPFs for excess electric energy. The Danish public utility, for example, takes account of the savings in transmission costs by paying 10% more than wholesale rates for independently generated wind power [66]. The central station would have had to produce a 10% excess of energy in order to deliver the same energy to the site of a wind generator as has been produced by the generator. In general, the excess electricity from a remote wind generator meets electric demand near the generator, not near the central station. The electric energy does not flow to the central station, but replaces energy that would otherwise have to be produced at and dispatched from the central station.

Savings in transmission costs are also made possible by installing utility-operated storage systems or combined storage and generation units at substations. At peak times, part of the energy outflow from the substation comes from the storage; thus the transmission capacity from the central station to the substation can be less than the peak demand. Whether substation storage or storage and generation is economically advantageous depends on the relative investment in central station generation capacity, transmission capacity, and on the growth patterns of the system demand. Dispersed storage and generation may be especially valuable in some rural electric utilities [67].

2.1.4 Public Policy and Electric Utility Operation

The purposes of Title I of PURPA (and implicitly of Title II) are to encourage

(1) conservation of energy supplied by electric utilities,

(2) the optimization of the efficiency of use of facilities and resources by electric utilities, and

(3) equitable rates to electric consumers [68].

The first two purposes are discussed in this section and the third is considered in the discussion of utility ratemaking in Section 4.0.

Energy supplied by electric utilities can be conserved by

- reduced reliance on electric energy for purposes (such as space heating) which do not require electric energy [69],
- encouraging the use of cogeneration by large consumers of both electric and thermal energy, and
- encouraging the production of electric energy from solar and other renewable resources.

Every kWh of electric energy produced (by a wind turbine generator, for example) displaces the fuel equivalent of over 3 kWh of fossil energy that would otherwise have been required to generate the same 1 kWh of electric energy. The goal of conserving energy resources is well served by encouraging CFs and SPPFs because they directly reduce the utility's fossil fuel requirements. In addition, independent facilities can serve to test and develop technologies that can later be used within utilities to replace fossil resources with solar resources.

A suitable encouragement for the production of electric energy from solar resources might be a price to the utility based on the incremental cost of the most expensive fuel used by the utility. The consistency of this recommendation with the provisions of § 210 of PURPA is discussed in Section 5.3.1. A relatively high price for solar electricity is justified because the replacement of even a small fraction of the fuel used to generate electricity can serve as a brake on rapidly escalating fuel costs. The effect on the cost of fuel by a marginal change in demand is dramatically illustrated by the very substantial pressure on the price of oil resulting from a 5% gasoline shortage during the summer of 1979.

The second goal of PURPA is the efficient use of the facilities of electric utilities. This goal requires efforts to improve load factors and capacity factors. A traditional way to improve load factors (and to reduce electric rates) has been to encourage new consumption of electricity during off-peak periods. In Great Britain, for example, the load curve has been considerably flattened* through the use of off-peak electric space heating, using thermal storage systems; at peak load times heat is taken out of storage and electric power is not required [70]. This method of improving load factors contradicts the first of the PURPA goals (to conserve energy) for it depends upon an increased use of fuel to generate electricity [71].

Alternative ways to improve capacity factors or reduce utility capital costs include:

- load management, to encourage the shifting of electric power use away from peak load times,
- attention to the optimal generation mix, that is, the balance of the different kinds of generating units available to the utility, and
- possible reductions in the reliability level needs of the generation system.

A narrow interpretation of the second and third goals of PURPA, the efficient use of facilities and equitable rates, can undermine the encouragement of CFs and SPPFs required by PURPA § 210(a). For example, it is possible to argue that the intermittent nature of electric power available from wind or direct sunlight provides energy (satisfying goal number one) but worsens the load factor (hence frustrating goal number two). It can be argued that the incentives that would encourage SPPFs might lead to inequitable rates and thus violate goal number three. This paper recommends rate structures and other possible regulations that would encourage CFs and SPPFs without undermining the second and third goals of PURPA. A necessary basis for such recommendations is the following exploration of reliability, load management, and ratemaking.

2.2 RELIABILITY

A persistent theme in PURPA and utility planning is the reliability of the system. Reliability is a measure of the likelihood that the generating capacity actually available to an electric utility is sufficient to meet the instantaneous demand; it is a technical term defined in terms of the "loss of load probability." Section 209 of PURPA is entirely devoted to reliability and other sections discuss it further: § 201 at 3(17)(C)(i), § 202 at 210(c)(2)(C), § 203 at 211(a)(2)(C), § 204 at 212(a)(3), § 205(b)(1)(C), and § 210(a).

The choice of a desired reliability level determines the required reserve margin of generation capacity. The higher the reliability level desired, the larger the reserve margin required. Since reserve margins require capital investment in generation capacity that will be idle much of the time, high reliability levels result in low capacity factors and high electricity costs. The benefits of high reliability must be carefully weighed against the costs.

Whenever the peak power demand on an electric utility increases without the addition of generation capacity, the likelihood that the utility can meet the demand, hence the reliability, decreases. Conversely, if new capacity is added without any increase in

*A flattened load curve corresponds to a higher, hence improved, load factor. A perfectly flat load curve would correspond to a load factor of 100%.

demand, the reliability of the system increases. If a suitably sized generation unit is added in order to meet an increased peak demand, the reliability is unchanged. When an electric utility adds a generation unit, it calculates the effective load carrying capability (ELCC) of that unit. The ELCC is the amount of added demand that can be carried by the utility with the added unit at the same overall reliability [72].

The way in which reliability requirements are applied by FERC and state regulatory authorities in setting rates for the exchange of energy between public utilities and interconnected CFs or SPPFs has a potential impact on the commercialization of solar production of electricity and cogeneration. CFs and SPPFs will be at a severe economic disadvantage if they must pay a premium for backup power or if they receive a reduced price for their excess energy as a result of their relative lack of reliability. However, it is not necessary to penalize independent facilities in this way. Although the reliability of a single small system is far less than that of a large utility (except at a prohibitive cost), the reliability of the composite system—consisting of the independent facility plus the interconnected public utility—is satisfactory. Interconnection should be encouraged precisely because it provides the advantages of decentralized, innovative, energy-conserving power production without a concomitant loss of reliability.

A method for protecting the incentive for independent power production by CFs and SPPFs is to determine reliability not separately for the independent facility but rather for the composite system. The ELCC of the generation unit external to the utility could be calculated in a way analogous to that customary for utility-owned units. The independent facility could be given "capacity credits" corresponding to the amount of utility generation capacity that need not be built because of the existence of the CF or SPPF.

2.2.1 Loss of Load Probability (LOLP)

Reliability is quantified in terms of the loss of load probability (LOLP). LOLP is expressed in days per year and is a measure of the amount of time per year that the utility may be unable to meet the demand—the time customers may not have power available to them. A high degree of reliability corresponds to a small value of LOLP. The standard reliability criterion for most American utilities is a LOLP of 0.1 per year.

How can there be a "loss of load"—an inability of the utility to supply the power demand—if the generation capacity exceeds the demand by a wide reserve margin? The utility may fail to meet the demand because each piece of generating equipment has a definite probability of failing—a certain forced outage rate. The forced outage rate tends to increase with the size and complexity of the unit [73]. Typical values range from below 2% to 10-12% [74]. When a generation unit fails, the utility will ordinarily have enough operating reserve to compensate for the unit. But there is a definite (though small) probability that additional units may fail before there is sufficient operating reserve to make up the deficiency. LOLP is determined by estimating the probable power demand for each of the 8,760 hours of the year, calculating the probability that the available equipment will fail to meet this demand, multiplying this probability by one hour to find the contribution of that hour's failure to the LOLP, and summing over the hours of the year; the sum is the LOLP in hours per year [75].

2.2.2 Cost/Benefit Analysis of the Reliability Level

How does a utility establish an acceptable level of LOLP? The generally accepted value in the United States, 0.1 day per year, is a compromise between the social and political costs of the highly visible brownout or blackout and the considerable, less visible, cost of achieving low LOLP [76]. The compromise seems (to technically alert observers) tilted too far towards small values of LOLP, perhaps because of the generally low cost of electricity during the decade before 1974 [77].

There are two reasons to favor a larger value of LOLP; e.g., 0.5 day per year. One is that the distribution system reliability is much worse than the generating system reliability. Thus, the distribution system is the limiting factor and an increase in LOLP would have no significant effect on most users. Most major blackouts, including the Northeast power blackout of 1965, have occurred despite adequate generation capacity [78]. The second reason to favor a larger value of LOLP is that the marginal cost of the generation capacity required to maintain a LOLP of 0.1 day per year exceeds the value of goods and services that might be lost due to additional system failure [79].

2.2.2.1 PURPA, Section 209

The trend to reexamine the 0.1 day per year criterion extends to PURPA. Section 209 requires a study by the Secretary of Energy to determine a "level of reliability appropriate to adequately serve the needs of electric consumers, taking into account cost effectiveness and the need for energy conservation." The section further requires the Secretary to consider "the cost-effectiveness of adding a number of small, decentralized conventional and unconventional generating units rather than a small number of large generating units with a similar total megawatt capacity for achieving the desired level of reliability." Congress has thus recognized not only the need to reopen the question of the desired level of reliability, but also the possibility that small units may better serve the goal of reliability than larger ones.

The Department of Energy study of reliability required by § 209 goes beyond the usual calculation of whether the generation capacity is sufficient to supply the demand. Section 209(a)(2) specifically requires consideration of "(A) . . . transmission and distribution facilities, and devices available to the electric consumer" as well as "(D) alternatives to adding new generation facilities to achieve such desired levels of reliability (including conservation)." The authors of this language evidently recognized that a cost-effective method to achieve high reliability is to reduce peak demand through a combination of conservation and load management. Conservation reduces overall demand, including peak demand. Load management shifts demand away from the peak. By flattening the load curve the utility achieves a higher load factor, a more uniform rate of electric production, and less demand at peak times. Presumably "devices available to the electric consumer" are load management or load control devices.

The Conference Report describes the purpose of § 209 as being "to improve the reliability of service to electrical consumers, . . . to authorize the Secretary [of Energy] to recommend to the electric utility industry standards for reliability" [80]. The statute requires a study of "various procedures that might be used in case of an emergency outage to minimize the public disruption and economic loss that might be caused by such an outage" [81]. Since emergency outages are most often the result of failures in the distribution system, not of inadequate generation capacity, the statute's goal to improve reliability does not imply a decrease of LOLP. The primary focus of § 209 is on aspects of the electric system other than generation.

2.2.2.2 Reliability Requirements as Possible Disincentives to Cogeneration and Small Power Production

Advocates of solar production of electricity must be wary of the emphasis on reliability in PURPA. Some of the references to reliability permit—though they do not require—implementation by FERC that would be inimical to the development of SPPFs for the generation of electricity from solar sources and possibly to the increased use of cogeneration.

Section 210(a) requires that rules "to encourage cogeneration and small power production . . . shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities." Section 201 requires FERC to set standards for "qualifying" SPPFs and lists reliability as an example of such a standard. The FERC proposed regulations pursuant to § 201 establish no minimum reliability requirement [82]. The FERC Staff Paper regarding regulations pursuant to § 210 explains that FERC "read[s] Section 201 as permitting but not requiring the Commission to establish a minimum standard for the reliability of small power producers" [83]. It would have been a severe blow to the development of SPPFs if FERC had required a producer of electricity from wind or direct sunlight, for example, to meet a minimum reliability standard. Since there is no way to regulate the availability of wind or sunshine, a minimum reliability standard would have amounted to a requirement for energy storage associated with each SPPF. But the value of interconnection of SPPFs with utilities is precisely to avoid the costs of individual storage units by taking advantage of the utilities' centralized storage or excess capacity and of their ability to absorb the variably available energy from SPPFs due to the large size of utilities.* FERC has thus avoided a regulatory action that would have stopped SPPF development at the threshold.**

While FERC has avoided the ultimate disincentive to SPPFs of setting a minimum reliability requirement, FERC appears ready to provide a lesser but still significant disincentive. The Staff Paper asserts that "the degree of reliability and/or availability can and should be reflected in the price for electric service, whether a utility or a Q[ualifying] F[acility] is the seller" [84]. This assertion can be read to permit open-ended price discrimination against QFs on the grounds of their relative unreliability, for it is economically unfeasible for a CF or a SPPF to achieve a reliability comparable to that of a utility. Unless FERC limits the extent to which the price of electricity exchanged between utilities and QFs may reflect reliability, independent solar production of electricity through the rate structure may be discouraged. The disincentives FERC avoided by not setting a reliability minimum may be introduced by an overcautious approach to rate setting.

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*The effect of interconnection of a small SPPF with a large utility is discussed in detail in Section 5.4.1.

**An interesting question of legal construction is whether FERC could have legally set a minimum reliability standard. On its face the act permits FERC to do so. However, the same act requires FERC to set rules to "encourage cogeneration and small power production." It would appear that FERC could not have simultaneously encouraged SPPFs and set minimum reliability standards. Since the act only permits and does not require minimum reliability standards, and since setting such standards would violate the mandate to encourage SPPFs, FERC may have made the only correct choice by not setting a minimum reliability standard.

2.2.3 Effective Load Carrying Capability (ELCC)

The effective load carrying capability (C') of an added generating unit of rated capacity (C) and forced outage rate (r) is calculated in two steps. The first step is to inquire how much the added unit improves the reliability from its LOLP value before the unit was added. The second step is to calculate how much the load served by the utility can increase before the LOLP will rise to its initial value. This additional load equals C'. C' is always smaller than C. The amount by which C' is smaller than C depends on the forced outage rate of the generating unit, and the ratio of the generation capacity of the unit to the generation capacity of the utility. The difference between C' and C is larger when the forced outage rate is larger; it is also larger for generating units whose capacity is a larger fraction of the utility's generation capacity. Large generating units tend to have ELCCs much smaller than rated capacity for two reasons: (1) a large unit tends to have greater forced outage rates (f.o.r.) than a similar small unit because of the large unit's greater complexity; (2) the large size alone increases the fractional discrepancy between C' and C, even if the f.o.r. were the same. A 1,000-MW nuclear plant, for example, may have a f.o.r. of 10% and an ELCC of only 450 MW [85]. Small units (below 50 MW) with reasonable forced outage rates have effective capabilities nearly equal to their rated capacities [86]. Congress appears to recognize the likelihood that small generating units may have advantages as to reliability. PURPA, § 209 (a)(2)(E), states that the study of reliability required by § 209(a)(1) shall include

> the cost-effectiveness of adding a number of small, decentralized conventional and nonconventional generating units rather than a small number of large generating units with a similar total megawatt capacity for achieving the desired level of reliability.

If a utility has an initial capacity C_0 and can meet a total demand of L_0 with a LOLP of 0.1 day per year, the addition of a generating unit of capacity C increases the utility's capacity to C_0+C and increases the demand which the utility can supply to L_0+C'. However, to say that an added generating unit has an ELCC of C' does not mean that this much capacity is available at all times. For example, if C = 35 MW and C' = 32 MW, the utility including this generating unit can supply a demand of 32 MW more than it could without that unit—even on those occasions when the unit suffers a forced outage. The forced outage rate is already taken into account in the calculation of C', which is always less than C.

The calculation of ELCC is a traditional and necessary part of utility planning and allows the planned expansion of generation capacity to correspond appropriately to projected increases of peak demand, at accepted levels of reliability. With the introduction of the concept of independently owned generation facilities that are interconnected with utilities, ELCC calculations should be equally applicable to generating units added externally to the utility as CFs or SPPFs. There is no essential difference, in terms of the preceding numerical example, between a utility-owned 35-MW generating unit with an ELCC of 32 MW and an independently owned 35-MW cogenerator with an equivalent f.o.r. and maintenance schedule. The utility-owned unit enables the utility to carry 32 MW more load (at given LOLP) than it could without the unit. The externally owned unit enables the composite system (utility plus CF) to carry 32 MW more load than the utility could carry alone, at the same LOLP.

A possible utility objection to treating CFs as having a load carrying capability is posed in the Staff Paper:

> the time or duration of an outage [cannot be predicted] since the operation of the facilities is outside utility control. In part, this argument comes down to prudent utility planning for meeting loads that are potentially volatile and are dependent in part on the maintenance practices of the nonutility operators. [87]

This argument does not, however, make it less possible to calculate a value of the ELCC of a generating unit external to the utility. Potentially poor maintenance would be reflected in a larger f.o.r., which in turn would result in a smaller value of C' for a given value of C. But nonutility maintenance would not render a calculation of ELCC less valid than such calculation for utility-owned units.

2.2.4 Reliability of Composite Systems: Public Utilities and Interconnected CFs or SPPFs

This section is an argument for performing ELCC calculations for independently owned CFs or SPPFs that are interconnected with a utility as if they were owned and operated by the utility.* In other words, the argument is that the reliability should be calculated for the composite system consisting of the utility plus the CF or SPPF. This proposal is in sharp contrast to the assumption made in the Staff Paper that sales from a QF to a utility would follow a wholesale model [88], and sales from a utility to a QF a retail model [89]. In the wholesale/retail model the utility and the QF are treated in all respects as separate entities; if reliability is significant at all, the reliability of the QF is separately calculated. In the model here proposed, the utility and the QF are separate entities except for the single purpose of calculating the composite reliability.

A portion of the cost of providing electric service is the capital cost of the generation facilities. For this reason a part of the charge to a consumer of electricity is based on the amount of generation capacity that must be dedicated to serving that consumer. The easiest conceptual way to allocate the capital cost of generation capacity to various consumers is in proportion to their "peak responsibility"—their power demands during the hour of the annual system peak load. The reason such an allocation would be fair is that the size of the total generation capacity needed is arguably determined by the size of the annual load peak.

The significance of calculating and properly crediting the load carrying capability of a CF or SPPF can be shown by a numerical example. Suppose two industrial consumers each have a steady demand of 30 MW. Suppose one of them has a 35-MW cogeneration facility that enables it to sell 5 MW to the utility most of the time, but that the CF suffers an occasional outage during which the consumer requires 30 MW from the utility. Suppose further that the f.o.r. is such that the CF would have an ELCC of 32 MW if calculated for the composite system. The consumer without a CF regularly contributes 30 MW to the peak demand and properly accounts for a 30-MW share of the peak. The consumer with the CF demands 30 MW occasionally. The overall effect of the CF on the utility is:

*The f.o.r. used for the calculation may be higher than it would be for the same unit operated and maintained by the utility. The f.o.r. would in any case be subject to periodic review, based on operating experience. Moreover, there might be stipulations regarding the timing of planned outages for maintenance; e.g., the scheduling of such maintenance might have to be coordinated with the utility.

- the total load that can be served by the utility plus the CF is $C' = 32$ MW more than the load that could be served by the utility alone;
- the CF owner consumes 30 MW; therefore
- the utility plus the CF can supply 2 MW more than the original demand on the utility plus the need of the CF owner.

Thus, the net effect of the CF is to expand the load that can be supplied by the utility by 2 MW with no capital cost to the utility. Such a consumer need be charged nothing for its contribution to the peak demand, since the consumer imposes no requirement for added generating capacity to the utility. In fact, the CF owner in this example should be paid more than alternative fuel costs for the energy it sells to the utility, since the CF displaces the capital costs that would be required to expand the utility capacity by 2 MW. Capital cost allocation payment would properly flow from the utility to the CF. In short, the CF should be given "capacity credits."

If the wholesale/retail model is employed for sales and purchases by the CF, and if the "degree of reliability and/or availability," not measured as here proposed, is "reflected in the price for electric service," considerable unfairness results [90]. Two consumers with as widely different impact on the utility as the 30-MW users of the preceding example would contribute equally to the capital costs associated with the utility's generation capacity if demand/energy were in use. Even a smaller "standby" rate for the occasional demand would represent a penalty. Such a penalty might be appropriate if the effect of an external unit were in fact to require the utility to expand its generation capacity to cover the CF-owner's demand at the time of a forced outage. But to argue that such a backup capacity is required denies the statistical basis underlying utility reliability computations.

The illogic of penalizing the independent consumer/producer of electricity by basing a capacity cost allocation on the maximum power demand can be demonstrated by a review of LOLP determination. Suppose first that instead of a single 30-MW consumer/producer there are 10. Their largest possible collective demand would be 300-MW. It is logically conceivable that all 10 would fail simultaneously, thus placing a 300-MW demand on the utility, just as it is logically conceivable that 10 of the utility's generating units would fail at once. However, this is not how utility computations are made.

In utility practice a statistical calculation is made. The probability is determined, based on the f.o.r. of each unit, that the 300-MW capacity will handle loads of 300, 290, 280, . . . , 200 MW. A textbook illustration calculates the load handling capability of a hyopothetical system of five 40-MW and three 50-MW units (350 MW in all), each with a forced outage rate of 1%. The eight units can sustain a 280-MW load with a LOLP of 0.1 day/year [91]. By similar statistical methods, one can compute the expected demand on capacity by ten 30-MW units. Assume for purposes of discussion that the result of such a computation is that 50 MW of generating capacity is required to maintain the utility's reliability while serving as backup to these ten 30-MW units. Each of the 10 units is then responsible for 5 MW of backup capacity. (The numbers are examples only, not the result of calculation; but the concept that the capacity requirement to provide backup is far less than the size of the individual units stands.)

The FERC Staff Paper on § 210 recognizes the appropriateness of a statistical treatment of the backup demand by a group of qualifying facilities. It states:

> By first pooling among themselves, QFs might facilitate individual contractual dealings with utilities and reduce its [sic] attendant costs. Pooled QFs certainly could make a much stronger argument that probabilistic analysis should be used in determining the backup charges, and based on the coordination, the analysis would show a lowered probability of coincident outages . . . . To the extent that operations are not coordinated and individual QFs and the group of QFs as a whole impose greater capacity requirements on the utility system, the costs of such backup service should be fully recovered [92]. (Emphasis added.)

The Staff Paper is in error when it implies that probabilistic analysis should not be used where only a single QF is involved. In utility planning, the effect of adding one more unit is routinely studied by statistical methods, for example when calculating LOLP and ELCC. The present proposal is novel only insofar as it extends the same statistical treatment to external generating units as has been used for utility-owned units.

2.3 LOAD MANAGEMENT

"Load management" is used in this paper to refer to any method for shifting electric power demand away from the load peak [93]. If electric demand is shifted away from load peaks, then the same amount (or more) of electric energy can be produced by a smaller generation capacity, resulting in more efficient use of the available generation capacity. In practice, utilities do not reduce generating capacity although the same capacity can serve an increased overall demand if the peak demand is kept the same through load management. Load management, therefore, satisfies the second of the goals of Title I of PURPA—"to encourage the optimization of the efficiency of use of facilities and resources by electric utilities" [94].

Load management includes price incentives for shifting consumer demand away from the peak (e.g., time-of-day rates, seasonal rates, interruptible rates) as well as what is defined as load management techniques in PURPA:

> The term "load management technique" means any technique (other than a time-of-day or seasonal rate) to reduce the maximum kilowatt demand on the electric utility, including ripple or radio control mechanisms, and other types of interruptible electric service, energy storage devices, and load-limiting devices. [95]

Although PURPA excludes time-of-day rates and seasonal rates from the definition of load management techniques, the act establishes that electric utilities should offer time-of-day rates, seasonal rates, and interruptible rates as well as offering load management techniques [96]. All the methods designed to flatten the load curves (Fig. 2-1 and 2-2) are seen as enhancing the efficiency of use of facilities and are to be encouraged under the purposes of PURPA.

Load management copes with the variability of the load curve by lowering the peaks and filling the valleys. The result of load management is a higher load factor and a lower cost of electricity per unit of electric energy. In addition to methods for directly influencing the demand or load curve, this section discusses two ways of adjusting to the curve, even though these may not fall within the definition of load management. One way a utility can adjust to a given load curve is by coordinating its operations with other utilities, in a power pool, or by obtaining power by contract from a remote supplier over the transmission lines of another utility (wheeling). Pooling and wheeling are discussed in

Section 2.3.1. A second way in which utilities can cope with a given load curve is by choosing a generation mix of base load, intermediate, and peaking generation designed to minimize the cost of production of electricity. Generation mix is discussed in Section 2.3.2 along with energy storage. Energy storage is a form of load management especially important to the development of SPPFs generating electricity from intermittent sources. A part of the exploration of the energy storage issue is postponed until after the more detailed discussion of wind and photovoltaic generation of electricity in Section 5.0.

Section 2.3.3 is an introductory discussion of utility rates as a load management tool. The principles of ratemaking are discussed in Section 4.0 and their application to interconnected CFs and SPPFs is discussed in Section 5.0

Load control devices are discussed in Section 2.3.4. Such devices allow the utility to limit electric service selectively during particularly high system peaks. By imposing a very limited inconvenience on consumers, load control devices make possible significant reductions in generation and/or transmission capacity and hence in the cost of electric service.

2.3.1 Pooling and Wheeling

A utility that serves a large number of customers in a diverse mix of demand patterns (residential, commercial, industrial) has a broader, less sharp peak than a small utility, or one without a good mix [97]. This broader peak results from the fact that diverse consumers' individual peaks are not likely to coincide. A small power producer or cogenerator lacks this consumer diversity; its own consumption pattern is unlikely to yield a flat load curve. To obtain the advantages of consumer mix, the independent producer needs interconnection with a public utility.

2.3.1.1 Pooling

Even a large utility with a diversified mix of customers must seek to flatten the demand curve further. It does so by membership in a regional power pool, which allows it an effective increase in consumer diversity. Just as the individual customers of a single utility do not make their peak demands at the same time, the individual utility peaks do not coincide. Thus, their aggregate peak is less than the sum of their individual peaks.

PURPA § 205 facilitates voluntary pooling among utilities by providing authority for FERC to exempt utilities (within specified limits) from state regulations that might inhibit pooling. Moreover, § 205(b) mandates a FERC study of "the opportunities for—(A) conservation of energy, (B) optimization in the efficiency of use of facilities and resources, and (C) increased reliability, through pooling arrangements." Here PURPA reflects statutory recognition of the desirability of conservation and economy through collective action, as is the case in § 210 relative to the encouragement of cogeneration and small power production through interconnection.

Interconnection with utilities of cogeneration and small power production facilities shares some of the characteristics of pooling. From the viewpoint of the independent producer, the utility is an "infinite reservoir" of electric power. Its load profile, already a smooth curve without excessive on-peak/off-peak variation, can absorb the narrower supply and demand peaks imposed by the independent facility, without appreciable effect on the utility's preexisting load curve. From the overall system point of view, the utility plus the interconnected independent producer is simply a larger pool. But from the viewpoint of the utility, the supply and demand spikes imposed by the independent facility are a nuisance that does not make load management any easier. The detailed effect of various kinds of solar production of electric power on load management by interconnected utilities is discussed in Section 5.0.

Interconnection that may be required pursuant to PURPA, §§ 210 or 202, differs from voluntary pooling. Ordinary pooling is among systems of comparable size, each of which has already achieved a certain degree of load curve smoothing and reliability. Finally, in pooling arrangements among utilities, the prices of exchange of electric energy and power are wholesale prices for all transactions. Conversely, in the buy and sell provisions of PURPA § 210 governing exchanges of energy between public utilities and independent facilities, the latter must buy at retail and sell excess to the utility at wholesale prices.

The concept of pooling plays an important role because pooling represents a useful model for the relationship between a utility and a CF or SPPF. Although the primary model for energy sales between utilities and QFs is expected to be wholesale (for sales to utilities) and retail (for sales by utilities), the FERC Staff Paper on § 210 regulation suggests that another model might be better. The paper states:

> With regard to the sale from a utility to a qualifying facility, the primary model is conventional State-regulated retail sales, <u>though in some instances partial requirements or interchange wholesale rates provide a better basis of comparison.</u> [98] (Emphasis added.)

2.3.1.2 Wheeling

In a wheeling arrangement, utility X sells electricity to utility Z using the transmission facilities of utility Y. Since electricity does not come in identifiable packages, this is tantamount to a sale of a fixed quantity of electric energy by X to Y and its resale to Z, with a markup corresponding to transmission costs.

The desire of utilities X and Z to enter into a contract arises when X has excess power available that it is prepared to sell to Z at a price lower than Y offers. Such a contract between X and Z is socially useful if the sale improves one or both load curves—if the facilities of X and Z can thus be used more efficiently. Both load curves will be improved, for example, if the load peaks do not coincide. However, utility Y may seek to negate the proposed contract by refusing to transmit the power, in the expectation that Z will then have no choice but to purchase (at a higher rate) from Y.

PURPA § 203 amends the Federal Power Act by authorizing FERC to order a utility (Y, in the preceding example) to wheel electric power from another (X) to a third (Z), provided that such an order would "(A) conserve a significant amount of energy, (B) significantly promote the efficient use of facilities and resources, or (C) improve the reliability of any electric utility system to which the order applies." Again, as is true of § 205 with respect to pooling, PURPA seeks to encourage conservation and efficient use of facilities through providing FERC with wheeling authority in § 203.

It is perhaps one of the serious shortcomings of PURPA that the authority to order wheeling does not apply to interconnected CFs or SPPFs. The incentives for cogeneration and independent production of electricity from solar sources would be enhanced if a facility could sell its excess production to an independent consumer at retail rates, while paying a transmission charge to the utility, instead of being obliged to sell its excess to the utility at the lower "rate which [does not exceed] the incremental cost to the electric utility of alternative electric energy" [99]. Accordingly, PURPA § 203 should be modified or amended to extend the authority to FERC to order utilities to wheel power from qualifying CFs or SPPFs to third parties, at least where the third party is owned by or in partnership with the owner of the CF or SPPF.*

2.3.2 Generation Mix: Base Load, Intermediate, and Peaking Generation; Storage

2.3.2.1 Generation Mix

Utilities attempt to optimize system expansion and minimize the cost of providing electric service by using a mix of base load, intermediate, and peaking generation units [101]. Ordinarily, base load is supplied by the cheapest energy sources—coal, nuclear, and possibly hydroelectric.** Intermediate load is usually supplied by oil. Peaking generation often uses relatively small combustion turbines, which are quickly brought on-line but burn expensive fuel with low efficiency. The percentage of system capacity provided by combustion turbines ranges from 10-18%, by region. Fuel costs and restrictions, combined with improved load management, will tend to reduce this percentage and lead to increased use of small fossil-fueled steam peaking units [103]. A schematic graph of the mix of the three kinds of generation is shown in Fig. 2-3 [104].

Baseload generating units operate 24 hr/day, except during planned and forced outages. Intermediate generating units are cycled (sometimes referred to as "cycling units") to

*A change in § 203 to allow FERC to order utilities to wheel power from a QF would have to be accompanied by deletion of a part of § 210(a) as well. In § 210(a) PURPA forbids FERC to "authorize a qualifying cogeneration facility or a qualifying small power production facility to make any sale for purposes other than resale." Without deletion of this language, FERC would still be foreclosed from ordering a utility to wheel power from a QF to a non-utility purchaser. The fact that PURPA withholds from FERC the power to authorize retail sales by QFs does not mean that PURPA forbids all such sales. The Conference Report states that "[t]he cogenerator or small power producer may be permitted to make retail sales pursuant to State law" [100]. Nevertheless, the restriction on FERC authority must be removed in order to make the proposed modification of § 203 meaningful.

**Cost of fuel is measured as internal cost to the utility. Not included are social or external costs. Such costs for nuclear fuels would include government enrichment of nuclear fuels, plant decommissioning costs, and ultimate waste disposal costs. Other external costs that are not accounted for are the detriment to human health from air pollution and low level radiation, and environmental damage such as oil slicks and strip-mine damage. The energy cost of hydroelectric power is low, and hydroelectric generation imposes no further environmental costs once the dam and water impoundment have been built. The low cost suggests the use of hydroelectric for base load generation. However, hydroelectric power is very responsive and suitable for meeting spikes in the demand curve. In many utilities, hydroelectric power is used for peaking generation to the extent that is consistent with downstream water requirements [102]. Of course the total energy available at a dam is determined by the water availability (in gal/min) and the height of the dam.

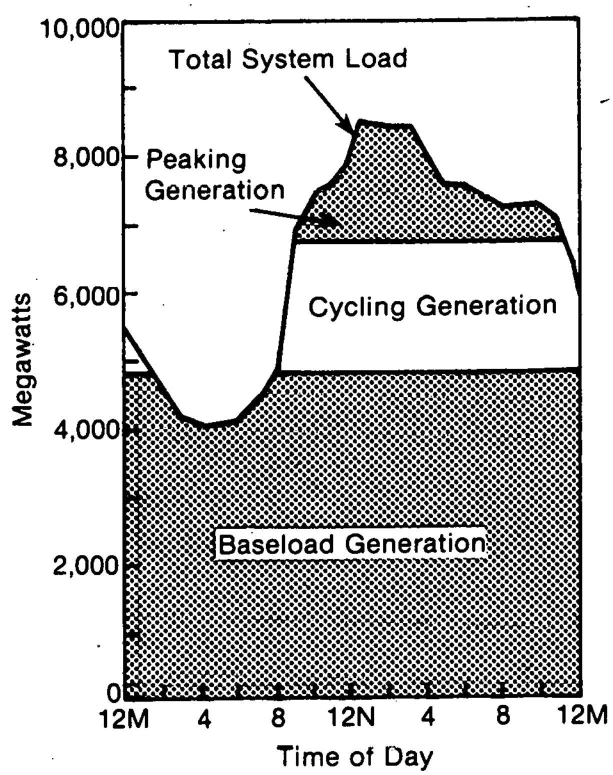

Figure 2-3. Schematic Graph of the Mix of Three Kinds of Generation

accommodate the regular daily fluctuations in the load curve. Peaking units are used for sudden fluctuations and to accommodate the top of the load peak. At the off-peak times, especially in the valley in Fig. 2-3, the base load generating units are under-utilized. Moreover, base load fuel costs are low. It is therefore economical to generate excess electricity at such times, if it can be converted and stored conveniently.

2.3.2.2 Storage

The storage most extensively used by utilities is pumped hydro [105]. Water is pumped through a conduit from a lower to a higher reservoir, using off-peak electric energy. During peak demand, the flow in the conduit is reversed and hydroelectric power supplies a part of the peak demand. The hydroelectric power capacity associated with pumped storage replaces part of the capacity requirement to meet demand peaks.

Other emerging technologies for energy storage are not as cost effective as pumped-hydro storage but may offer other advantages; moreover, their cost-effectiveness is expected to improve. They include fuel cells (reversible hydrolysis cells in which electric energy is used to dissociate water molecules into hydrogen and oxygen; then hydrogen and oxygen are allowed to recombine to generate electricity directly, without an intermediate thermal step); advanced storage batteries (projected as cheaper than lead-acid batteries); flywheels (storing rotational energy); compressed air; and electromagnetic storage (using superconductors). A virtue of many of these systems is the ease with which they can be used on a dispersed basis, for example, coupled with solar production of electricity in remote places with no access to utility interconnection.

2.3.2.3 Intermittent Hydroelectric Generation

Energy storage helps to improve the efficiency of use of generation facilities, which is the second PURPA goal. However, energy storage promotes this goal (in many cases, at the cost of using extra fuel) thus violating the first of the PURPA goals [106]. There are two ways of using storage that provide the advantages of load management without violating the goal of energy conservation. One example is the use of existing hydroelectric facilities for load management. Where downstream water requirements permit and the impoundment is adequate, water can be retained in the reservoir during off-peak times and used entirely to meet peak demands.* Such operation may require added turbines, since greater kilowatt capacity is required to generate the electricity available

*Springfield, Vt., voted to establish a municipal power system in 1977, based on a network of dams on the Black River and on projected enlargement of the Hawk Mountain reservoir. Springfield expects to meet its own peak load with 17.3% of the energy output from the hydroelectric system and to sell the remaining hydropower to other utilities at peak times. For other than peak-load use, Springfield will buy base load power from other utilities [107]. The technical effect of Springfield's operation is the same as if a larger utility network used the Black River dams for peaking production, thus reducing its need for fossil fuel capacity. The economic effect is a saving for Springfield because its (peak power) selling price is higher than its (base load power) buying price. It is not clear, however, that the economics of such an arrangement would work out as well for a small power production facility that did not have the status of a municipal utility. The transactions between the Springfield municipal utility and other utilities are conventional wholesale transactions.

from a fixed amount of water during peak-load hours than that needed to generate the same amount of energy distributed over the entire day. But, the cost of hydro-turbines is very small compared to the cost of a dam or the cost of a steam generating plant.

2.3.2.4 Storage and Interconnection

A second example is storage that makes possible the use of electric energy from solar sources such as wind, which might otherwise be unusable. If interconnection with a utility is not feasible, it is desirable to connect a wind generating system, for example, with a storage system. Such a storage system would allow the ultimate use of a portion of the excess energy that is generated, at times when there is insufficient wind. There is still, of course, a loss of energy resulting from the conversion of electric to chemical energy (in the storage battery) and back again; however, absent the storage, the entire excess energy would have been wasted. If, on the other hand, interconnection is feasible, both the capital cost and the energy costs of storage can be avoided, at least to modest levels of market penetration by solar technologies.

2.3.2.5 Planning for Solar Production of Electricity

Decisions concerning the optimum mix of base load, intermediate, and peaking generation, and desirable levels of energy storage capacity, have a large impact on the cost of electricity and the prospects for solar commercialization.* Significant levels of conservation, load management, development of generation facilities using solar resources, and use of cogeneration would diminish the required expansion of conventional electric generation capacity. Moreover, substantial use of wind energy (beyond at least 5% of the capacity of a utility) might make accelerated development of energy storage desirable. The electric utility industry has not as yet taken account of any such development in its forecasts [108].

2.3.3 Load Management Through Rate Structure

Peak-load pricing (or time-of-day rates) of electric service to large industrial users has proved a highly effective way to increase load factors in Europe during the past 20 years [109]. An experimental schedule by the Pacific Gas and Electric Co. for its largest customer has confirmed that time-of-day (T-o-d) rates are a feasible load management tool in the United States [110]. Residential customers also respond to experimental T-o-d rates by shifting demand away from the system peak [111].

Time-of-day rates may simply mean a much higher on-peak price per kWh than off-peak, as in residential applications; or there may be a relatively small energy price differential among peak, partial peak, and off-peak, along with a large demand charge difference [112]. A demand charge is usually based on the largest power demand in kW (averaged over a 15-min period) during the billing period.

Interruptible rates are another means to improve load factors or decrease system peaks. Consumers may be given a lower electric rate if they accept the contingency of having

*The economic consequences of poor decision making about generation capacity and mix are explored further in the course of the discussion about utility revenue requirements in Section 4.1.1.

their service disconnected during a system peak. The amount of the interruptible demand could be considered a part of the spinning reserve, since it can be interrupted as required by system contingencies.

A more benign form of interruptible rate is the curtailable rate. This allows the utility to cut off the excess over a certain minimum of service, as the need arises. Applied to residential users this would permit, for example, refrigerators, emergency lights, and the controls on nonelectric heating systems to remain on, while service to other appliances and general lighting could be cut off during system emergencies. The widespread adoption of such service could save much investment in reserve margin capacity, and even massive curtailment would be far more acceptable than a blackout. The cost of retrofitting existing housing stock to such fine-tuned curtailable service might be large. But serious consideration should be given to wiring code revisions that would make curtailable service possible. An instance of curtailable service is given in Section 2.3.4.

PURPA § 111(d) establishes as federal standards that time-of-day rates shall be charged insofar as they are cost effective, and that interruptible rates be offered to industrial and commercial customers. The restriction that the rates be cost effective requires a comparison of the long-run benefits of the rate with metering and other associated costs [113]. The standards do not constitute a requirement, however. Each state regulatory authority must, within three years of the adoption of PURPA (i.e., by 9 Nov. 81) consider the standards set in § 111(d) and determine "whether or not it is appropriate to implement such standard. . . " [114]. Thus, again, there is a congressional mandate for load management, though the mandate leaves much room for state inaction.

2.3.4 Direct Load Controls

Demand at times of system peaks can be reduced through direct radio control of a customer's power demand by the utility. For example, the Albany (Georgia) Water, Gas, and Light Commission can shut off air conditioning compressors on a computer controlled basis. This municipal utility buys electricity wholesale and pays a demand charge for 12 months based on its maximum kW demand coincident with the territorial peak. Any control that decreases Albany's demand at that time saves Albany $60/kW. By cycling 3,700 air conditioners and 700 hot water heaters off for 7-1/2 minutes per half hour during the worst 16 hours of summer 1978, Albany shaved its coincident peak by 9.5 MW, for a demand charge saving of almost $600,000. The control units have an average cost of under $80. The installation is optional with the customer, who receives no special rate for agreeing to the curtailment [115].

A more widely used direct load control is off-peak electric hot water heating. This allows for at least one of the hot water heating elements to be supplied by off-peak power only. The off-peak power is metered and billed separately.

SECTION 3.0

QUALIFYING SMALL POWER PRODUCTION AND COGENERATION FACILITIES

The Public Utility Regulatory Policies Act of 1978 defines a SPPF as one that produces electric energy from biomass, waste, or renewable resources, and has no more than 80 MW of generating capacity [116]. A CF is defined as one that produces "(i) electric energy, and (ii) steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes" [117]. The act defines a qualifying SPPF or CF as a facility that is "owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from CFs or SPPFs)" and "which the Commission determines, by rule, meets such requirements . . . as the Commission may, by rule, prescribe" [118].

Qualification is of fundamental importance in the commercialization of electric generation from solar and renewable resources. Qualifying SPPFs and CFs are eligible for interconnection with public utilities, including the right to sell excess electric energy and to buy backup energy from the utility at nondiscriminatory rates, and exemption from certain laws, including state regulation as an electric utility.

Interconnection is crucial for the commercialization of systems that generate electricity from intermittent sources (e.g., wind, sunlight) because backup energy may be required. Absent interconnection, these systems are useful only in conjunction with expensive storage systems, or for end uses that are readily interruptible. The ability to sell excess energy to the public utility is significant both to prevent waste (i.e., to allow the maximum displacement of fossil fuels) and to make the facility economically viable.

Exemption from state regulation may be necessary to permit sales of excess energy from SPPFs or CFs to utilities. In many states, such facilities are classified as electric utilities and subject to regulation as such, by virtue of selling electric power. State regulatory agencies may refuse SPPFs and CFs licenses to operate unless the SPPFs or CFs are exempted from such regulation. Alternatively, state regulation of SPPFs and CFs as electric utilities may impose economic and procedural requirements—designed for the regulation of monopolistic public utilities—that may be so burdensome that the small producer cannot operate economically. Thus, denial of qualification to a SPPF or a CF by depriving it of exemption from state regulation may make it impossible or uneconomical to operate.

Pursuant to PURPA § 201, the Commission has proposed rules that set the requirements for qualifying small power production and cogeneration facilities [119]. This section offers comment on the proposed rules, including a PURPA requirement incorporated into the FERC rules.

3.1 PROPOSED PROCEDURE FOR CERTIFICATION OF QUALIFYING STATUS

Sections 292.202-.204 and 292.208-.209 of the proposed rules establish a certification process for qualifying status of small power production and cogeneration facilities. Although FERC is required, by § 201 of PURPA, to formulate rules defining qualifying SPPFs and CFs, the act does not require case-by-case certification. The proposed certification rules are not necessary. It would be sufficient for FERC to establish generic rules as to qualification. Such rules would be available for use should a dispute arise between a utility and a power user/producer, and to assist state regulatory authorities in making generally applicable tariffs. The proposed certification procedure would serve as a disincentive to the establishment of CFs and SPPFs, because of the time and expense involved. The proposed regulations should be amended, on policy grounds, to eliminate the certification procedure.

3.1.1 The Procedure

When a small power production or cogeneration facility (of any size) seeks to interconnect with a utility, the first step is for it to negotiate directly with the utility. If the utility, with the agreement of the state regulatory authority, agrees to interconnect, buy excess power, and sell backup power at fair rates, the SPPF or CF need go no further. If the utility refuses to interconnect at fair rates, there are two possible scenarios under the Commission's proposed rules.

First, the applicant might seek to compel the utility to interconnect and/or provide a fair rate by appeal to the state regulatory authority. This regulatory authority, in turn, might either grant the appeal or might raise the question, "Are you a qualifying facility?" At this stage, if the applicant has not been certified pursuant to proposed rule 292.202, the answer will be "No." In that case the applicant would be forced to seek certification of qualifying status from FERC.

The applicant, having been refused interconnection at fair rates by the utility, could alternatively seek direct certification of qualifying status from FERC. The certification procedure is spelled out in proposed rules 292.202 and .208, and includes a requirement that the applicant serve notice of this FERC application on the utility and state regulatory authority (§ 292.203); moreover, the utility, the state authority, or other interested parties may file protests (§ 292.204).

If FERC certifies that the SPPF or CF qualifies, the proceedings presumably shift to the state regulatory authority for an order permitting the applicant to sell excess power and buy backup power at rates established by the state authority consistent with FERC regulations (yet to be proposed) pursuant to PURPA § 210. An alternative possibility might be (if a rate schedule exists already) that the certified SPPF or CF can now interconnect without a hearing at the state regulatory authority. A further possibility, not precluded by the text of PURPA § 210, is that FERC could set actual rates, thus allowing the state authority to be bypassed; however, indications are that FERC will not choose to do so.

3.1.2 Objections to the Procedure

The proposed certification procedure adds an extraneous step to the regulatory process. The imposition of such procedural requirements could have an adverse effect on the commercialization of solar sources of electric power (including biomass, wind, photovoltaic, solar thermal, low head hydroelectric) by small power producers, as well as cogeneration.

The rules could better serve solar commercialization by setting qualifications for SPPFs and CFs to be used in all proceedings in connection with PURPA. In a proceeding before a state public utility regulatory authority seeking interconnection and/or fair backup and sellback rates under § 210 of PURPA, a party seeking interconnection and/or fair rates would have to assert, among other claims, that it qualified under § 201 and the Commission's § 201 rules. The utility might dispute that claim, and the state authority would then determine whether the SPPF or CF qualified.

Section 201 of PURPA defines qualifying small power production and cogeneration facilities, giving several criteria, and providing for the Commission to prescribe, by rule, additional qualifications, including "fuel use, fuel efficiency, and reliability" for SPPFs and "minimum size, fuel use, and fuel efficiency" for CFs. The act also authorizes the Commission to determine who qualifies under the act "by rule." It does not provide for the Commission to "certify" case-by-case who qualifies. Section 201 directs the Commission to establish rules for qualification. Section 201 could be read broadly to authorize individual certification of qualifying facilities, but such a reading is not compelled by the language of the statute. It can be said that creation of a certification process by the Commission is not required by the act.

It is also unclear whether the intent of the proposed regulations is to require that every SPPF and CF obtain certification, or only those that cannot get interconnection at fair rates and need to invoke the state or federal regulatory process for relief. If the former is intended, all would face a regulatory proceeding, even those that were able to obtain interconnection at fair rates. If the latter, three results would likely ensue: (1) those needing relief would be forced to go through two proceedings rather than one—certification and interconnection; (2) the prudent SPPF or CF, rather than waiting for the outcome of its dispute, might apply for certification as soon as it encountered difficulties with the utility; and (3) the very existence of the certification procedure would mean far more SPPFs and CFs would have disputes with utilities.

Regardless of the intent of the proposed regulations, the effect of establishing a certification procedure is that a utility or state regulatory authority is likely to make its threshold question when dealing with a SPPF or CF: "Are you certified?" Such a request would mean that small power producers or cogenerators would have to invoke the administrative process. It would tend to make certification a universal requirement for interconnection, whether or not that is the intent of the proposed regulations.

The existence of the certification process is thus likely to retard the growing movement by state regulatory authorities to order interconnections and fair rates to WECS facilities, and to make more difficult the interconnection of other small power production facilities.

Further adding to the burden, if certification is challenged, the certification proceeding may make it expensive for those small power producers who use it. Although the application itself (proposed rule 292.202) may be fairly simple, the regulations require discussions with the local public utility with which interconnection is sought [§ 292.202(b) and (e)(5)], and notice to that utility of the application [§ 292.203(b)]. The regulations also allow the utility to protest the certification application (§ 292.204). Utilities may routinely contest such applications. Even if the Commission is expeditious in dealing with them (e.g., by adding a large number of new staff), keeps the backlog within manageable proportions, and does not invoke its power to toll the running of the decision period (§ 292.208), the process may be long, involved, and a significant cost burden to small businesses.

The net effect could be that even when self-generation or cogeneration of electricity is economical, it may well become uneconomical if the certification procedure is established.

The proposed certification process is likely to inhibit the commercialization of solar electric generation and tax the Commission's resources. Rather than try to determine which small power production and cogeneration facilities qualify in each case, the Commission's resources could be much better used to give adequate direction to state regulatory authorities in the qualification regulations.

3.1.3 Proposed Change of the FERC Regulation

The suggestion to discard the certification procedure implies a change of the title to:

"Subpart B—Requirements for Qualifying Small-Scale Power Production and Cogeneration Facilities."

In addition, a conforming change would be required to:

"§ 292.201 Scope. This subpart applies to the requirements which must be met by small power production and cogeneration facilities in order to be qualifying small power production or cogeneration facilities under Sections 3(17)(C) and 3(18)(B) of the Federal Power Act, as amended by Section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA)."

3.2 MINIMUM SIZE LIMITATION

Section 292.205(b)(2) establishes a minimum size limitation of 10 kW for qualifying SPPFs. Legal as well as policy arguments are advanced for the deletion of this section. A similar minimum size limitation is imposed on qualifying CFs by Section 292.206(g). Policy grounds are suggested for the possible deletion of this section.

The proposed imposition by FERC of a minimum size for qualification of SPPFs and CFs would deny the advantages of PURPA to under 10-kW facilities and make their interconnection with public utilities unlikely in many states. This result seems likely to seriously hinder the commercialization of under 10-kW small wind energy conversion systems (SWECS) and small-scale photovoltaic systems (PV). The focus on SWECS and PVs is not intended to be exclusive of other technologies, but results from the lack of any present commercialization efforts involving electric generation at less than 10-kW in other solar technologies, including biomass. There is no value, of course, in foreclosing such developments.

In Section 3.2.1, the legal and statutory authority of the Commission to set a minimum size standard for qualification of SPPFs is questioned. In Section 3.2.2, policy arguments are advanced that proposed rule 292.205(b)(2) is based on a premature dismissal of the economic viability of small systems, and on an erroneous assumption that the rule frees utilities from an analysis and planning burden to which they would otherwise be subjected.* A third policy argument is that, if proposed rule 292.205(b)(2) becomes final, the minimum size limitation would discourage the commercialization of SWECS and

*The Commission's rationale for the proposed minimum size limitation is that "there seems to be no advantage in encouraging uneconomic operation of commercial systems or burdening utilities with analysis and planning for hypothetical systems which are unlikely to be constructed because they cannot recover the investment costs" [120].

small-scale PV systems, and may very well have an adverse impact on the commercialization of larger systems for use by SPPFs. Moreover, opportunities for significant fuel savings and direct involvement of citizens in the effort to conserve energy would be foregone. In Section 3.2.3, these policy arguments are shown to be reasons for the deletion of a minimum size limitation for qualifying SPPFs, and in part, serve as arguments for deleting § 292.206(g) regarding the qualification of CFs as well.

3.2.1 Legal Authority to Regulate Minimum Size of SPPFs

Section 3 of the Federal Power Act, as amended by § 201 of PURPA, does not authorize FERC to place a minimum size limitation on qualifying SPPFs. PURPA states:

"(17)(C) '[Q]ualifying small power production facility' means a small power production facility—(i) which the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe. . . ."

"(18)(B) '[Q]ualifying cogeneration facility' means a cogeneration facility which—(i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule, prescribe. . . " (emphasis added).

Taken alone, § 3(17)(C) would appear to confer the authority on FERC to set any reasonable rule. But because Congress has specifically itemized minimum size with respect to CFs in § 3(18)(B), it is correct to assume that Congress has intended that the Commission should not regulate the minimum size of qualifying SPPFs. It is a rule of statutory construction that the expression of one thing is the exclusion of others. This rule applies with particular force when something (e.g., *minimum size requirements*) is provided in one part of a statute and omitted in another [121].

This distinction between SPPFs and CFs is consistent with the congressional intent in PURPA that nonrenewable resources be conserved. CFs conserve fuel to the extent they utilize less energy than would otherwise be required to provide electricity and heat; SPPFs, on the other hand, necessarily conserve fuel since they use only solar or renewable resources as primary sources.

3.2.2 Policy Grounds for the Deletion of Section 292.205(b)(2)

3.2.2.1 The Economic Viability of Small Systems

It is premature to conclude that systems under 10 kW "are unlikely to be constructed because they cannot recover investment costs" [122]. A number of SWECS are presently in service, interconnected with public utilities, with backup and sell-back provisions. Moreover, the Department of Energy (DOE) is developing improved 8-kW wind turbine generators in conjunction with the Rocky Flats experiments. Various studies within and for DOE predict that SWECS may become economically viable in the near term and that SWECS commercialization may displace from 0.3-0.5 quad of primary fuel annually by the year 2000 [123]. An additional annual displacement of 0.2-0.3 quad by 3.4-kW PVs may be economically feasible [124].

Even if these projections prove false in the long run, and even if FERC's perception is correct that under 10-kW SWECS are not cost-effective, the congressional intention to encourage SPPFs is better served by market forces than by FERC regulation that makes interconnection unlikely.

3.2.2.2 The Analysis and Planning Burden

FERC's concern with "burdening utilities with analysis and planning" for interconnection with SWECS (and ultimately small PVs) seems unfounded. The major analysis and planning burdens would seem to relate to safety, load management, and ratemaking. Qualification of SPPFs using unsafe equipment is not proposed. At least one manufacturer (EnerTech) has an interconnectable wind generator with an automatic brake that shuts down the SWECS when there is a loss of power on the utility line, thus solving one technical planning worry. Load management planning for under 10-kW systems should not differ substantially from that which is already required for those systems larger than 10 kW, which nevertheless enter the grid at the same level. A full analysis of the impact of interconnected SPPFs on public utility capacity, energy requirements, and ratemaking is best delayed until (1) the cost-of-service studies required by § 133 of PURPA (and by the corresponding FERC regulation, Subchapter K, Part 290) are available, and (2) a data base is established for assessing the impact of dispersed WECS on the utilities to which they are interconnected.

There is presently no adequate data base to assess the potential impact on utility capacity and fuel needs of a large number of dispersed SWECS.* An excellent data base will become available when a substantial number of SWECS (at least 100,000) are in use. Even with this number, no utility would have more than 1% of its residential customers SWECS-equipped. Since the impact on residential rate payers of allowing less than 1% of them to generate part of their own electricity would be negligible, a cost-of-service analysis could be postponed until an adequate data base (not mere simulation) is available.

3.2.2.3 The Proposed Rule's Adverse Effect on Energy Conservation

Proposed rule 292.205(b)(2) would almost certainly drive residential-scale WECS off the market and deter the introduction of residential PV systems (except in isolated situations where energy storage systems are economical). Even utilities that presently cooperate with such systems would have no reason to interconnect new customers. This chilling effect on SWECS (and ultimately small PV commercialization) has serious consequences:

- The development of the 1-10 kW market, and its impact on public awareness and acceptance, may have an influence on the development of the larger scale WECS market. The stifling of the SWECS market may undermine effective and economical development of intermediate size systems, especially those systems not owned by utilities, as envisioned in Title II of PURPA.

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*A simulation study (based on four wind regimes) by General Electric for the Electric Power Research Institute suggests that wind power plants have capacity value (which diminishes as the wind component rises above 5% of the system) [125]. A second study, currently in progress, simulates dispersed WECS, including small ones. A study with actual SWECS in place is being conducted at Rocky Flats by Rockwell International; this study will be extended to about 100 machines at diverse locations within the next 18 months.

- The potential fuel saving from 4-kW SWECS and 3.4-kW PVs would be 0.5-0.8 quad annually by 2000 if the MITRE projections prove correct. It would be unfortunate if FERC regulation were to foreclose so significant a contribution towards the national goal of saving 22 quads of nonrenewable fuel annually.
- President Carter's goal of enrolling citizens in the "energy war effort" would receive a setback. Individual homeowners who meet a part of their own energy budgets do far more than displace a little fossil fuel; they contribute to the public morale and the kind of public awareness of the energy situation that is necessary for ultimate solutions.

In conclusion, proposed rule 292.205(b)(2) has the potential of aborting the very development of SPPFs that Congress sought to encourage with Title II of PURPA. The deletion of this rule would have no foreseeably harmful effects.

3.2.3 A Minimum Size Limitation for Qualifying CFs

Direct information is lacking on the cost-effectiveness or fuel efficiency of residential-scale cogeneration (such as with diesel engines that supply both residential heating and electric needs). Moreover, it must be noted that Congress anticipated that FERC might set minimum size standards for qualifying CFs. Nevertheless, it should be noted that parts of the three policy arguments for the deletion of any minimum size limitation on qualifying SPPFs serve equally well as reasons for deleting rule 292.206(g). Thus, the issue of the economic viability of small cogenerators could be left to market forces. And as is true for SWECS, residential cogenerators would impose no analysis and planning problems not presented already by somewhat larger (qualifying) units. Finally, the deletion of the restriction would encourage the involvement of individual citizens in the national energy conservation effort. Although the Commission has the statutory authority to set a minimum size for qualifying cogeneration facilities, no obvious purpose is served by proposed rule 292.206(g) and it should be deleted.

3.3 FOSSIL FUEL FOR SPPFS: SECTION 292.205(a)(2)

Section 292.205(a)(2) of FERC's Proposed Rules limits the planned use of fossil fuel in SPPFs [126]. The limits, per MW of rated capacity, are:

- 500 barrels (bbl) of oil/yr (or its Btu equivalent in gas) for ignition, start-up, and testing;
- 0.2 bbl of oil/hr of operation (or its Btu equivalent in gas) for flame stabilization and control;* and
- 110 bbl of oil/yr (or its Btu equivalent in gas) during outages of the normal fuel supply.

Limits on fossil fuel use by SPPFs are required by § 201 of PURPA in which a SPPF is defined as one that "produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof. . ." (emphasis added). The act further states that:

*In the case of facilities burning solid municipal wastes, the limit is 0.5 bbl of oil/hr of operation.

"primary energy source" means the fuel or fuels used for the generation of electric energy, except that such term does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy—

(i) the minimum amounts of fuel required for ignition, start-up, testing, flame stabilization, and control uses, and

(ii) the minimum amounts of fuel required to alleviate or prevent—
(I) unanticipated equipment outages, and
(II) emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages. [127]

A technical and policy argument is presented below that the 110 bbl limit for use during outages of normal fuel supply is insufficient. A modification is proposed that the amount of 110 bbl in § 292.205(a)(2)(iii) be increased to 1210 bbl of oil/yr per MW of generating capacity. Alternatively, it is proposed that the aggregate fossil fuel for the purposes stated in all three subsections of § 292.205(a)(2) be set at 1800 bbl, with the distribution among the three uses at the discretion of the small power producer.

3.3.1 The Technical Need for Fossil Fuel in Hybrid Systems

Solar thermal electric generation is a promising use of solar energy for the production of electricity. Solar thermal units use steam generators in which heat is supplied to the boiler by sunlight reflected from an array of mirrors. The mirrors are motor driven by heliostats so that the reflected light continues to fall on the boiler while the position of the sun in the sky changes. An experimental 10-MW solar thermal electric installation is under construction by Southern California Edison Company at Barstow, Calif.

In the Southwest, there is adequate sunlight for 80% of the approximate 3500 hours during which utilities require peaking or intermediate generation [128]. By supplying solar thermal electric units with fossil fuel for 700 hr/yr, one would have a reliable substitute for peaking and intermediate generation capacity equal to the rated capacity of the unit. Such a hybrid system (part solar, part conventional fuel) obviates the need of utility generation capacity far more effectively than a pure solar thermal system would, since a pure system is unavailable about 20% of the intermediate and peak load time.

An annual allotment of 110 bbl of oil provides enough energy to generate 64 MWh, or 1 MW for 64 hours [129]. In order to provide fuel for 700 hours of operation per year, the allotment must be increased by the ratio 700:64 to 1210 bbl.

A somewhat more generous total oil use allotment is appropriate in order to extend the usefulness of solar thermal electric production into regions of the country where sunlight may be available for less than 80% of the peak load time. In places where adequate insolation is available only 70% of the peak and intermediate load time, a total of 1800 bbl/yr per MW capacity would allow fossil fuel operation during the remaining 30% of that time. The fossil fuel energy contained in 1800 bbl of oil equals the total electric energy output of a hybrid plant operating 3500 hr/yr. Thus, the proposed SPPF would generate as electric energy an amount equal to 100% of the chemical energy contained in the fossil fuel consumed, as compared to a conventional plant that may reach an efficiency of 33%.

3.3.2 Policy Arguments for Encouraging Hybrid Systems

Without an increased oil allotment "during outages of the normal fuel supply," it is not economical to build solar thermal electric plants. Facilities not owned by utilities, if barred from hybrid operation, would be at a hopeless disadvantage compared with utility-owned facilities, since the latter would not be bound by rules governing SPPFs. In order to encourage the development of any new energy technology, it is useful to rely on a private alternative. Utilities are not likely to take as much initiative in developing new technologies, because of a tradition of favoring large size and because state regulation does not encourage utilities to venture into new technologies [130].

The proposed 1210 bbl of oil to be used during outages of the normal fuel supply (in this case outages are simply unavailability of sunlight) actually represents less fossil fuel than would be allowed under FERC's proposed rule § 292.205(a)(2)(i-iii) per MW for a biomass plant operating 3500 hr/yr. The FERC proposed rule would permit the use of:

- 500 bbl of oil for start-up, etc.;
- 700 bbl for flame stabilization at 0.2 bbl/hr of operation; and
- 110 bbl during outages of normal fuel supply—for a total of 1310 bbl of oil/yr per MW. Since the hybrid system would in fact need no additional oil for start-up and for flame stabilization, it is no more wasteful of oil than biomass plants are allowed to be. In either case the fossil fuel use is about 20% of the amount a conventional plant would consume to generate the same power for the same number of hours.

3.3.3 Is An Increased Fossil Fuel Allotment Consistent with PURPA?

It appears that PURPA allows SPPFs fuel only during unanticipated equipment outages and emergencies. Strictly construed, the language defining "primary energy source" does not permit the use of fuel to make possible a hybrid system. It is not even clear in what way the act authorizes FERC's proposed allotment of 110 barrels "during outages of the normal fuel supply."

Authority for FERC to prescribe a limit of 1210 bbl (or preferably 1800 bbl for all purposes together) can be inferred from these sources:

- the proposed increased allotment is consistent with the purposes of Title I (quoted in Section 2.3), which are in turn consistent with Title II.
- The Conference Report on PURPA states that

  > [w]ith regard to the definition of "small power production facility", the conferees intend, for purposes of maintaining status as a small power production facility, that the phrase "primary energy source" does not preclude the use of gas or oil in a facility for the generation of electricity during scheduled outages. [131]

- The entire language governing "primary energy source" appears to be inadvertently unaware of the solar thermal technology.

Although the unavailability of sunlight is more nearly analogous to forced than to scheduled outages, the urgency of using oil during solar unavailability is even greater than the urgency of continuing to generate electricity during scheduled outages, for scheduled outages are not taken during peak load hours. The use of oil or gas for "flame stabilization" may be necessary for burning waste or biomass, but it is totally irrelevant to conventional fossil generation as backup for solar thermal. "Unanticipated equipment outages" similarly suggests a focus on fuel burning installations, since the sun is not really "equipment." Even FERC (relied on to give technical implementation to the PURPA requirements) speaks of "outages of the normal fuel supply," which does not seem to include sunshine unless read very broadly. It appears, therefore, that neither the drafters of PURPA nor FERC foresaw the special problems of solar thermal electric generation.

The changes here proposed to § 292.205(a)(2) of FERC's proposed rules under PURPA, § 201, are consistent with the intent of PURPA. Nevertheless, a modification of § 201 would be desirable. Section 3(17)(B) of the Federal Power Act, as amended by PURPA § 201, should be amended by adding:

> (iii) an amount of fuel to operate a solar thermal facility for up to 30% of its total operating time, during periods of insufficient insolation, provided, however, that the total fossil fuel energy expended is less than the total electric energy generated.

3.4 HYBRID COGENERATION/BIOMASS SPPFS

A gap in PURPA and the FERC proposed rules is the lack of clarity regarding hybrid facilities with portions that operate as CFs and other portions that operate as SPPFs. Neither PURPA nor the proposed rules make clear whether a facility that is a hybrid of cogeneration and small power production is qualified as either or as a combination.

An example of the type of facility that falls into this regulatory gap is the electric power facility of the Louisiana Pacific Corporation [132]. This facility uses wood waste to generate 35 MW of power—about 20 MW in a cogeneration mode and 15 MW in a conventional biomass-fueled steam turbine generating plant.

Section 201 of PURPA defines a SPPF as one which "has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 MW" (emphasis added). Since Louisiana Pacific uses biomass for its cogeneration and its small power production modes, and since both plants are at the same site, the facility would qualify as a SPPF. However, although Louisiana Pacific does qualify as a SPPF, it might well prefer to qualify as a CF.

A 35-MW SPPF is disadvantaged relative to a CF because:

> No qualifying small power production facility which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission) exceeds 30 MW, may be exempted [from the provisions of the Federal Power Act]. [123]

Because exemption is available to CFs, it would be an advantage for a facility such as Louisiana Pacific to qualify as a CF. However, taken as a 35-MW CF, the plant will not meet the efficiency requirements of § 292.206(d-f), since only about one-half the plant operates to utilize waste heat. Thus, it would be to Louisiana Pacific's advantage to qualify as a 20-MW SPPF and a 15-MW CF.

A sharper definition of the same problem is provided by a hypothetical 35-MW facility in which 20 MW are a fossil-fueled CF and 15 MW a biomass SPPF. In this case, the entire facility cannot qualify as either SPPF or CF; it is a hybrid of the two.

By separating its rules regarding qualifying SPPFs (§ 292.205) from those regarding qualifying CFs (§ 292.206), FERC has left unclear the status of a facility that is a hybrid of the two. A separate section is probably needed, to clarify that in a multiunit facility of which less than 80 MW falls under the definition of qualifying SPPFs and separate units fall under the definition of qualifying CFs, the composite may qualify in part as a SPPF and in part as a CF.

3.5 MAXIMUM SIZE LIMITATION

The preceding four recommendations constitute a comment on FERC's proposed implementation of § 201 of PURPA. The remaining recommendation is for a modification of the act itself insofar as it pertains to the qualification of SPPFs for exemption from certain laws. The recommendation is in two parts.

3.5.1 Recommended Amendments to PURPA

The first part of the recommendation is to delete § 210(e)(2). According to the definition in PURPA, a SPPF is limited to a rated power production capacity of 80 MW [134]. However, the exemption of qualifying SPPFs from regulation under the Federal Power Act, the Public Utility Holding Company Act, and state laws and regulations respecting rates or the financial or organizational regulation of utilities, is limited to SPPFs of 30-MW capacity or less [135].

The congressional intent behind the exemption is, in part, that

> the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producer's power should not be burdened by the same examination as are utility rate applications, but rather in a less burdensome manner. The establishment of utility type regulation over them would act as a significant disincentive to firms interested in cogeneration and small power production. [136]

There is no discernible reason for the distinction between the maximum power production capacity of a SPPF (80 MW)—hence, the criteria for interconnection—and the maximum capacity (30 MW) for exemption.

The second part of the recommendation is to change the maximum size criterion in the definition of a SPPF in § 201 from "a power production capacity . . . not greater than 80 MW" to "an annual energy production capability . . . not greater than 500 million kWh."

No rationale is offered for defining the capacity of a "small power production facility" in terms of its rated power capacity (in megawatts) in § 201 while defining the minimum capacity of electric utilities for purposes of "coverage" of Title I in terms of annual energy sales (in kilowatt hours) in § 102. Title I of PURPA applies to electric utilities whose annual volume of retail sales exceeds 500 million kWh. It is noteworthy that this is just equal to the energy output of an 80-MW plant operating at a 70% capacity factor. There appears, therefore, to be a certain correspondence between the PURPA drafters' sense of "too small for Title I to apply" and a "small" power production facility.

Insofar as the model of a SPPF is a biomass-fueled steam turbine generating plant, there is a rational connection between the power capacity limit of 80 MW and the § 102 concept of a small electric utility; one with the ability to produce 500 million kWh of electric energy/yr. However, a different situation remains for wind energy conversion systems (WECS) or other technologies that depend on a resource of limited availability. Is an 80-MW WECS or a 500 million kWh WECS more like the 80-MW biomass SPPF that generates 500 million kWh annually?

3.5.2 WECS Operation

The effectiveness of a WECS is strongly dependent on the local wind regime. The power available in the area intercepted by the turbine is proportional to the cube of the wind speed. No power is available, however, at wind speeds below the cut-in speed or above the cut-out speed of the particular machine. Moreover, each WECS has a rated output corresponding to a rated wind speed. At wind speeds greater than the rated speed and less than the cut-out speed, the WECS electric power output remains at the rated output; the benefit of increased output with increased wind speed is lost. The wind regime thus enters into the choice of WECS in two ways: (1) it is uneconomical to install a WECS unless there is adequate wind enough of the time, and (2) the rated value of wind speed must be appropriate. Too small a rated wind speed for the local wind regime means the WECS operates at capacity but foregoes much available wind energy; too large a rated speed means excessive capital costs for a machine that rarely operates at capacity [137].

The capacity factor is defined as the ratio of the energy generated in a time period to the energy that would have been generated had the WECS run at rated output continuously. The capacity factor is a measure both of the wind regime and the designer's trade-off between capital cost and the value of the energy obtained. Capacity factors as high as 50% are possible in high wind areas, but at least one study assumes an average capacity factor as low as 12% [138].

3.5.3 The Social Value of the Proposed Amendment

WECS may be used in four distinct modes. Small WECS may be used to provide the electrical needs of a household or farm, provided backup is available through interconnection. Intermediate or large WECS may be used to supply energy to an industrial or commercial facility. Groups of large WECS, constituting a "wind farm," may be owned and operated by utilities as a portion of their generation facilities. A similar wind farm can be independently owned and operated solely for the purpose of selling electric energy to the public utility.

The incentive for building an independently owned wind farm is economic—it will be done when an investor sees the possibility of an advantageous investment. Independent wind farms are socially useful because the risks inherent in a new technology are not assumed by the customers of the utility if private capital is used for this experimental purpose.

Independent commercial wind farms require a large capacity to be economically competitive; 30 MW is too small and 80 MW is marginal [139]. Exemption from regulation under the Federal Power Act is essential. Without exemption, the cost of production becomes a factor in the rates and the risk capital will not be forthcoming. With exemption, the rates are based on the provisions of § 210(b) of PURPA and may not exceed "the incremental costs to the electric utility of alternative electric energy." Thus, the restriction of exemption to SPPFs of no more than 30 MW would "act as a significant disincentive to firms interested in . . . small power production" [140].

The second of the proposed amendments has the practical significance of allowing larger wind farms than would be permitted under an 80-MW limit on SPPFs. An amendment to set a maximum annual energy output of 500 million kWh as a limit, instead of a maximum rated power capacity, has the additional advantage that technical choices about rated capacity would be based on economic and not on regulatory parameters. That is, the rated wind speed would be selected on technical grounds, not in order to meet a regulatory goal.

SECTION 4.0

ELECTRIC UTILITY RATE REGULATION

Section 3.0 addressed the issue of "qualification" under § 201 of PURPA and its implementation by FERC. Even facilities that qualify under the regulations face a potential barrier under § 210, which requires FERC to set standards for exemption of qualifying facilities from certain laws and regulations, and rules governing the rates at which utilities are required to buy from and sell to QFs.* Because of the large initial cost of most solar technologies for producing electricity, a favorable rate structure may be a necessary incentive.

FERC rating rules must implement the following statutory language:

> The rules . . . shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase—
>
> (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. [141]
>
> No such rule . . . shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy. [142]
>
> "[I]ncremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, 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. [143]
>
> The rules . . . shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale—
> (1) shall be just and reasonable and in the public interest, and
> (2) shall not discriminate against the qualifying cogenerators or qualifying small power producers. [144]

Section 5.0 explores how the preceding PURPA requirements concerning rates can be reconciled with the mandate of § 210(a) that FERC's rules "encourage cogeneration and small power production." Section 4.0 attempts to provide a background of public utility ratemaking principles against which the recommendations made in Section 5.0 can be understood.

Ratemaking is a complex if not arcane discipline, the subject of numerous profound treatises [145]. Among these treatises, the work by Bonbright has given rise to the widely recognized "Bonbright principles" of rate regulation. A detailed application of

*The rationale for exemption has been discussed in Section 3.5.1 and in the quote in the text accompanying Ref. 136. The focus of the remainder of this report, however, is on the rates and not on exemption.

marginal cost pricing to electric utility rate structures is the topic of an important scholarly article [146]. A helpful primer on electric utility rate design has been prepared by the Electric Power Research Institute for the National Association of Regulatory Utility Commissioners [147]. Two recent SERI publications provide brilliant expositions, both simple and lucid, of utility ratemaking in relation to the commercialization of solar energy technologies [148]. An earlier article relating solar energy development and utility rates is of seminal importance [149].

Section 4.1 discusses the three major Bonbright principles of rate regulation. The way in which these ratemaking principles are implemented affects the analysis of the costs imposed on utilities or averted by the commercialization of cogeneration and of solar production of electricity. Section 4.2 describes the use of long-range incremental cost (LRIC) analysis in utility ratemaking. The LRIC approach is one way to interpret the requirement of PURPA § 210(b) that "no such rule . . . shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy." A LRIC interpretation of this requirement may lead to a rate structure that successfully encourages QFs and SPPFs.

4.1 GOALS OF A RATE STRUCTURE

Ratemaking is widely recognized as meeting three primary and several secondary objectives [150]. These so-called Bonbright criteria are:

- Rates should provide sufficient revenue to keep the utility economically sound.
- Rates should be fair and nondiscriminatory, reflecting the cost of serving each class of customers.
- Rates should promote an efficient allocation of resources regarding:
  - the amount of utility service purchased by the consumer, and
  - the balance between peak and off-peak service.

Additional goals are the stability and continuity of rates, simplicity, clarity and feasibility of application, and public acceptance.

4.1.1 Revenue Requirement

The first step in a ratemaking procedure before a state regulatory authority is to determine the utility's revenue requirement [151]. The revenue requirement must cover operating expenses as well as a "fair return" on investments in the utility [152]. The inquiry into the revenue requirement is "often qualified by the stipulation that the relevant cost is necessary cost or cost reasonably and prudently incurred" [153].

Insufficient attention has been paid by regulators to the question of "necessary cost . . . prudently incurred." As noted in Section 2.1.2.3, the electrical industry has been severely overestimating the growth in demand. Arguably, such overestimates represent the sort of "imprudent cost" that should be excluded from the rate base. By way of an attempt to explain why, between 1977 and 1978, the "noncoincident peak demand for the country rose a feeble 1.3%," the authors of the 29th Annual Electrical Industry Forecast write: "the second possibility that occurs is that we have been undergoing a hidden conservation movement" [154]. However, the forecast continues, the "growth patterns throughout the forecast period remain basically unchanged from last year. We see increasing electrification offsetting conservation and load management" [155]. The forecast, which treats the conservation movement as "hidden," does not consider alternative sources of electric generation such as CFs and SPPFs or of utility-owned solar generating devices. Any economic advantage of cogeneration and small power production is likely to be lost if the electrical industry persists in expansion without taking into account alternative sources of electric production.

It is unclear whether the current excessive capacity resulted from simple mistakes, or whether they are an example of the Averch-Johnson effect; overcapitalization for the purpose of increasing the rate base and hence utility profits [156]. It is an open question whether the Averch-Johnson effect (goldplating) is a factor in a market in which utilities find it hard to raise capital. Former FPC Commissioner John A. Carver believes that the Averch-Johnson effect is illusory and that utility engineers make their decisions always with a view towards maximizing efficiency and minimizing costs [157]. While utility engineers may be driven by an urge towards efficiency, however, they seem also to be driven by an urge towards expansion. The electric industry is not complacent about slow growth rates. The 29th Annual Electrical Industry Forecast opens: "Peak demand grew only 1.4% and electric energy use only 2.6% in 1978, well below the most pessimistic forecasts of last year" [158] (emphasis added—a conservationist might regard slowed growth with optimism).

The general problem of overcapitalization has been more recently recognized in the literature:

> If electric rate increases are to be confined within reasonable limits, some method must be found to control the magnitude of utility investment in the years ahead . . . .
>
> [One such method would be] to subject such programs to governmental scrutiny to ascertain whether such programs are based on realistic rather than inflated projection of growth in system peak demands. [159]

While the direct consequence of uncontrolled utility investment is excessive retail rate increases to all consumers, there is also an indirect effect that could be adverse to CFs and SPPFs. To the extent that utilities have excess capacity, they will not value the effective load carrying capability of CFs and SPPFs. The price paid by utilities for independently generated electricity is less likely to contain a credit for capacity replacement than would be the case in a utility without excess reserve capacity.

A related area in which some control over utility investment decisions would be conducive to the commercialization of several solar technologies is the area of generation mix. At high levels of penetration of WECS or PV systems, the most useful capacity additions by utilities could be central station storage capacity. Such construction would compensate for intermittent production of electricity from solar sources at a much lower cost than separate storage dedicated to each generating unit [160]. Also, such storage would facilitate load management, thus further reducing the capital cost of utilities.

Establishment of a utility's revenue requirement has been traditionally a mere matter of bookkeeping—based on a simple formula [161]. Given the goals of PURPA [162],* and the PURPA mandates to reconsider reliability standards [163], practice load control [164],

*To conserve energy, to use facilities efficiently, and to set equitable rates.

and encourage cogeneration and small power production [165], the question is not "how large an investment has the utility made?" The central issue is "how prudent are the investment decisions?"—particularly how much to expand, and which expansion form and generation mix best promotes the goals and mandates of PURPA.

4.1.2 Fair Allocation of Cost of Service

"One standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike—the standard of cost of service," writes Bonbright [166]. This goal, the second of the Bonbright triad of major goals of a rate structure, is given a special place also in PURPA. "Cost of Service" is the first of the rate standards established by § 111(d). Section 132 authorizes the Secretary of Energy to notify state regulatory authorities of "methods for determining cost of service," along with innovations in electric utility ratemaking and load management techniques. Section 133 requires FERC to gather information regarding "the costs of serving each electric consumer class." Moreover, the criterion of a fair allocation of costs of service is emphasized in the requirement of § 210(b) and § 210(c) that rates not discriminate against CFs and SPPFs, coupled with the assertion of the conference committee that § 210 is not intended to require utility ratepayers to subsidize CFs and SPPFs [167]. The question remains: how does one allocate the cost of electric service fairly?

Costs of serving an electric customer are traditionally classified into three components: a customer cost, an energy cost, and a demand cost component [168]. The customer cost is related to metering, billing, entrance service, and transformers associated with the individual customer. The energy cost is related to the fuel and operating cost and a portion of the distribution cost. The demand cost reflects the customer's proportionate contribution to the system load peak, which in turn determines the necessary power generating capacity of the system. Thus, the demand charge relates to the capital equipment required to provide the service. PURPA § 133 specifies that in the information gathering by FERC, the costs are to be separated into these three components, to the extent practicable.

4.1.2.1 Customer Charges

Every electric consumer imposes a customer cost on the utility, which is independent of the amount of energy or the maximum amount of power furnished. Within a customer class there is usually no difference in the customer charge, though diverse customers may impose different costs because of variable distance from existing electric lines. Customer charges are frequently hidden in a high monthly minimum charge or in a high charge for the first one or two small blocks of energy [169]. Alternatively, the customer charge may be explicit [170].

If PURPA standards § 111(d)(1)—cost of service and § 111(d)(2)—declining block rates are implemented, one can expect explicit customer charges even on residential electric bills. Section 115(a) sets rules for the determination of cost of service. It requires the "identification of differences in cost-incurrence attributable to differences in customer, demand, and energy components of cost" (emphasis added). Moreover, the standard regarding declining block rates is that "the energy component of a rate . . . may not decrease as kilowatt-hour consumption . . . increases" (emphasis added). Because utilities have often used declining block rates to hide customer costs, proper customer cost identification together with an end to declining block rates will lead to explicit customer charges.

It would not be equitable for CFs or SPPFs to escape a customer charge corresponding to a fairly attributable customer cost. However, the charge must accurately reflect the customer cost lest the charge be a form of discrimination against CFs or SPPFs, which is proscribed by § 210(c).

4.1.2.2 Declining Block Rates

Declining block rates are the most prevalent form of residential rate. They serve two distinct purposes. In the first place, they are able to hide both customer and demand costs in an apparently simple rate schedule [171]. The schedule appears to charge only what the consumers think they are buying (energy) and relies on the familiar concept of the quantity discount. In the second place, the declining block rate is a promotional rate designed to encourage increased use of electricity. In times of cheap oil and gas, such promotional rates could be justified on the basis that electrical industry expansion (e.g., between 1950 and 1965) brought with it improved efficiency and improved load factors with resulting savings for all customers. Promotional rates have tended to favor the largest users but have been found reasonable where they have produced benefits to all customers [172]. However, in times of high energy costs and vanishing resources, promotional rates are not acceptable. PURPA standard § 111(d)(2) forbids declining block rates for the energy component of electric service.

Declining block rates may lead to severe discrimination against consumers who conserve, use solar heating, or generate a part of their own electric energy. For example, an 80% solar-heated home may have only a 30% saving on the utility bill [173]. The reason for this anomaly is that the demand charge, as well as the customer charge, is in effect built into the first few blocks of consumption. Consumers who supply a part of their own needs either through independent generation of electricity in CFs or SPPFs or through conservation never reach the inexpensive blocks of energy consumption.

Alternative ways to allocate the energy cost imposed by each customer class are flat or inverted block energy rates. In such rates, the energy component is priced uniformly or at increasing levels for successive blocks of energy consumption [174]. The inverted block rate especially is designed to promote conservation, in direct contrast to the declining block rate.

A possible objection to flat and inverted block rates is that diminished energy consumption by a consumer leaves the fixed costs to the utility to be distributed over a smaller amount of energy sales. In that sense, energy conservation by any one consumer imposes a larger cost on all other consumers. There are both technical and public policy arguments against this objection to flat and inverted rates. The technical fact is that even with conservation or conversion by some consumers to cogeneration or small power production, the total energy and power demands in the nation are likely to increase. Thus, the consumer with diminished demand is not contributing to idle capacity but rather to slowed growth. Because of increasing capital expenditures for a given amount of generation capacity, the consumer who contributes to slowed growth actually contributes to holding electric rates to a slower growth. The public policy argument for inverted rates is that conservation of fossil fuel is a national goal of the greatest importance. Even if inverted rates turn out to be a departure from a strict cost of service allocation of charges, they are justified by the overriding need to conserve resources.

4.1.2.3 Demand/Energy Rates

Section 115(a)(2) of PURPA calls for cost-of-service determination to determine "differences in cost-incurrence attributable to differences in customer, demand, and energy components of the cost" (emphasis added). This suggests that demand/energy rates might be appropriate. Such rates make a separate charge for power demand (in kilowatts) and energy consumed (in kilowatt-hours). The demand charge may be based on the peak-coincident demand. Ordinarily, it is the noncoincident demand for which the charge is made. The distinction between coincident and noncoincident demand must be understood, for there is a vast difference in the effect of the two methods of charging, especially for consumers who obtain some of their energy from the sun or who operate CFs or SPPFs.

Each consumer's proportionate share of the capital costs of a utility is that consumer's "peak responsibility"; the ratio of that consumer's demand to the total system demand at the time of the annual system peak. For example, it is peak responsibility (i.e., peak-coincident demand) that is the basis for the demand charge paid by Albany Water, Gas, and Light for wholesale purchases from the Georgia Power Company [175].

Noncoincident peak demand is more easily measured [176]. The kilowatt demand is determined by dividing the month's highest 15-min kWh consumption by one-fourth hour. It is immaterial whether this maximum consumption rate occurs on-peak or off-peak. However, "[b]asing demand charges on individual maximum demands rather than on demands at the time of the system peak is a serious theoretical flaw in current two-part tariffs" [177].

The difference of the effect of charging for coincident peak demand or noncoincident demand is illustrated most clearly by a hypothetical example. Suppose a steady 50-kW consumer has a WECS that generates 50 kW one-half of the time, on the average, and 0 kW the other half of the time. Assume that the times the WECS power is available are random. This hypothetical consumer has a 50-kW peak-coincident demand, on the average, one-half of all billing periods (since the billing peak is equally likely to fall in a WECS-on or in a WECS-off period); in the other billing periods the demand is zero. Yet the same consumer would be sure to have a 50-kW noncoincident demand every billing period. The demand charge on a peak-responsibility basis averages out to just one-half the noncoincident demand charge for the hypothetical consumer whose WECS supplies power half the time.

Demand/energy rates, as conventionally measured, would be inappropriately applied to CFs and SPPFs because they would violate § 210 of PURPA in two ways. First, noncoincident demand charges would make backup service so costly that the rate structure would fail to "encourage cogeneration and small power production." Second, noncoincident demand charges would be discriminating against CFs and SPPFs as compared with users of the same class and consumption patterns who do not provide any of their own electricity.

4.1.2.4 Time-of-Day and Seasonal Rates

The costs associated with consumer demand depend critically upon the time of day and season of the year. The reason is that power demand at times other than the time of the system peak load does not govern the necessary generating capacity of the system, whereas demand that coincides with the system peak is precisely what determines the amount of capital investment that is necessary. To a smaller extent there are similar time variations in the energy cost component because energy generated by base load units is less expensive than energy generated by peaking units. Furthermore, base load energy is cheaply available from other utilities that desire to increase their off-peak generation as a measure of load management (to raise the valleys relative to the peaks) while peak load energy is very expensive. PURPA § 111(d)(3) establishes time-of-day rates as a standard of ratemaking. In gathering information under § 133, FERC is required to measure the cost of serving each customer class "including costs of serving different consumption patterns within such class, based on voltage level, time of use, and other appropriate factors" (emphasis added). Similarly, § 111(d)(4) establishes the standard of seasonal rates.

Time-of-use differentiation may be applied to either demand/energy or to flat energy rates. If demand/energy rates are used on a time-of-day or a seasonal basis, the off-peak demand charge should be small or zero [178]. A sharply differentiated time-of-day demand/energy rate more closely approximates a fair allocation of the costs of service when the demand to be billed is the on-peak demand than when it is the maximum monthly demand regardless of time of use.

Nevertheless, the objections that were raised in Section 4.1.2.3 still apply. A SPPF or CF ordinarily will have a significant on-peak power demand at some time during each billing period, though it has a good chance of not contributing to the annual system peak. A closer approximation to the annual peak responsibility would result from a flat (or inverted) energy rate that is sharply time-differentiated, and includes the demand costs as a part of the energy rate. Such a rate is justified because when energy is measured over a relatively short period of time (such as peak time only), the power demand is nearly proportional to the energy consumed. Thus, the energy charge properly reflects the capital as well as operating costs imposed by the consumer. Conservation, solar energy use, cogeneration, and small power production are all encouraged by a time-of-day energy rate that incorporates demand costs into the energy charge [179].

4.1.2.5 Interruptible Rates

The availability of interruptible rates to commercial and industrial customers is one of the standards established by PURPA § 111(d)(5). Interruptible rates are primarily a form of load control. Significant savings in utility capital expenditures are possible by limiting consumer demand at the times of maximum peak loads. These savings are properly reflected in drastically reduced demand charges to consumers who accept interruptible service. While interruptible customers are subject to interrupted service at any time, they are not likely to lose service for very long.

Cogenerators and small power producers expecially may want to avail themselves of interruptible rates. An intermittent producer of electricity is even less likely to lose service as a result of accepting interruptible rates than a consumer who produces no electricity. Interruption of a nonproducing consumer can occur whenever the utility's capacity is strained; interruption of a CF or SPPF will occur only if the utility's capacity is strained at a time when the CF or SPPF is not producing. The resort to interruptible rates may become necessary in states that require demand/energy rate schedules, or if the final FERC regulations pursuant to § 210 require demand/energy rates.

4.1.3 Economic Efficiency and Marginal Rates

The third of the major Bonbright goals for a rate structure is that the structure should promote an "efficient allocation" of resources. A pricing structure is "efficient" if a consumer chooses among all alternative expenditures on the basis of the actual social cost of all goods and services. Such cost-based choices are held to maximize satisfaction because the choices are not distorted by artificial subsidies or surcharges [180].

Economically "efficient" allocation of goods and services would result if all goods and services were priced at "marginal cost." The marginal cost of an item (such as 10 kW of power, or 200 kWh of electric energy) is the cost to society of making available one additional item or unit.

Marginal cost can be computed on a short-run or long-run basis. Short-run marginal cost is the cost of providing for an additional increment of consumption from a fixed amount and type of capacity [181]. Long-run marginal cost is the total cost of meeting a sustained increment of demand at a particular time period each year, assuming optimal adjustments of a utility's generation capacity and mix [182]. Applied to electric rates, marginal cost pricing is generally accepted to translate to LRIC. LRIC pricing was first adopted by a state regulatory authority in re Madison Gas and Electric, in a decision that also serves as a primer on this method of determining the cost of electric service [183].

Marginal cost pricing is an analysis distinct from the traditional accounting cost method. Accounting costs are based on operating expenses plus the historic or embedded costs; the costs of the capital investment already in place. Marginal costs differ in that they look to future expansion or replacement. Accounting costs have not been extensively used for determining time-differentiated costs. The adoption of marginal or LRIC is associated with time-differentiated cost analysis. Although PURPA is silent on the question of accounting vs. marginal costs, it emphasizes the need to determine how costs differ by time of day and season of the year. Accordingly, FERC's regulations pursuant to § 133 require utilities to supply raw data as well as computations under both accounting cost and marginal cost methods [184]. Either type of cost analysis may be used consistently with the Bonbright criterion that rates to each customer class reflect the cost of service.

4.2 LONG-RANGE INCREMENTAL COSTS

LRIC analysis can be illustrated with a simple example. Suppose X opens a plant that will have a 1-MW demand coincident with the utility system peak and will consume 5000 MWh of energy per year. And suppose further that the utility would have planned, but for X's factory, to install or replace an amount of generating capacity C in the course of the ensuing 10 years, and that annual energy output would have been E. Then the long-run incremental demand cost is the difference in cost to the utility between expanding its capacity by C and expanding it by C plus 1 MW; the long-run incremental energy cost is the difference, in the planned utility system over the next 10 years, between generating an amount of energy E and generating the amount E plus 5000 MWh annually. It is assumed for LRIC calculation that the added generating capacity is designed to optimize the base load/intermediate/peaking generation mix [185].

A LRIC analysis still leaves room for some critical judgment calls. The calculation is especially sensitive to judgment as to what constitutes an optimal generating mix. To the extent that LRIC is the basis of ratemaking, it is important to solar commercialization and hence to resource conservation, that the mix used by utilities be compatible with the use of solar contributions to the electric energy output of the utility as a whole. If, for example, a 10-20% penetration of wind energy is foreseeable in a given utility, capacity expansion should be in peaking capacity, including hydroelectric and storage, rather than in base load capacity, such as nuclear [186].

The adoption of LRIC pricing of electricity is likely to encourage cogeneration and small power production. PURPA requires that the maximum price FERC can require utilities to pay is the incremental cost of alternative electric energy.* If this incremental cost is calculated on a LRIC basis, it is likely to be greater than it would be on an accounting basis since the cost savings of new plant capacity are more than the cost allocations to past plant construction. Moreover, the conference report supports the concept that the incremental cost is not merely the cheapest energy cost, but the cost avoided. The report gives as an example:

> an electric utility which owns a source of hydroelectric power and which is offered the sale of electric energy from a cogenerator or small power producer might, if measured over the short term, have a low incremental cost of alternative power because of its access to hydropower; however, it may be the case that by purchasing from the cogenerator or small power producer and saving hydropower for later use, the utility can avoid the use of expensive electric energy generated by fossil-fired units during later months of its seasonal generation cycle. [187]

4.2.1 An Example of LRIC Ratemaking: Madison Gas and Electric

In 1974, the Wisconsin Public Service Commission approved a rate structure for Madison Gas and Electric that was based on a LRIC analysis. The resulting rate structure significantly reapportioned costs between industrial and residential consumers, and it almost completely flattened the previously declining block rates. There are two deviations from a flat energy rate. Rather than impose the entire residential customer charge in a single break with the past, the Commission allowed a small customer charge and established a slightly inflated first energy block to collect the balance of a customer charge. At the other end of the energy blocks, in winter only (Madison is a summer peaking utility) there was a reduced charge per kWh above 1500 kWh per month, a reduction for winter space heating. From the strict economic viewpoint of marginal cost pricing, the seasonal price advantage for electric home heating was correct since this extra use did not occur during the peak season and would not increase capacity requirements.

A concurring opinion by Commissioner Cudahy points to two possible shortcomings in the Madison decision [188]. First, he notes that an inverted block rate (charging increasing amounts per kWh for successive blocks of energy use and thus discouraging electric use, though not justified on LRIC grounds that count only internal costs) would have been justified by incorporating externalized social costs (such as the cost of pollution) in the revenue base. Second, he notes that the winter home heating rate, justified by the higher (hence more favorable) load factor imposed by winter heating than that imposed by summer air conditioning, might serve to promote electric space heating. Increased electric space heating could give rise to two problems: (1) electric heating is intrinsically wasteful [189], and (2) if electric heating increased enough, in response to the lower rate, the annual peak might be shifted to winter; in that case the winter heating would cause the need for more capacity.

The significance of Madison is, first, that it was the first ratemaking decision that embraced LRIC methods [190]. Further, Madison illustrates some of the limitations of marginal cost pricing as applied to electric utilities. The very dictates of marginal cost

*The definition of "incremental cost of alternative electric energy" is quoted in Section 4.0, in the text accompanying Ref. 143.

analysis lead to the possible encouragement of a practice that is wasteful of limited resources—electric home heating. Further, LRIC analysis does not have room (as Cudahy notes with regret) for taking the external costs into account, whereas the economic theory of marginal cost pricing is based on the expectation that external (social) costs are counted [191].

One potential difficulty of LRIC analysis did not occur in Madison. If costs are based on the cost of incremental expansion of the utility's capacity and not on the actual historical investment, LRIC is likely to give higher revenues if the cost of new construction (in constant dollars) is more than the cost of past construction; LRIC would yield lower revenues than accounting cost pricing if new construction could serve to replace inefficient equipment with more efficient equipment. Thus, in general, there is no assurance that LRIC rates would match the revenue requirement. It happens that in Madison the rates matched the requirement.

4.2.2 Contradictions and a Possible Resolution

The Bonbright ratemaking goals cannot be equally served by any one rate structure. If one criterion (e.g., economic efficiency), is to dominate then it is easy to agree that a particular approach (such as LRIC) should be the basis for the rate structure. But,

> if several objectives are deemed desirable, it becomes increasingly difficult to prove that any one of the ratemaking alternatives can best serve these multiple objectives. Thus arguments for any ratemaking alternative to attain the eight Bonbright criteria or similar, lengthy lists of objectives must be based on subjective appeals or judgments. [192]

A severe contradiction may arise between pursuing the economic efficiency goal and the revenue requirements goal. According to a California PUC Staff Report on Electric Utility Rate structures, a LRIC analysis for Southern California Edison Company would have yielded revenues of $3.3 billion; the revenue requirement was $1.8 billion [193]. In such a case, how is one to reconcile the quest for economic efficiency with that of a fair return for the utility?

Huntington suggests an answer that reconciles economic principles of efficient allocation with reaching the correct revenue requirement. If the marginal rate would collect too much revenue, rebates should be given on the rates. To maintain the economic efficiency advantages of marginal cost pricing, the rebate to the different consumer classes should be in inverse ratio to their respective demand elasticities [194]. Such a rebate runs somewhat afoul of the nondiscrimination goal; but as Huntington points out, it is a downward adjustment—all classes get the advantage of a rebate [195]. The actual effect would be that industrial customers would get the smallest rebate, since their demand elasticity is largest, and residential customers the largest rebate; the rebates, of course, are from sharply increased rates. Huntington suggests that the rebate should be applied first toward customer charges and also to finance lifeline rates [196]. A proper way to take into account the external costs (that will have been omitted from the LRIC computation) might be to devote a part of the rebate to subsidizing solar electric production.

At first blush, Huntington's suggestion seems a radical redistribution. In fact, however, the traditional allocations of cost are no more fair and no more accurate a reflection of costs imposed by various classes of consumers. The compromise among the various criteria for ratemaking is necessarily a difficult one. The significance of Huntington's work is that it calls attention to the timeliness of the trend towards marginal cost methods in utility ratemaking. Just as promotional rates could be justified in a time when expansion of electric production lowered costs for all consumers [197], LRIC rates that discourage expansion and energy use are justified at the present time. The inflationary burden that results from oil imports and high energy costs could be lightened for all consumers by a reduction of energy use and by a reduction of capital expenditures for more generating capacity. All consumers would benefit; thus, even discriminatorily favorable rates for solar producers of electricity could be justified.

Huntington's reconciliation of LRIC pricing with the Bonbright criteria gains special force where solar production of electricity is involved. Long range incremental costs do not include external (i.e., social and environmental) costs. To this extent LRIC is a poor implementation of the doctrine of marginal cost pricing. But the availability of a surplus of LRIC revenue over the utility's revenue requirement makes possible a rebate that reflects social costs. Nuclear and fossil-fueled electric plants impose significant costs in terms of health care (necessitated by environmental pollution) and waste disposal. Electricity is artificially inexpensive because the social costs are not internalized; they do not appear in the utility's books but are paid for by the public and by individuals, in no relation to their individual consumption of electricity. The artificially low price of nuclear and fossil-fuel-produced electricity puts the small power producer into an artificially poor competition position. A "clean electricity" subsidy to facilities that produce no harmful waste products (such as producers using wind, hydropower, direct sunlight) is consistent with the economic theories underlying marginal cost pricing.

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SECTION 5.0

RATE REGULATION OF INTERCONNECTED UTILITIES

This section offers recommendations for FERC regulation of rates for energy sales between qualifying cogenerators or small power producers and utilities with which they are interconnected. The regulations must reconcile the specific requirements of § 210(b-d) with the general mandate of § 210(a) that the FERC regulations must "encourage cogeneration and small power production."

The recommendations are made in the light of the ratemaking principles discussed in Section 4.0 and of the technical ways in which CFs and SPPFs affect the utilities with which they are interconnected. Some generating facilities, for example, may be able to supply excess energy to the utility steadily, requiring backup energy only during an occasional forced outage. Other facilities may generate electricity intermittently and will supply excess or demand backup on a fluctuating basis. In addition, the energy supplied to or required from the utility may be on-peak or off-peak. It may be possible for the independent facility to tailor its production to give optimum value to the utility. Conversely, it may be more cost-effective for the utility to accommodate itself to the energy demand and supply of independent facilities. Different patterns of energy supply and demand have different impacts on capacity requirements, reliability, spinning reserve, and fuel consumption. Moreover, any given CF or SPPF would affect different utilities differently. Details of the rates may be quite variable, but it is possible to set forth some general principles.

Section 5.1 describes, in the form of a case study, the way a rate structure can place obstacles in the way of cogeneration and small power production. This section presents the questions that are to be addressed in implementing a suitable rate structure.

Section 5.2 discusses the capacity cost imposed on utilities by the backup requirements of CFs and SPPFs. These costs are considered in the light of the characteristics of (1) steady production facilities such as CFs, biomass or waste-fueled SPPFs, low head hydro, and solar thermal/fossil fuel hybrid facilities, and (2) intermittent production facilities such as WECS and PVs. Following these technical discussions of capacity credits, Section 5.2.3 considers the effect on qualifying facilities of different possible backup power rate structures.

Section 5.3 discusses rate structures for the purchase of surplus energy from CFs or SPPFs by utilities. The problem of sell-back rates is a proper interpretation of "incremental cost to the utility of alternative electric energy." Short-range and long-range marginal cost pricing are explored, firm and non-firm energy sales are discussed, and the question of penalty clauses in firm power contracts is considered.

Section 5.4 treats the special problems of SPPFs that supply the residential or small agricultural market—small power producing consumers whose purchases would normally be on the residential schedule. An argument is presented that such generation can properly be encouraged by a net energy purchase (running the meter backwards) up to modest penetration levels of the utility by the SPPF technology.

Section 5.5 notes that rates which distinguish too sharply between firm and non-firm power may lead to uneconomic use of storage. The section suggests changes in PURPA that would give added encouragement to small power production.

5.1 RATE DISINCENTIVES TO COGENERATION AND SMALL POWER PRODUCTION

The case study presented in Section 5.1.1 is an example of ways in which traditional rate structures have been used to reduce incentives to cogeneration.* The California Energy Commission observes:

> Because cogeneration may result in utilities losing profitable large baseload customers, utilities have discouraged cogeneration by charging high rates for providing standby power, and paying low prices for excess industry-generated power. (During the past year significant progress has been made by the private California utilities toward rectifying this situation.) In addition, utilities commonly refuse to transmit, or "wheel," excess cogenerated power to any party who may wish to buy it from the generating industry. [198]

Any effort by utilities to deliberately discourage cogeneration would violate PURPA. On its face, PURPA requires that rates for standby power as well as prices for excess power may not discriminate against CFs or SPPFs. However, the unfavorable rates in the Louisiana Pacific case study may fall short of overt "discrimination." The rates reflect a statistically unenlightened measure of demand and capacity. Only an enlightened implementation of PURPA by FERC and by state regulatory authorities can assure a rate structure that encourages cogeneration and small power production.

Sections 5.1.2 and 5.1.3 set forth the issues that must be addressed to arrive at rates consistent with the PURPA mandate. Section 5.1.4 notes that the PURPA section on wheeling does not extend far enough to cure the problem of Louisiana Pacific.

5.1.1 A Case History: Louisiana Pacific Corporation

Louisiana Pacific (L-P) is a forest products industry with a major plant in Samoa, Calif. and smaller plants within 40 miles [199]. L-P uses all its waste wood and forest slash from a 100-mi radius to provide its steam needs and 35 MW of electric power. About 20 MW is produced in the cogeneration mode and 15 MW in a conventional biomass-fueled steam turbine generating plant. L-P's electric need is about 30 MW. On occasion, L-P's generating output drops to 28 MW, and it then requires 2 MW from Pacific Gas and Electric (PG&E) instead of supplying 5 MW to PG&E. Energy production figures for 1978 are as follows:

Total energy generated:	232,000 MWh
Energy used by L-P:	196,000 MWh
Energy sold to PG&E:	35,000 MWh
Energy bought from PG&E:	666 MWh

Thus, the backup energy purchased by L-P amounted to less than 2% of the excess energy sold by L-P.

The rate paid by PG&E for L-P's excess was $20/MWh, for a total of $700,000. The energy rate charged by PG&E was from $40-$45/MWh. At that rate, L-P would have paid under $30,000 for its 666 MWh of backup energy. But, standby or penalty charges, occasioned by the fluctuation of L-P as a 5-MW supplier or 2-MW consumer, brought

*The same defects in the rate structure that discourage cogeneration apply at least equally to small power production.

PG&E's charge to $157,000. Averaged over purchases of 666 MWh, this represents an effective rate of $328/MWh, 12 times the energy rate paid by PG&E for L-P's excess.

Louisiana Pacific sought to improve its position relative to PG&E by requesting that PG&E wheel its excess to other L-P plants. These plants purchased 36,000 MWh at a total cost of $1,500,000. With a wheeling contract, the Samoa plant could have supplied nearly this whole amount. Transmission charges for wheeling electricity in the Northwest are about $3/MWh. L-P would have saved $1,500,000, foregone $700,000 of income, and spent $108,000 for transmission charges. To date, PG&E has not agreed to wheel power for L-P, and the California Public Utility Commission has not required PG&E to do so.

5.1.2 Standby Rates for Backup Power

The large cost for the energy bought by L-P from PG&E resulted from standby charges for the occasional 2-4 MW of power required by L-P. The PG&E standby rate, prior to March 1979, was a demand charge of $2.10/kW per month [200]. This rate contains a component that pays for transmission and distribution facilities, dedicated to the occasional backup need of between $0.40 and $0.75 per kW per month [201]. The remainder of the rate is a generation capacity charge. A brief argument has been presented in Section 2.2.4 to show the inappropriateness of charging this generation capacity cost to cogenerators. A more complete statistical analysis supports the preceding argument and has concluded that "[b]ecause cogeneration is more reliable than its utility-owned central station alternative, the cost of generation capacity should not be included in standby charges" [202]. This study also points out that a 750-MW central station plant would require a forced outage rate of 7% to provide the same ELCC as an aggregate of 750 MW of dispersed cogeneration with an average forced outage rate of 16%. The study further concludes that a proportion of spinning reserve costs and transmission and distribution costs is properly charged to the CF, since "some distribution capacity may actually sit idle to back up a cogenerator" [203]. Section 5.2.1 considers technical details concerning appropriate capacity credit for various energy conserving technologies that produce steady power.

Intermittent power producers have a harder task in justifying low standby rates. There is a view that wind power has value as energy only and no capacity value, that the installation of a WECS does not alleviate the need for other capacity additions [204]. If that is so, a WECS saves only the cost of the displaced fuel (which represents somewhat less than half the cost of electricity; the rest is associated with the capital costs). A further difficulty that is sometimes raised is that energy sold to the utility during off-peak times has little or no value because base load plants are not sufficiently responsive to reduce their output to accommodate the intermittent energy available from WECS [205]. On the other hand, a recent study of the projected effect of WECS on the New England Gas and Electric Association states that

> [t]he addition of WECS to a utility's equipment mix causes an increase in the utility's reliability. This is caused by the fact that even though WECS power is of a stochastic (i.e., random, probabilistic) nature, there is a finite probability that a specific WECS power level will be available at any given time. [206]

In Section 5.2.2, the problems of assigning proper capacity credit and of the effect of high levels of WECS market penetration are explored, and the behavior and appropriate capacity credit of photovoltaic systems is considered.

Rate structures for standby rates are analyzed in Section 5.2.3. To the extent that rate structures favor steady over intermittent production of electricity from solar sources, SPPFs may be stimulated to attempt to smooth their energy outputs. Two methods are available to intermittent producers to achieve a smooth output—energy storage and hybrid operation with hydroelectric power. The costs and benefits of storage and hybrid operation for SPPFs are considered in Section 5.2.4.

5.1.3 Sell-Back Rates for Excess Power

The sell-back rate paid by PG&E to L-P for its surplus electric energy was less than one-half the retail price PG&E charged its industrial customers. The rate for such sales is of crucial importance to those CFs and SPPFs that have a significant net energy production, and to producers who generate exclusively for wholesale to utilities.* Without an adequate sellback rate there is no incentive for surplus independent electric energy production.

The issues that must be addressed in order to arrive at a fair sellback rate are:

- Do sales from steady suppliers with occasional outages qualify as "firm" energy sales?**
- If they do, what should be the criteria for penalties for failures to deliver the contracted power?
- If they do not, how should the capacity value of the QFs be compensated?
- How should rates for non-firm energy be calculated?
- To the extent that non-firm power has energy value only, how should the avoided energy cost be calculated?

5.1.4 Wheeling by Qualifying Facilities

The economic disincentive to L-P to generate surplus electric energy would be resolved if PG&E were to agree to wheel the excess to other L-P plants. A good test of PURPA is to inquire whether L-P could obtain a wheeling order from FERC, under the provisions of PURPA (which was enacted after the date of the L-P case study). The answer is apparently not, since § 203 authorizes FERC only to order a utility to wheel the power of another utility. A cure for this deficiency of PURPA has been recommended in Section 2.3.1.2.

5.2 UTILITY SALES TO QUALIFYING FACILITIES

5.2.1 Sales to Steady Producers with Occasional Backup Needs

Little or no demand charge is justified for backup power furnished to steady producers with only occasional backup demands, because their interconnection requires little or no

*Such facilities are the subject of Section 3.5.

**"Firm" energy sales to a utility are guaranteed to be available to meet a utility's peak needs; non-firm energy is not guaranteed to be available to coincide with utility peaks.

added generating reserve of the utility. The forced and scheduled outage rates of CFs and of SPPF steam plants using biomass or wastes as fuel are comparable to those of conventional power plants. Although the entire power requirement of the CF owner can be imposed on the utility at the time of an outage, it is incorrect for a utility to "dedicate" to the backup task a generating capacity reserve equal to the CF capacity [208].

The best method for correctly finding the backup generation capacity required begins by determining the effective load carrying capability. The ultimate result of one such calculation shows that the existing necessary reserve margin of a utility is more than adequate to absorb the outages of a CF that sells as much energy as it buys [209]. When the utility can maintain its reliability level without added reserve generating capacity to meet the backup load demand of an added CF, no generation capacity demand charge is justified. An alternative computation must be used if the recommendation of Section 2.2.4 and of W. B. Marcus of the California Energy Commission are rejected. According to this method, one multiplies any generation demand charge by the forced outage rate. This means that for a CF with a 10% forced outage rate (i.e., a 10% probability of unavailability) the demand charge would be based on 10% of the measured demand [210]. Both methods assume that scheduled outages for maintenance are taken in off-peak seasons with notice to the utility.

Two other types of SPPFs can provide an even steadier supply of excess energy and require backup power less frequently. One is hydroelectric plants and the other a hybrid of solar thermal and fossil steam generation. The latter can qualify for § 210 privileges only if proposed FERC rules are modified in accordance with Section 3.3. The same types of computations would be applicable to these technologies. The results will likely be that no generating capacity additions are needed to provide backup; if this guess is correct then standby charges for generation capacity are not justified.

5.2.2 Sales to Intermittent Producers

Intermittent producers, such as WECS and PV systems, undoubtedly impose on the utility the need for backup generation capacity. Various computer simulation studies of WECS and PVs suggest that capacity credit is properly assigned to WECS and PV systems [211]. The ELCC (the amount of conventional capacity addition that a utility can forego as a result of installing large WECS) lies in the range of 15-45% of the rated capacity of the WECS. The ELCC for PVs is between 20% and 40% of rated capacity. By way of comparison, the ELCC for large conventional generating units is about 70-85% of rated capacity and for nuclear plants about 45% [212].

5.2.2.1 WECS Capacity Credit, Penetration, and Dispersal

A study of the New England Gas and Electric Association shows that the capacity credit for WECS may be as high as 53% [213]. That is, a WECS of rated capacity C displaces other generating capacity in the amount $C' = 0.53 \times C$. There is a slight increase in the operating reserve (or spinning reserve) that must be charged against the WECS usage [214]. Similarly, slightly less dramatic results were obtained by a General Electric simulation study of large WECS in four utilities in diverse wind regimes. Effective load carrying capabilities were 46%, 37%, 6%, and 19% of rated capacities (at 5% penetration) [215]. The 6% figure arose from a particularly poor wind year; a typical value for the location (the Oregon coast) would be 20% [216]. Close studies of wind regimes are essential before building wind plants, since capacity displacement is highly sensitive to the coincidence of good wind with system peak loads. After a WECS is built the individual ELCC computation should be periodically updated in the light of actual wind performance.

The studies of WECS capacity credits have all assumed large units (or aggregations of units) and ownership and operation by utilities. They therefore leave open the questions: (1) Is it appropriate to apply reliability analysis to externally owned and operated WECS? (2) How reliable are small wind energy conversion systems (SWECS)? (3) How should a capacity credit be reflected in the rate structure?

The first of these three questions has been emphatically answered in the affirmative in Section 2.2.4. Two studies are currently underway which may help to answer the second of the three questions. One of these is a General Electric study for the Electric Power Research Institute, extending the work reported previously to small dispersed systems. Another study by Rockwell International will place at least two interconnected SWECS (in the 1-kW to 40-kW range) in each of the 50 states and will record, for each unit, the wind speed, energy generated, energy used, and energy sold to the utility every 15 minutes for one year. The last of the three questions is addressed in Section 5.2.3 with respect to backup rates and in Section 5.3 with respect to sell-back rates.

After the market penetration has reached about 5%, the capacity credit for additional WECS generating units begins to deteriorate. That is, once more than about 5% of a utility's generating capacity is supplied by WECS, successive WECS units contribute smaller amounts of effective load carrying capability. The reason is that the outages of WECS in any one location are correlated. The decrease in ELCC is not significant in most cases until penetrations exceed 15% [217].

Wide geographical dispersal of WECS in a system improves their reliability or their ELCC [218], according to a study based on actual wind regimes in 19 locations in California, Oregon, and Washington. The correlations of wind speeds at sites remote from each other are quite low; i.e., the wind is likely to be adequate at one site when it is insufficient at another. The ELCC (and hence the capacity credit) turns out to be 26% at 11% penetration in the PG&E service area of northern California. The benefits attributable to dispersal saturate and do not continue to increase with further dispersal over areas greater than northern California.

5.2.2.2 Photovoltaic Systems

Photovoltaic systems produce electricity intermittently. PV electric output is somewhat less random and unpredictable than that of WECS, but is limited on an annual average to no more than half time (daytime only), whereas WECS may produce power more than 70% of the time in some wind regimes. Flat-plate collectors have a capacity factor, the ratio between the energy output to the output at rated capacity all the time, of approximately 20% [219]. The reason for the relatively low capacity factor is in part the lack of output at night and in part the fact that the plate faces directly into the sun for only a small portion of the day.

Any projections of the economic viability of PVs are more certain than projections respecting WECS. PVs are a new technology, still in a phase of rapid technological developments. Costs have dropped from $300/W$_p$ in 1973 (Skylab program) to $22/W$_p$ in 1977 and $7/W$_p$ in 1979 for collectors [220], and a further reduction to $0.15-0.40/W$_p$ collectors and system costs of $1.30/W$_p$ or less are expected [221]. (W$_p$ are peak Watts; i.e., the rated output.) The actual cost will determine the pace of commercialization of

PVs and the amount of nonrenewable fuel displaced. The assessment of existing studies performed in the Domestic Policy Review of Solar Energy indicates that PVs could displace anywhere from 0.1-1.0 quad of nonrenewable fuel annually by the year 2000 [222].

Effective capability, the measure of the capacity credit for the PV installation, is around 40% in Arizona and New England (despite capacity factors as small as 20%) and about 20% in Florida [223]. The reason for this discrepancy is quite revealing. The insolation peak (insolation is the available power from the sun per unit area) very nearly coincides with the system load peak in the Arizona and New England utility studies, while the Florida load peak occurs several hours after the insolation peak. For this reason, the power generated by PVs in Arizona or New England comes during the time in which the capacity margin is smallest, while the power from Florida PVs comes at a partial-peak time when it contributes less to system reliability [224]. PV systems make an especially good addition to a utility in those regions where the load curve has its peak near the insolation peak, because the PVs then supply the most power when power is most needed.

PVs have one other minor advantage over WECS. PVs never produce excess energy when there is a valley in the load curve since they generate no power at night. WECS experience times when utilities would wish to pay "dump rates" for their excess energy, or preferably not accept the energy at all [225].

As is the case for WECS, PVs have lower capacity values when their penetration in a utility increases much beyond 5% of system capacity [226]. However, even at small penetration where their effective capability is considerable, "it seems unlikely that utility system managers will give installed capacity credit approaching the calculated effective capacity . . . without much more investigation and operating experience" [227]. The SPPF using PVs may face the same obstacle that confronts the WECS user: utilities will consider the independent power production facility as only an energy or fuel saver and not as a contributor to the utility's reliability.

5.2.3 Possible Rate Structures for Utility Backup of CFs and SPPFs

5.2.3.1 Demand/Energy Rate for Backup

The case against a demand/energy rate has been stated in Section 4.1.2.3. Such a rate for standby service has been specifically abandoned in California [228].* It should be proscribed by FERC regulation pursuant to § 210 of PURPA. That is, the maximum monthly kilowatt demand for occasional or intermittent backup of a CF or SPPF should not be the basis for a generation capacity demand charge.

5.2.3.2 Demand/Energy Rate Modified by Capacity Credit

One way to retain the concept of a demand/energy rate without outright discrimination against CFs and SPPFs would be to compute a modified demand in accordance with the analysis of Section 5.2.1. This requires an ELCC computation or, as a second option, the

*There is no objection to charging a demand rate for dedicated distribution and transmission costs or for spinning reserve.

multiplication of the measured demand by the forced outage rate or the unavailability factor.

An alternative way to retain the concept of demand/energy would be to determine demand on a seasonal peak-coincident basis. This method has a certain theoretical purity in that it perhaps reflects the actual cost of service most clearly. However, to be significant the method would have to be applied to all consumers (otherwise it does not actually measure relative peak responsibility). Because of the needed universality of application and because of the prevalence of monthly maximum 15-min demand meters, peak-coincident demand measurements would be impractical.

5.2.3.3 Time-Differentiated Modified Demand/Energy Rate

Even a modified demand/energy rate would be a poor measure of the relative cost incurrence of different consumers unless daily and seasonal time-of-use rates were computed for the modified demand and for the energy. The importance of time-of-day rates and of seasonal rates can be shown by several examples:

- Small power producers who obtain energy from direct sunlight (PV or solar thermal) may have their major backup needs at night, off-peak. Accordingly these producer/consumers should have the advantage of lower backup rates.
- WECS facilities in a wind regime with a good match between wind availability and peak load make a larger contribution than facilities with contrary wind regimes. It is therefore appropriate to encourage facilities preferentially. Time-of-day rates would have this effect, since the well-sited WECS has its backup needs primarily off-peak.
- Hydroelectric power that peaks in peak seasons should be encouraged preferentially, since it makes a more significant contribution than hydropower that peaks in off-peak seasons. Seasonal backup rates are a justifiable way to provide the preferential encouragement.

Unfortunately, time-differentiated modified demand/energy rates are likely to violate several of the secondary Bonbright goals cited in Section 4.1. The rates lack the desired simplicity, clarity, and perhaps public acceptability. In addition, the rates require metering and billing that is inappropriately complex and expensive for very small facilities.

5.2.3.4 Time-of-Use Energy Rate

Most of the virtues of time-differentiated modified demand/energy rates can be approximated by time-of-use energy rates. The approximation accurately reflects the relative cost incurrence of different consumers if the time blocks are finely graduated; there should be at least three—peak, partial peak, off-peak. Time-of-use energy rates incorporate the demand cost, which is zero off-peak, very low at partial peak, and very considerable on-peak, into the energy cost. The approximation is best for consumers with a typical load factor—a typical ratio of average power demand to maximum power demand during any one of the rating periods. Thus, incorporating the demand cost in the time-differentiated energy charge approximates the cost-of-service allocation of a well-founded demand/energy rate. A customer charge should be itemized separately.

Time-of-use energy rates also approximate the second of the two capacity credit computations discussed in Section 5.2.1. A producer/consumer (with a typical load factor) who requires backup 40% of the peak load time, pays 40% of the demand charge that would be due on a demand/energy rate. The approximation is very adequate for intermittent producers. The steady production facility, however, might be somewhat better served by an ELCC computation, since that would free it from any demand costs.

Time-of-use energy rates are probably the best approximation to cost of backup service that is simple, has a good chance of acceptability, and provides the required encouragement to cogeneration and small power production. They would avoid the anomaly of a consumer who cuts consumption by 80% and electric bills by 30%.

5.3 PURCHASES BY UTILITIES OF EXCESS POWER FROM QUALIFYING FACILITIES

Every purchase of electricity by a utility changes the utility's position with respect to energy and power. Each kWh of energy bought from a QF is a kWh the utility need not generate or buy from another utility. Moreover, each kW of power supplied by a QF may save the utility some amount of generation capacity expansion, provided the power is supplied with enough reliability to allow the utility to plan its expansion accordingly.

Several questions occur: (1) How should the cost be measured of a unit of energy that the utility can avoid generating? (2) How much generation capacity is avoidable as a result of power supplied by qualifying facilities? (3) What degree of reliability of power allows the utility to consider the power in its plans?

5.3.1 Marginal Cost of Avoided Energy Production

The Public Utility Regulatory Policies Act § 210(b,d) limits the rates FERC can require utilities to pay QFs to the "incremental cost of alternative electric energy." A staff recommendation to the California Public Utilities Commission (CPUC) suggests that short-range marginal costs are the proper way to determine this incremental cost [229]. A brilliant, detailed economic analysis, prepared by the California Energy Commission, describes the application of marginal cost energy pricing to a hypothetical California utility with a varied generation mix [230].

Marginal energy costs are (in the California example) nearly twice the average cost to the utility [231]. The decreased production of energy by the utility that is made possible by sales from QFs is most likely to be decreased peak or cycling generation, since base load generation usually operates at full capacity. Moreover, hydroelectric power used in a controlled (load managing) but energy-limited manner is not displaced at all by power purchases by the utility. The major displacement of fuel is of the fossil fuel in the cycling and peaking units that are designed to follow load fluctuations.

The marginal energy cost approach of the California Energy Commission and the CPUC staff is reflected also in the statement of the conference committee on PURPA. In the example propounded in the conference report, the wholesale price of purchased hydroelectric power was not regarded as a measure of the cost to the utility of alternative power. This interpretation is correct because the purchase of power from a QF would not in fact prompt a utility to reduce its purchase of hydroelectric power, but rather to reduce the output of a cycling unit.

FERC regulations pursuant to § 210(b) should require that the energy component of electric purchases by utilities from qualifying facilities should be calculated on a marginal cost basis. The California Energy Commission report could serve as a primer, or as the draft of a primer, regarding the method of computation of marginal energy costs.

5.3.2 Long-Range Marginal Cost of Avoided Capacity Expansion

How much plant expansion can the utility forego by purchasing power from a CF or a SPPF? What increment over the energy cost should the utility pay for the capacity value of the power? Several approaches are possible to answering these questions. The first is that of a staff recommendation to the CPUC. The others derive from principles already explored in this report.

5.3.2.1 Firm and Non-Firm Power Agreements

The CPUC proposal divides energy sales into firm and non-firm power agreements. "A firm power agreement is one in which the seller agrees to make sales at specific levels for specified periods, allowing the utility to alter its resource plan" [232]. The proposal would allow only energy costs, calculated as marginal costs as in Section 5.3.1, for non-firm sales. The capacity value of firm power would be based on a long-range marginal cost analysis of the avoided capacity, considered as gas turbine capacity.*

Qualifying facilities have been divided into "intermittent producers" and "steady producers with occasional outages." Clearly the first can make only non-firm contracts. The second, despite occasional outages, should be able to make firm contracts for a definite amount of surplus and sell any additional surplus on a non-firm basis. The CPUC paper assumes that occasional failures to perform the firm power contract will be reflected in damage payments by the seller to the utility:

> Recovery for damages will basically be one of two types. First, the utility can recover the extra costs of their obtaining the input elsewhere. Second, the contract may call for a fixed schedule of dollars per day of failure to meet the contract provisions. [233]

The long-range marginal cost yields a rate that will not hurt the ratepayers [234]. A utility could buy power priced above marginal cost only at an extra cost to ratepayers. On the other hand, if the price were below marginal cost the external producer would be subsidizing the ratepayers and would suffer undue discrimination. In a competitive market, a good priced below marginal cost is in such demand that its price goes up until the marginal cost is reached. But the market faced by the CF or SPPF is a monopsony; there is but one possible buyer—the utility. The monopsonist utility must be regulated lest it have unrestrained bargaining power [235].

The rationale of the CPUC study for regulating the rates the utility must pay for firm power should be applied as well to regulate the penalty clauses in firm power contracts.

*It is unclear why the CPUC chose the cost of gas turbines to measure the capacity value of CFs or SPPFs. It would be more in keeping with the principles of marginal cost pricing to use the cost of a rational generation mix. Regulatory supervision over generation mix may be desirable (see Section 4.1.1 and Ref. 158).

Without such regulation the utility could defeat the rate regulation, by charging prohibitive penalties for the inevitable occasional outage suffered by the CF or SPPF. It is recommended that no greater penalty be assessable against the QF supplier of firm power than the actual cost to the utility of necessary substitute power.

5.3.2.2 Capacity Charges for Non-Firm Power

The CPUC scheme would deprive intermittent producers of any economic reward for their effective load carrying capability. As has been argued in Sections 2.2.4 and 5.2.2.1, even intermittent producers reduce the amount of generation reserve capacity a utility must have in order to maintain a given reliability. The amount of capacity that a utility would have to install in order to improve its reliability or its ELCC by the same amount as the utility achieves by purchases from the QF is properly credited to the QF. This capacity credit should be offered on the same basis (i.e., long-range marginal cost) for suppliers of non-firm power as the CPUC study proposes for firm power suppliers. The capacity credit will of course be for a smaller fraction of the generation capacity of the intermittent producer than the capacity credit for the steady producer.

Capacity payments to SPPFs with intermittently available power are an especially necessary incentive for the establishment of independent wind farms for wholesale purposes only.* Since it is technologically immaterial whether such wind farms are owned by utilities or independent corporations, the ELCC computations that would be appropriate in the former case are appropriate in the latter.

The ELCC of intermittent CFs or SPPFs should be determined, relative to the utility with which they are interconnected. A capacity credit should be awarded on the basis of the reserve generation capacity that a utility can forego because of the electric power supplied. The rates for purchase by utilities from qualifying facilities should reflect this capacity credit.

5.3.2.3 Incorporating Capacity Credit into Time-Differentiated Energy Rates

If the long-range marginal cost of power and energy is determined, it should be possible to develop a sharply time-differentiated energy rate that incorporates capacity credit into the energy charge for utility purchases, in a manner analogous to developing a time-of-use energy rate from a demand/energy rate for utility sales. Such purchase rates might be discounted relative to utility sale rates by a factor that takes into account the direct expenses to the utility for handling the externally produced power. A study is recommended to explore a simple time-of-use purchase rate for energy from CFs and SPPFs that is based on utility energy cost avoidance and utility capital cost avoidance.

5.3.3 Rates in Excess of the Utility's Marginal Costs

Purchase rates in excess of the utility's marginal costs can be justified as fuel conservation promotional rates. Electric consumption promotional rates were justified as bringing down all rates, even though they distributed the largesse unevenly [236]. Similarly, conservation promotional rates can be justified if they hold the increase in fuel prices to a slower pace, even if some ratepayers would in effect be subsidizing CFs and SPPFs.

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*See Section 3.5.3, text accompanying Ref. 139.

Rates in excess of the utility's marginal costs can further be justified because the marginal cost computation is artificially low. The marginal cost computation is low for two reasons. On the one hand, the marginal cost computation fails to include external, social costs incurred as a result of environmental pollution by fuel by-products and waste products.* In the second place, the internal costs to the utility are low because of governmental fuel subsidies. Subsidies for conventional energy production for 1977 alone amounted to $19.3 billion [237]. The level of subsidy that would allow solar energy parity with oil and nuclear energy production should range between $0.20 and $1 per million Btu displaced [238]. Additional subsidies of $0.70-$0.90 would be justified by contributions to national welfare, such as decreased medical costs associated with pollution and avoidance of costs for environmental protection equipment [239]. But while such subsidies are quite justified, it is uncertain whether the utility ratepayers are the proper parties to provide them.

The language of § 210(b,d) limits FERC to rules requiring no more than incremental rates to be paid by utilities. The intent of Congress to avoid subsidies by ratepayers to independent producers has been made clear in the conference report. Thus, FERC is legally prevented from requiring rates greater than marginal rates. However, FERC should state explicitly that state regulatory authorities may choose to set such rates, and PURPA should be amended by striking the last sentence in § 210(b): "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."

It is not the recommendation of this report that rates for the purchase by utilities of power from qualifying facilities be set above marginal rates (except in the limited sense of Section 5.4). But, this report recommends that the prohibition against rules requiring such rates be ended.

5.4 EXPERIMENTAL NET ENERGY RATES FOR RESIDENTIAL QUALIFYING FACILITIES

Net energy rates have been offered by at least one utility to residential consumers who generate a part of their own electric requirement [240]. The watthour meter is run backwards whenever the consumer produces excess energy that returns to the utility lines. The monthly bill reflects the electric energy received from the utility minus the energy returned to the utility. There is a minimum charge for the first block of 100 kWh (net) consumption per month and there is no carry-over for a negative balance; i.e. a net energy excess. In effect, the first block represents a customer charge. At a net consumption greater than 100 kWh, such consumer/producers obtain a sell-back rate equal to the backup rate. The net energy rate is offered as a time-limited experimental rate to the first 25 customers interconnected.

This report recommends that FERC authorize, under § 210(b,c), an experimental rate consisting of a customer charge plus the ordinary flat or block residential class energy rate for the net energy consumed during any billing period by consumers who generate a portion of their own electric requirements by means of interconnected qualifying SPPFs; that this rate be limited to facilities with a maximum generation capacity of 40 kW; that this rate be available until the generation capacity of the residential qualifying facilities comprises 1% of the utility's generation capacity dedicated to residential consumption; that the net energy is the difference between the energy supplied to the consumer and

*See discussion in Section 4.2.2.

the energy supplied back to the utility; that the consumer is not entitled to credits during billing periods in which the net energy flows to the utility.

A net energy rate for cogeneration and small power production on the residential scale is desirable because it encourages such production,* it is simple to understand and to administer, and it is defensible under the requirements of PURPA. The remainder of this section explores the apparent clash between the PURPA limitation of FERC rules for purchases by the utility to the incremental cost of alternative electric energy and the proposed net energy rate.

5.4.1 The Effect of Very Small QFs on Utility Load Fluctuations

What is the effect on the load swing of a utility of interconnecting a SPPF? The sudden onset of the generation of 20 kW of power of a WECS has the same effect as the sudden shutting off of 20 kW worth of motors.** The utility in both cases must burn fuel more slowly and generate 20 kW less energy until the next system fluctuation requires another adjustment.

As far as fluctuations are concerned, a 20-kW WECS is virtually a 10-kW load fluctuating ±100% or ±10 kW, between 0 kW and 20 kW. Even though the WECS has a 100% fluctuation, as compared with a utility system load swing of perhaps ±3%, superimposing the SPPF's fluctuation of ±10 kW has no noticeable effect on the potential load swing of ±120 MW (i.e., 120,000 kW) of a 400-MW system.

The effect on a utility of interconnecting a small intermittent SPPF is similar to the effect of dumping a bucket of boiling water into a pond. The larger unit in each case acts as an "infinite reservoir" relative to the smaller. The pond absorbs thermal energy from the boiling water without perceptible temperature rise. The utility absorbs random power fluctuations from the SPPF without perceptible effect on its own, much larger, random fluctuations.

Load swing has a statistical character and is independent of the fluctuating power production of an interconnected SPPF. The effect of independent random fluctuations is found by first squaring each number (in kilowatts, not in percent), adding the squares, and finally taking the square root of the sum. Even a very large SPPF—for example, one with one-tenth the fluctuation of the system's load swing (a super-WECS of 12 MW ± 12 MW)—would have almost no effect on the overall system fluctuation; the fluctuation of the composite system increases from ±120MW to ±121 MW, one adds the squares of the fluctuations not the fluctuations themselves. (The ±10-kW fluctuation of a 20-kW WECS only increases the effective load swing from ±120 MW to ±120.005 MW.)

The fluctuations of separate WECS are partially correlated. If they were uncorrelated, their cumulative effect would be entirely negligible. But, even if they were completely correlated the interconnection of 1% WECS capacity to a utility has only a slight effect on the load fluctuations. One percent of a 4000-MW utility is 40 MW. This is the equivalent of 20 MW ± 20 MW. Superimposing a fluctuation of ±20 MW on load swing of ±120 MW gives ±121.7 as the composite fluctuation. Thus, it is practically no more

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*The social usefulness of small power production on a residential scale (and, if technically feasible, of cogeneration) has been argued in Section 3.2.2.

**See Section 2.1.2.5 on load swing.

difficult for a utility to cope with the fluctuating nature of the residential scale SPPF at 1% penetration than it is to cope with the variations in the ordinary load.

5.4.2 The Effect of Very Small QFs on Utility Generation Capacity

How does the installation of residential SPPFs with an aggregate capacity equal to 1% of the residential load affect the generation capacity needs of the utility? The answer depends on several variables. One variable is the existing size of the utility's reserve generation capacity. A second variable is the extent to which the SPPFs are used to reduce existing electric consumption.

It can be argued that the proposed rate is a form of subsidy from the ratepayers as a group to the small power producing consumer. If it is a subsidy, is it within the range that accords with the intent of PURPA? On its face, the answer is no, in view of the explicit language of the conference report quoted in Section 1.4.1 and in the text accompanying Ref. 31. The level of subsidy may nevertheless be well within limits consistent with the act. The largest possible adverse impact on other ratepayers is well within 1%. This is to be compared with rate inequities large enough to be of special concern in § 133 of PURPA. The possible 1% subsidy is to be compared also with the subsidy explicitly acceptable to PURPA in providing for lifeline rates.

Finally, it is noteworthy that the proposed net energy rate for residential scale SPPFs is experimental and that it avoids any danger of permitting profiteering at the expense of ratepayers.

5.4.2.1 A Reduction of Sales Without a Reduction of Fixed Costs

If all of the installations of residential SPPFs were by existing customers, the effect would be no increase in peak demand and a slight decrease in energy sales. (Because the capacity factor of most SPPFs, at least of WECS and PVs, is small compared to utility capacity factors, the amount of reduction of energy sales would be well under 1%.) The total energy sales could be reduced without a corresponding saving in fixed costs. As a result, the cost per kWh would rise slightly. On the other hand, no new capacity would need to be built since the backup demand would be no more than the original demand. In this respect, the partial replacement of energy purchases by self-generation is equivalent to conservation and the installation of solar heating. It would be contrary to social policy to allow rate structures that penalize such conservation measures [241]. In order to assure that such measures (including conservation, solar heating, and solar generation of a portion of one's electric needs) are protected against discriminatory rates, it would be wise to obtain new legislation such as H.R. 2798, which "prohibits electric and gas utilities from charging higher rates to residential consumers who conserve energy or utilize alternative energy sources" [242].

5.4.2.2 New Construction Can Be Delayed

SPPFs that are installed by new electric consumers will hold down the expansion need at least to the extent of the ELCC of the SPPFs. If such installations are in the typical utility, overdesigned due to past overestimates, the fraction of 1% of capacity can be absorbed by the utility. In such cases there is no new burden placed on the other ratepayers by the alternative energy investments of the new consumers who install SPPFs. In fact, the added energy sales could reduce the per kWh cost to the ratepayers who are presumably paying a premium rate because of the overcapitalization of the utility.

If SPPFs are installed by new consumers in a system that is not overbuilt, some expansion would seem to be called for. It is in these situations where the other ratepayers might in fact be subsidizing the SPPF owners (by less than 1%). But these are the rate situations in which the ratepayers are significantly advantaged relative to average utility customers, since these are ratepayers not burdened by the costs of overcapitalization. The subsidy would come from advantaged ratepayers in order to make possible the development of alternative energy sources in places with the largest pressure to expand.

5.4.2.3 Equity Among Consumers

The proposed experimental net energy rate would have the effect on a small power producing consumer of assessing a smaller share of the utility's fixed costs than that same consumer would bear without the SPPF. This is because the consumer would otherwise be paying for more kWh and it is assumed that the fixed costs are incorporated into the energy charge. This reduced assessment of the capacity costs results whether the SPPF is installed by an existing or a new customer and whether the SPPF is interconnected with an over- or under-capitalized utility. But the producer/consumer is not necessarily advantaged relative to other consumers. Because rate structures do not reflect cost of service precisely, it is quite possible for two consumers who impose different burdens on the utility to have the same bill to pay, or for two consumers who impose equal burdens to be billed differently [243].

PURPA recognizes the existence of inequities among the members of a single customer class in § 133(a)(1). That subsection requires FERC to gather information about "the costs of serving each consumer class, <u>including costs of serving different consumption patterns within such class</u>, based on voltage level, time of use, and other appropriate factors" (emphasis added). In order to insure a high level of equity among the members of the residential class, a finely graduated time-of-day rate would be required. In order for such a rate to avoid discrimination against solar energy users, demand charges should be incorporated into a sharply differentiated time-of-use energy rate (see Sections 4.1.2 and 5.2.3.4).

PURPA, however, shows a much greater concern with "the costs of serving each consumer class" than it does with equity within each class. For example, in § 111(a)(3), time-of-day rates are established as a federal standard: ". . . rates . . . for each class of electric consumers shall be on a time-of-day basis . . . ." And even this greater concern with the equity between classes, as compared to equity within classes, is qualified. Time-of-day rates are to be established <u>where cost effective</u>; i.e., "if the long-run benefits of such rate to the electric utility and its electric consumers in the class concerned are likely to exceed the metering costs and other costs associated with the use of such rate" [244].

In requiring a cost-of-service study, PURPA implicitly accepts the existence of rate inequities—at least until FERC's implementation of § 133 establishes an adequate basis for more equitable rate structures. Moreover PURPA explicitly accepts rate inequities (subsidies) for a special purpose in § 114(a):

> No provision of this title prohibits a State regulatory authority . . . from fixing, approving, or allowing to go into effect a rate for essential needs . . . of residential electric consumers which is lower than a rate under the standard [of cost-of-service].

Given this departure from the "no subsidies" idea and given the general inaccuracy of the relationship between residential rates and cost-incurrence, it would be inappropriate to single out SPPFs (at a concentration of less than 1% of residential use) for strict adherence to the no-subsidy rule.

5.4.2.4 The Scope of the Proposed Experimental Rate

The proposed net energy rate is an experimental rate. It is limited to SPPFs whose net energy balance is that of a consumer—not a supplier—and limited to an amount of generation capacity that aggregates no more than 1% of the capacity to serve the residential consumer class of a utility.

The principle behind the experimental rate is that it would be premature to (1) place residential consumers who generate a portion of their own electricity in a class by themselves, or (2) establish a rate structure for this very small subset of residential consumers that differs materially from the rate structure of the remainder of the class. In addition, the simplicity and cost saving as to metering and bookkeeping warrants the slight imprecision that accompanies net energy rates. The rate is experimental in that it is designed to provide the opportunity to study the actual effect of interconnecting many SPPFs with the utility, while providing enough encouragement so that there will be a sufficient sample for the study. Until the effect of such interconnection can be observed (not merely computer-simulated) and until the general accuracy of rates as a reflection of costs of service is better understood through the FERC study under § 133, it would be difficult to devise a realistic rate that is both more accurate than the proposed rate and that encourages small power production. Any other rate would suffer equally from imprecision. In short, it is premature to arrive at a final rate. If the residential class as a whole has an energy block rate (with customer charges either separate or incorporated into the first block), it is a good enough approximation to allow small power producing consumers to pay for the net energy they consume. If a demand/energy rate is in force, the objections already stated in Section 4.2.1 still hold. If a time-of-use energy rate is in force, the proposed rate would call for net energy measurements in each of the time periods in question.

The proposed rate does not permit payment by the utility to the residential SPPF for a net energy flow to the utility. This restriction serves to avoid any possibility of private profiteering at the possible expense of the remaining ratepayers. The net energy rate is designed for consumers who meet a part of their own needs, much as other consumers can decrease their needs by conservation or direct solar energy use.

Finally, no injustice is done by giving an advantage to the first 1% of the residential consumers over any additional consumers who may add a SPPF later. The cost of installing a SPPF is much greater in the early stages of commercialization of a given technology than it is in later stages. If it turns out that net energy rates constitute a subsidy, it is appropriate that the recipients of the subsidy be limited and that the costs of the subsidy be trivial. The restrictions of the proposed rate are designed to assure that any subsidy that results should be an insignificant portion of any other ratepayer's cost.

5.5 RATES FOR INTERCONNECTED FACILITIES AND ENERGY STORAGE

The rate structure for exchanges of energy between QFs and utilities ought not to encourage counterproductive planning decisions. For example, a rate schedule that charges a high price for maximum power demand and a low price for energy may invite even highly reliable CFs to invest in duplicate generating equipment in order to become wholly independent of the utility [245]. Excessive reliance by regulatory authorities on the model of utility may lead to excessive distinctions between firm and non-firm power. The resulting difference in treatment of steady and intermittent producers may lead the latter to take undue measures to smooth their power output. Such measures would defeat the utility's ability as an infinite reservoir to serve as the equivalent of a storage system. The electric network can absorb solar-generated electric power without storage if solar penetration is less than 15% of the utility's output [246]. It is, therefore, more cost effective (in total cost to the society) for the utility to adapt its behavior to the intermittent output of solar sources of electric power than it is for SPPFs to rely on storage or complex hybrid arrangements to be able to provide firm peak power to utilities. Rate structures should not attempt to create false economic signals that defeat this reality.

5.5.1 Cost-Effective Storage

At low penetration of solar production, storage is an unnecessary expense. At high penetration, storage may be a cost-effective alternative to expansion of generation capacity. Dispersed storage dedicated to individual SPPFs is not cost effective, however. A "dedicated" storage system is one that is charged only from the pertinent solar system. Decentralized dedicated storage for SPPFs is uneconomical in two ways. First, it is up to four times more expensive than the equivalent amount of central station storage [247]. Second, system-wide storage can be charged from the grid itself whenever the system has cheap off-peak energy, and is 2.7 times as effective as dedicated storage that can be charged only from the particular unit to which it is dedicated [248]. The total cost to society of decentralized dedicated storage is therefore unacceptably high compared with utility system storage.

An example of the way a rate structure can falsely make a dedicated storage system appear cost effective is one that allows little or no payment by the utility for energy from SPPFs. Assuming no sales to the utility, for example, a 10-kW PV system can increase the electricity it supplies to a residence by 46-58% by adding 24 kWh of storage [249]. Without storage, this excess production over instantaneous residential demand is wasted unless sold to the utility. But since the energy can be sold to, and absorbed by the utility, the energy "saving" is illusory. The rate structure should sufficiently reward the SPPF for sales so that it is not encouraged to build unnecessary storage.

Less drastic rate structure defects can give similar false signals. For example, if a high minimum ELCC were required in order for a SPPF to be entitled to capacity credit, the SPPF might be tempted into cost-ineffective measures. For large central station utility-owned WECS, storage improves the 46% capacity credit (at 10% penetration in Kansas) to 70% [250]. However, dedicated storage was found inferior to system storage and neither was found worth adding at 5% WECS penetration [251].

An intermittent facility such as a WECS or PV can most effectively tailor its output to suit the utility by hybrid operation in conjunction with a low-head hydroelectric plant that has reservoir storage. The hydroelectric component of such a hybrid can be used not only to compensate for the variations of the WECS but to arrange that the net surplus energy is available for firm peak power sales. The idea of interconnecting wind and hydroelectric power had already been proposed in the early 1940s in conjunction with the first large (1.75 MW) wind machine, the Smith-Putnam machine at Grandpa's Knob, Vt. [252]. The Smith-Putnam turbine lost a blade that could not be replaced because of wartime shortages; thus, the hybrid project never was put into practice.

Two modern variants include a plan under consideration by the Niagara Mohawk Power Company in New York State and a plan of the Bureau of Reclamation for a wind farm at Medicine Bow, Wyo. The New York State plan would use the wind power solely to pump water back up into a reservoir at an existing hydroelectric station [253]. In that case there is no need to generate electric power that is compatible with the electric network from the WECS and the electric output (from the hydroelectric plant) could be used to smooth the utility's load curve. The Wyoming installation is not planned as a direct hybrid; it would take advantage of the fact that the seasonal variations of water availability just offset the seasonal variations of wind speed [254].

In a hybrid system the hydroelectric component may be manipulated to provide a desirable firm power output. A SPPF thus operated may be able to avoid the need for backup power or to reduce its backup need to base load power, and it may command a much higher price for surplus energy than an intermittent system can. However, the hydroelectric component of the hybrid system could be used even more efficiently as a load management device for the composite system (utility plus WECS) than it can to manage the output of the WECS/hydro hybrid SPPF. If it is used to match the hybrid SPPF's output to a predetermined firm power sales agreement, it is not used with as much flexibility in meeting the actual demand on the utility as it could be. System-wide load management remains the most efficient use of energy-limited hydroelectric power [255].

5.5.2 An Approach to Subsidizing Solar Production of Electricity

In Title II of PURPA, Congress has found a brilliant way to take advantage simultaneously of the large size of utilities and the small size of SPPFs. Its large size permits a utility to absorb the fluctuating electric output from solar sources. Their small size makes SPPFs flexible and suitable to rapid innovation. By requiring utilities to offer interconnection, PURPA takes a large step toward encouraging solar production of electricity. A second step that PURPA should take to provide a higher level of encouragement is to permit modest subsidies within the utility system.

Two related approaches to subsidizing solar production of electricity are proposed. The first looks to the utility (and ultimately its ratepayers) to subsidize SPPFs by absorbing the capacity costs for any backup energy. The second looks to the federal treasury to assist utilities in absorbing the capacity costs.

5.5.2.1 Utility Absorption of Capacity Costs of Qualifying Facilities

This report suggests amending PURPA § 210(c) and § 210(b) to permit:

- backup rates for QFs that do not reflect the cost of generation capacity; and
- energy sales by QFs to utilities to be credited against purchases from utilities, to provide for net energy purchases by QFs.

These suggested amendments represent a departure from the intent of PURPA as well as its language because they allow for a possible subsidy of QFs by the remaining ratepayers. The burden of carrying the costs of expanded generation capacity of the utility would be borne by only those ratepayers who do not own QFs.

The recommended implementation by FERC of such an amended act would provide that:

- Net energy rates* be charged to all CFs and SPPFs that are net consumers of electricity, limited to no more than 10% of the generation capacity serving each customer class;
- The rates would not reflect a generation capacity cost but would include transmission and distribution as well as customer charges;
- The limitation to 10% penetration would be relaxed if the recommendation in Section 5.5.2.2 is adopted.

The rationale for these added incentives to SPPFs and CFs is that rapid commercialization of these technologies may well require more incentives than Title II provides at present. In addition, the economy generally and utility ratepayers in particular would benefit from the fuel savings. The proposals do not benefit all QFs equally. Cogeneration, biomass, and hydroelectric facilities may already be in a position to obtain capacity credit and would presumably benefit less than WECS or direct sunlight facilities. This unequal subsidy is appropriate. Cogeneration, biomass, and hydroelectric facilities use limited renewable resources. WECS and direct sunlight facilities use literally inexhaustible energy supplies.

Subsidization by utility ratepayers rather than society at large is appropriate. First, the class of electric consumers is almost congruent with society at large. Second, the hidden environmental burden imposed by conventional power plants (and to a lesser degree by CFs, biomass, and waste burning plants) is proportional to electricity use. Since these hidden costs are not included in rates, it is appropriate that consumers whose consumption pattern imposes those costs subsidize others whose production decreases the environmental costs of electricity.

The limitation to 10% penetration is selected for three reasons: (1) at less than 10% penetration the intermittent availability of solar production of electricity can be absorbed in the normal load fluctuations, (2) there is no need for system-wide storage at low penetration, and (3) most utilities are overdesigned by more than 10%.

The proposal may be thought to treat differently those utilities that are overdesigned and need no expansion to accommodate the capacity needs of QFs from those utilities that have no excess capacity. Different utilities, however, offer very different electric rates and high rates are due in no small part to overdesign. If the burden of subsidizing CFs and SPPFs falls unequally on different utilities, it at least falls less heavily on consumers of overdesigned utilities who are already paying an excessive rate.

5.5.2.2 Federal Subsidy for Utility System Storage

This report recommends that direct federal subsidies be provided to finance system-wide storage for utilities with over 10% penetration of generation facilities using intermittently available renewable resources. Utility-owned systems for generating electricty from solar resources are included as "generation facilities using intermittently available renewable resources."

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*Net energy rates is used in the sense discussed in Section 5.4, except that the proposal of Section 5.4 was limited to residential SPPFs at penetrations below 1%.

The proposed federal subsidy would limit to well below 10% the subsidy provided by the utility's absorption of the capacity costs of qualifying facilities, as proposed in the preceding subsection. Only after the total rated generation capacity of devices for producing electricity from solar sources reaches 10% of the utility's capacity would subsidized storage be built. That is, the generation capacity subsidy for solar facilities would be assumed by the utility to 10% penetration and by the Federal Government for any excess over 10%.

Solar production by the utility itself would be counted in arriving at the aggregate of 10% penetration. The federal subsidy would therefore encourage the development of solar production of electricity both internally and externally to the utility. It is correct to make no distinction between subsidizing the utility's WECS and independent WECS. In either case—SPPF or utility WECS—the ratepayer supports the difference between rated capacity and effective load carrying capability. In either case, the ratepayer should be relieved after 10% of the system is solar or intermittent.

A subsidy in the form of federally financed energy storage shifts the generation mix into one suitable to support intermittent production from solar sources. The storage paid for by public funds would not be a part of the rate base for ratemaking purposes. The proposed program would avert a utility response to solar production of increasing fossil fuel or nuclear capacity, thus expanding the rate base.

SECTION 6.0

REFERENCES

1. Pub. L. No. 95-617, hereinafter cited as PURPA.

2. The Federal Energy Regulatory Commission was established as an agency within the Department of Energy by the Department of Energy Organization Act, Pub.L. No. 95-91, 4 Aug. 77, 42 U.S.C. § 7134. FERC's regulatory functions related to interstate sales of electric power were transferred to FERC by Pub.L. No. 95-91 from the Federal Power Commission (FPC).

3. Id. § 210 (a).

4. Id. § 201.

5. Id.

6. Id. § 210(e).

7. Id. § 210(a).

8. Id. § 201.

9. Id. § 201 requires that the primary energy source be biomass, waste, or renewable resources; "primary energy source" excludes, in accordance with rules to be prescribed by FERC, "(i) the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and (ii) the minimum amounts of fuel required to alleviate or prevent—(I) unanticipated equipment outages, and (II) emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages." The Proposed Regulations pursuant to § 201 issued by FERC on 17 June 79, Docket No. RM79-54, set such fuel use standards in § 292.205(a).

10. In 1976, 21.4 quads of source energy were used to generate 6.96 quads of electric energy, of which 6.28 quads was delivered. The Bureau of National Affairs, Inc. Energy Users Report; Energy Information Administration. Annual Report to Congress. Vol. III (1977) at 7 and 103. Thus, the average generating efficiency is 6.96/21.4 = 32.5% and the system efficiency is 6.28/21.4 = 29.3%.

11. Title IV of PURPA calls on the Secretary of Energy to establish a program "to encourage municipalities, electric cooperatives, industrial development agencies, nonprofit organizations, and other persons to undertake the development of small hydroelectric power projects in connection with existing dams which are not being used to generate electric power." Title IV also provides for loans for feasibility and project costs. There are abandoned electric generating plants at many existing dams, which can be reactivated, and turbines can be installed in the outlets of other dams. See U.S.DOE. Environmental Readiness Document: Small-Scale Low-Head Hydro. Washington, D.C.: Sept. 1978.

12. SERI. Annual Review of Solar Energy. Oct. 1978.

13. See note 10. The 1976 delivered energy of 6.28 quads represents 90.2% of the 6.96 quads of electric generated.

14. Meadows, D. "Fallacies that Block the Search for an Alternative Energy Plan." DSD #94. Hanover, N. H.: Dartmouth College Systems Dynamic Group; Dec. 1977.

15. Hewett, C. E.; High, C. J. "Construction and Operation of Small, Dispersed, Wood-Fired Power Plants." DSD #117A. Hanover, N. H.: Dartmouth College System Dynamics Group; Mar. 1979.

16. Odland, R. Decentralized Energy Studies. PR-220. Golden, CO: Solar Energy Research Institute; at 9 and 10.

17. Id. See also FERC Docket No. RM79-54, supra note 9, at 4: the Federal Energy Regulatory Commission believes that §§ 201 and 210 of PURPA "reflect a belief that improved energy resource utilization may be accomplished with projects based on unconventional technologies or using small unit sizes which might not be developed by electric utilities" (emphasis added).

18. The limited efficiency of electricity generation follows from a law of nature, the Second Law of Thermodynamics, that states that no heat engine can have a greater efficiency (mechanical output divided by heat input) than the ideal Carnot cycle. This maximum efficiency is $(T_2-T_1)/T_2$ where T_2 and T_1 are the intake and exhaust temperatures in degrees Kelvin (absolute). A steam engine is not as efficient as the Carnot cycle because of the large amount of heat required to evaporate water. The figure one-third is a conservative statement of the actual performance of electric power plants. Cf. note 10.

19. The minimum overall efficiency required in the proposed regulations defining qualifying cogeneration facilities must be at least 60%. Federal Energy Regulatory Commission, Proposed Regulations Providing for Qualification of Small Power Production and Cogeneration Facilities Under Section 201 of the Public Utility Regulatory Policies Act of 1978 (issued June 27, 1979), § 292.206(c)(5), (d)(2), and (e)(3), Docket No. RM79-54. This compares with an overall efficiency of about 29% for conventional electric plants. Cf. note 10.

20. Louisiana-Pacific Corp. in Samoa, CA, generated all its own steam as well as 232 million kWh of electric energy in 1978. This supplied all of L-P's requirement of 196 million kWh plus an excess of 35 million kWh sold to Pacific Gas and Electric (PG&E). Louisiana-Pacific purchased 0.666 million kWh from PG&E during major maintenance shutdowns or forced outages. Taylor, E. "Louisiana Pacific Corporation." Biomass Energy Conversion Workshop for Industrial Executives. 9-10 Apr. 79. Golden, CO: SERI.

21. Univ. of Oklahoma, The Science and Public Policy Program. Energy Alternatives. Washington, D.C.: U.S. Government Printing Office; 1975, at 9-13 (hereinafter cited as Energy Alternatives).

22. In New York City, the public utility rates and the backup rate permitted by the Public Service Commission are so high that "most cogenerators in the New York area install their own standby generators, even though in some cases they may have to invest more than twice as much as they would if they had a utility backup." Alexander, T. "The Little Engine that Scares Con Ed." Fortune. 31 Dec. 78.

23. PURPA § 210(b).

24. Id.

25. PURPA § 210(d).

26. PURPA § 210(c).

27. Federal Energy Regulatory Commission. "Staff Paper Discussing Commission Responsibilities to Establish Rules Regarding Rates and Exemptions for Qualifying Cogeneration and Small Power Production Facilities Pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978." Docket No. RM79-55.

28. Docket No. RM79-54, supra note 19.

29. Docket No. RM79-55, supra note 27.

30. House of Representatives, Report No. 95-1750, hereinafter cited as Conference Report.

31. Id. at 98.

32. PURPA § 101.

33. PURPA § 111(d).

34. PURPA § 113(b).

35. PURPA § 121(a).

36. PURPA § 112.

37. U.S. District Court, Southern District of Mississippi, Jackson Division, Civil Action No. J79-0212(C), filed 7 May 79.

38. Id. V.1.a, at 7.

39. FERC, Docket No. RM79-55, supra note 27, at 4.

40. The Constitution of the United States, Art. I, Sec. 8 (3).

41. PURPA § 2.

42. Ray v. Atlantic Richfield Co., 55 L.Ed. 2d 179. "[T]he historic police powers of the States [are] not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress." Rice v. Santa Fe Elevator Corp., 331 U.S. 218, 230(1947).

43. 18 C.F.R. Ch. 1, Subchapter K, Part 290.

44. FERC, Docket No. RM79-55, supra note 27, at 4.

45. Conference Report, supra; see note at 97.

46. Excess electric energy can be converted into gravitational energy in pumped-hydro storage systems or into chemical energy in electric storage batteries, or converted and stored by other means. But all such systems involve a considerable capital expense per kWh of energy storage capacity. In addition, they involve the loss of a fraction of the energy put into and taken out of storage and the capital cost for the generator or conversion device, in dollars per kW of the rate at which energy is to be put into or taken out of storage.

47. Biomass is plant material, including wood grown as a fuel and replaced through reforestation programs. Biomass includes waste plant material such as wood wastes in the forest products industry and organic waste products such as paper, as well as agricultural wastes (manure) and the organic component of municipal and industrial waste.

48. See notes 10 and 18.

49. Energy Users Report, supra note 10, at 68.

50. Computed from data in "29th Annual Electrical Industry Forecast." Electrical World. 15 Sept. 78, at 72 (hereinafter cited as Forecast).

51. Electric Utility Rate Design Study. Rate Design and Load Control (A Report to the National Association of Regulatory Utility Commissioners). Palo Alto, CA: Electric Power Research Institute; Nov. 1977, at 16 (hereinafter cited as Rate Design Study).

52. Adapted from Id. at 14.

53. Marsh, W. D.; et al., Requirements Assessment of Photovoltaic Power Plants in Electric Utility Systems. EP-685-SY. Palo Alto, CA: EPRI; June 1978, at 20.

54. The sum of the annual demand peaks of U.S. utilities in 1978 was 400,000 MW while the generating capacity was 552,000 MW. Forecast, supra note 50, at 72.

55. Id. at 73.

56. Id. at 72.

57. "15th Steam Station Design Study." Electrical World. 15 Nov. 78, at 86.

58. Mr. Gregory Sullivan, Boston Edison Co., conversation of 20 Sept. 79.

59. Prof. Thomas Reddick, Electrical Engineering, University of Tennessee, conversation of 13 Aug. 79.

60. Sullivan, supra note 58.

61. Id.

62. Cf. note 10.

63. The 1977 expenditures in billions of dollars were: generation—20.4; transmission—3.3; distribution—4.8. Forecast. Supra note 50, at 75.

64. Rate Design Study, supra note 51, at 24.

65. Odland, supra note 16, at 11.

66. D. Horgan, SERI, conversation of 22 Aug. 79.

67. Hajdu, L. P. "Dispersed Storage and Generation—the Impact on Rural Distribution Systems," NRECA Energy Conservation Technology Conference, 22-23 Aug. 77, Washington, D.C.

68. PURPA § 101.

69. A thorough exposition of the desirability of avoiding the use of electric energy where other forms of energy are usable is given in Lovins, A. B. Soft Energy Paths. New York, NY: Harper and Row; 1977.

70. Asbury, J. G. "Central and Dispersed Storage for Electric Utility Load Leveling." Presented to AUA/ANL Nuclear Engineering Student-Faculty Conference, Economics of Central Station Power. 20-22 Feb. 79.

71. Electric space heating is an inefficient use of fossil energy. Cf. note 69.

72. Garver, L. L. "Effective Load Carrying Capability of Generating Units." IEEE Trans. on Power Apparatus and Systems. Aug. 1966, Vol. PA5-85, at 910-919.

73. Marsh, W. D. Requirements Assessment of Wind Power Plants in Electric Utility Systems. Prepared by General Electric. Palo Alto, CA: EPRI; Jan. 1979. EPRI/ER-978, Vol. 3, at A1-2.

74. Id. at A1-3.

75. Billinton, R. Power System Reliability Evaluation. New York, NY: Gordon and Breach; 1970.

76. Telson, M. "The Economics of Alternate Levels of Reliability for Electric Power Generation Systems." 6 The Bell Journal of Economics 691 (1975).

77. Id. Reliability expectations are too high also according to former FPC Commissioner John A. Carver, Esq. Conversation of 26 June 79.

78. Telson, Id. at 686 and 691.

79. Id. at 689-90.

80. Conference Report, supra note 30, at 97.

81. PURPA § 209(a)(1)(C).

82. Docket No. RM79-54, supra note 19.

83. Docket No. RM79-55, supra note 27, at 12.

84. Id.

85. Marsh, supra note 73, at A1-13.

86. Id. at A1-12.

87. Docket No. RM79-55, supra note 27, at 18.

88. Id. at 5.

89. Id. at 4.

90. Id. at 12.

91. Billinton, supra note 75, at 111.

92. Docket No. RM79-55, supra note 27, at 18.

93. This usage is consistent, for example, with that in Rate Design Study, supra note 51.

94. PURPA § 101.

95. PURPA § 3(8).

96. PURPA § 111(d).

97. A two- or three-shift industry has a higher load factor, for example, than a single shift industry.

98. Docket No. RM79-55, supra note 27, at 5.

99. PURPA § 210(b). Louisiana-Pacific, for example, seeks to wheel power from its Samoa, CA, plant to other L-P operations in the area by using the PG&E system and paying an appropriate charge. Taylor, supra note 20.

100. Conference Report, supra note 30, at 97.

101. Rate Design Study, supra note 51, at 14.

102. Professor John A. Carver, Denver University Law School, conversation of 26 June 79.

103. Forecast, supra note 50, at 75.

104. Adapted from Rate Design Study, supra note 51, at 15.

105. Forecast at 74. The 1978 pumped storage capacity was about 3% of the total utility generating capacity.

106. Cf. note 21.

107. Peters, E.; et al. "Factors Hindering the Development of Small-Scale Municipal Hydropower: A Case Study of the Black River Project in Springfield, Vermont." DSD #144, Hanover, NH: Dartmouth College; March 1979.

108. Forecast, supra note 50; Prof. Reddick, supra note 59.

109. Acton, J. P.; Mitchell, B. M.; Manning, W. G., Jr. European Industrial Response to Peak-Load Pricing of Electricity with Implications for U.S. Energy Policy. Santa Monica, CA: The Rand Corp.; March 1978.

110. PG&E. Time-of-Use Rates for Very Large Customers. San Francisco, CA: PG&E; March 1978.

111. Johnson, C. R.; Mintz, S. "DOE: T-o-d Rates Shift kWh and kW." Electrical World. 15 Nov. 78 at 110-112.

112. For example, the PG&E schedule, supra note 110, makes the following peak season charges:

Customer Charge	$715.00
Demand Charge	
On peak, per kW of Maximum Demand	3.45
partial peak, per kW of Maximum demand	.28
off peak	no charge
Energy Charge	
on peak, per kWh	.00951
partial peak, per kWh	.00751
off peak, per kWh	.00551

113. PURPA § 115(b). The restriction is likely to make the implementation of time-of-day rates for residential customers very slow.

114. Id. §§ 111(a), 112.

115. Don Baldwin, light director, Albany Water, Gas, and Light Commission, conversation of 9 Aug. 79.

116. Federal Power Act of 1920 (FPA), § 3(17)(A), as amended by PURPA § 201.

117. FPA § 3(18)(A), as amended by PURPA § 201.

118. FPA § 3(17)(C) and (18)(B), as amended by PURPA § 201.

119. Docket No. RM79-54, supra note 19.

120. Id. at 15.

121. Sutherland. Statutes and Statutory Construction. § 47.23 (4th ed. 1973); United States v. Wiltberger, 5 Wheat. (18 U.S.) 76, 5 L.Ed.37 (1820).

122. Docket No. RM79-54, supra note 19, at 15.

123. Merriam, M. F. "Wind Energy Use in the U.S. to the Year 2000." Wind Energy Report. Aug. 1978 (report prepared for the Nuclear & New Technologies Division, Federal Energy Administration, submitted in Oct. 1977). Merriam projects a fuel displacement from dispersed mode SWECS of 0.4 quad annually by the year 2000, two-thirds of it residential, i.e., below 10 kW.

DOE Office of Commercialization Resource Management, Small Wind Systems. Preliminary Commercialization Plan for Small Wind Systems. 16 Feb. 79. The report states, at p. 3:

> These four elements [development, demonstrations, incentives, information] form the major thrust of the commercialization strategy which will lead eventually to the development of a wind industry infrastructure, the production of low-cost durable small wind systems and the penetration of the market for those systems. . . .
>
> Rural residence and remote power needs, along with farm applications, are expected to comprise the primary market for small wind systems. Widespread use of the systems would contribute 0.3 quad of primary energy by the year 2000.

The MITRE Corporation, under DOE Contract #EM-78-C-01-5147, has published a draft report "Toward a National Plan for the Commercialization of Solar Energy," June 1979. The report projects the following levels of market penetration for 4-kW SWECS and 3.4-kW PVs:

	1985		1990		2000	
	units	quads	units	quads	units	quads
4-kW SWECS	154,000	(0.01)	1,040,000	(0.05)	6,350,000	(0.3)
3.4-kW PVs	21,000	--	700,000	(0.03)	6,000,000	(0.2)

These figures are for MITRE's "reference case" (14.7 quads solar by 2000). The assumptions are that volume production and the level of incentives built into the statutes of the National Energy Act of 1978 will suffice to make this degree of market penetration economically viable. The (quads) is the fuel annually displaced that would be required to generate the equivalent electric energy. The corresponding figures for MITRE's "22 quad scenario"—the solar contribution required to meet the national goal of 20% solar in 2000—are 0.5 quad displaced by 4-kW SWECS and 0.3 quad by 3.4-PVs. This accelerated level of solar development would require greater incentives.

124. MITRE study, Id.

125. Marsh, supra note 73.

126. Docket No. RM79-54, supra note 19.

127. PURPA § 201, 3(17)(B).

128. Robert Danziger, Jet Propulsion Laboratory, Pasadena, CA, personal communication, 14 Aug. 79. Also, "Comments of the Jet Propulsion Laboratory on Notice of Proposed Rulemaking Establishing Requirements and Procedures for a Determination of Qualifying Status for Small Power Production and Cogeneration Facilities."

129. Id. The calculation assumes that 1 bbl has a heat value of 5.85 million Btu and generates 0.585 MWh at a fuel to electric energy conversion of 34%.

130. Cf. note 17, supra.

131. Conference Report, supra note 30, at 88-89.

132. Cf. note 20, supra.

133. PURPA § 210(e)(2).

134. PURPA § 201.

135. PURPA § 210(e)(2). Biomass-fueled SPFFs in the 30-80 MW range may, however, be exempted from the Public Utility Holding Company Act and from state regulation; they may not be exempted from regulation of interstate sales under the Federal Power Act.

136. Conference Report, supra note at 98.

137. Eldridge, F. R. Wind Machines. 1975, at 50ff.

138. Marsh, W. D. "Requirements Assessment of Wind Power Plants in Electric Utility Systems." ER-1110-SR. Proceedings of the Workshop on Economic and Operational Requirements and Status of Large Wind Systems. Palo Alto, CA: EPRI; July 1979, at 121. Capacity factors ranged from 35-50% in four different wind regimes. The MITRE Study, supra note 123, at 37 and 26, projects 6.35 million 4-kW units to displace 0.3 quad of fuel; this works out to a capacity factor of 12%.

139. Don Hardy, Pan-Aero Corp., Golden, CO. Private communication, 23 Aug. 79.

140. Cf. note 136.

141. PURPA § 210(b).

142. Id.

143. Id. § 210(d).

144. Id. § 210(c).

145. Bonbright, J. Principles of Public Utility Rates. Irvington-on-Hudson, NY: Columbia University Press, 1961; Garfield, P.; Lovejoy, W. Public Utility Economics. Englewood Cliffs, NJ: Prentice-Hall, 1964; Kahn, A. The Economics of Regulation: Principles and Institutions. New York, NY: John Wiley & Sons, 1970; Priest, A. Principles of Public Utility Regulation. Charlottesville, VA: Michie Co., 19__; Berlin, E.; Cicchetti, C.; Gillen, W. Perspectives on Power: A Study of the Regulation and Pricing of Electric Power. Cambridge, MA: Ballinger Publishing Co., 1974.

146. Huntington. "The Rapid Emergence of Marginal Cost Pricing in the Regulation of Electric Utility Rate Structures." 55 B.U. L. Rev. 689-774 (1975). The lead regulatory case concerned with marginal cost pricing is Wisc. Public Service Commission, Re Madison Gas and Electric Company, 5 P.U.R. 4th, 28. Moreover, this case provides a detailed exposition of ratemaking principles.

147. Cf. note 51.

148. Laitos, J.; Feuerstein, R. J. Regulated Utilities and Solar Energy. SERI/TR-62-255. Golden, CO: Solar Energy Research Institute, June 1979; Feuerstein, R. J. "Utility Rates and Solar Commercialization." 1 Solar Law Reporter. July/August 1979.

149. Dean, N. L.; Miller, A. S. "Plugging Solar Energy into the Utility Grid." 7 Env. Law Reporter 50069-82 (1977).

150. Bonbright, supra note 145, at 290. These goals have been widely accepted and are cited in Rate Design Study, supra note 51, at 17; Huntington, supra note 146, at 703-4; and adopted by the Wisconsin Public Service Commission in Madison Gas and Electric, supra note 146, at 34.

151. Garfield and Lovejoy, supra note 59, at 44.

152. Bonbright, supra note 145, at 292, 238-283; FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944).

153. Id. at 67.

154. Forecast, supra note 50, at 72 and 73.

155. Id. at 73.

156. Averch, H.; Johnson, L. "The Behavior of the Firm Under Regulatory Constraint." American Economic Review. 1963. This paper postulates that utilities may add unnecessarily to their capital cost rate base in the expectation of a virtually guaranteed return on investment.

157. Personal communication, 26 June 76.

158. Forecast, supra note 50, at 61.

159. Huntington, supra note 146, at 695 and 696.

160. Marsh, W. D.; et al. Requirements Assessment of Wind Power Plants in Electric Utility Systems. ER-978. Prepared by General Electric for Electric Power Research Institute. Palo Alto, CA: EPRI; January 1979. Vol. 2, at H-32 and H-52; Johnson, A. W.; et al. Applied Research on Energy Storage and Conversion for Photovoltaic and Wind Energy Systems. Prepared for National Science Foundation and DOE; January 1978; Vol. I, at 5-22 and 2-14.

161. Cf. note 151.

162. PURPA § 101.

163. PURPA § 209.

164. PURPA § 111(d)(6).

165. PURPA § 210(a).

166. Bonbright, supra note 145, at 67.

167. Conference Report, supra note 30, at 98.

168. Rate Design Study, supra note 51, at 24.

169. Pub. Serv. Co. of Colorado, General Residential Service, Schedule R-1 (eff. 23 Aug. 78) is a typical declining block rate.

First 30 kWh or less	$1.72
Next 70 kWh	.04317/kWh
Next 900 kWh	.03467/kWh
All over 1000 kWh	.02409/kWh

(Added on a flat per kWh basis is a fuel adjustment charge.)

The cost of the first 100 kWh is $4.74, which exceeds the cost of 100 kWh at the over-1,000 kWh rate by $2.33. It would appear that a customer charge of about $2.33 is hidden in the first two energy blocks.

Pub. Serv. Co. of Colorado, Residential Demand Service, RD-1 (eff. 23 Aug. 78) is a typical demand/energy rate. The difference between the first and subsequent kW of demand would appear to be a hidden customer charge.

Demand Charge:	
First kW of Billing Demand or less	$7.50
All over 1 kW of Billing Demand or less	3.20/kW
Energy Charge:	
All kWh	0.01001/kWh

(Added on a flat per kWh basis is a fuel adjustment charge.)

170. Detroit Edison Co., Residential Electric Service, Domestic, Schedule D1.

Customer Service Charge	$2.50
First 500 kWh	.0385/kWh
Next 500 kWh	.0415/kWh
All over 1,000 kWh	.0445/kWh

This is an example of an inverted rate structure. Note that the user of exactly 1,000 kWh pays $21.75 for the first 500 kWh including customer charge, and $20.75 for the second 500 kWh. The "inversion" of rates applies only to the energy component of the charge.

See also the rate schedule for the largest industrial customers of Pacific Gas and Electric Co., supra note 112. That schedule states customer, demand, and energy charges separately.

171. See, for example, schedules R-1 and RD-1, supra note 168. Comparing the over-1,000 kWh rate of $0.02409/kWh with the energy charge in schedule RD-1 of .01001 per kWh, it is fair to attribute the difference, $.01409/kWh, to a hidden demand charge.

172. Dean and Miller, supra note 149, at 50071-2.

173. Feuerstein, supra note 148, at 326.

174. Schedule RD-1, supra note 168, is an example of a flat energy rate. Schedule D1, supra note 169, is an example of an inverted block rate.

175. Cf. Section 2.3.4 and note 115.

176. Various meters which determine both the energy (kWh) and the noncoincident peak demand (kW) are described in Rate Design Study, supra note 51, at 67.

177. Huntington, supra note 146, at 713.

178. Note, for example, the sharply time-differentiated demand charges in the PG&E schedule, supra note 112.

179. Feuerstein, supra note 148, at 330-34.

180. Kahn, supra note 145, at 65-67.

181. Rate Design Study, supra note 51, at 33.

182. Id. at 34.

183. Madison Gas and Electric, supra note 146.

184. FERC, Docket No. RM79-6, supra note 43, at 7-9.

185. Cf. note 180.

186. Johanson, E. E.; Goldenblatt, M. K. "Wind Energy Systems Application to Regional Utilities." ER-1110-SR. Proceedings of the Workshop on Economic and Operational Requirements and Status of Large Wind Systems. Palo Alto, CA: EPRI; July 1979, at 136.

187. Conference Report, supra note 30, at 99.

188. Madison Gas and Electric, supra note 146, at 52.

189. Cf. notes 69, 9, and 18.

190. Subsequent to Madison Gas and Electric, long-range incremental pricing has been adopted in New York (Consolidated Edison Co., 8 P.U.R. 4th 475, 478-81) and Oregon (Portland Gas and Electric Co., 8 P.U.R. 4th 393, 415).

191. Kahn, supra note 145, at 69.

192. Rate Design Study, supra note 51, at 18.

193. Cited in Huntington, supra note 146, at 740.

194. Huntington, id. at 742, 3.

195. Id. at 745.

196. Id. at 742.

197. Cf. note 171.

198. Weisenmiller, R. B.; Dier, D., Jr. Testimony before the P.U.C. of California in the matter of OII No. 26, 18 June 79, at 5.

199. Cf. note 20.

200. Marcus, W. B. "Cost Based Rates for Cogeneration in California." Draft. Sacramento, CA: California Energy Commission; 14 May 79, at 3.

201. Id. Since March 1979 the standby rate has been $0.75/kW per month on-peak and $0.40/kW per month off-peak. There would be no justification for any demand charge, based on generation capacity required, off-peak. It can be inferred that at least $0.40 and perhaps as much as $0.75/kW per month is for transmission, distribution, and spinning reserve.

202. Id. at 9.

203. Id. at 9, 10.

204. Merriam, M. F. "Wind, Waves and Tides." 3 Annual Review of Energy 52 (1978).

205. Id. at 54.

206. Johanson, supra note 185, at 129.

207. Weisenmiller, supra note 197, at 8.

208. Cf. Sections 2.2.3 and 2.2.4. See also Marcus, supra note 199, at 1.

209. Marcus, supra note 199, at 9. The argument is a statistical one, based on the assumption of uncorrelated outages of different CFs or of CFs and the utility's generating units. As a simplified version of Marcus' argument, imagine a utility interconnected with a number of CFs whose aggregate rated capacity is 750 MW. Reasonable assumptions about their outage rates and about the utility yield an ELCC of 620 MW. Assume further that the aggregate demand of the CF owners is 620 MW, so that they sell as much energy to the utility as they buy from it. Marcus shows that for the utility to supply the 620 MW absent the CFs, it would have to add considerably more than 750 MW of rated capacity in order to operate at the same reliability. That is, the utility would need more reserve capacity than is comprised by the CFs in order to serve the same need. This implies that the present reserve capacity is more than adequate to absorb the fluctuations—to supply deficiencies when less than 620 MW is being generated by the CFs.

210. This second alternative, less favorable to SPPFs than the first, is justified by a simple, intuitive probability argument. (The argument suffers from imprecision compared with the statistical argument of Marcus.) Suppose there were ten identical CFs. On the average, one would be out of service at any one time. Hence, the system capacity would need to be increased by that of one CF, i.e., by one-tenth the total CF generating capacity. One might object that, if there were only one CF, its whole capacity and not merely one-tenth would need to be replaced. But if there were only one CF, its outage would fall easily within the reserve margin of any utility. One need not worry about added generation capacity until an appreciable total of external generation capacity is interconnected.

211. Marsh, supra note 159; Johanson, supra note 185; Marsh, supra note 53.

212. See Section 2.2.3, and note 85.

213. Johanson, supra note 185, at 134.

214. Id.

215. Marsh, supra note 159, at H-27.

216. Id. at H-29.

217. Id.

218. Kahn, E. "The Reliability of Distributed Wind Generators." 2 Electric Power Systems Research 1-14 (1979).

219. Marsh, supra note 53, at 31.

220. McDowell, E. "Solarville, Ariz.: Down to $7 a Watt." New York Times. 24 June 79.

221. U.S.DOE. Office of the Assistant Secretary for Energy Technology. Photovoltaics Program Multi-Year Plan, Draft. 7 May 79, at 2-6.

222. Id.

223. Marsh, supra note 53, at 32.

224. The effective capability of PVs in the Florida system can be almost doubled by the use of 6-hr storage, which makes the peak PV power available at the time of the load peak. The improvement in effective capability in the other two utilities through the use of energy storage is less significant.

225. Pacific Gas and Electric seeks to reserve the right to refuse to buy back CF- or SPPF-produced energy for as much as 600 hours/yr when it uses no oil or gas. Weisenmiller, supra note 197, at 10. Such refusal may be in violation of § 210 of PURPA.

226. Marsh, supra note 53, at 33.

227. Id. at 46.

228. Marcus, supra note 199, at 3.

229. Mattson, B. W. Order Instituting Investigation No. 26. "Recommended Commission Policies and Price Rules for Utility Purchases of Cogenerated, Auxiliary, and Small Power Production Facility Power." San Francisco, CA: Cal. PUC. 20 July 79, at 1.

230. Marcus, supra note 199, at 11 to 23.

231. Id. at 23.

232. Mattson, supra note 228, at 1.

233. Id. at 20.

234. Id. at 9. See also the discussion of marginal cost pricing in Section 4.1.3 and accompanying references.

235. Id. at 4-BWM (Appendix: "Qualifications and Prepared Testimony of Burton W. Mattson").

236. See also Section 4.1.2.2 and note 171.

237. Cone, B.; et al. "Long-Term Solar Parity Considerations Based on an Analysis of Incentives to Energy Production." Batelle Northwest Laboratories; Nov. 78.

238. MITRE Study, supra note 123, at A-4.

239. Id. at 44 and A-7.

240. Southern California Edison Co., Parallel Generation Schedule PG-1.

241. See Section 4.1.2.4 and note 178.

242. 1 Solar Law Reporter 434.

243. For example, two residential consumers subject to a declining block rate may use identical kWh monthly. One may use the power during the daily and seasonal peak for air conditioning; the other may be using power at night for hot water. The actual costs represented by these two consumption patterns are dramatically different because the first contributes to the capacity requirement and the second does not.

244. PURPA § 111(d)(3) and §115(b).

245. Cf. note 22.

246. Metz, W. D. "Energy Storage and Solar Power: An Exaggerated Problem." 200 Science 1471; 30 June 78.

247. Central station battery storage costs about half that of intermediate size (i.e., commercial or industrial SPPFs) battery storage. Pumped-hydro storage is half as costly as central station battery storage. Johnson, supra note 159, at 5-22.

248. Id. at 2-14.

249. Johnson, supra note 159, at 2-7.

250. Marsh, supra note 159, at H-32.

251. Id. at H-52.

252. Inglis, D. R. Wind Power. Ann Arbor, MI: The University of Michigan Press, 1978, at 56.

253. Metz, supra note 246, at 1472.

254. Scher, Z. "Putting Wyoming Winds to Work." Denver Post (Empire Magazine). 15 July 79.

255. Cf. note 250.

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15. Supplementary Notes

16. Abstract (Limit: 200 words)

The Public Utility Regulatory Policies Act of 1978 (PURPA) is designed to promote energy conservation, the efficient use of utility resources, and equitable rates. PURPA specifically directs the Federal Energy Regulatory Commission (FERC) to encourage small power production from renewable resources (and also cogeneration of electric energy as well as heat) by setting standards under which facilities qualify for interconnection, and guidelines for sales between utilities and independent facilities. The way FERC carries out this mandate may critically affect the development of solar alternatives to electric power production from fossil and nuclear resources. This report comments on proposed FERC regulations and suggests ways to encourage small power production within the PURPA mandate. In addition, some internal strains within PURPA are analyzed that seem to limit the effectiveness with which FERC can encourage independent facilities, and possible modifications to PURPA are suggested.

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