BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE INVESTIGATION OF THE IMPLEMENTATION OF CERTAIN REQUIREMENTS OF TITLE II OF THE PUBLIC UTILITIES REGULATORY POLICY ACT OF 1978 REGARDING COGENERATION AND SMALL POWER PRODUCTION.	)	DECISION AND ORDER (F-3365)

Section 210 of the Public Utilities Regulatory Policy Act of 1978 (PURPA) establishes certain standards for the encouragement of cogeneration and small power production. Section 210(a) requires the Federal Energy Regulatory Commission (FERC) to prescribe rules requiring electric utilities to offer to sell electric energy to qualifying cogeneration and small power production facilities and to offer to purchase electric energy from such facilities. The FERC is also required to promulgate rules establishing a minimum reliability requirement for qualifying facilities and for emergency electrical service to those facilities. Section 210(a) prohibits the FERC from authorizing a qualifying facility to make any sale for purposes other than resale.

Section 210(b) provides general standards for establishing rates for purchases of electrical energy by a utility from a qualifying facility. Such rates are required to be just and reasonable to the electric utility electric consumers, in the public interest, and non-discriminatory as between qualifying facilities. That section also sets a ceiling for rates for purchases at the incremental cost to the electric utility of alternative electric energy. Similarly, Section 210(c) sets general standards for establishing rates for sales of electric energy by utilities to qualifying facilities. Such rates must be just and reasonable, in the public interest, and non-discriminatory.

Rules promulgated by the FERC implementing Section 210 of PURPA are found at 18 C.F.R. Section 292. Subpart A establishes General Provisions for implementing the statute. Subpart B establishes criteria for determining the qualification of small power producing facilities and cogeneration facilities. Subpart C establishes rules for arrangements between electric utilities and qualifying facilities. Subpart D provides for the implementation of the FERC's rules by state regulatory authorities. Subparts E and F establish rules for the exemption of certain qualifying facilities from other federal laws.

This docket was commenced pursuant to 18 C.F.R. Section 292.401, which requires state regulatory authorities to implement the provisions of Sections 292.303-308. Pursuant to that requirement, the Commission entered its Order for Investigation in this docket on October 31, 1980. Under the terms of that Order, Commission Staff was authorized and directed to investigate how the FERC's rules on cogeneration and small power production should be implemented. On November 24, 1981, the Commission entered its Order for and Notice of Procedural Schedule herein establishing a time for intervention, and setting a schedule for the filing of testimony and exhibits by all parties and a time and place for hearing. An Order granting the petition to intervene of the Little River Lumber Company was entered by the Commission on December 8, 1981. Public hearings were commenced in Pierre on January 6, 1982. Testimony and exhibits were presented by Commission Staff, Black Hills Power and Light Company (BHP&L), Northwestern Public Service Company (NWPS), Northern States Power Company (NSP), Montana-Dakota Utilities Company (MDU) and Otter Tail Power Company (OTP). Following the hearing, briefs or position statements were filed by Staff, Montana-Dakota Utilities Company, Northwestern Public Service Company and Northern States Power Company. Based on the testimony and evidence presented at hearing, the briefs and position statements filed by the parties, and arguments of counsel, the Commission makes the following:

FINDINGS OF FACT

I.

STAFF POSITION

Staff's position was presented through the testimony and exhibits of Luis C. Bernal of Whitfield A. Russell and Associates. Mr. Bernal testified that cost-effective cogeneration and small power production can reduce the nation's dependence on foreign oil and its use of non-renewable domestic fuel. He further testified that in his opinion, the FERC's regulations are intended to stimulate an increase in the number of cogeneration and small power production facilities for the purpose of lessening dependence on oil and reducing the cost of electricity. Mr. Bernal testified that cost-effective generation and small power production can also reduce the need for electric utilities to raise capital to finance new generation and transmission facilities, and can reduce the environmental impact of fossil fuel burning.

A. Contractual Rates for Purchases

In his recommendations for the design of rates for purchases from qualifying facilities (QF), Mr. Bernal proposed that the electric utilities and qualifying facilities should be encouraged to agree on contractual rates with minimum Commission intervention. Such an approach, he testified, will reduce the regulatory burden on the QF, the utility, and the Commission. He recommended that the contracts contain a provision making the Commission the final arbiter as to any disagreements about the reasonableness of rates, terms or conditions set by the contract. He recommended that complaint proceedings before the Commission be established as the best vehicle for resolving any contractual disputes between utilities and QF's.

Mr. Bernal's recommendations differentiate between two types of contracts for purchases by electric utilities, long-term contracts and short-term contracts. These two types of contracts are based on different considerations. Mr. Bernal testified that short-term contracts should reflect cost savings realized by the utilities' avoided higher cost of fuel mix peaking generation. As he pointed out, in the short-term, the generation provided by a QF "increases the probability" that the utility can meet its daily load with less expensive fuel cost generation and especially during the on-peak hours. He further noted that such generation also increases the utility's reliability in the short-term by providing increased overall system capacity. He recommended, therefore, that short-term contracts include capacity credits based upon the cost of the utility's installed turbine peaking generation, unless the utility can show there are no avoided capacity costs.

Mr. Bernal proposed that long-term contracts, i.e., contracts of 10 years' duration or longer, should include capacity credits based upon the avoided cost of base load generation. He recommended against adjustments to the capacity credit over the life of the contract. Mr. Bernal testified that the generation that a QF provides can change the long-run future load which must be met by the utilities' generating system. Thus, the added capacity provided by the QF increases the probability that the electric utility can alter its construction schedule so as to cancel or defer planned generating additions, scale down the size of future plant additions, or reduce its firm purchase commitments. Witness Bernal further testified that the capacity credit included in the long-term contracts should be applied to the average KW provided by the QF during the on-peak hours of each month.

Mr. Bernal testified that the energy credit included in long-term and short-term contracts should be based on the average of the expected hourly incremental avoided costs calculated over the hours in the appropriate peak and off-peak hours as defined by the utility. He recommended that the QF be paid according to its contribution of kilowatt hours during each of the periods. Witness Bernal recommended that the off-peak and on-peak periods reflected in the energy credit be consistent with the periods reported in the utility's filing with the FERC under PURPA Section 133.

B. Standard Rates

Witness Bernal recommended, as required by PURPA, that standard rates be developed for purchases from QF's with a design capacity of 100 KW or less.

C. Interconnection Costs

Witness Bernal testified that interconnection facility costs should be borne by the QF on a levelized basis over the life of the interconnection facility. He further testified that appropriate safety and/or disconnecting equipment should also be installed and controlled by the utility and paid for by the QF. He testified such equipment is necessary to prevent backfeeding on the system during maintenance or repair work on the utility's system.

D. Emergency, Backup and Supplementary Power

Witness Bernal testified that rates charged by the utility to QF's for emergency, backup or supplementary power should not exceed the capacity or energy credits collected for each period.

II.

NORTHERN STATES POWER COMPANY POSITION

A. Contractual Rates for Purchases

Northern States Power Company (NSP) presented testimony through Witness Dennis L. Platteter. Mr. Platteter agreed with Staff Witness Bernal's recommendation that the Commission maintain a role of minimum intervention in negotiated agreements between QF's and utilities on purchase rates, limited to a role of settling contractual disputes between utilities and QF's.

Although Mr. Platteter agreed with Staff Witness Bernal's recommendation that both long-term and short-term contracts should be made available to QF's, he testified against Mr. Bernal's recommendation that short-term contracts should contain capacity payments based on a combustion turbine peaking unit cost. Mr. Platteter testified that they may not be the avoided capacity costs for the particular qualifying facility. Mr. Platteter testified that each utility should be given the opportunity to determine its own avoided capacity costs depending on its own unique generation mix.

Company Witness Platteter also disagreed with Mr. Bernal's testimony that PURPA Section 133 information should be the sole basis of information for determining capacity credits. He pointed out that with the likelihood of the Department of Energy being dismantled, such information may not be available. He also disagreed with Mr. Bernal's recommendation that average monthly KW be used as the basis for capacity credits. Witness Platteter recommended that such credits be based upon actual capacity displaced.

Mr. Platteter further found fault with Staff Witness Bernal's recommended basis for determining energy credits. Although Mr. Platteter agreed generally that avoided energy payments might be based on system incremental energy costs, he suggested that the appropriate energy cost may be different depending on whether or not any associated capacity credit is given to the qualifying facility and also the basis of the avoided cost determination. He recommended that the Commission not set any general requirements for the proper basis for avoided energy payments.

Mr. Platteter expressed one final point of disagreement with Staff over the linking of sales rates with purchase rates. Mr. Platteter testified that the cost of emergency, backup and supplementary power are a part of the utility's retail tariff structure and are not, therefore, necessarily related in any way to avoided costs. Instead, he testified that the appropriate retail rate for emergency, backup and supplementary power be applied to qualifying facilities.

B. Standard Rates

Mr. Platteter also generally supported Witness Bernal's recommendation that standard rates be established for QF's of 100 KW or less. He testified that for such small QF;s, the output may not be sufficient to justify the expense of a negotiated rate. Again, Mr. Platteter urged the Commission to take a minimal role in setting standard rates for small QF's and favored placing on the utility the burden to develop rates appropriate to its system. He noted that any such rates would have to be submitted to the Commission for its final approval.

III.

NORTHWESTERN PUBLIC SERVICE COMPANY POSITION

Northwestern Public Service Company (NWPS) presented testimony through Witness Dale E. Jepsen. Mr. Jepsen testified that because of the Company's adequate capacity position, both short-term and long-term, NWPS will not likely be in a position to buy energy or capacity from a QF. He testified that the Company's generation and transmission system are "essentially complete" through the early 1990's, and that the availability of capacity from QF's would not reduce NWPS' need to raise capital to finance future generation plant and transmission line additions. He concluded, therefore, that QF's cannot reduce the Company's capital needs until such sources effectively replace part or all of a major transmission or generation project.

IV.

MONTANA-DAKOTA UTILITIES COMPANY

Montana-Dakota Utilities Company (MDU) presented testimony through Witness Gary L. Paulsen. Mr. Paulsen testified that for purposes of determining rates for purchases of QF's, he considered "avoided costs" to mean "the incremental costs to MDU of electric energy or capacity, or both which, but for the purchase from the qualifying facility ... MDU would generate itself or purchase from the Midwestern Area Power Pool ...". Mr. Paulsen differentiated between these avoided costs which MDU proposes to recognize for small QF's and those the Company proposes to recognize to large QF's. Small QF's are those with an output of less than 100 KW; large QF's are those with any greater capacity.

A. Contractual Rates for Purchases

Mr. Paulsen took issue with a number of Staff Witness Bernal's recommendations. Mr. Paulsen disagreed with Mr. Bernal's recommendation that capacity payments should be included in short-term contracts. Mr. Paulsen testified that the short-term avoided costs described by Mr. Bernal relate to energy, not capacity, and that, therefore, avoided capacity costs are not applicable to short-term contracts. In support of that position, he quoted certain sections from the FERC's Order No. 69 in Docket RM79-55 which established the final rules for cogeneration and small power production. Mr. Paulsen read the FERC's Order to allow avoided capacity costs to be included in contracts only if capacity can be avoided. Mr. Paulsen stated MDU's position to be that avoided energy costs should be provided to those QF's that provide energy only, and that capacity payments would be paid to those QF's, regardless of size, who meet the Company's reliability requirements.

Mr. Paulsen also disagreed with Mr. Bernal's recommendation that PURPA Section 133 data be used to calculate avoided capacity costs. He pointed out that the purpose for which Section 133 data is being provided is not necessarily the same as required to calculate Section 210 avoided costs. Mr. Paulsen also disagreed with Mr. Bernal's recommendation that capacity costs be paid on an average KW basis. He pointed out that MDU is proposing to pay avoided capacity costs based on a maximum demonstrated capacity, provided the 65% capacity factor requirement (discussed in Section B, infra) is met. He testified that if capacity costs are paid only on an average KW, the QF would not receive payment for all capacity actually avoided.

Mr. Paulsen disputed Mr. Bernal's testimony that all avoided energy costs be based on system incremental costs. To do so, he testified, would in some cases overstate avoided costs, contrary to FERC rules limiting rates for purchases to a utility's avoided costs. He testified that a QF which supplies energy only and does not defer capacity should receive purchase rates based on system incremental costs as those costs are actually avoided. However, where a QF also qualifies for avoided capacity payments, Mr. Paulsen testified, the avoided energy costs should be based on the cost of the energy which would have been produced by the same deferred capacity. Otherwise, avoided capacity costs would be paid on a base load unit while avoided energy costs (if based on system incremental costs) would include fuel costs for intermediate and peaking generation. Mr. Paulsen again referred to FERC Order No. 69 which he claimed prohibited Mr. Bernal's proposed system incremental cost recommendation.

B. Standard Rates

Mr. Paulsen testified that MDU proposes to offer to small QF's three purchase rate options: Non-firm energy purchases, non-time differentiated; non-firm energy purchases, time differentiated; and firm energy purchases. Time-differentiated rates would reflect on and off-peak hours. Non-time differentiated rates would not reflect the time of purchase as between on and off-peak hours. Only those small QF's which meet specified dependability qualifications would be eligible to receive firm purchase rates, which include avoided capacity cost payments. Mr. Paulsen testified that his analysis determined that purchases from small QF's would not result in any avoided distribution or transmission costs to the MDU system. He concluded, therefore, that the only factors includable in avoided energy costs to small QF's are avoided fuel costs and avoided variable operation and maintenance expenses associated with the avoided fuel costs.

Witness Paulsen determined avoided energy costs for non-firm purchases by examining MDU's non-firm sales, non-firm purchases and MDU's own generation, which are the sources of energy which would be displaced by purchases from small QF's. He testified that intermediate and peaking units would be the most common source of displaced energy, except that during off-peak hours, base load units would also become the source of displaced energy. Mr. Paulsen further testified that MDU had developed its incremental energy costs by developing a system dispatch for the year 1982 which was based on MDU's internal generation and its probable MAPP purchases. He noted that MAPP purchases generally displace peaking generation and not intermediate or base load generation.

Mr. Paulsen testified that MDU's estimated average energy costs for firm purchases were based on the Antelope Valley Station No. 2 unit. The rate for firm purchases from a small QF are calculated on the avoided capacity costs of a base load unit and the avoided energy costs of the same unit. Mr. Paulsen also testified that in order for a small QF to qualify as a firm supplier, it should deliver energy at a 65% capacity factor on-peak and supply energy during the Company's seasonal peak. The 65% figure was based on the minimum capacity factor of 65% of most base load generating units.

Mr. Paulsen testified that capacity costs should be paid to firm suppliers because firm suppliers will enable the Company to avoid some future capacity. Although MDU does not anticipate any capacity deficiencies until 1983 and does not plan adding additional capacity until 1985, Mr. Paulsen testified that the Company was willing to include capacity credits in firm purchase rates immediately in order to encourage small power production and cogeneration.

Mr. Paulsen testified that he calculated MDU's avoided capacity costs based on the cost of the Antelope Valley Station No. 2, the next major generating unit addition to MDU's system. The avoided costs reflect avoided capital costs, avoided fixed operation and maintenance expenses, and avoided fuel inventory, where applicable. The actual avoided capacity costs paid to a QF will be calculated by applying an appropriate discount factor to ensure that the purchase rate reflects only MDU's actual avoided costs.

C. Interconnection Costs

Mr. Paulsen testified that, in accordance with the FERC rules, small QF's should bear the full cost of providing a safe and reliable interconnection with the company. He testified that the utility and its ratepayers should not have to bear the burden of financing interconnection costs. Mr. Paulsen disagreed, however, with Mr. Bernal's testimony that the cost of interconnection facilities should be levelized over the life of the facility. He pointed out that in a case where MDU has to finance the interconnection costs and the QF defaults, the unpaid portion of the interconnection facility would then have to be absorbed by MDU's ratepayers.

V.

BLACK HILLS POWER AND LIGHT COMPANY'S POSITION

Black Hills Power and Light Company presented testimony through Witnesses W. R. Chaney and Dan Landguth.

Witness Landguth presented the results of a survey of BHP&L's industrial customers conducted to ascertain their interest in cogeneration. Of those customers, only 2 sawmill customers indicated interest in using their waste products for possible cogeneration. Mr. Landguth testified that BHP&L considers cogeneration to be "very limited" in the Company's service territory at this time.

Witness Chaney disagreed with Staff Witness Bernal's recommendations (1) that capacity credits be included in both short-term and long-term contracts, (2) that capacity credits for long-term contracts be based on the avoided costs of base load generation, and (3) that rates for sales for backup, emergency, and supplementary power should not exceed capacity and energy credits included in rates for purchases.

A. Contractual Rates for Purchases

Mr. Chaney first argued that Mr. Bernal's testimony on these three points was contrary to FERC rules found at 18 C.F.R. Section 292.304 regarding rates for purchase and at Section 292.305 regarding rates for sales. Mr. Chaney testified that Mr. Bernal's recommendations violate the standards of these sections that rates for purchases and sales be non-discriminatory, and that rates for purchases not exceed the utility's avoided costs.

Mr. Chaney further testified that Mr. Bernal's inclusion of capacity credits in short-term contracts would require a utility to pay for deferred capacity when no capacity costs had been avoided. He testified that the installed cost associated with peaking generation is fixed and will not be avoided as a result of purchasing power and energy from a QF on a short-term basis.

Mr. Chaney criticized Mr. Bernal's recommendation that long-term capacity credits be based on the avoided costs of base load generation, and that the capacity credits be undisturbed over the life of the contract. Mr. Chaney testified that under Mr. Bernal's proposal utilities would be required to pay an energy credit based on the avoided costs of energy both on-peak and off-peak, while at the same time it would be required to pay a capacity credit based on the avoided cost of base load capacity. He testified that the basis of the capacity credit (i.e., base load) must be the same as the basis of the energy credit. Mr. Chaney also testified that capacity credits should only be given at such time as costs have actually been avoided. Otherwise, the utility's existing customers would be required to pay for cogenerated power in advance of the time avoided costs are actually realized by the company.

B. Emergency, Backup and Supplementary Power

Finally, Mr. Chaney disagreed with Witness Bernal's recommendation that rates for sales of emergency, backup and supplementary power to QF's not exceed the energy or capacity credits collected for each period. Mr. Chaney testified that such rate treatment would be discriminatory as it is contrary to the basis upon which other rates of the utility are designed. Instead, he testified that such rates should be based on the considerations of cost used in developing the utility's basic rate structure.

VI.

COMMISSION FINDINGS

A. Contractual Rates for Purchases

18 C.F.R. Section 292(c)(1) requires state regulatory authorities to implement standard rates for purchases from QF's with a design capacity of 100 KW or less. That section leaves to the discretion of each state regulatory authority whether or not to implement standard rates for purchases from QF's with a design capacity of more than 100 KW. The Commission's findings as to standard rates for purchases from QF's with a design capacity of 100 KW or less are discussed in Subsection B, below. The Commission finds that in light of the recommendations of all parties to this proceeding, it will not implement standard rates for purchases from QF's with a design capacity of greater than 100 KW.

The Commission finds that rates for purchases from QF's with a design capacity of more than 100 KW should be set by contract negotiated between the QF and the electric utility. The Commission agrees with the recommendations of all parties that the Commission should play a minimal role in the negotiation of such contracts, a role limited to resolving any contract disputes which arise between the parties. The Commission finds such a limited role to be consistent with the provisions of 18 C.F.R. Section 292.403(a) that an acceptable method of implementation of the FERC's rules by a state regulatory authority is "an undertaking to resolve disputes between qualifying facilities and electric utilities ...".

The Commission finds, nevertheless, that in accordance with Staff's recommendation, it should set certain parameters for the negotiation of such contracts. The Commission finds that Staff's recommendations on contractual purchase rates are reasonable and should be adopted as minimum requirements for purchase rate contracts.

The Commission finds that it is reasonable to distinguish between short-term and long-term contract purchase rates as recommended by Staff Witness Bernal. The Commission finds that Mr. Bernal's testimony offers a rational basis for distinguishing between rates for purchases fixed by contract with a duration of less than 10 years ("short-term contract") and rates for purchases set by contract with a duration of 10 years or more ("long-term contract"). As Mr. Bernal testified, 10 years is the normal planning horizon for utilities under the Commission's jurisdiction. 1/ A utility's construction plans will generally be formulated and known in advance for this 10 year period. It is not likely, therefore, that the potential capacity contribution of a QF will affect a utility's construction plans over the 10 years following the time the contract purchase rate is agreed to. A purchase rate contract for more than 10 years, however, has greater potential for altering the utility's long-range construction planning. Ten years is thus a logical demarcation point for determining long-run versus short-run avoided capacity costs.

The Commission finds that Staff Witness Bernal correctly identified the basis for long-run versus short-run avoided capacity costs. The Commission finds that long-term contracts

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1/ SDCL 49-41B-3 reflects this 10 year planning horizon by requiring electric utilities to file 10 year construction plans with the Commission and to update those plans every 2 years.

and short-term contracts should reflect such avoided capacity costs through capacity credits. The Commission finds that capacity credits included in short-term contracts should be based on the cost of installed turbine peaking generation, as short-term contracts will primarily tend to reduce the use of peaking generation and thus reduce the utility's use of more expensive and non-renewable fuels such as oil and gas. 2/ The Commission finds that capacity credits included in long-term contracts should be based on the avoided cost of base load generation. The Commission finds that it is the addition of base load capacity which will most likely be affected by the capacity contribution of the QF under the long-term contract. The Commission further finds that capacity credits included in long-term contracts should reflect the average KW supplied by the QF for each month during the utility's on-peak period.

The Commission also finds that the capacity credits included in long-term contracts should be made constant over the duration of the contract. The Commission finds this position to be consistent with the concerns expressed in the comments accompanying the FERC's rules. 45 Federal Register, 12214, 12216-12233 (1980). Those comments reflect a concern that contractual rates for purchases establish a fixed rate to which a QF can look in planning its investments. 45 Federal Register at 12224. The assurance of a constant capacity credit over the duration of the contract term provides this measure of dependability.

The Commission finds that both short-term and long-term contracts should include an energy credit based on the average of the expected hourly incremental avoided costs calculated over the hours in the appropriate on-peak and off-peak hours as defined by the utility. The Commission finds, as Mr. Bernal testified, that such a basis of calculation recognizes that the avoided energy cost to the utility's system changes constantly. Hourly incremental costs vary greatly depending on which unit of generation is being added in the next increment. The Commission finds that Staff's recommendation will accurately track the actual avoided energy cost to the utility.

The Commission finds that the hourly energy cost data required to be filed under Section 133 of PURPA is an appropriate data source for determining avoided energy costs. NSP's objection to the use of such data on the basis that DOE may soon be dismantled is highly speculative. Although MDU argues

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2/ Short-term capacity costs are recognized in MAPP Service Schedule H. The Commission agrees with Staff's argument that inasmuch as utilities pay for short-term capacity for purchases under MAPP Schedule H, it is not improper to reflect such short-term capacity costs in purchase rates from QF's.

that Section 133 data is not designed to satisfy Section 210 requirements, it has failed to show with any specificity how or why such data would be inappropriate for determining avoided energy costs. Staff's recommendation on this point, therefore, will be adopted. In line with this holding, the Commission finds that each utility's on-peak and off-peak periods for purposes of calculating hourly avoided incremental energy costs should be consistent with its on-peak and off-peak periods as reflected in its Section 133 filings. This requirement will assure consistency in the calculation of avoided energy costs.

B. Standard Rates

The Commission finds that 18 C.F.R. Section 292.304(c) requires electric utilities to develop standard rates for purchases from QF's with a design capacity of 100 KW or less. No party to this proceeding has disputed this basic premise. The Commission agrees with the recommendations of a number of the parties that the Commission should play a minimal role in each company's calculation of such standard rates. The Commission finds, therefore, that each company should be allowed the opportunity to develop and submit prepared rates for purchases from such small QF's. Such standard rates should include both capacity and energy credits, as applicable. The Commission finds that the capacity credits included within standard rates should be applied to the average KW provided by the QF during the utility's on-peak hours for each month, as recommended by Staff. The Commission finds that the avoided energy costs included in standard purchase rates should be calculated at the average of the expected hourly incremental avoided costs over the hours in the utility's appropriate on-peak and off-peak periods. The Commission bases this finding on the same evidence cited in support of its position set forth in Section A, supra.

The Commission finds that each company should submit such proposed rates at the earliest possible date, and that at the latest, each company should submit such proposed rates as part of its next regularly filed rate increase application. The Commission finds that if any company unreasonably delays its submission of such proposed rates, the Commission may issue a further Order in this docket ordering immediate filing of such rates.

C. Interconnection Costs

The Commission finds that 18 C.F.R. Section 292.306 requires each QF to pay "any interconnection costs which the State regulatory authority ... may assess against the qualifying facility on a non-discriminatory basis with respect to other customers with similar load characteristics". The Commission finds that an assessment of interconnection costs can only be made on a case by case basis. The amount of such costs will rarely involve a standard fee but must vary according to the specific requirements of each interconnection to be made. The Commission finds that it should limit its role in the determination of interconnection charges to such time as actual disputes arise between utilities and QF's over the amount of such costs.

As to their method of recovery, however, the Commission finds that interconnection costs should be levelized over the life of the facility, as recommended by Staff Witness Bernal. To require a QF to pay the entire cost of interconnection up front might present too great a financial obstacle, and tend to discourage development of cogeneration and small power production.

D. Supplementary, Backup, Maintenance and Interruptible Power

The Commission finds that it is precluded from adopting Staff's position on rates for sales of supplementary, backup, maintenance and interruptible power. Staff Witness Bernal recommended that such rates be limited to the amount of capacity and energy credits received by a QF over the billing period. The Commission finds that the effect of such a rate would be to limit the charge which a QF would have to pay for such power in any given period to the amount of the company's total purchases of power (based on both energy and capacity credits) from the QF over the same period, regardless of the amount of supplementary, backup, maintenance or interruptible power delivered to the QF, and regardless of the cost of that power to the utility's system. The Commission finds that such a rate for sales would be clearly discriminatory, and is, therefore, prohibited under Section 210(c) of PURPA. Excerpts from the Public Utilities Regulatory Policy Act of 1978 Conference Report make clear that such discrimination is prohibited by the Act. The Report states at page 98 that:

> (T)he conferees do not intend that the cogenerator or small power producer pay any more or any less than is otherwise just and reasonable in terms of the utility receiving the reasonable rate of return for providing service to those kinds of users.

Furthermore, the Report specifically construes the phrase "not discriminate against any cogeneration or small power production" contained in Section 210(c) of the Act to prohibit discrimination against electric consumers of the utility as well:

> This phrase should not be construed to permit discrimination against the electric consumers of an electric utility in formulating rates under this provision. The provisions of this section are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers. (Id.)

Analysis of 18 C.F.R. 292.305 and the FERC's comments relevant thereto further lead the Commission to conclude that rates for supplementary, backup, maintenance and interruptible power must be formulated on the basis of traditional cost of service ratemaking concepts.

Paragraph (a) of that section sets general requirements for rates for sales. Such rates are to be just and reasonable, in the public interest and non-discriminatory "against any qualifying facility in comparison to rates for sales to other customers served by the electric utility". Subpart 2 of Paragraph (a) provides that rates of sales shall be deemed not to be discriminatory to the extent that they are also applicable to other customers of the electric utility "with similar load or other cost-related characteristics". Paragraph (b) of that section delineates certain "additional services" which electric utilities are obligated to provide to QF's. Utilities must provide, upon request, supplementary, backup or interruptible power to the QF, as those terms are defined by the rules. Paragraph (c) provides two specific guidelines to be considered in the setting of rates for backup and maintenance power. Nothing in Paragraphs (b) or (c), however, indicate that rates for supplementary, backup, maintenance or interruptible power are to be considered outside the general framework of the requirements of Paragraph (a).

The FERC's comments on Section 292.305 support this conclusion. Generally, rates for sales are to be formulated "on the basis of traditional ratemaking (i.e., cost of service) concepts" (45 Federal Register, 12228). An industrial cogenerator should receive service "at a rate applicable to a non-generating industrial customer unless the electric utility shows that a different rate is justified on the basis of load or other cost related data" (Id.).

Specifically, as to supplementary, backup, maintenance or interruptible power, the FERC's comments reveal a similar intent that rates be based on load or other cost-related data. For example, they provide that a QF is entitled to a rate for stand-by or backup power which reflects

> the probability that the qualifying facility will or will not contribute to the need for and the use of utility capacity. Thus, where the utility must reserve capacity to provide service to a qualifying facility, the costs associated with that reservation are properly recoverable from the qualifying facility, if the utility would similarly assess these costs to non-generating customers. (<u>Id.</u>)

As further example, the comments indicate that rates for interruptible power "are best handled through the pricing mechanism". (45 Federal Register at 12229). The Commission concludes from these comments that rates for supplementary, backup, maintenance and interruptible power must be arrived at according to the application of normal cost of service analysis.

Staff's proposal to set limits for such rates according to the amount of both energy and capacity credits received by a QF over a billing period attempts to artifically cap those rates, and thus contradicts the requirement that they be cost-based. Mr. Bernal's supporting rationale for Staff's proposal is to provide an additional incentive for the development of cogeneration and small power production. However desirable such an added incentive might prove to be, it does not excuse compliance with the legal requirements of the Act. It must, therefore, be rejected.

The Commission finds that each utility should develop and submit for approval tariffs for sale of supplementary, backup, maintenance and interruptible power to QF's, as those terms are defined at 18 C.F.R. Section 292.101 and Sections 292.305(b) and (c). The Commission finds that such rates should be developed to reflect the cost of providing such service and should be non-discriminatory as between rates to QF's and other electric consumers. The Commission notes that to the extent existing approved tariff revisions on file with the Commission regarding stand-by, supplementary, emergency or interruptible power are adequate to provide for such sales to QF's, no further tariffs need be filed by the companies. <u>3/</u>

<u>3/</u> In particular, the following companies have the following tariffs on file with the Commission: Northern States Power Company, "General Rules and Regulations", Section 10 (Tariff Section No. 5, 1st Revised Sheets 8 through 8.2); Iowa Public Service Company, "Service Rules and Regulations", Paragraph 11 (Tariff Sheet No. VI, 2nd Revised Sheet No. 3); Otter Tail Power Company, "General Rules and Regulations", Paragraph 8, (Tariff Section No. 5, Vol. I, 3rd Revised Sheet No. 2); Black Hills Power and Light Company, Section 306, "Auxiliary Electric Service", (Tariff Section No. 5, 1st Revised Sheet 12).

E. Utilities' Obligations to Purchase

Section 210(a) of PURPA requires the FERC to promulgate rules requiring utilities to offer to purchase electric energy from QF's. 18 C.F.R. Section 292.303(a) reiterates this obligation to purchase "energy and capacity" which is, either directly or indirectly, made available from a QF. The FERC's comments on this section make unequivocal the obligation of each electric utility under this Commission's jurisdiction "to purchase all electric energy and capacity made available from qualifying facilities with which the electric utility is directly or indirectly interconnected", except under certain specific circumstances. 45 Federal Register at 12219. Within this framework of federal statutory and regulatory requirements, the Commission is not in a position to entertain any argument that any particular electric utility under its jurisdiction should not have to purchase energy or capacity from a QF. Such purchases have been mandated by Congress and the FERC.

The question is, given this obligation to purchase, how much should a utility have to pay for such energy and capacity, particularly those which may currently have excess capacity. The Commission sees this question underlying a number of the objections which several companies have made to Staff's recommendations in this case. NWPS took the position at hearing that it did not expect to be in a position to buy energy or capacity from a QF for some time. NWPS seems to have moderated this position somewhat in its "Statement of Position" filed after the evidentiary hearings. It now recommends that the Commission adopt rules for small power production and cogeneration but predicts that its avoided costs over the near term would be "miniscule". Witness Chaney, on behalf of BHP&L, testified that Staff's recommendation to include capacity credits in short-term contracts would require utilities "to pay a capacity credit for a qualifying facility output where no costs have been avoided". Mr. Paulsen of MDU voiced the same complaint.

The Commission reads both the FERC's rules and Mr. Bernal's testimony in such a way as to dispel these points of contention. The Commission finds that the capacity credits to be included in any purchase rates, whether contractual or otherwise, should be based on capacity actually avoided, and if the purchase does not enable a utility to avoid capacity costs, capacity credits should not be allowed. Again, the FERC's comments on Section 292.303(a) provide useful insight:

> A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. (45 Federal Register at 12219)

Those comments further suggest that a utility with excess capacity can only be required to pay avoided energy costs (Id.). The Commission does not read the FERC's rules to permit a utility to pay capacity costs where none are avoided. To do so would have the effect of requiring the utility to pay twice for the same capacity and would thus impose added and unnecessary costs on the utility's other customers, contrary to clear congressional and FERC intent.

The Commission understands Mr. Bernal's position to be in accord with this view. On cross-examination, Mr. Bernal was specifically questioned about payment of capacity credits under short-term contracts where the utility could not be sure that the capacity contribution of the QF would allow the utility to avoid any capacity costs. Mr. Bernal replied that if the utility could not "count on" capacity savings, it should not be required to pay capacity credits.

In holding that capacity credits should be included in short-term contracts, the Commission is not requiring payment of such credits where no capacity is in fact avoided in the short run. It is the Commission's holding, however, that if in the short run there are to be capacity savings, they are most likely to be in peaking generation. Accordingly, as discussed in Section A, supra, it is the Commission's finding that such credits should be based on the cost of the company's intalled turbine peaking generation, as recommended by Mr. Bernal. But such credits can only be excluded in short-term contracts where the utility has shown that no capacity costs have been avoided.

F. Applicability to Utility Subsidiaries

The Commission finds that the provisions of this Order should be made applicable to the purchase and/or sale of electrical energy by and between electric utilities and qualifying facilities which are also subsidiaries of those electric utilities. The Commission further finds that all contracts for the purchase and/or sale of electrical energy by and between electric utilities and qualifying facilities which are also subsidiaries of those electric utilities should be submitted to the Commission for review. The Commission finds this to be necessary in order to ensure that all such contracts fully comply with applicable statutory and other regulatory requirements.

Based on these Findings, the Commission concludes as a matter of law:

I.

That it has jurisdiction over the subject matter of this proceeding and the parties hereto, pursuant to SDCL Chapter 49-34A-, 16 USC 824(a) and 18 C.F.R. Section 292.401.

II.

That the rates established by this Order are just and reasonable and fully comport with all statutory and constitutional requirements.

III.

That all motions and objections not heretofore specifically ruled on should be denied. It is therefore

ORDERED, that Black Hills Power and Light Company, Iowa Public Service Company, Montana-Dakota Utilities Company, Northern States Power Company, Northwestern Public Service Company, and Otter Tail Power Company shall file with the Commission tariff sheets consistent with the terms of this Order establishing standard rates for purchases of electrical energy and capacity from qualifying facilities (as defined under 18 C.F.R. Section 292) with a design capacity of 100 KW or less; and it is

FURTHER ORDERED, that all rates for purchases of electricity by said companies from qualifying facilities, and all rates for sales of electricity from said companies to qualifying facilities shall be consistent with the terms of this Order; and it is

FURTHER ORDERED, that such companies shall, to the extent required by the terms of this Order, file with the Commission tariff sheets providing terms for the sale to qualifying facilities of supplementary, backup, maintenance and interruptible power consistent with the terms of this Order; and it is

FURTHER ORDERED, that the Commission shall retain jurisdiction over all transactions between said companies and qualifying facilities to the extent required under 18 C.F.R. Section 292.401.

Dated at Pierre, South Dakota, this 14 day of December, 1982.

BY ORDER OF THE COMMISSION:

Charlotte Fischer, Chairman

Ken Stofferahn, Commissioner

Jeff Solem, Commissioner

(OFFICIAL SEAL)