PUC Exhibit No. E
File No. PUC-82-063BC
Bdc Date 8-12-82
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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Lillian Warren-Lazenberry	Chairman
Leo G. Adams	Commissioner
Roger L. Hanson	Commissioner
Terry Hoffman	Commissioner
Juanita R. Satterlee	Commissioner

In the Matter of the Proposed Adoption of Rules of the Minnesota Public Utilities Commission Governing Cogeneration and Small Power Production.

STATEMENT OF NEED AND REASONABLENESS

DOCKET NO. E-999/R-80-560
H. E. DOCKET NO. PUC-82-063-BC

I. INTRODUCTION.

The Minnesota Public Utilities Commission (the Commission) has drafted this Statement of Need and Reasonableness to support and accompany the Commission's Proposed Rules governing cogeneration and small power production through the public hearing process.

Cogeneration is the sequential use of the heat of combustion both to generate electricity and to perform other useful work (such as heating a building). Small power production is the generation of electricity from renewable resources (hydro, wind, solar, biomass, etc.).

The Proposed Rules are intended to encourage the development of cogeneration and small power production, consistent with protection of electric utility ratepayers and the general public. They are responsive to both federal and state laws which recognize that cogeneration and small power production can help reduce our dependence on foreign sources of energy, conserve scarce fossil fuels, be more efficient in our use of energy, and protect the environment.

For administrative purposes, the Commission's proposal is organized into 14 separate Proposed Rules:

4 MCAR § 3.0450	Scope and Purpose
4 MCAR § 3.0451	Definitions
4 MCAR § 3.0452	Filing Requirements
4 MCAR § 3.0453	Reporting Requirements
4 MCAR § 3.0454	Conditions of Service
4 MCAR § 3.0455	Rates for Sales
4 MCAR § 3.0456	Standard Rates for Purchases A. Net Energy Billing B. Simultaneous Purchase and Sale C. Time of Day Purchase Rates
4 MCAR § 3.0457	Negotiated Rates for Purchases
4 MCAR § 3.0458	Utility Treatment of Costs
4 MCAR § 3.0459	Wheeling and Exchange Agreements
4 MCAR § 3.0460	Disputes
4 MCAR § 3.0461	Notification to Customers
4 MCAR § 3.0462	Interconnection Guidelines
4 MCAR § 3.0463	Existing Contracts

The rules on Scope and Purpose and Definitions apply to all the other rules. The rule on Filing Requirements sets up the avoided cost calculations which are to be used in Standard Rates for Purchases and Negotiated Rates for Purchases. The Filing Requirements section also relates to Conditions of Service, Notification to Customers, and Interconnection Guidelines. The rule on Reporting Requirements covers data which utilities are required to report to the Commission. The Conditions of Service, and Interconnection Guidelines rules cover the interconnectioon arrangements apart from actual rates for purchases and sales. Rates are covered in the Rates for Sales, Standard Rates for Purchases, Negotiated Rates for Purchases, and Existing Contracts rules. The appropriate ratemaking treatment of utility purchases from qualifying facilities is covered in Utility Treatment of Costs. The rule on Wheeling and Exchange Agreements takes care of cases in which the qualifying facility sells electricity to a utility with which it is not interconnected. The Disputes rule sets forth the Commission's obligation to resolve disputes over application of these rules, and the Notification to Customers section sets forth the utilities' obligation to inform their customers about these rules. The 14 proposed rules thus form a unified, integrated approach to cogeneration and small power production.

This Statement follows the numerical organization of the Proposed Rules. In all cases, the actual rule language is reproduced, followed by the Commission's discussion of why that language is necessary and reasonable.

This Statement of Need and Reasonableness is designed to comply with 9 MCAR § 2.104. It contains a summary of the evidence and argument which the Minnesota Public Utilities Commission (the Commission) intends to present and rely upon at the hearings on the proposed rules.

In the Commission's opinion, this Statement supports the need for the proposed rules and the reasonableness thereof.

II. <u>DISCUSSION OF RULE PROVISIONS</u>.

4 MCAR § 3.0450 Scope and purpose. The purpose of 4 MCAR §§ 3.0450-3.0463 is to implement certain provisions of M.S. § 216B.164; the Public Utility Regulatory Policies Act of 1978, 16 United States Code, Sections 2601-2645 (Supplement III, 1979); and the Federal Energy Regulatory Commission regulations, 18 Code of Federal Regulations, Sections 292.101-292.602 (1981). Nothing in 4 MCAR §§ 3.0450-3.0463 excuses any utility from carrying out its responsibilities under these provisions of state and federal law. Rules 4 MCAR § 3.0450-3.0463 shall at all times be applied in accordance with their intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public.

In the 1981 session, the Minnesota Legislature added a new section to the Public Utilities Act. That section, codified as M.S. § 216B.164, established a statutory framework for the development of cogeneration and small power production in Minnesota. M.S. § 216B.164 sets forth certain specific standards for utility purchases of the output of cogeneration and small power production facilities (subd. 3), for wheeling of that power among utilities (subd. 4), for resolution of disputes (subd. 5), for reports to the legislature (subd. 7), and for the treatment of certain costs (subd. 8). In addition, M.S. § 216B.164, subd. 6 states, "the [Public Utilities] Commission shall promulgate rules to implement the provision of this section." These proposed rules are designed to comply with the directive of M.S. § 216B.164, subd. 6.

The Commission has general rulemaking authority under M.S. § 216A.05, subd. 1. In addition, the Commission is empowered to regulate public utilities generally under M.S. § 216B.08. That regulation extends to setting reasonable rates (M.S. §§ 216B.03 and 216B.16), ensuring that utilities provide safe, adequate, efficient, and reasonable service (M.S. § 216B.04), prohibiting unreasonable preferences, advantages, prejudices, or disadvantages through utility rates or services (M.S. § 216B.07), and fixing just and reasonable standards, regulations, and practices for public utilities (M.S. § 216B.09). In addition, the Commission has been granted investigatory (M.S. § 216B.14) and complaint authority (M.S. § 216B.17).

As part of the National Energy Act of 1978, the United States Congress passed the Public Utility Regulatory Policies Act (PURPA), Pub. L. 95-617. A portion of PURPA, codified as 16 U.S.C. § 843a-3, amends the Federal Power Act and governs cogeneration and small power production. 16 USC § 843a-3(a) requires the Federal Energy Regulatory Commission (FERC) to promulgate rules as necessary to encourage cogeneration and small power production, which rules are to require electric utilities to offer to sell electric energy to and purchase electric energy from cogeneration and small power production facilities. 16 USC § 824a-3(f) requires state regulatory authorities (including the Commission) to implement the cogeneration and small power production rules which the FERC promulgates under PURPA.

The FERC subsequently put rules into place which implemented the cogeneration provisions of PURPA. 18 CFR § 292.401 requires state regulatory authorities, not later than one year after the FERC rules take effect, to commence implementation of 18 CFR §§ 292.301 and 292.303-.308. The FERC indicated that the state implementation could be by the issuance of regulations, by resolution of disputes between utilities and qualifying facilities, or by any other action reasonably designed to implement the FERC rules.

The proposed rules are thus generally necessary to comply with the direction of M.S. § 216B.164, subd. 6, as well as to fulfill the Commission's obligations under Federal law and FERC regulations. As will be discussed hereinafter, the provisions of the proposed rules are reasonable to carry out the intent of the state and federal legislation and regulations.

M.S. § 216B.164, subd. 1, states, "This section shall at all times be construed in accordance with its intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public." The Commission has adopted the identical standard as the general intent of the proposed rules. The Commission believes it is necessary to be consistent with state law, and is reasonable to adopt the clear and unambiguous statutory language.

The Commission considers the inclusion of a Scope and Purpose section to be of importance. It is recognized that the proposed rules are complex. This section is intended to act as an introductory section to assist the reader in determining the origin, the general purpose, and intent of the rules, as well as their overall effect.

4 MCAR § 3.0451 Definitions.

A. Applicability. For purposes of 4 MCAR §§ 3.0450-3.0463, the following terms have the meanings given them.

It is necessary to define these terms so they have consistent meanings throughout these rules.

B. Average annual fuel savings. "Average annual fuel savings" means the annualized difference between the system fuel costs that the utility would have incurred without the additional generation facility and the system fuel costs the utility is expected to incur with the additional generation facility.

This term is defined so it may be used in the calculation of avoided costs. It is applicable to a utility which intends to build new generating capacity.

One reason for building new capacity is to reduce system fuel costs. This can happen, for example, when a baseload unit replaces a peaking unit or purchased power in providing large amounts of electric energy. It can also happen when a new, efficient unit replaces an old, inefficient unit. The definition reasonably calls for a comparison of the system fuel costs to meet the expected annual load with and without the planned new unit. The difference is the average annual fuel savings.

C. Backup power. "Backup power" means electric energy or capacity supplied by the utility to replace energy ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the facility.

This definition and the definitions for Interruptible power, Maintenance power and Standby power, are necessary because they are used in the rule to indicate which types of power are to be offered by the utility. The definitions are reasonable because they are consistent with standard industry usage of the terms. Furthermore, the four definitions correspond with the four classifications of power to be sold to qualifying facilities as established by the FERC. The rule appropriately distinguishes each type of power from the others. This is necessary because the cost of providing one type may differ from the cost of providing another. For example, a utility supplying Interruptible power may curtail sales to the qualifying facility at the time of system peak, and in so doing may conserve capacity and reduce capacity costs. In contrast, a utility supplying Backup power must allow for the possibility that the qualifying facility will suddenly begin to take power at the time of system peak, and it must incur some of the cost consequences of this contingency even if no power is actually drawn. It may be possible for a qualifying facility to arrange scheduled maintenance to coincide with a time when the utility has excess reserves; if so, the cost of providing it as maintenance power (and its price to the qualifying facility) may be low. Likewise, Supplementary power, which is routinely provided to the qualifying facility, carries its own distinct cost consequences. The cost differences, therefore, make it necessary to establish these classifications and demonstrate their reasonableness.

The definition of each type of power is reasonable in that it is consistent in meaning and application with the FERC rules. Such consistency will tend to avoid confusion and ambiguity. It will also promote harmony between the State and Federal rules thus alleviating the burdens of interpreting conflicting or inconsistent provisions by interested persons. By reducing confusion and ambiguity, a more favorable climate is established for encouraging cogeneration and small power production.

D. Capacity. "Capacity" means the capability to produce, transmit, or deliver electric energy.

Capacity is one of two elements (the other is energy) which together make up electric service. It is necessary to define capacity because qualifying facilities may enable a utility to avoid acquiring capacity of its own. If they do, they are eligible for compensation. The definition is reasonable in that it is consistent with general use of the term in the electric utility industry.

E. Capacity costs. "Capacity costs" means the costs associated with providing the capability to deliver energy. They consist of the capital costs of facilities used to generate, transmit, and distribute electricity and the fixed operating and maintenance costs of these facilities.

A definition of capacity costs is needed because qualifying facilities which provide capacity to utilities are entitled to be paid the costs of the capacity avoided by the utilities. The definition is reasonable because it is consistent with the general use of the term in the electric utility industry.

F. Commission. "Commission" means the Minnesota Public Utilities Commission.

This term is self-explanatory.

G. Energy. "Energy" means electric energy, measured in kilowatt-hours.

It is necessary to define energy because qualifying facilities are to be compensated for energy supplied to utilities. The definition is reasonable because it includes electric energy and excludes all other forms of energy. The utility is only required to purchase electric energy.

H. Energy costs. "Energy costs" means the variable costs associated with the production of electric energy. They consist of fuel costs and variable operating and maintenance expenses.

Energy costs must be defined because compensation to qualifying facilities for energy they supply is based on the costs utilities would incur if qualifying facilities did not supply them. Those costs are energy costs. The definition is reasonable because it is consistent with the way the term is used generally in the electic utility industry.

I. Interconnection costs. "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the utility that are directly related to installing and maintaining the physical facilities necessary to permit interconnected operations with a qualifying facility. Costs are considered interconnection costs only to the extent that they exceed the corresponding costs which the utility would have incurred if it had not engaged in interconnected operations, but instead generated from its own facilities or purchased from other sources an equivalent amount of electric energy or capacity. Costs are considered interconnection costs only to the extent that they exceed the costs the utility would incur in selling electricity to the qualifying facility as a nongenerating customer.

It is necessary to define interconnection costs because these costs are explicitly assigned to qualifying facilities by both the FERC rules (18 CFR § 292.101 (b)(7)) and Minnesota law (M.S. § 216B.164, subd. 8). Interconnection costs are costs which would not be incurred if the utility did not engage in interconnected operations with cogenerators and small power producers. The definition above is reasonable. Except for the last sentence, it is substantially the FERC definition, with only minor wording changes. The Commission has added the provision that only costs in excess of the costs of connecting nongenerating customers of the same class be considered interconnection costs. This provision is necessary and reasonable because often part or all of the costs it excludes are recovered by the utility in fixed charges as part of retail rates. Under Minnesota law and these rules, qualifying facilities must pay any fixed charges in the tariff under which they consume electricity. Therefore, without this provision, the qualifying facility could be discriminated against relative to other members of its class. Both the discrimination and the result of paying the utility twice for the same costs would be unreasonable.

J. Interruptible power. "Interruptible power" means electric energy or capacity supplied by the utility to a qualifying facility subject to interruption under certain specified conditions.

K. Maintenance power. "Maintenance power" means electric energy or capacity supplied by a utility during scheduled outages of the qualifying facility.

The necessity for and reasonableness of the definitions of these two items are established in the discussion of "Backup power," 4 MCAR § 3.0451(C).

L. Marginal capital carrying charge rate. "Marginal capital carrying charge rate" means the percentage factor by which the amount of a new capital investment in a generating unit would have to be multiplied to obtain an amount equal to the total additional annual amounts for the cost of equity and debt capital, income taxes, property and other taxes, tax credits, depreciation, and insurance which would be associated with the new capital investment.

It is necessary to define marginal capital carrying charge rate because the term is used in calculating a utility's avoidable capacity costs. When a utility avoids installing a generating unit, it also avoids costs related to the cost of capital, taxes, depreciation, and insurance. This definition is reasonable because it includes these factors, puts them on an annual basis, and relates them to the cost of the generating unit as a percentage. Thus the marginal capital carrying charge rate, as defined, may be used directly in the calculation of annual avoidable capacity costs.

M. On-peak hours. "On-peak hours" means, for utilities whose rates are regulated by the Commission, those hours which are defined as on-peak for retail ratemaking. For any other utility, on-peak hours are either those hours formally designated by the utility as on-peak for ratemaking purposes or those hours for which its typical loads are at least 85 percent of its average maximum monthly loads.

A definition of on-peak hours is needed because utility costs, and utility avoidable costs, vary between on-peak hours and off-peak hours. Since compensation to qualifying facilities is based on costs utilities can avoid, it is essential to have some determination of which hours are on-peak.

The proposed definition accepts determinations of on-peak periods made by the Commission or by the utility when the utility has defined on-peak hours for retemaking. Since many utilities have already determined on-peak and off-peak periods, this will tend to eliminate duplication of work on the part of the utility and will provide for appropriate time periods because existing rates and rating periods can be presumed to be reasonable. At the same time, a non-regulated utility that has not yet designated on-peak periods may choose to examine its load characteristics and determine which hours will most appropriately be included in the on-peak hours. If such a utility is unable or unwilling to perform a comprehensive and possibly time consuming examination, the rule provides for a simple method to determine on-peak periods which will minimize the amount of analysis required and at the same time will produce on-peak periods which will span the hours during which the utility is most likely to experience its system peak. A rule of thumb such as the 85 percent rule of thumb employed in the rule was used to establish on-peak periods for at least two of the utilities regulated by the Commission (i.e., Minnesota Power and Light Company, Docket No. E-015/GR-80-76 and Interstate Power Company, Docket No. E-001/GR-78-1065).

Thus, this general approach has been relied upon for larger utilities and there is no reason to believe that this approach would not be reliable when applied by smaller utilities. Based upon its experience, the Commission has determined that an 85 percent level would be appropriate because it would provide an additional level of certainty that the peak demand experienced by the utility would fall in the on-peak period. Consequently, the proposed definition is reasonable.

N. Purchase. "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by a utility.

This term is self-explanatory.

O. Qualifying facility. "Qualifying facility" means a cogeneration or small power production facility which satisfies the conditions established in 18 Code of Federal Regulations, Sections 292.201-292.207 adopted through 46 Federal Register 33025-33027 (1981). The initial operation date or initial installation date of a cogeneration or small power production facility shall not prevent the facility from being considered a qualifying facility for the purposes of 4 MCAR §§ 3.0450-3.0463 if it otherwise would satisfy all stated conditions.

A definition of qualifying facilities is necessary because these rules are all about interconnections between qualifying facilities and utilities. Section 201 of PURPA amended Section 3 of the Federal Power Act to add definitions of, among other things, small power production facilities and cogeneration facilities. It also required the FERC to promulgate rules further defining qualifying small power production facilities and qualifying cogeneration facilities. The cites in the proposed definition are to the FERC rules defining qualifying facilities. It is reasonable to use the FERC definitions, since the FERC rules were based on extensive public participation and apply nationally. Furthermore, all persons commenting to the Commission during the solicitations of comment and opinion which underlie these proposed rules assumed the Commission's definition would correspond with the FERC's.

There is nevertheless one difference between the two definitions. In promulgating its rules, the FERC reasoned that facilities already in existence did not need the incentive of PURPA and its rules; they were already engaged in cogeneration or small power production. Consequently, the FERC authorized State regulatory authorities to treat such facilities differently (and less favorably) than qualifying facilities coming on line, presumably, because of the incentives of PURPA and the FERC rules. In proposing this definition, the Commission determined it would be unreasonable to take advantage of such authority. As a practical matter, the Commission would have to determine that a rate lower than that applicable to other qualifying facilities was nevertheless sufficient to encourage cogeneration and small power production. Making such a determination would likely be time consuming and not cost beneficial. As a matter of equity, the Commission thinks it would be unreasonable to provide less compensation to one of two facilities, each of which allowed the utility to avoid similar costs, simply because that facility was in operation or had been installed prior to some arbitrary date.

P. Sale. "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

This term is self-explanatory.

Q. Supplementary power. "Supplementary power" means electric energy or capacity supplied by the utility which is regularly used by a qualifying facility in addition to that which the facility generates itself.

The necessity for and reasonableness of the definition of this item is established in the discussion of "Backup power" at 4 MCAR § 3.0451 (C).

R. System emergency. "System emergency" means a condition on a utility's system which is imminently likely to result in significant disruption of service to customers or to endanger life or property.

The proposed rules have specific provisions governing utility treatment of qualifying facilities during system emergencies, as called for in the FERC rules, so it is necessary to define system emergency. The definition used corresponds with the one used by the FERC in 18 CFR § 292.101 (b)(4), and is, therefore, reasonable for use in this application.

S. System incremental energy costs. "System incremental energy costs" means amounts representing the hourly energy costs associated with the utility generating the next kilowatt-hour of load during each hour.

This term needs definition because it lies at the heart of the calculation to determine a utility's avoidable energy costs. The proposed definition is reasonable in light of two considerations. First, the definition is consistent with the way the term is used in the electric utility industry, and will, therefore, be easily understood by utilities seeking to follow the procedures established by these rules. Second, the definition may be seen as summing the variable costs of generating an additional kilowatt-hour at any time. The system incremental energy costs thus represent costs which may be saved if the utility does not generate that additional kilowatt-hour. These costs are clearly avoidable costs, and are reasonably used in determinations of avoided costs of utilities.

T. Utility. "Utility" means any public utility engaged in the generation, transmission, or distribution of electricity in Minnesota. The term includes cooperative electric associations and municipally-owned electric utilities.

These proposed rules place many demands on utilities, so it is necessary to define utility to know which entities are required to act. The definition includes only electric utilities, which is reasonable because qualifying facilities will not be interconnecting with any utilities other than electric utilities. The definition includes cooperative and municipal utilities which, in general, are not subject to rate regulation by the Commission. This inclusion is reasonable in that the Minnesota Legislature specifically determined in M.S. § 216B.164, subd. 2, that the Commission's rules on this matter were to apply to all Minnesota electric utilities, including cooperative electric associations and municipal electric utilities.

4 MCAR § 3.0452 Filing Requirements.

A. Filing dates. Within 60 days after the effective date of 4 MCAR §§ 3.0450-3.0463, on January 1, 1983, and every 12 months thereafter, each utility shall file with the Commission, for its review and approval, a cogeneration and small power production tariff which shall contain Schedules A through F or, if applicable, Schedules A through D plus Schedules F and G.

It is necessary that the covered utilities file timely cost information so that the cogeneration and small power production tariffs will reflect up-to-date avoided costs as required by M.S. § 216B.164, subd. 3. At the same time, the Commission wishes to minimize the administrative burden on the reporting utility. Accordingly, it is reasonable that the cogeneration and small power production tariff be filed every 12 months. The initial filing will be required within 60 days of the effective date of this rule to allow the covered utility adequate time to prepare the tariff filings.

B. Schedule A. Schedule A shall contain the estimated system average incremental energy costs by seasonal peak and off-peak periods for each of the next five years. For each seasonal period, system incremental energy costs shall be averaged during system daily peak hours, system daily off-peak hours, and all hours in the season. Schedule A shall describe in detail the method used to determine the on-peak and off-peak hours and seasonal periods and shall show the resulting on-peak and off-peak and seasonal hours selected.

The hourly incremental energy costs are the direct fuel and variable operation and maintenance costs incurred by a utility when an additional kilowatt-hour is produced. As such, the incremental energy cost is the direct cost that will be avoided by the utility if a qualifying facility generates that kilowatt-hour instead of the utility. It has been the Commission's experience that incremental energy costs exhibit significant diurnal and seasonal variation. Each utility will have a unique set of hourly incremental energy costs due to such things as its generation mix and its load pattern. Consequently, this information is necessary for the computation of the utilities' avoided costs and it is reasonable to expect these costs to be peculiar to each utility. It is necessary for these incremental energy costs to be projected and reported for the next five years to enable potential qualifying facilities to evaluate the probable benefits of installing electric generation equipment. If the projection were made only for the coming year, there would be insufficient information for the qualifying facility to determine likely energy payments, because there could be no trends established. On the other hand, projection of these costs over a period of, for example, 10 years, would undoubtedly be costly, and the results of projections that far in the future could hardly be relied on. The choice of a 5 year projection is thus a reasonable compromise which yields useful results without extraordinary costs.

The utilities are required to file their method of determining daily peak and off-peak and seasonal hours in order to provide interested parties an opportunity to review the methods and make judgments as to their reasonableness. This is necessary to insure that appropriate avoided cost rates are computed and to insure that the time periods selected are reasonable.

C. Schedule B. Schedule B shall contain the information listed in 1.-5.

1. Schedule B shall contain a description of all planned utility generating facility additions anticipated during the next ten years, including:

a. Name of unit;

b. Nameplate rating;

c. Fuel type;

d. In-service date;

e. Completed cost in dollars per kilowatt in the year in which the plant is expected to be put in service, including allowance for funds used during construction;

f. Anticipated average annual fixed operating and maintenance costs in dollars per kilowatt;

g. Energy costs associated with the unit, including fuel costs and variable operating and maintenance costs;

h. Projected average number of kilowatt hours per year the plant will generate during its useful life; and

i. Average annual fuel savings resulting from the addition of this generating facility, stated in dollars per kilowatt.

Information regarding the operational characteristics of all planned utility generating facilities is necessary so that the Commission and any interested party can effectively make comparisons of utilities' generation plans and make judgments concerning the reasonableness of these plans. The costs associated with the planned generation facility are estimated future costs. As such, it is reasonable that the Commission be provided with at least a minimal description of the facility to be constructed. A disclosure of the name of the unit, its nameplate rating, the fuel type, energy costs and projected number of kilowatt-hours to be produced by the plant will provide a barebones sketch of the most important operating characteristics of the unit. It is reasonable to expect that any utility planning a major expenditure of this nature would have this basic information readily available. The in-service date, the completed cost per kilowatt, anticipated average annual fixed operation and maintenance cost in dollars per kilowatt, and the annual fuel savings are all required in order for the avoided capacity related generation costs to be calculated in 4 MCAR § 3.0452 (B)(4).

2. Schedule B shall contain a description of all planned firm capacity purchases, other than from qualifying facilities, during the next ten years, including:

a. Year of the purchase;

b. Name of the seller;

c. Number of kilowatts of capacity to be purchased;

d. Capacity cost in dollars per kilowatt; and

e. Associated energy cost in cents per kilowatt-hour.

Planned firm capacity purchases are capacity purchases the utility intends to make to supplement its own generation or its present purchases, either indefinitely, or until it can bring its own new generation facilities on line. These purchases may be distinguished from capacity purchases to replace generation facilities during maintenance, and from unplanned purchases executed to take advantage of transitory economies. Planned firm capacity purchases would appear in generation capacity expansion plans, and would be marked by identification of a specific kilowatt or megawatt purchase size.

In the event that a utility does not have any generation facilities planned for construction in the next 10 years, the computation of the utility's avoided capacity costs will be based on its planned firm capacity purchases, excluding any purchases from qualifying facilities, during the next 10 years. The capacity cost and energy cost components of the rates paid by the utilities for such purchases are an integral part of the calculation of the avoided cost rates for sales by qualifying facilities. Consequently, the reporting of these figures is necessary in order for these calculations to be made. A utility exercising sound judgment would be likely to have this information readily available since it would be an important factor in its decision to purchase power rather than build an additional power plant. Hence, this reporting requirement is reasonable. In addition, the characteristics of the proposed purchase, the year of the purchase, the name of the seller and the number of kilowatt-hours purchased is information that would be readily available to the utility and is needed to evaluate the nature of the avoidable costs.

3. Schedule B shall contain the utility's overall average percentage of line losses due to the distribution, transmission, and transformation of electric energy.

The overall average percent of line losses must be reported because it is used in the calculation of the utilities' avoided costs in 4 MCAR § 3.0452 (4)(g). An explanation of its necessity and reasonableness is provided there.

4. Schedule B shall contain the utility's net annual avoided capacity cost stated in dollars per kilowatt-hour averaged over the on-peak hours and the utility's net annual avoided capacity cost stated in dollars per kilowatt-hour averaged over all hours. These figures shall be calculated as follows:

The rates paid to qualifying facilities will be determined, in part, by the capacity cost that the utility will avoid due to the electric energy deliveries from qualifying facilities, so the avoided capacity cost must be measured. Once it is measured it will be expressed in two ways: cost per on-peak kilowatt-hour and cost per kilowatt-hour averaged over all hours. Qualifying facilities choosing to sell power based upon time of delivery would be compensated for the utilities' avoided capacity cost based upon the qualifying facility's on-peak deliveries. The qualifying facility would only receive compensation for deliveries of energy during off-peak hours. Qualifying facilities not choosing the time-of-day option would receive compensation for avoided capacity costs based upon total kilowatt-hour deliveries. It is shown below that such a division between on-peak capacity rates and all-hours capacity rates is necessary to appropriately compensate qualifying facilities and at the same time it is reasonable because it facilitates a system that minimized administrative costs.

a. The completed cost per kilowatt of the utility's next major generating facility addition, as reported in Schedule B, shall be multiplied by the utility's marginal capital carrying charge rate. If the utility is unable to determine this carrying charge rate as specified, the rate of 15 percent shall be used.

Since a utility's electric generating plant will be in service for longer than a one year period, its costs must be spread out over a period of time representative of its expected useful life. This is accomplished by determining an appropriate marginal capital carrying charge rate, as discussed in the definition section earlier, and applying it to the investment cost of the new generation facility. The Commission is aware that some utilities may have difficulty determining the marginal capital carrying charge rate, which requires a complex calculation, so a default value of 15 percent has been established. This rate is reasonably close to comparable figures presented in recent electric utility rate case proceedings before this Commission. Such cases include Minnesota Power and Light, Docket No. E-015/GR-80-76 and Interstate Power Company, Docket No. E-001/GR-78-1065. Consequently, this figure may be used as a practical alternative for a utility that is unable to determine such a rate. This section of the proposed rule is necessary and reasonable because it provides for a reasonable estimate of the utility's avoided cost.

b. The dollar amount resulting from the calculation set forth in a. shall be discounted to present value, as of the midpoint of the reporting year, from the in-service date of the generating unit. The discount rate used shall be the most recent overall rate of return authorized by the Commission for the reporting utility. If the reporting utility is not rate regulated by the Commission or is regulated but has not yet had an overall rate of return established by the Commission, the utility shall use the overall rate of return most recently authorized for the largest electric utility, measured by annual Minnesota revenues, in the Commission's jurisdiction.

It is important that the dollar amounts used in calculating the avoided cost based rates are stated in dollars of the year in which the rates are applicable. Due to inflation and the time preference for money, a dollar spent a few years from today is not as valuable as a dollar spent today. In order to compare dollars to be spent in the future with dollars spent today, future dollars must be discounted. An appropriate discount factor is the overall rate of return authorized by the Commission for each utility. This figure, which is a reasonable approximation of the cost of capital to the individual utility, captures the effects of inflation and investors' time preference for money. Obviously, if the utility is not rate regulated by the Commission, an overall rate of return will not be established by the Commission. In such a case, the overall rate of return most recently authorized by the Commission for the largest electric utility in the Commission's jurisdiction is a reasonable approximation of the appropriate discount rate. Also, such a figure is readily available. This entire section of the proposed rule is a necessary and reasonable step in the computation of the utilities' avoided costs.

c. The figure for average annual fuel savings per kilowatt described in 1.i. shall be discounted to present value using the procedure of b.

d. The number resulting from the calculation in c. shall be subtracted from the number resulting from the calculation in b. This is the net annual avoided capacity cost stated in dollars per kilowatt at present value.

A utility planning to build additional generation capacity must decide to build one of two basic types of plants: a baseload plant (e.g., a coal fired plant) or a peaking plant (e.g., a combustion turbine). A baseload plant is characterized by high capital costs and low running costs. Conversely, a peaking plant is characterized by low capital costs but high running costs. The utility, in its attempt to minimize total system costs, will choose between the alternative plants based upon the number of hours that each would be expected to be "on-line." It would only be economic to install a peaking plant if it was expected to be "on-line" for a relatively small number of hours. A baseload plant would be installed only if it was expected to be put "on-line" for a substantial number of hours in the year. Since a new baseload plant is likely to be much less expensive to run than many of the utility's existing plants, which are likely to be older, less fuel efficient plants, the utility could reduce fuel costs by installing and running a baseload unit. Consequently, the utility may be incurring capital costs in order to reduce its energy costs. Thus, the total increase in capital costs should be reduced by the fuel savings resulting from the installation of this plant in order to properly reflect the net additional cost resulting from the addition of this plant. This net figure represents the avoided capacity cost, i.e., the cost the utility avoids by virtue of not having to install the plant at all or by delaying the building of the plant for a year. It is important that the fuel savings be discounted to present value so that this cost will be on a comparable basis with the investment cost of a new plant, which also is discounted to present value. The calculation required by this portion of the proposed rule is necessary and reasonable in order to accurately compute the avoided costs of the utility resulting from a qualifying facility's delivery of electric energy.

e. The net annual avoided capacity cost calculated in d. shall be multiplied by 1.15 to recognize a reserve margin.

Each utility must have a certain amount of reserve capacity available to meet system emergencies. The reserve margin for utilities belonging to the Mid Continent Area Power Pool is 15%. This means that for every kilowatt of coincident peak demand the utility must build or have available to it 1.15 kilowatts of capacity. Conversely, if a customer's peak demand is reduced by 1 kilowatt and the utility's demand is reduced by 1 kilowatt, the utility needs to build 1.15 kilowatts less than it otherwise would have built. Every kilowatt delivered by a qualifying facility reduces the load that is required from the utililty by 1 kilowatt. The reduction in load of 1 kilowatt means that the utility will be responsible for providing 1.15 kilowatts less of capacity than otherwise. Therefore, in order to accurately compute the cost avoided due to the qualifying facility's production, the reserve margin must be taken into account. Consequently, this section of the proposed rule is necessary and reasonable.

f. The figure determined from the calculation of e. shall be increased by the amount of the anticipated average annual fixed operating and maintenance costs as reported in 1. f.

When an electric utility installs a new generation plant it will incur fixed operation and maintenance costs, on an annual basis, which result from the installation of this plant. If this generation plant is not installed those costs will be avoided. Clearly, it is necessary and reasonable that those costs be included in the amount representing avoided capacity costs.

g. The figure determined from the calculation of f. shall be increased by the percentage amount of the average system line losses as shown on Schedule B.

Utilities typically generate electricity at centralized generation stations, step up power to transmission level voltage, transport it via transmission and subtransmission facilities to load centers, step down the power to distribution level and deliver it, via distribution facilities, to customers' locations. In the process of transforming and delivering power to load centers and to individual locations, significant amounts of electric power are lost. Since the output from qualifying facilities will typically be located near load centers, the amount of line losses from qualifying facility delivered power may be negligible. Consequently, for each kilowatt-hour produced by qualifying facilities, the utility will be able to avoid more than 1 kilowatt-hour of electric generation. For example, if the utility's reported average system line losses are 10%, the utility would avoid the producton of 1.1 kilowatt-hours for every kilowatt-hour delivered by a qualifying facility. In order for the qualifying facility to be appropriately compensated for the avoided cost of the utility, consideration of the line loss is necessary and reasonable.

h. The annual dollar per kilowatt figure, as calculated in accordance with g., shall be divided by the annual number of hours in the on-peak period as specified in Schedule A. The resulting figure is the utility's net annual on-peak avoided capacity cost in dollars per kilowatt-hour.

Up to this point in the calculation of the capacity related avoided generation costs, all costs have been expressed in terms of dollars per kilowatt. However, rates paid to qualifying facilities will be based upon kilowatt-hour deliveries, not kilowatt deliveries. Therefore, the cost per kilowatt must be converted to cost per kilowatt-hour. In fact, there must be two separate conversions. In this section of the proposed rule, the cost per kilowatt is converted to cost per on-peak kilowatt-hour. In this way customers providing on-peak power will be compensated for their proportionate share of the generation costs which are avoided.

The following example illustrates this point. First, assume that the avoided generation capacity cost is $129.60 per kilowatt per year. This is equivalent to $10.80 per kilowatt per month. Second, assume that the on-peak hours make up 50% of the total number of hours. Since there are 720 hours in the typical month, there would be 360 on-peak hours in a month. The capacity component of the rate paid to a qualifying facility in this example would be \$10.80 ÷ 360 hours = 3.0¢/kwh.

In order to show how this rate would be applied to an individual qualifying facility, the example can be extended. Assume that the qualifying facility provides a peak output of 50 kilowatts and that this 50 kilowatts is generated continuously over the on-peak period. The capacity component of the compensation to the qualifying facility would be:

50 kw x 360 hours = 18,000 kwh
18,000 kwh x 3.0¢/kwh = \$540.00

Since \$540 ÷ 50 kw = \$10.80 per kw, the qualifying facility would be compensated appropriately.

If the same customer was generating at peak output during only 80% of the on-peak hours, compensation would be proportionately less:

50 kw x (360 hours x .8) = 14,400 kwh
14,400 kwh x 3.0¢/kwh = \$432.00

Since \$432 is 80% of \$540 this qualifying facility would be paid proportionately less because it generated proportionately fewer kilowatt-hours during the on-peak period.

This is similar to the way that retail tariffs are applied to non-demand metered customers of utilities. The demand or capacity costs are averaged into the kilowatt-hour rate. This has been traditionally accepted because there is a strong relationship between kilowatt-hours consumed by individual customers and the amount of capacity needed by the utility.

This section of the proposed rule is necessary and reasonable because it requires utilities to compensate qualifying facilities for delivered capacity on an appropriate basis.

i. The annual dollar per kilowatt figure resulting from the calculation specified in g. shall be divided by the total number of hours in the year. The resulting figure is the utility's net annual avoided capacity cost in dollars per kilowatt-hour averaged over all hours.

For qualifying facilities not choosing to sell power on a time-of-day basis, the capacity costs must be averaged over all hours instead of just on-peak hours. In the example stated above, the monthly rate per kilowatt-hour would be computed as follows:

\$10.80 ÷ 720 hours = 1.5¢/kwh

Although this rate is only 50% of the on-peak rate it is available to qualifying facilities for twice as many hours during the month. A qualifying facility with a peak capacity of 50 kilowatts that operates at 100% load factor in the month would receive compensation as follows:

50 kw x 720 hours = 36,000 kwh
36,000 kwh x 1.5¢/kwh = \$540.00

This is the same amount that would be paid to the qualifying facility under the time-of-day rate option.

This calculation of avoided costs is a reasonable calculation because it shows that, on average, a qualifying facility would be appropriately compensated because the purchase rates reflect avoided costs. In addition, this method of calculation is similar to the methods used by utilities in computing their retail rates. It is reasonable to employ the same methods where applicable, in the computation of purchase rates.

5. If the utility has no planned generating facility additions for the ensuing ten years, Schedule B shall contain its net annual avoided capacity cost stated in dollars per kilowatt-hour averaged over the on-peak hours and the utility's net annual avoided capacity costs stated in dollars per kilowatt-hour averaged over all hours. These shall be calculated as follows:

a. The annual capacity purchase amount, in dollars per kilowatt, for the utility's next planned capacity purchase, other than from a qualifying facility, shall be discounted to present value as of the midpoint of the reporting year, from the year of the planned capacity purchase. The discount rate used shall be determined in the manner described in 4.b.

If the utility has no planned generation facility additions for the ensuing 10 years, generation of electric energy by qualifying facilities will not help the utility avoid any generation capacity costs. Hence, under this condition, it would not be reasonable for the purchase rates to be based on avoided generation capacity costs.

Even if the utility has no planned generation facilities, it may have planned capacity purchases. It is reasonable to assume that the utility can decrease these planned purchases if qualifying facilities deliver energy and capacity to the utility. The avoided cost to the utility would be the cost of the planned capacity purchase which would not have to be made. The cost of the planned purchase shall be expressed in current year dollars by applying an appropriate discount rate. In this way, qualifying facilities will be compensated on the basis of current year dollars. It is necessary and reasonable that rates accurately reflect the time period of expenditure because the value of the dollar changes over time.

b. The net annual avoided capacity cost shall be computed by applying the figure determined in a. to the steps enumerated in 4.d.-4.i., excluding 4.g.

There is a minor error in this section of the proposed rule. It should read:

> "The net annual avoided capacity cost shall be computed by applying the figure determined in a. to the steps enumerated in 4.e.-4.i., excluding 4.f."

With this change, Schedule B will reflect the avoided costs of the utility. Since this section of the rule is applicable only to utilities with no planned generating facilities it is not appropriate to take into account the annual fixed operation and maintenance expenses associated with a new generating facility.

Adjustments for a reserve margin and line losses are required in the same manner as in the previous section. In addition, the avoided costs are expressed on a kilowatt-hour basis in the same manner as in the previous sections. As previously discussed, those calculations are both necessary and reasonable.

D. Schedule C. Schedule C shall contain all standard contracts to be used with qualifying facilities, containing applicable terms and conditions.

It is necessary and reasonable that all interested parties have available to them the standard contracts which a utility will use with qualifying facilities. This will allow qualifying facilities the opportunity to analyze the contracts and will give them an opportunity to either accept the contract or pursue a course of action whereby changes could be made in the contract. In addition, the requirement that all standard contracts be filed will help insure that all qualifying facilities are treated equally and fairly by the utility. Thus, this is a necessary provision since the Commission must implement fair and reasonable rates. It is reasonable because the utilities will have these documents readily available.

E. Schedule D. Schedule D shall contain the utility's safety standards, required operating procedures for interconnected operations, and the functions to be performed by any control and protective apparatus. These standards and procedures shall not be more restrictive than the interconnection guidelines listed in 4 MCAR § 3.0462. The utility may include in Schedule D suggested types of equipment to perform the specified functions. No standard or procedure shall be established to discourage cogeneration or small power production.

It is necessary that the utility file its safety standards, required operating procedures for interconnection operations and the functions to be performed by any control and protective apparatus in order to facilitate communication between the utility and the qualifying facility. A clear understanding of the technical requirements will help the qualifying facilities minimize their cost of interconnection equipment and will minimize safety related problems. An explicit publicized statement of the utility's operating procedures will help the parties coordinate their activities. The rule provides that the utility may not make requirements of a qualifying facility that are overly restrictive or that are established to discourage cogeneration and small power production. This is both necessary and reasonable since it is consistent with the intent of M.S. § 216B.164, to give the maximum possible encouragement to cogeneration and small power production. Anything more restrictive would not be consistent with the intent of the state law. On the other hand, each utility is allowed to require the qualifying facility to install all necessary control and protective apparatus as specified in 4 MCAR § 3.0462. Consequently, the proposed rule is consistent with the protection of the ratepayer and the public, as required by M.S. § 216B.164, subd. 1, and is necessary and reasonable.

F. Schedule E. Schedule E shall contain procedures for notifying affected qualifying facilities of any periods of time when the utility will not purchase electric energy or capacity because of extraordinary operational circumstances which would make the costs of purchases during those periods greater than the costs of internal generation.

18 CFR § 292.304(f) provides that any electric utility which seeks to cease purchasing from qualifying facilities must notify each affected qualifying facility prior to the occurrence of such a period, in time for the qualifying facility to cease delivery of energy or capacity to the electric utility. It further provides that this notification can be accomplished in any reasonable manner determined by the State regulatory authority. Schedule E in the proposed rule implements this requirement by simply requiring each utility to state the procedures it would use for notifying affected qualifying facilities of any periods of time when the utility will not purchase electric energy or capacity. The reasonableness of these procedures may then be reviewed by the Commission and other interested parties.

The only time that a utility may refuse to purchase power from a qualifying facility is when a utility is experiencing an extraordinary operational circumstance, i.e., during a light loading period. Such a period was described by the FERC in an explanation of its rules at 45 Fed. Reg. 38,12227:

> If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when the system demand later increased. As a result, the utility would be required to utilize less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output. The result of such a transaction would be that rather than avoiding costs as a result of the purchase from a qualifying facility, the purchasing electric utility would incur greater costs than it would have had it not purchased energy or capacity from the qualifying facility.

The Commission believes that an extraordinary operational circumstance would indeed be an unusual occurrence. The proposed rule is necessary and reasonable because it implements federal law, it is consistent with purchase rates set at avoided cost and it does not discourage cogeneration and small power production.

It is necessary that the Commission and all interested parties have an opportunity to review the notification procedures to be used by the utility when the utility will not purchase electric energy or capacity due to extraordinary operational circumstances. Without such an opportunity the Commission would not be able to judge whether or not the utility acted in a reasonable and non-discriminatory manner as required by state law. Thus it is necessary and reasonable. There is no reason to expect that such a filing requirement would place an unreasonable burden on the utilities.

G. Schedule F. Schedule F shall contain and describe all computations made by the utility in determining Schedules A and B.

This filing requirement is necessary in order for the Commission and all interested parties to review the reasonableness of the utilities' computational methods. Such a review may be necessary to determine whether or not the utilities' filings conform with the requirements of the rule. This requirement is reasonable since the Commission is responsible for the enforcement of the rule.

H. Schedule G. Special rule for nongenerating utilities. An electric utility which purchases all the power it sells shall obtain the data for Schedule A and Schedule B from its supplying utility. The nongenerating utility shall file this data as Schedule A and Schedule B. In addition, the nongenerating utility shall file Schedules C, D, F, and Schedule G. Schedule G shall list the rates at which the nongenerating utility currently purchases energy and capacity.

Schedule G applies to utilities that purchase all of their power for resale. Such a nongenerating utility is required to file Schedules A-G excluding E. The information for Schedules A and B are to be determined from cost information provided by the utility's suppliers since the nongenerating utility would have no such information pertaining to its own system. This information will be necessary for the Commission and other interested parties to compare the generation costs of all utilities and this will provide potential qualifying facilities with information that will help them estimate the likely future avoided cost payments from the utility. Schedules C, D and F are necesssary and reasonable for the reasons stated above. Schedule E is not needed because the conditions assumed thereunder do not apply to nongenerating utilities. Schedule G is necessary because the rates for purchase of power delivered by qualifying facilities will be based on the rates paid by the utility for power from its normal supplier. The reasonableness of this basis for the avoided cost computation will be discussed in this statement under the explanation of 4 MCAR § 3.0455.

I. Availability of filings. All filings required by A.-H. shall be made with the Commission and shall be maintained at the utility's general office and any other offices of the utility where rate case fillings are kept. These filings shall be available for public inspection at the Commission and at the utility offices during normal business hours.

It is necessary that all tariff filings concerning purchase rates be made readily available so that the Commission, all qualifying facilities, and any potential qualifying facility can estimate present and future avoided cost based purchase rates. Access to filings will allow interested parties an opportunity to make a judgment as to the reasonableness of all computations and an opportunity to understand their responsibilities as sellers of energy to a utility. Restricting access to the filed information would serve to frustrate the purpose of M.S. § 216B.164 by discouraging cogeneration and small power production and would be unreasonable.

4 MCAR § 3.0453 Reporting requirements.

A. General requirements. Each utility shall provide the Commission with the following information on or before November 1, 1982, and at any other such times and in any form as the Commission may require.

B. Net energy billed qualifying facilities. For qualifying facilities under net energy billing, the utility shall provide the Commission with the following information:

1. A summary of the total number of interconnected qualifying facilities, the type of interconnected qualifying facilities, and the name plate ratings of such units;

2. For each qualifying facility type, the total kilowatt-hours delivered per month to the utility by all net energy billed qualifying facilities;

3. For each qualifying facility type, the total kilowatt-hours delivered per month by the utility to all net energy billed qualifying facilities; and

4. For each qualifying facility type, the total net energy delivered per month to the utility by net energy billed qualifying facilities.

C. Other qualifying facilities. For all qualifying facilities not under net energy billing, the utility shall provide the Commission with the following information:

1. A summary of the total number of interconnected qualifying facilities, the type of interconnected qualifying facilities, and the nameplate ratings of such units; and

2. For each qualifying facility type, the total kilowatt-hours delivered per month to the utility, reported by on-peak and off-peak periods to the extent that data is available.

D. Wheeling. The utility shall provide a summary of all wheeling activities.

E. Major impacts. The utility shall provide a statement of any major impacts that cogeneration or small power production has had on the utility's system.

F. Effectiveness. The utility shall provide a statement of the effectiveness of Minn. Stat. § 216B.164 and 4 MCAR §§3.0450-3.0463 in encouraging cogeneration and small power production, as observed by the utility.

Pursuant to M.S. § 216B.164, subd. 7, the Commission is required to submit a report to the Legislature on Jan. 1, 1983.

Such a report must address at a minimum, the following issues:

1) The location, type, and output of cogenerators and small power producers in the state;

2) Whether cogeneration and small power production has resulted in any major impacts on the utility system; and

3) The effectiveness of the provisions of the state law and the Commission's rules in encouraging cogeneration and small power production.

Because of this statutory requirement, the Commission must obtain reliable and accurate information from which a report may be compiled. The Commission believes that such a reporting requirement is necessary and reasonable, because in most cases only the utility will have possession of the needed data or access thereto. In addition, the Commission does not possess the resources necessary to adequately collect and assemble the essential information.

One of the basic premises underlying the cogeneration and small power production portions of PURPA was to alleviate as many burdens on the qualifying facility as possible and to provide it with a favorable climate in which to operate. To impose the reporting requirements on the individual qualifying facility, over which the Commission does not have general regulatory jurisdiction, would place a burden on the qualifying facility which would be contrary to the intent of the FERC rules as well as pertinent portions of PURPA. Such a reporting requirement may be more appropriately placed on the utilities which are within the scope of traditional regulatory jurisdiction.

In order for the Commission to accurately assess and report on the output of interconnected qualifying facilities as required by M.S. § 216B.164, it is necessary for the Commission to require the utilities to submit a summary of the following where applicable:

1. Total number of interconnected qualifying facilities.

Such information is needed for the Commission to determine the extent of interconnected qualifying facilities as well as to evaluate the distribution of qualifying facilities within the respective service areas throughout the state.

2. Nameplate ratings.

The nameplate ratings are necessary to appraise the apparent addition of capacity through the interconnection of qualifying facilities.

3. Type of interconnected qualifying facilities.

By distinguishing qualifying facilities by type (e.g., wind, photovoltaic, hydro, etc.), the Commission will be able to determine what technologies are in fact being utilized as well as providing public information with repect to the use and contribution of various technologies.

4. For each qualifying facility type, the total Kwh delivered per month to the utility.

This information is needed to effectively evaluate the amount of energy generated by small power production and cogeneration units in Minnesota. Such information is of great public importance also, as it may indicate the viability of alternative means of energy generation in the future. By segregating the information into unit types, the Commission will be able to appraise the relative effectiveness and contribution of energy to the system by different types of qualifying facilities, as well as to determine which technologies are capable of significant current contributions to the utility's system.

5. For each qualifying facility type, the total Kwh delivered per month by the utility.

This information is needed to evaluate the total impact of qualifying facilities on the utility system. Such information will allow the Commission to determine what effect, if any, interconnection of qualifying facilities will have on the system load.

6. For each qualifying facility type, the net energy delivered per month to the utility.

This data is needed to analyze the net impact of cogeneration and small power production units on the system as well as to assess the potential benefit to be gained from alternative means of energy production.

7. For each qualifying facility type, the total Kwh delivered per month to the utility, reported by on-peak and off-peak periods.

This information will allow the Commission to review the total amount of energy generated by those qualifying facilities not under the net billing option. By distinguishing between on-peak and off-peak deliveries, it will be possible to determine whether or not qualifying facilities are providing energy during crucial on-peak demand periods. This information will also allow the Commission to accurately describe and detail the output of those qualifying facilities utilizing the time-of-day classification.

The utilities are also required to submit a summary of all wheeling activities. Such information is needed to determine the extent of the wheeling of energy generated by qualifying facilities and to evaluate the attendent problems or concerns thereof by all interested parties.

The utilities are also required to include in their reports:

A) A statement of any major impacts that cogenerators and small power production has had on the utility system; and

B) A statement of the effectiveness of M.S. § 216B.164 and the Commission's rules in encouraging cogeneration and small power production.

Both statements present an opportunity for the Commission to receive comments and information concerning cogeneration and small power production, as well as an opportunity for the utilities to submit their concerns, observations and subjective evaluations to the Commission for its consideration and evaluation.

The November 1, 1982 date was selected and is needed to provide the Commission with sufficient time to review and evaluate the submitted information and to prepare an accurate and comprehensive report to be delivered to the Legislature on January 1, 1983.

The Commission has also reserved the right to require utilities to comply with the reporting requirements in the future should the need to prepare additional reports or other similar data compilations arise.

The Commission recognizes the possibility that the legislature may direct the Commission to submit additional reports. In response to such a contingency, the Commission has reserved the right to require utilities to comply with the reporting requirements should the need to prepare additional reports or other similar data compilations for the legislature arise. It is anticipated that the Commission will utilize such a provision only when so directed by the legislature.

An alternative proposal which was considered but rejected was one requiring utilities to submit annual reports to the Commission. Such an option would have provided the Commission with the means to obtain the necessary information but with little or no flexibility. By requiring the submission of reports only when the need arises, all parties concerned are relieved of an unyielding burden.

The future reporting provision is necessary as well as reasonable in that it is a legitimate means by which the Commission could receive accurate and timely information from which future reports may be compiled should the need to do so arise.

4 MCAR § 3.0454 Conditions of service.

This proposed rule establishes the conditions which must be met by both the utility and the qualifying facility for engaging in interconnected operations. It is necessary because established conditions enable each party to know in advance what is expected of it and the other party. That knowledge greatly reduces uncertainty. It is reasonable to expect that reduction of uncertainty will encourage cogeneration and small power production. In addition, established conditions ensure uniform treatment of qualifying facilities by utilities, and provide a basis for resolving disputes. This proposed rule is reasonable because it fairly assigns responsibility for meeting conditions between the utility and the qualifying facility.

A. Requirement to purchase. The utility shall purchase energy or capacity from any qualifying facility which offers to sell energy to the utility and agrees to the conditions set forth in 4 MCAR §§ 3.0450-3.0463.

This section requires the utility to purchase electricity from any qualifying facility agreeing to the conditions. The requirement to purchase is necessary because a utility which refused to purchase could leave the qualifying facility without a market for its power. A possible result could be that more efficient generation (by the qualifying facility) would be foregone for less efficient generation (by the utility). Such a result would be contrary to the most basic reason for encouraging cogeneration and small power production: promoting efficient use of resources. The requirement for utilities to purchase from qualifying facilities is part of both PURPA (Section 210 (a)) and the FERC rules (18 CFR § 292.303(a)). This section is reasonable in that it also requires qualifying facilities to agree to the conditions established in this rule.

B. Written contract. A written contract shall be executed between the qualifying facility and the utility.

Interconnection implies the purchase and sale of energy and capacity by the utility and the qualifying facility over substantial periods of time. Neither the transactions nor the physical equipment necessary to accomplish the transactions are simple. It is both necessary and reasonable, therefore, that the parties to the transactions state their understanding of the terms and conditions in writing. This statement will prevent disputes from arising and will aid in the resolution of disputes.

Some persons have argued that requiring a contract would be in itself a significant discouragement to potential owners of qualifying facilities. The argument suggests both that unnecessary costs of legal review would be incurred and that utilities would unilaterally make unfair requirements of qualifying facilities in such contracts.

The Commission believes this argument is without merit. First, a written contract is a reviewable document. It, therefore, discourages unreasonable demands which might otherwise be made in oral agreements. Second, a written contract tends to make each party explicitly aware of its rights and obligations. Third, written contracts better enable the Commission to ensure uniform treatment of qualifying facilities by utilities. Fourth, standard written contracts, especially for small qualifying facilities, will effect significant administrative cost savings, as the contract need not be redrawn each time a qualifying facility applies for interconnection.

C. Compliance with national electrical safety code. The interconnection between the qualifying facility and the utility shall comply with the requirements of the 'National Electrical Safety Code,' 1981 edition, issued by the Institute of Electrical and Electronics Engineers as American National Standards Institute Standard C2 (New York, 1980).

Safe handling of electricity is vital to qualifying facilities, to utilities, and to the general public. In an early draft submitted for comment the Commission proposed to require the qualifying facility to comply with the National Electrical Safety Code. One manufacturer of small power production equipment objected that adherance to the Code could damage his equipment. The Commission has determined, therefore, that a reasonable requirement would be for the interconnection to meet Code specifications. The Commission notes that the Minnesota State Board of Electricity has asserted its jurisdiction over safe wiring of qualifying facilities.

D. Responsibility for apparatus. The qualifying facility, without cost to the utility, shall furnish, install, operate, and maintain in good order and repair any apparatus the qualifying facility needs in order to operate in accordance with Schedule D. At the request of the qualifying facility, the utility shall furnish, install, operate and maintain all or any portion of the apparatus and bill the qualifying facility for the equipment and service at cost.

This section requires qualifying facilities to install, operate, and maintain equipment required for safe and reliable generation in parallel with the utility, or, in the alternative, to pay the utility to install, operate, and maintain the equipment. It is a necessary condition that the qualifying facility pay for interconnection costs. This is a requirement of state law (M.S. § 216B.164, subd. 8) and of the FERC regulations (18 CFR § 292.306), and is logically consistent with the purpose behind requiring utilities to pay full avoided cost to qualifying facilities. Payment of full avoided cost ensures that, in a "frictionless" world, all cogeneration and small power production which is more efficient (i.e., cheaper) than marginal utility production will come into being. All incremental efficiency gains are manifested as profits of qualifying facilities. The utility ratepayer then pays exactly as much for electricity generated by qualifying facilities as he would have if the utility had generated it all. He is thus economically indifferent between the sources. If, however, he were required, through his utility, to pay interconnection costs as well as full avoided costs, he would no longer be indifferent, but would be better off if the utility generated all its electricity and purchased none from qualifying facilities. It is, therefore, reasonable that the qualifying facility be responsible for this interconnection equipment.

The utility may nevertheless have knowledge and expertise about interconnections which it would not be cost effective for the owner of the qualifying facility to acquire. The utility may also be able to purchase interconnection equipment at lower prices than may be available to individuals. Consequently, it is reasonable to require the utility to install, operate, and maintain interconnection equipment if requested by the qualifying facility, provided the utility is reimbursed for its costs.

E. Liability insurance. A utility or qualifying facility shall not require the procurement of liability insurance as a condition of service.

F. Legal status not affected. Nothing in 4 MCAR §§ 3.0450-3.0463 affects the responsibility, liability, or legal rights of any party under applicable law or statutes.

In the development of these proposed rules, few issues have generated as much controversy as has the question of whether utilities may require qualifying facilities to hold liability insurance.

Utilities have generally taken the view that the nature of their business makes them prime targets for persons seeking liability damage awards. In their view, interconnecton with cogenerators and small power producers reduces the utility's control over its transmission and distribution system, and may, therefore, increase its exposure for liability. At the same time, utilities have feared that even if a qualifying facility is clearly at fault, it is the utility which will be sued, both because of the direct physical connection with the utility and because of the greater certainty of payment if damages are awarded. Utilities have, therefore, often demanded that qualifying facilities purchase liability insurance - usually in amounts of $500,000 to $1 million - as a condition of interconnection.

Owners and manufacturers of qualifying facilities, on the other hand, have taken the position that the real reason for requiring liability insurance is to discourage and inhibit cogeneration and small power production. They have argued either that such insurance is simply not available, or is available at a cost which is prohibitively high. The result in either case, they have said, is the same as having the utility simply refuse to interconnect and purchase power.

The Commission observes that there is little practical experience of the effects of interconnected cogenerators and small power producers on utility power supply systems. Consequently, there is no information of which the Commission is aware on how often interconnected operations cause damage (if ever), or on the size of claims won because of such damages. It is, therefore, impossible for the Commission to determine how much liability insurance would be appropriate if insurance were required.

The Commission believes that a prudent person, engaging in a business venture to supply a product as potentially dangerous as electricity, would want to secure liability protection. Nevertheless, the Commission feels it is appropriate for each owner of a qualifying facility to make his own judgement on this issue. It is likely that if an uninsured qualifying facility were successfully sued, the news would get out to other qualifying facilities, and might influence those without protection to seek it.

The Commission concludes, therefore, that it would be both unnecessary and unreasonable to require liability insurance as a condition of service. Section E. of this proposd rule makes this clear. Section F. is a necessary and reasonable warning of the fact that the absence of an insurance requirement does not remove responsibility or liability from any party.

G. Payments for interconnection costs. Payments for interconnection costs may, at the option of the qualifying facility:

1. Be made at the time the costs are incurred;

2. Be amortized over the life of the contract; or

3. Be made according to any schedule agreed upon by the qualifying facility and the utility.

Interconnection costs could, in some circumstances, amount to a very considerable sum. Because qualifying facilities may already be experiencing large capital requirements prior to beginning operations, the requirement to pay interconnection costs "up front" as well could cause a potential owner of a qualifying facility to decide not to proceed with the project. In that case, cogeneration and small power production would have been discouraged simply through the timing of payments. The FERC recognized this possibility and gave State regulatory authorities responsibility for determining the manner of payments for interconnection costs, expressly including the possibility of reimbursement over a reasonable period of time (18 CFR § 292.306 (h)). The Commission believes that a period equal to the time covered by the contract between the utility and the qualifying facility is a reasonable period, as all other rates, terms, and conditions are covered over the same period.

Some qualifying facilities may nevertheless find it advantageous, perhaps for tax purposes, to pay all interconnection costs as they are incurred. It is, therefore, reasonable to do as this section of the proposed rule has done, and offer the qualifying facility its choice of the two possibilities. Because it is not possible for the Commission to foresee the circumstances of all qualifying facilities and utilities facing interconnection under these rules, it is also reasonable to allow both parties to agree to some payment schedule other than the two specific ones the qualifying facility is entitled to.

Whenever payments for interconnection costs are spread over a period of time, an additional cost - the cost of capital - is incurred. This cost would not exist without the interconnection and the qualifying facility's election not to pay all interconnection costs at once. Consequently, this cost of capital is appropriately classified as an interconnection cost, and is the responsibility of the qualifying facility. The proposed rule is reasonable because it does not prohibit the utility from recovering this cost through charges to the qualifying facility.

H. Types of power to be offered. The utility shall offer maintenance, interruptible, supplementary, and back-up power to the qualifying facility upon request.

The FERC rules (18 CFR § 292.305 (b)) require utilities to offer maintenance, interruptible, supplementary, and back-up power to qualifying facilities upon request. The availability of these types of power may affect the economics of qualifying facilities such that it is necessary to provide them to encourage cogeneration and small power production. There is no requirement to provide these services below cost, so this condition is reasonable. It is also reasonable to only require these services to be offered on request. They are needed primarily by large cogeneration facilities. Many utilities, who will never interconnect with this kind of qualifying facility, or who will do so only several years from now, can save the time and expense of immediately establishing these services and charges if there is no blanket requirement.

I. Metering. The utility shall meter the qualifying facility to obtain the data necessary to fulfill its reporting requirements to the Commission as specified in 4MCAR § 3.0453. The qualifying facility shall pay for the requisite metering as an interconnection cost unless the qualifying facility is operating under net energy billing. In that case, the utility shall provide the second meter without cost to the qualifying facility.

Metering is another very controversial issue. Much, but not all, of the controversy centers on cost. There is also controversy over the ownership and control of information made available through metering.

To understand the nature of the cost controversy and the Commission's proposed resolution of the issue, it is helpful to keep the following points in mind: 1. Meter costs are interconnection costs and by the logic of the FERC rules are the responsibility of the qualifying facility. 2. Although metering costs tend to be greater for larger, more sophisticated facilities, those costs are a more significant proportion of total interconnection costs for smaller, less sophisticated facilities. 3. Metering costs are far larger, relative to potential revenues, for small qualifying facilities than for large qualifying facilities. 4. Some owners of qualifying facilities intend to make money selling electricity to utilities. 5. Some owners of qualifying facilities simply want to reduce their dependence on utilities and reduce their electric bills.

In enacting M.S. § 216B.164, the Legislature made a special provision for qualifying facilities having capacity less than 40 kilowatts. That provision, known as "net energy billing," makes the net flow of electricity between the qualifying facility and the utility during a billing period the basis of the bill calculation. A single watt-hour meter, capable of running accurately forward and backward, would be sufficient to measure the net flow of electricity, in both direction and magnitude. Most classes of utility customers are already metered for sales by the utility. Hence, if only a single meter were required, its cost would not exceed the cost the utility would incur in selling electricity to the qualifying facility as a nongenerating customer, and would, therefore, not be an interconnection cost. The result would be that the qualifying facility would not have to pay an explicit metering charge. (The cost of the meter, or some part of it, may already be reflected in the monthly service charge for which the qualifying facility remains responsible). The Commission believes it is reasonable to infer that the Legislature wanted to remove metering cost disincentives from small potential cogenerators and small power producers.

The Legislature nevertheless required the Commission to report "[t]he location, type and output of cogenerators and small power producers in the state . . ." Although "output" could mean a measure of capacity, in kilowatts, the Commission believes it would be more meaningful as a measure of energy, in kilowatt-hours. A single meter running forward and backward could not measure output in this sense, as it could not distinguish between two qualifying facilities, one of which purchased 400 kilowatt-hours and sold 600, and the other of which purchased 20,000 kilowatt-hours and sold 20,200. In either case, the meter would show a net flow of 200 kilwatt-hours to the utility. The effects of the two qualifying facilities on the utility's system could, however, be drastically different. The Commission believes it is reasonable, therefore, both to meet its narrow reporting requirement and to provide information relative to utility planning and broad public policy questions, to require metering which will measure total deliveries to and receipts from the utility system.

Several persons observed that a full measure of "output" can only be achieved by metering the generator of the qualifying facility, because there may be load between the generator and the interconnection with the utility. Some suggested that the Commission's rules should permit the utility to install a third meter, at its own expense, if it wanted to monitor generator output.

Several owners and at least one manufacturer of qualifying facilities urged rejection of this suggestion. They claimed that the information sought was proprietary, and no one's business but theirs. They also feared utilities would make selective use of such information to discourage potential cogenerators and small power producers.

The Commission believes the information needed for utility planning, public policy, and its own reporting requirements is that information detailing the interaction of qualifying facilities and utilities. It is, therefore, not necessary to gather information on the output of the generator; energy flows at the point of interconnection will do. Nothing in the proposed rule prevents a utility from installing a third meter, either at its own expense or at the expense of the qualifying facility, if it is agreeable with the qualifying facility.

This section of the proposed rule requires the utility to meter the qualifying facility to obtain the data it must report to the Commission. It requires the qualifying facility to pay for the metering unless the qualifying facility is operating under net energy billing, in which case the utility must provide the additional metering without cost to the qualifying facility.

This section is both necessary and reasonable. Even if there were no reporting requirements, and no public policy needs for the information, metering would still be necessary to document the transactions between qualifying facilities and utilities. The proposal fairly apportions those costs to qualifying facilities except where those costs, as recognized by legislative action, would put an undue burden on small qualifying facilities, and thus discourage small-scale cogeneration and small power production. The Commission believes that the possible effect of a limited increase in rates to other consumers who, ultimately, must pay those costs, would be counterbalanced by the benefits, including externalities, of encouraging cogeneration and small power production.

J. Discontinuing sales during emergency. The utility may discontinue sales to the qualifying facility during a system emergency, if the discontinuance is not discriminatory.

This section is necessary to implement 18 CFR § 292.307 (b) (2). It is reasonable in that a qualifying facility must be treated on a nondiscriminatory basis in any load shedding program - i.e., on the same basis that other customers of a similar class with similar load characteristics are treated with regard to interruption of service.

K. Interconnection plan. The utility may, prior to interconnection, require the qualifying facility to submit an interconnection plan in order to facilitate interconnection arrangements. If such a plan is required, it shall include no more than:

1. Technical specifications of equipment;

2. Proposed date of interconnection; and

3. Projection of net output or consumption by the qualifying facility when available.

Some owners and manufacturers of small qualifying facilities have maintained that there is no need to inform the utility that a small qualifying facility is coming on line. In their view, the physical effect of a small generator beginning to feed into the distribution system is the same as the effect felt when an electric motor of the same size is shut off. One is not required to tell the utility about the disposal of an appliance with an electric motor, so there should be no requirement to inform the utility about the acquisition of a small qualifying facility. These owners and manufacturers also admit to a revenue effect on the utility: as the qualifying facility generator takes part of the customer's load from the utility, the customer's bill and utility revenues fall. They argue that a person who replaces an electric water heater with a solar water heater causes the same effect, and does not have to inform the utility.

The Commission has considered these arguments, and has decided that the utility may require an interconnection plan. There are a number of reasons why the Commission believes this section of the proposed rule is necessary and reasonable. First, although the effects of very small qualifying facilities on the utility's system may be very small, these rules cover interconnections with qualifying facilities of all sizes. Interconnection with some of these will certainly require substantial modification of distribution systems, and perhaps transmission systems as well, and these modifications should be planned for. Second, as discussed above, the Commission has determined that it is both necessary and reasonable to collect data which is not available when a single meter runs both forward and backward. Consequently, the utility, which is responsible for gathering the information, must be told in advance that the interconnection will take place. The utility also needs to know the nature of the qualifying facility to anticipate its interconnection requirements. Finally, the Commission believes there is a fundamental difference between a retail utility customer and a qualifying facility which necessitates that the utility be informed in advance. That difference is that the qualifying facility injects power into the utility's system; the retail customer does not. Because the utility is responsible for providing power of a certain quality from its system to its users on demand, it has a legitimate need to know when someone other than itself is energizing its system.

This section of the proposed rule is reasonable as well as necessary. The interconnection plan which may be required is simple and straightforward, and will not be an undue burden on qualifying facilities. At the same time, it will provide the utility with the information it will need to arrange the interconnection smoothly.

4 MCAR § 3.0455 Rates for sales.

A. Rates to be governed by tariff. Except as otherwise provided in B., rates for sales to a qualifying facility shall be governed by the applicable tariff for the class of electric utility customers to which the qualifying facility would belong were it not a qualifying facility.

This section requires utilities to sell electricity to qualifying facilities under standard retail tariffs. It is necessary to assure qualifying facilities that the Commission, not the utility, will set the rates for their purchases. It is reasonable in that it assures both qualifying facilities and other utility customers that neither group will be discriminated against relative to the other. It is also consistent with 18 CFR § 292.305 (a) (ii).

B. Petition for specific rates. Any qualifying facility may petition the Commission for establishment of specific rates for supplementary, maintenance, backup, or interruptible power.

This section enables any qualifying facility to petition the Commission to establish specific rates for supplementary, maintenance, interruptible, or backup power. It is necessary to establish a mechanism to develop rates for these types of power, which the utility must offer, on request, under 4 MCAR § 304.54 H. It is reasonable in that the initiative remains with the qualifying facility and in that the determination of an appropriate rate by the Commission need not necessarily await a general rate case for the utility.

4 MCAR § 3.0456 Standard rates for purchases.

A. General. For qualifying facilities with capacity of 100 kilowatts or less, standard rates apply. Qualifying facilities with capacity of more than 100 kilowatts may negotiate contracts with the utility or may be compensated under standard rates if they make commitments to provide firm electric power. The utility shall make available three types of standard rates, described in B., C., and D. The qualifying facility shall choose interconnection under one of these rates, and shall specify its choice in the written contract required in 4 MCAR § 3.0454 B. Any net credit to the qualifying facility shall, at its option, be credited to its account with the utility or returned by check within 15 days of the billing date. The option chosen shall be specified in the written contract required in 4 MCAR § 3.0454 B. Qualifying facilities remain responsible for any monthly service charges and demand charges specified in the tariff under which they consume electricity from the utility.

18 CFR § 292.304 (c) provides that standard rates will apply for qualifying facilities with capacity of 100 kilowatts or less. This will eliminate the administrative burden that would exist if all rates were negotiated separately. Furthermore, this will insure that rates for purchase are made available on a nondiscriminatory basis to all qualifying facilities selling to a particular utility. The existence of a simple standardized rate schedule for purchases of energy by utilities will serve to encourage cogeneration and small power production by making relevant information available to potential qualifying facilities.

Qualifying facilities with capacity of more than 100 kilowatts may negotiate contracts with the utility. This will allow the special circumstances of a large qualifying facility to be taken into account when rates for purchase are determined. This will not be unreasonably burdensome to the utilities because it can be expected that there will be a relatively smaller number of those types of qualifying facilities.

The standard rates may be considered a floor price for qualifying facilities with capacity of more than 100 kilowatts provided they make commitments to provide firm electric power. In this sense, large qualifying facilities will be treated the same as smaller qualifying facilities. The requirement that large qualifying facilities provide firm electric power is necessary because the likelihood of diversity of load among large qualifying facilities is lower than the likelihood of diversity among smaller qualifying facilities. In addition, there would be a larger negative impact upon the utilities if the larger qualifying facility did not provide firm power (or a group of large qualifying facilities did not provide firm power, on average, after considering diversity) than if smaller qualifying facilities (taken as a whole with recognition of diversity) did not provide firm power because of the absolute size of the facilities.

It is necessary that the qualifying facility specify its choice of one of the three types of standard rates in the written contract to insure clear communication between the parties involved. It is necessary that compensation to the qualifying facility be made either through a credit to its account with the utility or through direct payment by check. It is reasonable for the qualifying facility to have the option to choose the method of compensation since the qualifying facility is, in effect, the seller of electricity and it is common business practice that the seller prescribe the terms of sale. It is desirable that both parties have a clear understanding of the chosen arrangement. Thus, it is reasonable that the option chosen be specified in the written agreement.

Finally, this section proposes that qualifying facilities continue to pay any monthly service charges and demand charges specified in the tariff under which they purchase electricity from the utility. This provision implements part of M.S. § 216B.164, subd. 8. It is a reasonable requirement because these fixed charges are designed to recover all or part of those costs of providing service which do not vary with the consumption of electricity, and which may not be avoided through the generation of electricity by the qualifying facility. If the qualifying facility were not required to pay these charges, the costs would have to be borne by the utility's other ratepayers through higher utility rates. This result would violate the Commission's mandate from the Legislature that cogeneration and small power production be encouraged consistent with protection of the ratepayers.

B. Net energy billing rate.

1. The net energy billing rate is available only to qualifying facilities with capacity of 40 kilowatts or less which choose not to offer electric power for sale on a time-of-day basis.

M.S. § 216B.164 provides that net energy billing be available to qualifying facilities with capacity of 40 kilowatts or less. This section of the proposed rule does just that. In addition, this section restricts availability of the net energy option to customers not choosing to sell power on a time-of-day basis. The net energy billing option is designed for smaller scale cogeneration and small power production that wish to minimize their metering costs and sell as much energy as can be efficiently produced. On the other hand, the purpose of the time-of-day option, which is discussed in a following section of this statement, is to encourage cogenerators and small power producers to provide substantial amounts of on-peak power. However, the time-of-day option requires much more expensive metering which should be paid for by the qualifying facility. A large amount of on-peak power relative to off-peak power would have to be generated by the qualifying facility in order to pay for the more expensive metering. Since it is the Commission's purpose to only encourage cost-effective applications of the time-of-day purchase rates, this provision is efficacious.

2. The utility shall bill the qualifying facility for the excess of energy supplied by the utility above energy supplied by the qualifying facility during each billing period according to the utility's applicable retail rate schedule.

This section is necessary in order to implement M.S. § 217B.164, subd. 4 which states the following:

> "For qualifying facilities having less than 40 kilowatts capacity, the customer shall be billed for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer."

This provision is reasonable because it treats qualifying facilities in the same way that it treats the utility's other customers.

3. When the energy generated by the qualifying facility exceeds that supplied by the utility during a billing period, the utility shall compensate the qualifying facility for the excess energy under a. or b.

a. For a qualifying facility with capacity of 20 kilowatts or less, compensation shall be at the energy rate of the rate schedule applicable to sales to the qualifying facility. If the rate schedule consists of more than one block, the lowest per kilowatt-hour rate shall apply. The compensation shall reflect changes to the energy rate due to the operation of the utility's fuel adjustment clause.

This section of the proposed rule provides that payments for excess energy delivered to the utility by a net energy billed qualifying facility of 20 kilowatts or less shall be at the energy rate of the utility's retail rate schedule for serving the facility. If the utility charges its customers 5¢ per kilowatt-hour on that schedule, the utility would pay 5¢ per kilowatt-hour for energy delivered by the qualifying facility in excess of energy offsetting the qualifying facility's consumption from the utility. This section also provides that if the utility has a blocked rate schedule (a fixed number of kilowatt-hours at one rate, more at a different rate), the lowest priced block shall apply.

It is necessary for the Commission to set the rates for payments to net energy billed qualifying facilities. M.S. § 216B.164, subd. 3, establishes net energy billing for qualifying facilities of less than 40 kilowatts. It includes this language:

> In the case of net input into the utility system by the qualifying facility, compensation to the customer shall be at a per kilowatt-hour rate set by the Commission. In setting these rates, the Commission shall consider the fixed distribution costs to the utility not otherwise accounted for in the basic monthly charge and shall ensure that the costs charged to the qualifying facility are not discriminatory in relation to the costs charged to other customers of the utility. Notwithstanding any other language to the contrary in this section, the Commission shall set the rates for net input into the utility system based on avoided costs as defined in 18 C.F.R. Section 292.101 (b)(6), the factors listed in 18 C.F.R. Section 292.304, and all other relevant factors.

It is clear that the Commission must set the rates, that the rates must have a basis in avoided costs, and that the Commission must consider the utility's fixed distribution costs both with respect to the monthly fixed charge and with respect to the utility's other customers. In this statement, the Commission will first discuss fixed distribution costs and will then explain the avoided cost basis of its proposal.

The costs of providing electric utility service are often assigned to one of three categories: customer related costs, demand related costs, and energy related costs. Customer related costs vary not with usage, but with the number of customers on the system. The costs of meters, meter reading, and billing are usually classified as customer related costs. Demand related costs are costs which vary with the rate at which energy is consumed, and they are important both at the individual customer level, and across the whole system. Electric utility systems must be designed to meet maximum demands of individual customers as well as the maximum demand of the entire system (system peak). Energy related costs vary with the amount of energy consumed. In the short run, energy related costs tend to be variable, while demand and customer related costs are relatively fixed.

Rate schedules for residential consumption typically establish a two-part rate: a fixed monthly charge and one or more energy block rates. Under these schedules, a customer's bill is computed by multiplying his consumption by the energy rate and adding the fixed charge.

Often the fixed charge does not cover the full amount of the average fixed costs (demand and customer related) allocated to residential customers. When this is the case, the energy charge is raised from where it otherwise would be, so that the utility can collect its total costs. Sometimes this is done only in the initial block or blocks of consumption. The result is the familiar "declining block" rate structure, in which the charge for consuming an additional kilowatt-hour declines as consumption increases beyond set levels. In other cases, the rates are designed such that the energy charge per kilowatt-hour is constant at all levels of consumption.

In the short run, generation by qualifying facilities enables utilities to avoid energy related variable costs, but not customer related and demand related fixed costs. As has been discussed above, state law and these proposed rules require qualifying facilities to pay any monthly fixed charges which are assessed to similar nongenerating customers.

The Commission has considered "the fixed distribution costs to the utility not otherwise accounted for in the basic monthly charge." The Commission believes that if this were its only requirement it would be reasonable in many cases to assess qualifying facilities an additional fixed charge to recover fixed distribution costs which other customers pay through consumption of energy at elevated energy rates. However, the Commission must also "ensure that the costs charged to the qualifying facility are not also discriminatory in relation to the costs charged to other customers of the utility." If a nongenerating customer reduces his consumption to zero, he must pay only the monthly fixed charges. Consequently, the Commission believes it would be discriminatory to require a qualifying facility to pay more than the standard monthly fixed charge.

The analysis above does show that if compensation for energy provided by a qualifying facility is to be at the retail energy rate, the lowest priced block in a blocked rate is the appropriate rate to choose. That lowest priced block is most closely related to costs the utility can avoid.

The Commission believes that it is appropriate to set the rate for net deliveries to the utility by this group of qualifying facilities at the retail energy rate. The Commission has reached this belief after consideration of a number of factors.

One of the factors was the level of retail rates relative to avoided cost rates. In most cases, the Commission anticipates retail rates will be higher than rates set at full avoided energy and capacity costs as calculated elsewhere in these rules. This is primarily because utilities cannot avoid all their costs, but their retail rates must collect enough revenues to cover total costs. The discussion above pointed out that utilities do not avoid fixed transmission and distribution costs. Some utilities also have costs like those associated with energy audits under the Minnesota Energy Conservation Service program which are not avoidable but which are recovered through retail rates.

While the Commission anticipates that the retail rate will in most cases be higher than the avoided cost rates calculated elsewhere in these rules, the Commission cannot be certain that the retail rate will be higher than the sum of the actual avoided cost of the utility and the external costs (e.g., acid rain caused by coal fired power plants) to the public. Although the Commission has attempted to balance the interests of qualifying facilities, utilities, ratepayers, and the general public with great care in developing the avoided cost calculation, that calculation is not perfect. One reason for this is that the Commission's calculated avoided cost rates excludes external costs. Since external costs are, by their very nature, unquantifiable, it is not appropriate to explicitly take them into account in the calculation of avoided cost based rates. Nevertheless, the Commission believes that it is appropriate to take them into account in a judgemental way when setting purchase rates for qualifying facilities with capacity of less than 20 kilowatts. It is possible, therefore, that the retail rate may approximate avoided costs for these smaller facilities.

A related consideration taken into account in developing these proposed rules was the unquantifiable nature of some of the factors the Commission was directed to weigh. Examples of these are the aggregate value of capacity from qualifying facilities on the utility system, and the smaller capacity increments and shorter lead times available with additions of capacity from qualifying facilities. These both serve to increase the value of qualifying facilities, and are particularly applicable to the smaller facilities under discussion here. Yet neither lends itself to quantification in an avoided cost calculation.

A third factor the Commission considered was the advantage in simplicity and customer understandability of using retail rates instead of the avoided cost calculation. The retail rate is a readily available number which the potential owner of a qualifying facility can use to determine the feasibility of an investment without having to work through the complexities of the avoided cost calculation. Thus the use of the retail rate should encourage cogeneration and small power production by these small facilities, which are likely to be less sophisticated than larger facilities.

The Commission's fourth consideration was the effect of this proposal on the development and small power production throughout the state. Each utility has its own cost structure and its own plan for generation expansion. Consequently, there is great variation in the avoided costs of Minnesota utilities. This could lead to encouragement of cogeneration and small power production in some areas, and discouragement in others. Larger facilities may be able to wheel (transmit) power to other utilities, and thereby get around this problem, but small facilities are essentially limited to the utility to which they are interconnected. Use of retail rates should encourage more balanced development, and provide reasonably similar incentives to potential owners of qualifying facilities throughout the state.

Finally, the Commission considered legislative intent. In February of 1981, the Commission published and gave wide distribution to a proposed rule concerning cogeneration and small power production. In that document the Commission proposed to compensate small qualifying facilities for net deliveries at retail rates. That proposal was well known to House and Senate sponsors of H.F. 473, the bill which eventually was enacted as M.S. § 216B.164. The Commission received generally favorable comments on the proposed rule from those legislators. Representative Earl Hauge, chief House author of the bill wrote, "I think your proposed rules are excellent and will implement the intent of H.F. 473 and the PURPA regulations." Senator Gregory Dahl wrote:

> I want to emphasize at the outset that I did not author the cogeneration and small power production legislation because I was dissatisfied with the Commission's actions in this area previously. Quite to the contrary. The Commission is to be strongly commended for the admirable job it has done in implementing PURPA 210 and the FERC rules in the face of a myriad of novel and complex issues.
>
> Nearly all legislators supporting enactment of H.F. 473 were strong supporters of the Commission's proposed rule (although some wished higher purchase rates for small power production) and wanted to ensure that the Commission's rule and jurisdiction in this area would apply statewide, rather than merely to investor-owned utilities. Accordingly, in assessing the impact of H.F. 473 as enacted on the Commission's previously proposed cogeneration and small production rule, the Commission should keep in central focus that the Legislature's intent with this legislation was not to displace the Commission's proposed rule, but rather to expand and supplement the Commission's power to act in this area.

In light of these considerations, the Commission asserts that its proposal to compensate qualifying facilities of 20 kilowatts or less for energy delivered to the utility in excess of their consumption at the energy component of the retail rate is both necessary and reasonable.

Finally, it is necessary that the rates for purchase reflect changes to the energy rate due to the operation of the utility's fuel adjustment clause because as the utility's cost of fuel increases, its avoided cost will also increase. This is a convenient and reasonable way to track changes in avoided costs from year to year and month to month.

b. For a qualifying facility with capacity of more than 20 kilowatts but not greater than 40 kilowatts, compensation shall be a specified under C.3.

This part of the proposed rule sets payment for excess energy deliveries of net energy billed qualifying facilities larger than 20 kilowatts at full avoided energy and capacity costs, as calculated through application of these rules.

The Commission believes it is necessary and reasonable to distinguish between smaller and larger net energy billed qualifying facilities. Such a distinction results in a more equitable balance between encouragement of cogeneration and small power production and protection of ratepayers.

In its discussion in the previous section, the Commission observed that retail rates may approximate avoided costs, particularly when externalities and unquantifiable concepts are taken into account. The Commission nevertheless thinks that its calculation of avoided cost is in most cases a better approximation of real avoided costs. The Commission also thinks the conditions which make the retail rate appropriate for qualifying facilities of 20 kilowatts or less do not apply to larger units.

If rates were set precisely at avoided costs, rates paid by utility customers would always be the same whether the utility purchased from qualifying facilities or generated all of its own electricity. If rates were set below avoided costs, ratepayers would probably be somewhat better off if the utility purchased from qualifying facilities. On the other hand, if rates for purchases from qualifying facilities were set above avoided cost, rates paid by utility customers would be higher with purchases from qualifying facilities. The ideal balance of encouraging cogeneration and small power production consistent with protection of ratepayers is achieved by setting rates equal to avoided costs.

Unfortunately, it is not possible to set rates precisely equal to avoided costs. The best that can be done is to approximate avoided costs. In developing its avoided cost calculation, the Commission has exerted every effort to achieve a reasonable approximation of real avoided costs. Nevertheless, judgments had to be made, and in exercising its judgement the Commission preferred to err on the side of encouraging cogeneration and small power production. To that extent, it is reasonable to expect one result of implementation of these rules to be a tendency to push utility rates slightly higher than they otherwise would be. This result will be tolerable if, as expected, the increase is very small, and cogeneration and small power production lead to expected benefits to the general public.

If the analysis above is correct, and the calculated avoided costs are in fact above the real avoided costs, by however small a margin, then it follows that purchase rates equal to retail rates, which are above calculated avoided costs, are also above real avoided costs, and by a greater margin. Compensating qualifying facilities at the retail rate thus presents a greater risk to the ratepayer than compensating them at calculated avoided costs.

The Commission believes that the increased risk is justified when the qualifying facility is 20 kilowatts or less, but not when it is larger. A 20 kilowatt generator is the largest unit which would reasonably be installed to simply replace utility power with self-generated power for the typical residential or farm customer. Any larger unit would be installed by one of these customers for the purpose of making net sales to the utility.

When the unit is installed simply to offset consumption from the utility, net deliveries to the utility will presumably be both random and small. Under these conditions, the Commission believes the additional risk and possible cost to the ratepayers will be kept under reasonable bounds, and will be justified by the additional encouragement given to cogeneration and small power production.

When the unit is installed to make net sales to the utility, however, the possible cost to the ratepayer increases substantially. Under these conditions, the Commission believes the better balance is struck by paying the larger qualifying facility at the calculated avoided cost rate. The cutoff level of 20 kilowatts is reasonable because that is the largest unit which would reasonably be installed simply to meet the individual needs of a typical residential or farm consumer.

C. Simultaneous purchase and sale billing rate.

1. The simultaneous purchase and sale rate is available only to qualifying facilities with capacity of 40 kilowatts or less which choose not to offer electric power for sale on a time-of-day basis.

The Commission believes it is necessary to allow a qualifying facility to sell all its output to a utility and at the same time purchase all its needs from the utility in order to encourage cogeneration and small power production. If purchase rates, as calculated under this rule and based on avoided costs, are greater than retail rates, this provision will encourage potential qualifying facilities to deliver energy to the system. Without this provision the maximum compensation to the qualifying facility for the initial kilowatt-hours generated would be the retail rate and consequently, because the purchased rates were greater than the retail rate, the qualifying facility would be compensated at a rate below the utility's avoided cost.

All qualifying facilities with capacity of greater than 40 kilowatts are covered in later sections of the proposed rule. Also, any qualifying facility of 40 kilowatts or less may choose to sell power on a time-of-day basis or on a net energy basis. Such a qualifying facility would not be covered under this section. The purpose of this section of the proposed rule is to simply describe which qualifying facilities are covered under this section.

2. The qualifying facility shall be billed for all energy and capacity it consumes during a billing period according to the utility's applicable retail rate schedule.

3. The utility shall purchase all energy generated by the qualifying facility. Compensation to the qualifying facility shall be the sum of a. and b.

a. The energy component shall be the appropriate system average incremental energy costs shown on Schedule A; or if the purchasing utility is nongenerating, the energy rate shown on Schedule G;

b. The capacity component shall be the utility's net annual avoided capacity cost per kilowatt-hour averaged over all hours as calculated according to 4 MCAR § 2.0452 C.4 or C.5. as appropriate; or if the purchasing utility is nongenerating, the capacity component shall be the capacity cost per kilowatt shown on Schedule G, divided by the number of hours in the billing period.

Qualifying facilities choosing to sell power under the simultaneous purchase and sale billing rate agree to consider their purchases and sales as separate economic transactions. These sections provide that purchases of energy and capacity by the qualifying facility shall be billed according to the utility's applicable retail rate schedule, just as all other customers of the utility are treated. By the same token all purchases of energy by the utility shall be set at appropriate rates, based upon the calculated avoided costs of the utility. It is necessary and reasonable to give qualifying facilities this purchase/sale option. In the event that avoided cost rates are higher than the applicable retail rate this option would compensate the qualifying facility based upon the utility's avoided cost. The qualifying facility would be paid less than avoided cost under this condition if it did not have this option and sold power on the basis of net energy billing. Because M.S. § 216B.164 requires that the purchase rates be based upon avoided cost, it is both necessary and reasonable that this option be provided.

The sum of paragraphs (a) and (b) is the utility's calculated avoided energy and avoided capacity costs per kilowatt hour averaged over the on-peak and off-peak periods. This section simply directs the utility to sum the avoided energy and avoided capacity costs pertaining to either generating or nongenerating utilities as calculated in an earlier section of the proposed rule to determine the appropriate purchase rate. It was shown earlier in this statement that those amounts are appropriate estimates of the utility's avoided energy and avoided capacity costs. Since the utility avoids both energy related costs and capacity related costs this section is necessary and reasonable if the qualifying facilities are to be compensated at avoided cost, as required by state law.

D. Time-of-day purchase rates.

1. Time-of-day rates are required for qualifying facilities with capacity greater than 40 kilowatts and less than or equal to 100 kilowatts, and they are optional for qualifying facilities with capacity less than or equal to 40 kilowatts. Time-of-day rates are also optional for qualifying facilities with capacity greater than 100 kilowatts if these qualifying facilities provide firm electric power.

Purchase or buy back rates based upon the time-of-day of energy deliveries have several advantages over non-time differentiated rates. First, since the utilities' incurred costs vary by the time of day so do the utilities' avoided costs vary by the time of day. In short, a kilowatt-hour delivered to a utility during on-peak hours is more valuable than a kilowatt-hour delivered during off-peak hours because it is more expensive for the utility to generate electricity in the on-peak hours. Consequently, the utility's avoided costs are higher in the on-peak period than in off-peak periods and so to the extent that purchase rates are based upon time-of-day energy deliveries those purchase rates will be more accurate estimates of the utility's avoided costs.

In addition, purchase rates based upon the time of day of energy deliveries will give qualifying facilities appropriate incentives to deliver as much on-peak energy as is economically possible. Under this pricing scheme, the qualifying facilities will be paid higher rates for on-peak energy deliveries and so they are likely to deliver more energy during on-peak hours than they otherwise would.

The disadvantage of time-of-day purchase rates is the higher metering cost that will be incurred in order to implement this method of pricing. The qualifying facility will have to finance a time-of-day meter. These meters are more expensive than standard watt-hour meters. The cost of these meters is the reason that time-of-day purchase rates are not being implemented on a mandatory basis for qualifying facilities with capacity of less than 40 kilowatts.

It is the Commission's judgement that 40 kilowatts is an appropriate and reasonable cutoff point for the implementation of mandatory time-of-day purchase rates. Clearly, at some point the advantages previously discussed begin to outweigh the disadvantage of slightly higher metering costs. It is likely that the 40 kilowatt level is a conservative estimate of this balancing point and hence is a reasonable level.

An example may illustrate the appropriateness of the chosen cutoff level. Assume the following:

1. The standard purchase rate is 3¢/kwh.
2. The on-peak purchase rate is 4¢/kwh.
3. The off-peak purchase rate is 2¢/kwh.
4. 50% of all hours are on-peak and 50% are off-peak hours.
5. $4.60/month is a reasonable estimate of the monthly carrying cost of one time-of-day meter (this is the fixed monthly charge which Northern States Power Company bills its General Service Time-of-Day customers).

Given these assumptions, a qualifying facility with generating capacity of 40 kilowatts and an average monthly load factor of 80 percent would generate (40 kwh x 720 hours x .8 = 23,040 kwh) 23,040 kilowatt-hours in one month. If we further assume that such a qualifying facility would respond to time-of-day purchase rates by shifting some production of energy from off-peak to on-peak hours the benefit to the qualifying facility can be measured. If, after the switch, the qualifying facility generated energy at 100% of capacity on-peak and at 60% of capacity off-peak, a comparison of the before and after payments is as follows:

<u>Payment under standard rate</u>

23,040 kwh x 3.0¢ = $691.20

<u>Payment under time-of-day rate</u>

on-peak kwh = 40 kw x 360 hours x 1.0 = 14,400
off-peak kwh = 40 kw x 360 hours x .6 = 8,640
on-peak: 14,400 kwh x 4.0¢ = $576.00
8,640 kwh x 2.0¢ = 172.80
23,040 $748.80

payment under time-of-day rate = $748.80
payment under standard rate = 691.20
difference (per month) $ 57.60
less: monthly cost of one time-of-day meter 4.60
net gain to qualifying facility $ 53.00

This example shows that it would be cost effective for a qualifying facility with the operating characteristics shown to sell energy on a time-of-day basis.

For the above reasons the proposed rule would be effective at encouraging cogeneration and small power production and would more accurately compensate qualifying facilities for the utilities' avoided costs. Consequently, this section of the proposed rule is both necessary and reasonable.

It is necesssary and reasonable that the 40 kilowatt limit be applied in a mandatory fashion so that qualifying facilities will be compensated appropriately and given the proper production incentives. This will not place an unreasonable burden on these qualifying facilities. At the same time, it is reasonable that any qualifying facilities with capacity less than 40 kilowatts that are willing to pay the additional metering costs should be allowed to sell energy on a time-of-day basis.

In addition, it is necessary and reasonable that qualifying facilities with capacity greater than 100 kilowatts also have the option to sell energy on a time-of-day basis to insure that these qualifying facilities are not treated unfairly in comparison with other qualifying facilities. At the same time, however, it is necessary to make eligibility for this rate conditional upon the delivery of firm power to protect the financial condition of the utility and to protect the utility's ratepayers. The protection of the utility and its ratepayers is a serious concern when considering the rate for purchase applicable to qualifying facilities with capacity greater than 100 kilowatts because these qualifying facilities may not necessarily be generating during the utility's peak load hours whereas a large number of smaller qualifying facilities will on average be generating a consistent proportion of energy during those peak hours. Therefore, due to this potential lack of diversity, the utility may need some guarantee that the qualifying facility with capacity greater than 100 kilowatts will provide firm power during peak hours in order to meet the utility's peak demand.

2. The qualifying facility may be billed for all energy and capacity it consumes during such billing period according to the utility's applicable retail rate schedule. Any utility rate-regulated by the Commission may propose time-of-day retail rate tariffs which require qualifying facilities that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis.

This section of the proposed rule requires that the qualifying facility will not be billed on a net energy basis if it chooses to sell power on a time-of-day basis. Any appropriately sized qualifying facility wishing to sell energy on a net energy basis may do so under 4 MCAR § 3.0456 (B) so it is unnecessary to duplicate that option here. Further, since the qualifying facility shall be billed according to the retail rate schedule it will be treated in a nondiscriminatory fashion, compared to the utility's other ratepayers.

If it were not for the high cost of metering, it is safe to assume that most utility rates would be based upon time-of-day, i.e., time-of-day rates would be the standard instead of the exception. This proposed rule provides that if a qualifying facility has time-of-day metering installed and if the utility to which the qualifying facility is connected is rate regulated by this Commission, the utility may petition to require the qualifying facility to buy energy as well as sell energy on a time-of-day basis. This is necessary and reasonable because it will allow the utility to more appropriately price the electric service to the qualifying facility. At the same time, the qualifying facility's interests will be protected by representation before the Commission.

3. The utility shall purchase all energy generated by the qualifying facility. Compensation to the qualifying facility shall be the sum of a. and b.

a. The energy component shall be the appropriate on-peak and off-peak system incremental costs shown on Schedule A; or if the purchasing utility is nongenerating, the energy rate shown on Schedule G.

b. The capacity component shall be the utility's net annual avoided capacity cost per kilowatt-hour averaged over the on-peak hours as calculated according to 4 MCAR § 3.0452 C.4. or C.5. as appropriate; or if the purchasing utility is nongenerating, the capacity cost per kilowatt shown on Schedule G, divided by the number of hours in the billing period.

There is a typographical error in the proposed rule. It should read:

> "The capacity component shall be the utility's net annual avoided capacity cost per kilowatt-hour averaged over the on-peak hours as calculated according to 4 MCAR § 2.0452 C.4. or C.5. as appropriate; or if the purchasing utility is nongenerating, the capacity cost per kilowatt shown on Schedule G, divided by the number of on-peak hours in the billing period."

With this change, the qualifying facilities will be appropriately compensated based upon the time-of-day of their energy deliveries.

This section of the proposed rule is identical to Section C.3. and it is necessary and reasonable for the same reasons stated in the applicable Section of this statement.

4 MCAR § 3.0457 Negotiated rate for purchases.

A. Contracts negotiated by customer. For qualifying facilities with capacity greater than 100 kilowatts, the customer may negotiate a contract with the utility. The contract shall set the applicable rates for payments to the customer of avoided capacity and energy costs.

Under the FERC regulations (18 CFR § 292.304 (c)), utilities must offer to purchase from qualifying facilities of 100 kilowatts or less on the basis of standard rates. There are several advantages to using established standard rates. Among the advantages are the assurance of non-discriminatory treatment, the ability to plan construction and interconnection of a qualifying facility more easily because rates, terms, and conditions already exist, and a reduced administrative burden on both the qualifying facility and the utility. These advantages make standard rates particularly appealing for smaller qualifying facilities.

There are nevertheless disadvantages to standard rates. When all are treated alike, individual differences are not taken into account. One qualifying facility may employ a unique technology or operating practice which is particularly suited to helping its interconnected utility to avoid costs. If the qualifying facility is interconnected under standard rates, it may lose payment for some of those avoided costs. Worse, the standard rates may operate to deter development of such technologies or practices.

The inability to account for special circumstances becomes a greater disadvantage as the capacity of the qualifying facility increases. Also, because more resources are invested in the qualifying facility and its effects on the utility are greater, it becomes more cost effective to devote administrative efforts towards addressing challenges and opportunities involved as the capacity of the qualifying facility increases.

The FERC recognized these phenomena in requiring standard rates for qualifying facilities of 100 kilowatts and under, and making them an option above that capacity. The Commission also believes that recognition is necessary and reasonable.

B. Amount of payments; considerations. The amount of such payments shall be determined through consideration of:

1. The capacity factor of the qualifying facility;

2. The cost of the utility's avoidable capacity;

3. The length of the contract term;

4. Reasonable scheduling of maintenance;

5. The willingness and ability of the qualifying facility to provide firm power during system emergencies;

6. The willingness and ability of the qualifying facility to allow the utility to dispatch its generated energy;

7. The willingness and ability of the qualifying facility to provide firm capacity during system peaks;

8. The sanctions for noncompliance with any contract term; and

9. The smaller capacity increments and the shorter lead times available when capacity is added from qualifying facilities.

A number of factors may offset the costs avoided by the utility as a result of the qualifying facility's energy output. It is necessary and reasonable that each of these factors is listed in the proposed rule to insure that these relevant factors are considered by the parties in their negotiation. Each of the factors affects either the amount of capacity, in kilowatts, which the qualifying facility causes the utility to avoid or they affect the cost, per kilowatt, of the capacity avoided due to the delivery of power by the qualifying facility. The capacity factor of the qualifying facility, the length of the contract term, the scheduling of maintenance, the willingness and ability of the qualifying facility to provide firm power or capacity during system emergencies or system peaks and its willingness to allow the utility to dispatch its generated energy are all factors which, together with the rates capacity of the qualifying facility, may determine the amount of capacity, measured in kilowatts, which the qualifying facility is causing the utility to avoid. Obviously, the cost of the utility's avoidable capacity is the cost, per kilowatt, of the capacity avoided due to the delivery of power by the qualifying facility. Any sanctions for noncompliance with contract terms and the smaller capacity increments and the shorter lead times available when capacity is added from qualifying facilities are factors which may affect, in a general sense, the costs which a qualifying facility causes the utility to avoid.

C. Full avoided energy costs. The qualifying facility shall be entitled to the full avoided energy costs of the utility. The costs shall be adjusted as appropriate to reflect line losses.

The energy output from the qualifying facility with capacity greater than 100 kilowatts will cause the utility to avoid incremental energy costs in the same way that the output from smaller qualifying facilities cause the utility to avoid energy costs. Consequently, in order to base purchase rates on avoided cost it is necessary and reasonable to insure that qualifying facilities are compensated for the full avoided energy costs adjusted for line losses as described earlier in this statement.

D. Qualifying facilities of greater than 100 kilowatts. Nothing in A.-C. prevents a utility from connecting qualifying facilities of greater than 100 kilowatts under its standard rates.

Upon mutual agreement of the qualifying facility and a utility, a utility may simply connect the qualifying facility according to the standard rates applicable to all other customers. However, since these qualifying facilities have capacity of greater than 40 kilowatts (in fact greater than 100 kilowatts) the only standard rate to which these qualifying facilities would be eligible is the time-of-day rate tariff. This provision is necessary and reasonable since it simply allows one possible outcome of the negotiation process (the connection of the qualifying facility at standard rates) to occur.

4 MCAR § 3.0458 Utility treatment of costs. All purchases from qualifying facilities with capacity of 100 kilowatts or less, and purchases of energy from qualifying facilities with capacity of over 100 kilowatts shall be considered an energy cost in calculating an electric utility's fuel adjustment clause.

This rule is needed to insure that utility purchases of electricity from qualifying facilities are properly accounted for. It is reasonable in that it flows these costs through to ratepayers in the same manner that costs of purchases from other energy suppliers (i.e., other utilities) are flowed through via Minn. Reg. PSC 392.

4 MCAR § 3.0459 Wheeling and exchange agreements. For all qualifying facilities with capacity of 30 kilowatts or greater, the utility shall, at the qualifying facility's request or with its consent, provide wheeling or exchange agreements whenever practicable to sell the qualifying facility's output to any other Minnesota utility that anticipates or plans generation expansion in the ensuing ten years. The following provisions apply unless the qualifying facility and the utility to which it is interconnected agree otherwise.

Wheeling is simply the transmission of electric power from one utility to another. M.S. § 216B.164, subd. 4(c), requires the utility to wheel a qualifying facility's output to another utility if the qualifying facility requests such wheeling, provided that the qualifying facility is at least 30 kilowatts and provided that the wheeling is practicable.

This rule is needed to encourage cogeneration and small power production throughout the state. Because electric utilities have exclusive franchises to serve in particular areas, most potential cogenerators and small power producers can interconnect with just one utility. Different utilities, though, have different cost structures and different load growth expectations. In theory, a utility with no plans to build or purchase capacity for at least 10 years has no avoidable capacity costs. Because utilities are required to pay only their full avoided costs, payments to qualifying facilities from this utility would be correspondingly less than payments from a utility with a great deal of generation expansion planned, and hence large avoidable capacity costs. The wheeling provision enables the qualifying facility to sell to whatever utility is offering the best price, no matter where the utility is located in Minnesota, as long as wheeling is practicable. Looked at from another angle, the wheeling provision encourages power produced from cogenerators and small power producers throughout the state to flow to those utilities with the greatest need for it. This provision is needed to provide the greatest substitution of power produced from cogenerators and small power producers for power produced from utility central generating stations.

A. Inter-utility payment; wheeling. The utility to which the qualifying facility is interconnected shall pay any reasonable wheeling charges from other utilities arising from the sale of the qualifying facility's output.

B. Inter-utility payment; energy and capacity. Within 30 days of receipt, the utility ultimately receiving the qualifying facility's output shall pay its resulting full avoided capacity and energy costs by remittance to the utility with which the qualifying facility is interconnected.

C. Payment to qualifying facility. Within 15 days of receiving payment under B., the utility with which the qualifying facility is interconnected shall send the qualifying facility the payment it has received less the total charges it has incurred under A. and its own reasonable wheeling costs.

These sections provide a reasonable means of accomplishing the wheeling provision. The utility to which the power is wheeled pays exactly its full avoided costs. The payment is made to the utility to which the qualifying facility is interconnected. That utility pays the wheeling charges which have been incurred. It subtracts these payments and its own wheeling costs from the amount it was paid by the receiving utility. The difference is the payment to the qualifying facility. Line losses and transformation losses are automatically accounted for, since the receiving utility pays only for power delivered. The qualifying facility pays for the wheeling, as contemplated in both Minnesota law and the FERC regulations. Finally, the qualifying facility is not burdened with the necessity to deal directly with more than its own local utility.

4 MCAR § 3.0460 Disputes. In case of a dispute between an electric utility and a qualifying facility or an impasse in the negotiations between them, either party may request the Commission to determine the issue. When the Commission makes the determination, the burden of proof shall be on the utility.

The Commission has jurisdiction generally to resolve disputes between utilities and their customers under M.S. § 216B.17, and has promulgated Minn. Reg. PSC 507 and 508 to establish procedures for handling informal and formal customer complaints. This section of the proposed rules is needed to clearly indicate the Commission's ability and intent to resolve disputes over rule-related issues.

In addition, M.S. § 216B.164, subd. 5 contains essentially the same language as this section of the proposed rules. It is reasonable for the Commission to adopt the same scope of jurisdiction and burden of proof as are required by the enabling legislation.

4 MCAR § 3.0461 Notification to customers.

A. Contents of written notice. Within 60 days following each annual filing required by 4 MCAR § 3.0452, every electric utility shall furnish written notice to each of its customers:

1. That the utility is obligated to interconnect with and purchase electricity from cogenerators and small power producers;

2. That the utility is obligated to provide customer information to all interested persons free of charge upon request; and

3. That any disputes over interconnection, sales, and purchases are subject to resolution by the Commission upon complaint.

The notice shall be in language and form approved by the Commission.

B. Customer information. Each utility shall publish customer information that shall be available to all interested persons free of charge upon request. Such customer information shall include at least the following:

1. A statement of rates, terms, and conditions of interconnections;

2. A statement of technical requirements;

3. A sample contract containing the applicable terms and conditions;

4. Pertinent rate schedules;

5. The title, address, and telephone number of the department of the utility to which inquiries should be directed; and

6. The statement: "The Minnesota Public Utilities Commission is available to resolve disputes upon written request," and the address and telephone number of the Commission.

This rule imposes a duty upon the appropriate utilities to provide notice to their respective customers of:

1) the utility's obligation to interconnect with and purchase electricity from cogenerators and small power producers;

2) the utility's obligation to provide customer information concerning cogeneration and small power production to all interested persons free of charge upon request; and

3) that any disputes concerning interconnection, sales and purchases are subject to resolution by the Commission upon complaint.

This notification requirement is intended to annually inform the utility's customers of the existence of rules concerning cogeneration and small power production in addition to identifying some of the very basic provisions of the rules (i.e., utility's obligation to interconnect with and purchase from a qualifying facility).

Another important aspect of this rule is the notification portion with respect to the availability of free customer information upon request. It is the Commission's position that to effectively encourage cogeneration and small power production, the public must know that there is conveniently accessible information available for their examination and review. Such information is to be available without charge to encourage the unrestricted dissemination and the continuous flow of information to the public.

The required notice is also designed to insure that the public is aware that there is a governmental agency with the capacity to resolve disputes that may be utilized upon proper complaint procedures.

All notices are to be approved in form and content by the Commission to insure clarity and understandability.

In addition to the notice requirement, this rule also imposes an obligation on the utility to publish and make available customer information without charge. The Commission recognizes that there is a need to have customer information available for interested persons to inspect.

At a minimum, such customer information must include:

1. A statement of rates, terms and conditions of interconnection;

This information is necessary to provide accurate information from which a prospective cogenerator or small power producer may make an informed and prudent decision. Such information will allow an individual to determine the approximate cost of interconnection as well as the attending obligations and implications thereof.

2. A statement of technical requirements;

Such information is needed to allow a prospective cogenerator or small power producer to determine the appropriate technical specifications to be complied with as well as to select and install the equipment necessary for safe and proper interconnection.

3. A sample contract containing the applicable terms and conditions;

A sample of the contract is needed to allow the prospective cogenerator or small power producer to review, understand and become familiar with the obligations, duties, rights and responsibilities that may be involved by the execution of such a contract.

It is only reasonable and prudent that an individual contemplating the execution of a document be furnished with the document to become familiar with it in order to fully comprehend the implications and obligations thereof.

4. Pertinent Rate Schedules;

This information is intended to provide an accurate foundation for a cogenerator or small power producer to calculate the approximate value of actual or projected output. Such information may be invaluable to an individual contemplating interconnection as it will allow him to evaluate the economic feasibility of such a venture.

5. The title, address and telephone number of the department of the utility to which inquiries should be directed;

This provision is intended to provide a means by which a utility may be contacted to answer questions or to supply additional information. It is an attempt to enhance the flow of information and stimulate communication between potential qualifying facilities and the utilities.

6. This statement: "The Minnesota Public Utilities Commission is available to resolve disputes upon written request," and the address and telephone numbers of the Commission.

This provision is intended and is needed to provide information to any interested person concerning the availability of the Commission to assist in the resolution of any disputes that may arise in addition to providing the public with an address and telephone number by which the Commission may be contacted.

4 MCAR § 3.0462 Interconnection guidelines.

The Commission believes a rule covering interconnection guidelines is necessary to achieve two broad objectives. The first of these is to insure the reliability and safety of electric utility service; the second is to encourage cogeneration and small power production.

Electric utilities must furnish continuous reliable service to their customers - service at a fixed frequency with voltages maintained within prescribed limits. Further, their systems must be constructed and operated to be safe for their employees and the general public. Different systems may vary considerably in the physical plant and electrical characteristics employed to deliver electric service safely.

Like utility systems themselves, the generating units used by qualifying facilities may be of many different types. They will probably come in a broad range of capacities and may exhibit markedly different operating characteristics. Their effect on any particular distribution system may vary with both their location on the system and the concentration of qualifying facilities on the system.

There is a potential for problems to develop on the utility system when a utility engages in interconnected operations with a qualifying facility. Whether such problems actually occur depends on the specific electrical characteristics and capacity of the qualifying facility, its location and the concentration of such units on the utility system, the characteristics of the distribution system, and the interaction of these factors with each other. In general, interconnected operations will be successful to the extent these potential problems are anticipated and resolved.

Each of the interconnection guidelines in this proposed rule is designed to prevent one or more of the following potential problems:

1. Safety hazards resulting from a qualifying facility energizing a portion of a distribution system which has been deenergized because of an outage or to enable utility personnel to perform maintenance.

2. Improper operation of equipment installed to protect and regulate the distribution system because qualifying facilities have changed the nature of power flows on the system.

3. Damage to or improper operation of customer-owned equipment due to irregularities in frequency or voltage, or both, or due to excessive harmonics, resulting from interconnected operations with qualifying facilities.

4. Interference with communications circuits caused by excessive levels of harmonic frequencies which may be produced by some qualifying facilities.

These problems point out the need for interconnection guidelines to insure safe and reliable electric service. The Commission believes the proposed rule on interconnection guidelines is also necessary to encourage cogeneration and small power production.

The Commission notes that uncertainty concerning required interconnection equipment may deter potential qualifying facilities. If interconnection guidelines are established by rule, a great deal of uncertainty is eliminated or reduced. In turn, planning becomes simpler and feasibility calculations more accurate. Further, reasonable guidelines established by rule prevent utilities from making unreasonable demands on qualifying facilities. Utilities which did not want to encourage cogeneration and small power production might make such demands in the absence of a rule.

A. Denial of interconnection application. The utility may refuse to interconnect a qualifying facility with its power system until the qualifying facility has properly applied under 4 MCAR § 3.0454 K. and has received approval from the utility. The utility shall withhold approval only for failure to comply with applicable utility or governmental rules or laws. The utility shall be permitted to include in its contract reasonable technical connection and operating specifications for the qualifying facility.

The rule as proposed needs to have the word "without" inserted in the headnote between "interconnection" and "application."

This section is necessary in that it provides the utility with advance notice prior to interconnection. The utility and the qualifying facility may then together work out any potential problems before electricity flows and damage is done. It reasonably prohibits the utility from denying interconnection for reasons other than noncompliance with applicable laws or regulations.

B. Notification of telephone utility and cable television firm. The electric utility shall notify the appropriate telephone utility and cable television firm when a qualifying facility is to be interconnected with its system. This notification shall be as early as practicable to permit coordinated analysis and testing before interconnection, if considered necessary.

This section makes the electric utility responsible for notifying communications companies of an impending interconnection with a qualifying facility. The notification is necessary to prevent potential communications problems due to possible increases in harmonics in the utility lines. There are two reasons for the utility, rather than the qualifying facility, to take this responsibility. First, it is reasonable to minimize the administrative burden on the qualifying facility in order to encourage cogeneration and small power production. Second, the utility has had to cooperate with telephone and cable firms in the historical development of its system. This implies that coordination has already been established among the appropriate personnel. It is more efficient to make use of this established coordination than to require each qualifying facility to try to find the right people to talk to.

C. Separate distribution transformer; when required. The utility may require a separate distribution transformer for the qualifying facility if necessary either to protect the safety of employees or the public or to keep service to other customers within prescribed limits. Ordinarily, this requirement should not be necessary for an induction-type generator with a capacity of five kilowatts or less or other units with a capacity of ten kilowatts or less that utilize line-commutated inverters.

This section is necessary for two reasons. First, some installations using inverters may require a transformer to provide proper grounding for safety. Second, a separate distribution transformer may be necessary to prevent service problems such as excessive light flicker or equipment operating problems caused by voltage variations experienced by nearby utility customers. These problems may be caused by the starting, stopping, or irregular operations of a generating unit feeding into a common distribution transformer. A separate distribution transformer for the qualifying facility should largely mitigate these voltage variations. The section reasonably limits the ordinary requirement of this equipment to those units of size and operating characteristics where such problems might be expected to arise.

D. Limiting capacity of single-phase generators; when permitted. If necessary, to avoid the likelihood that a qualifying facility will cause problems with the service of other customers, the utility may limit the capacity and operating characteristics of single-phase generators in a way consistent with the utility limitations for single-phase motors. Ordinarily, single-phase generators should be limited to a capacity of ten kilowatts or less.

Utility distribution circuits are generally three-phase or single-phase. Three-phase power is more effective in supplying larger electrical loads than is single-phase. Single-phase distribution circuits are generally supplied from three-phase circuits. In a balanced three-phase circuit, each conductor, or phase, supplies approximately the same amount of power, and the voltage conditions on each phase are approximately equal. If one phase carries considerably more electrical load, or if single-phase generators connected to that phase supply considerably more power than the other two phases, then higher losses or voltage regulation problems, or both, may result.

To protect other customers from voltage and service problems, utilities have for years limited the maximum size, starting, and operating characteristics of single-phase motors which may be served from their system. Some generating units are operated as motors in starting up to reach the necessary rpm. Other single-phase generators are also expected to affect local voltage levels in the same way as single-phase motors.

This section is necessary, therefore, to protect service to other customers, just as their service is protected by limitations on motors. It is reasonable because it places no burden on qualifying facilities which are different from the burdens of similar, but nongenerating, customers.

E. Automatic isolation of generator. The utility may require that the qualifying facility have a system for automatically isolating the generator from the utility's system upon loss of the utility's supply.

This section of the proposed rule addresses another point of extremely intense controversy: disconnection of the qualifying facility from the utility when the utility line is deenergized.

The need for disconnection is acknowledged by all. Maintenance, such as restoring a line after an outage, must be carried out while the line is deenergized. The generation which comes from a qualifying facility can shock just as severely as the utility's own generation.

The utility's system is designed, through use of devices such as circuit breakers, to automatically isolate a line, or a portion of a line, from the utility's generation when a fault occurs on the line.

Utility work rules require repair crews to open and tag a manual disconnect switch on either side of the fault before beginning work on the line. In addition, the crews are supposed to ground the line on each side of the fault. Utilities have maintained that the safety of their employees requires each qualifying facility to have a manual disconnect switch which is accessible to the utility at all times and which the utility may lock open while performing maintenance.

Qualifying facilities may employ any of several different generating and interconnection technologies. Some of these require an electric signal to be present in the electric utility system in order to operate, while others will generate regardless of whether the utility system is energized.

Some owners and manufacturers of qualifying facilities which use technologies requiring input from the utility system have maintained that a lockable manual disconnect switch should not be required. Because their generator would automatically shut down on the loss of the utility signal, they say, a manual disconnect would be an unnecessary additional expense. They also object to giving the utility unlimited access to their property and ultimate control over their generator. They have recommended instead that a postive disconnect on loss of utility signal be the only feature required.

Utilities have voiced a concern that under certain conditions of load and operation of qualifying facilities on portions of a distribution system it would be possible for several facilities to excite each other and continue to energize the line even after the loss of utility power. The reponse of owners and manufacturers to this concern has been that the probability of exactly the right conditions occurring is so remote as to be completely negligible, and that without the utility's fixed frequency signal, even if the conditions did occur, generation could not continue beyond a few seconds after loss of utility power.

The Commission believes this section of the proposed rule is reasonable. If a utility requires a qualifying facility to disconnect automatically on loss of utility supply, and if the utility employee properly grounds both sides of the fault before working on it, utility personnel will not be endangered. At the same time, the qualifying facility will not be subjected to needless expense and possible utility harrassment.

F. Discontinuing parallel operation. The utility may require that the qualifying facility discontinue parallel generation operation when necessary for system safety.

This section is necessary and reasonable for the reasons given in the previous section.

G. Permitting entry. The qualifying facility shall make equipment available and permit electric and communication utility personnel to enter the property at reasonable times to test isolation and protective equipment, to evaluate the quality of power delivered to the utility's system, and to test to determine whether the qualifying facility's generating system is the source of any electric service or communication systems problems.

This section is necessary to afford the utility and affected communications companies a reasonable opportunity to assure safe and effective operations of their systems in conjunction with parallel electric generation by qualifying facilities. It reasonably limits the reasons for entry and the times at which entry may be gained. Specifically, entry may occur only during reasonable hours, and only for purposes of evaluating the qualifying facility's impact on system safety and quality of service.

H. Maintaining power output. The power output of the qualifying facility shall be maintained so that frequency and voltage are compatible with normal utility service and to not cause that service to fall outside the prescribed limits of Commission rules and other standard limitations.

I. Varying voltage levels. The qualifying facility shall be operated so that variations from acceptable voltage levels and other service-impairing disturbances do not adversely affect the service or equipment of other customers, and so that the facility does not produce undesirable levels of harmonics in the utility power supply.

These two sections establish a necessary and reasonable requirement that operations of the qualifying facility not disturb the quality of service to other customers through frequency or voltage variations or through introduction of undesirable levels of harmonics. This requirement conforms to the legislative intent that encouragement of cogeneration and small power production be consistent with protection of the ratepayers and the public.

J. Safety. The qualifying facility shall be responsible for providing protection for the installed equipment and shall adhere to all applicable national, state, and local codes. The design and configuration of certain cogeneration and small power production equipment might require an isolation transformer as part of the qualifying facility installation for safety and protection of the qualifying facility equipment.

This section is necessary to establish the location of responsibility for safety and protection of equipment owned by the qualifying facility. It reasonably places that responsibility with the qualifying facility, not the utility. It warns a potential owner of the responsibility and suggests investigation of a particular piece of equipment which may be necessary.

K. Right of appeal for excessive technical requirements. The qualifying facility has the right of appeal to the Commission when it considers individual technical requirements excessive.

The purpose of this provision is to protect the qualifying facility against unreasonable demands of the utility where such demands have the effect of discouraging cogeneration and small power production, and where such demands are not warranted to insure safety, protection of equipment, quality of service, or protection of ratepayers. This provision is necessary to carry out the legislative mandate that disputes must be determined by the Commission.

4 MCAR § 3.0463 Existing contracts. Any interconnection contracts executed between a utility and a qualifying facility before the effective date of 4 MCAR §§ 3.0450-3.0463 may, at the option of either party, be cancelled and replaced by interconnection contracts under 4 MCAR §§ 3.0450-3.0463.

The Commission is aware that qualifying facilities have begun interconnected operations with utilities around the state, and is aware that contracts have been executed between qualifying facilities and utilities in conjunction with these operations. The Commission has to date received two formal complaints (Docket No. E-002/C-82-117 and E-148/C-81-5486) concerning the terms and conditions of the contracts being offered by the utilities.

All utilities covered by the proposed rules will be required, under 4 MCAR § 3.0452 (D) to file for Commission review and approval all their standard contracts. The Commission will thus approve the form of all contracts to be executed between utilities and qualifying facilities.

The Commission believes it would be unreasonable to create, through inaction, two classes of qualifying facilities: one with unreviewed and unapproved contracts, the other with reviewed and approved contracts. The Commission has previously found that its jurisdicton extends to the provisions of contracts which were privately negotiated between an electric utility and its retail customers. Anoka Electric Cooperative, Docket No. U-75-103 (February 24, 1977). The Commission has scrutinized contractual rate provisions and abrogated provisions it has found to be unlawfully discriminatory, Minnesota Power and Light Company, Docket No. E-015/GR-76-408 (December 18, 1976), or preferential, Minnesota Power and Light Company, Docket No. E-015/GR-77-360 (February 3, 1978).

On appeal of the latter case, the St. Louis County District Court upheld the Commission's right to investigate and, after notice, to abrogate contracts. This provision of the proposed rules is necessary to provide notice to utilities and qualifying facilities that contracts drawn and executed before the effective date of the proposed rules may be replaced with a standard, approved contract under the proposed rules.

It is reasonable to permit either party to reopen a pre-rule contract, since the provisions of the standard, approved contract are as likely to work in favor of one party as the other.