

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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Chair
 Commissioner
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 Commissioner

In the Matter of Establishing Generic Standards
 for Utility Tariffs for Interconnection and
 Operation of Distributed Generation Facilities
 under Minnesota Laws 2001, Chapter 212

ISSUE DATE: September 28, 2004

DOCKET NO. E-999/CI-01-1023

ORDER ESTABLISHING STANDARDS

PROCEDURAL HISTORY

On August 1, 2001, Minnesota Statutes § 216B.1611 became effective. Subdivision 2 of that statute directs the Commission to initiate a proceeding to establish standards for the terms under which an electric utility would permit a plant with the capacity to generate up to ten megawatts (MW) of power to interconnect with the electric grid.

On August 20, 2001, the Commission issued its ORDER INITIATING DOCKET, inviting people to propose standards, and inviting people to comment on the proposed standards.

On June 19, 2002, the Commission issued its ORDER ORGANIZING WORK GROUPS AND SETTING PROCEDURAL SCHEDULE. That Order directed industry work groups, under the leadership of the Minnesota Department of Commerce (the Department), to develop guidelines for tariffs designed to help a generator interconnect with an electric utility's system, to make periodic reports on their progress, and to make a final report by February, 2003.

On February 3, 2003, the Department filed a report, and supplemented it on February 14. The report identified topics on which the participants had reached consensus and topics on which disagreements remained, and noted that participants continued to work on developing technical standards. At the Department's recommendation, the Commission solicited comments on the report. The Commission received comments from –

- the Department;
- Connexus Energy, East Central Energy, Minnesota Valley Electric Cooperative, and Wright-Hennepin Cooperative Electric Association (collectively, the Cooperatives);
- Great River Energy (GRE);
- Hennepin County;
- the Minnesota Municipal Utilities Association (MMUA);

- Dakota Electric Association (Dakota Electric), Interstate Power and Light Company, Minnesota Power, Northern States Power Company d/b/a Xcel Energy (Xcel), and Otter Tail Power Company (collectively, the Regulated Electric Utilities);
- CenterPoint Energy Minnegasco, Hennepin County, Institute for Local Self-Reliance, Izaak Walton League of America – Midwest Office, Korridor Capital Investments LLC, Minnesota Chamber of Commerce, Prairie Gen, and the Minnesota Project (collectively, the DG Coalition); and
- Missouri River Energy Services, Western Minnesota Municipal Power Agency, and the municipal utilities of Adrian, Alexandria, Barnseville, Benson, Breckenridge, Detroit Lakes, Elbow Lake, Henning, Jackson, Lakefield, Lake Park, Luverne, Madison, Moorhead, Ortonville, St. James, Sauk Centre, Stables, Wadena, Westbrook and Worthington (collectively, MRES).

On May 22, 2003, the Department filed a report on technical standards for permitting distributed generators to interconnect with a utility's network. In response, the Commission received comments from –

- Dakota Electric;
- Minnesota Power;
- the DG Coalition; and
- Xcel.

By June 30, 2003, the Commission had received reply comments from –

- Windustry, a non-profit organization promoting rural economic development through the use of wind power for generating electricity in rural areas;
- the Regulated Electric Utilities;
- the Cooperatives;
- Innovative Power Systems, Inc., which promotes the use of solar energy in new home construction;
- Minnesotans for an Energy-Efficient Economy (ME3);
- the DG Coalition;
- the American Council for an Energy-Efficient Economy (ACE3), an organization promoting the adoption of energy-efficient technologies;
- the Clean Water Action Alliance (CWAA);
- the North American Water Office (NAWO);
- the Minnesota Wind Energy Association (MWEA), a trade association of Minnesota businesses that develop wind energy or provide ancillary services such businesses;
- Xcel;
- Cummings Power Generation (Cummings); and
- the Department.

The Commission invited further comment on the comments received. By July 29, 2003, the Commission had received further comment from –

- the Department;
- Dakota Electric and Minnesota Power;
- Xcel; and
- Cummings.

This matter came before the Commission on July 20, 2004. The Commission heard argument from the Cooperatives, the Department, the DG Coalition, the Green Institute and the Regulated Electric Utilities, and received written comments from Hennepin County.

The hearing recessed until July 27, 2004. When the hearing reconvened, the Commission heard from the DG Coalition, the Regulated Electric Utilities, and the Green Institute. The Commission received written proposals from both the DG Coalition and the Regulated Electric Utilities, including a proposed resolution of technical issues.

FINDINGS AND CONCLUSIONS

I. Background

Most electricity is generated at large power plants, then transmitted long distances to where it is needed. "Distributed generation," in contrast, refers to the practice of generating electricity with multiple, dispersed power plants. Many benefits have been attributed to distributed generation, including reducing the demand on long-distance transmission lines, enhancing reliability, ameliorating environmental consequences and increasing customer choice.

The potential for these benefits would be lost, however, if the process of connecting small generators to the electric grid proved too dangerous, or the process of negotiating such connections proved too burdensome. To avoid this outcome, the Legislature adopted § 216B.1611 to facilitate the process. In particular, the Legislature directed the Commission to establish parameters for interconnection that would balance the needs of the utility and its ratepayers with the needs of the small generators. Utilities would then propose tariffs establishing standardized terms for interconnection consistent with the Commission-approved parameters.

In its June 19, 2002 Order, the Commission accepted the Department's offer to lead work groups in developing the outlines of terms for interconnecting generators with no more than 10 MW of capacity to the electrical grid. The Technical Work Group was charged with drafting documents and guidelines for tariffs so that a person interested in developing distributed generation could know what technical requirements to expect when applying for interconnection with any electric utility in the state. The Rate Work Group was charged with drafting documents and guidelines for tariffs so that a person interested in developing distributed generation could anticipate the financial terms for interconnecting with any electric utility in the state.

II. Analysis and Commission Action Generally

The Commission appreciates the work of all parties that have participated in this docket throughout the past three years, especially those that participated in the Work Groups. In particular, the Commission joins many of the commentors in acknowledging the Department's efforts in presenting the joint work of the Work Groups. Thanks to these efforts, the Commission now has the information necessary to establish generic standards for utility tariffs for the interconnection and parallel operation of distributed generation, as required by statute.

Having reviewed the Work Groups' reports and commentors' remarks, the Commission finds the reports to be reasonable, reflecting an appropriate balance of concerns. Consequently, the Commission will adopt the positions of the Work Group reports, except as otherwise specified below.

III. Technical Standards

A. Party Positions and Settlement

As noted above, the Department filed the report of the Technical Work Group on May 22, 2003, and the Commission received various comments on it. Generally, the Regulated Electric Utilities emphasized that new generators must not be permitted to create new hazards for the people operating the generators, for the utility's personnel, or for the electric system and the public that rely on it. On the other hand, the DG Coalition expressed concern that excessive technical requirements could create an unwarranted barrier to distributed generation. The DG Coalition encouraged the Commission to refrain from approving technical requirements unless they were reasonably necessary for the safety of persons and equipment or for the reliable operation of the electric distribution system.

At the Commission's final hearing on July 27, 2004, the DG Coalition and the Regulated Electric Utilities presented joint recommendations resolving nearly all of the contested technical issues. The joint position articulated a process and technical requirements for interconnecting generators with 10 MW or less of capacity to the electrical grid. The position was set forth in five attachments:

- Attachment 1, "Proposed Interconnection Process for Distributed Generation Systems," including five appendices,
- Attachment 2, a statement of "Distributed Generation Interconnection Requirements,"
- Attachment 3, a two-page form labeled "General Interconnection Application,"
- Attachment 4, a five-page form labeled "Engineering Data Submittal" and
- Attachment 5, a "Proposed Interconnection Agreement," including five exhibits.

No party opposed the resolution, except as discussed below.

B. DG Coalition Concerns

While the DG Coalition generally supports the resolution, it recently identified two items of concern in the text of Attachment 5 which it asks the Commission to amend.

First, the DG Coalition notes that Attachment 5 (“Proposed Interconnection Agreement”), part VIII (“Operational Issues”), subpart F (“Disconnection of Unit”) permits the electric power system (EPS) operator to disconnect a distributed generator –

as necessary, for termination of this Agreement; non-compliance with this Agreement; system emergency, imminent danger to the public or Area EPS personnel; routine maintenance, repairs and modifications to the Area EPS.

The DG Coalition notes that disconnections can impose substantial costs to its members, and therefore argues that the EPS operator should have to act reasonably in exercising its discretion to disconnect a generator.

The Regulated Electric Utilities note that the language already constrains them to act only “as necessary.” Nevertheless, the Regulated Electric Utilities do not object to modifying this language to say, “as reasonably necessary.”

Second, the DG Coalition notes that Attachment 5, part IX (“Limitation of Liability”), subpart B) limits each party’s liability to the other for failure to abide by the terms of the interconnection agreement, even if the other party acted intentionally or negligently. The DG Coalition argues that each party to the agreement should bear responsibility for its own intentional or negligent acts. However, the DG Coalition did not provide a detailed comparison between its proposal and traditional limits on liability enjoyed by regulated utilities.

C. Commission Action

Regarding concerns about unreasonable disconnections, the Commission finds the amendment offered by the Regulated Electric Utilities reasonable. Consequently, the Commission will modify the language of Attachment 5, part VIII, subpart F), to permit the EPS operator to disconnect a distributed generator –

as reasonably necessary for termination of this Agreement; non-compliance with this Agreement; system emergency, imminent danger to the public or Area EPS personnel; routine maintenance, repairs and modifications to the Area EPS.

Regarding concerns about limitations of liability, the Commission is not persuaded of the need to change this language. Given the ubiquitous use of utility services, the consequences of service interruption can be difficult to foresee, and to insure against. If an electric utility bore the risk of compensating customers for the damages arising from service interruptions, some of that cost would need to be incorporated into rates charged for electrical service, resulting in higher electric rates. Consequently, limitations on utility liability for service interruptions have long been regarded as “reasonable where, absent the limitation, the broad liability exposure would invariably

raise the costs and rates for electric service.”¹ Nothing in the record persuades the Commission of the wisdom of changing this longstanding policy in the current context.

Having reviewed the July 27, 2004 joint proposal and considered the positions of the parties, the Commission finds the proposal reasonable as amended above. The amended proposal will be adopted as guidelines for the process and technical requirements for interconnecting generators with no more than 10 MW of capacity to the electrical grid.

IV. Rate Standards

The Rates Work Group report was filed on February 3, 2003, and the Commission received various comments on it. Generally, commentors address the financial arrangements between the non-utility generator and the public utility for services rendered and power delivered. The non-utility generator must rely on the electric utility to supply supplemental, maintenance, and backup power services, and needs rates that are reasonable and non-discriminatory. At the same time, the utility is able to buy power from the generators. Some commentors note the importance of setting the price of this power equal to the value of the power to the utility. Whether distributed generation is financially viable to the generator, or is unduly burdensome to the utilities, depends in part on how these prices are set. The Work Group’s report addresses these issues.

1. Availability²

Some customers have back-up generators at their sites which they operate only when the utility’s electric service is interrupted, and which may or may not generate electricity in phase with the utility’s generators. Whatever the merits of these arrangements, they do not promote the goals of distributed generation noted above. An electric utility could not count on such generators to contribute to system capacity or reliability or to relieve the demand on distribution facilities. Consequently, these generators are beyond the scope of the current docket.

The report of the Rate Work Group recommends the following guideline:

The DG customer must connect in parallel to the utility distribution system.

That is, a tariff resulting from these guidelines would apply only to a non-utility generator that is able, at any moment, to put power onto the utility’s grid because the generator operates constantly – not just when a service interruption occurs – and in phase with the electricity distributed by the utility. This limitation is consistent with the language of Minnesota Statutes § 216B.1611.

¹ *Computer Tool & Engineering, Inc. v. Northern States Power Company*, 453 N.W.2d 569, 573 (Minn. App. 1990) (citing *Lee v. Consolidated Edison Co.*, 98 Misc.2d 304, 305, 413 N.Y.S.2d 826, 828 (N.Y.Sup.Ct.1978)).

² The paragraph numbering of the Rate Work Group’s report is altered in this Order to conform to the numbering system used in later comments and during the Commission hearings.

Hennepin County argues that this guideline does not go far enough, and suggests that if a generator will provide service to a customer during unscheduled service interruptions, the generator should have a “certified transfer switch” to automatically disconnect the customer from the rest of the grid.

While no party opposed Hennepin County’s suggestion in the abstract, the Regulated Electric Utilities reasoned that it was not necessary to state that policy as a condition for qualifying for the tariffs resulting from these guidelines.

The Commission finds the Regulated Electric Utilities’ view reasonable; the Commission is not persuaded of the need to mandate that a certified transfer switch is a condition for qualifying for DG tariffs. Consequently, the Commission will adopt the language of the Rate Work Group report unmodified.

2. Qualifications

a. Ownership

The Rate Work Group report recommends the following language to describe the types of generators that would qualify for the tariffs resulting from the guidelines:

The DG facility must be an operable, permanently installed or mobile generation facility and shall be owned by the customer receiving retail electric service from the company at the same site.

The DG Coalition and Hennepin County express concern about the extent of DG facility ownership required of the utility customer. These commentors note that DG financing arrangements can involve ownership by many parties; the commentors oppose any qualification that would needlessly exclude generators financed in non-traditional ways from the scope of tariffs resulting from these guidelines.

The Department and the Regulated Electric Utilities had initially advocated for an ownership provision as a means of expressing that these guidelines would not apply to “merchant plants” – that is, generators developed for the purpose of selling electricity at wholesale, without the expectation that the generators would also consume any of the electricity. The Department reasons that merchant plants are already adequately regulated by the Federal Regulatory Energy Commission (FERC). Acknowledging the DG Coalition’s concerns, however, the Department and the utilities do not object to replacing the ownership language with language focusing on the idea that a DG facility is intended to serve the customer at the facility’s site.

The Commission finds this accommodation reasonable. Consequently, the Commission will adopt the following language:

- a. The DG facility must be an operable, permanently installed or mobile generation facility serving the customer receiving retail electric service at the same site.*

b.-d. “Must Buy”

The Rate Work Group report recommends the following language:

- b. Must buy: The utility must buy all the energy supplied by the DG customer that sells power under the tariffs to be developed.*
- c. Customer options: Customer may sell all the DG energy to the utility, “sell” all the DG energy to itself, or self-generate part of its needs and sell the remaining energy to the utility.*
- d. Transactions outside the tariff: DG owners and utilities may pursue reasonable transactions outside the DG tariff. However, such transactions are beyond the scope of the work group.*

Various commentators object to this “must buy” language. Hennepin County argues that a DG customer should be able to sell its electricity to whomever it desires in order to maximize economic benefits. The Department and the Regulated Electric Utilities do not oppose merchant plants selling their electricity to whomever they choose, but argue that such plants are already regulated by FERC and are beyond the scope of the current docket.

The Cooperatives and MRES also object to the “must buy” language. They note that many electric cooperatives and municipalities do not generate or transmit their own electricity, but instead contract with other entities, such as GRE and MRES, to supply all of their generation and transmission needs.³ The Cooperatives and MRES object that the language of the Work Group report would appear to compel cooperatives and municipalities to offer to buy electricity from DG customers in violation of their “full requirements” contractual obligations. As a remedy, the Cooperatives and MRES ask that the language be changed to permit generation and transmission companies to assume the obligation to purchase the energy from a DG customer. The DG Coalition supports this remedy, and the Department has no objection.

The DG Coalition argues that the guidelines should not merely require a utility to buy all the electricity offered by a DG customer, but should also require the utility to pay for the generating capacity that the customer makes available to the utility. The Regulated Electric Utilities oppose amending Part 2 of the guidelines for this purpose. They argue that Part 2 of the guidelines (“Qualifications”) is intended merely to articulate the scope of the tariffs that will result from the guidelines; this Part is not intended to articulate all of the parties’ obligations to each other.

³ Commentors acknowledge that “full requirements” contracts have exceptions to accommodate the statutory requirement that distribution utilities purchase power from certain co-generation and small production facilities. Minn. Stat. §§ 216B.1611, 216B.164, 216B.1691, 216B.2411.

The Commission is persuaded that the language of the Work Group report defines the scope of the docket appropriately. The Legislature adopted Minnesota Statutes § 216B.1611 to simplify the process of analyzing the viability of a DG project, and to streamline the process of implementing such projects. Standardized provisions, such as a “must buy” clause, are necessary to streamline the process for the benefit of both the customer and the utility. Specifically, the rate principles established later in these guidelines are based on the premise that any electricity generated but not used by the DG customer would be made available to the utility. The Department correctly acknowledges that this docket does not preclude any party from developing a merchant plant; such plants, however, are beyond the scope of this docket. The Commission will modify the Work Group report language to clarify this intent.

Similarly, the Commission will modify the language to accommodate the needs of distribution utilities that have “full requirements” contracts with wholesale electric suppliers. The new language will provide for the wholesale supplier to assume the distribution utility’s role in acquiring the electricity from a DG customer that wishes to sell electricity.

Finally, the Commission will defer the question a utility’s duty to pay for a DG customer’s capacity until the discussion of part 6 (“Calculation of Avoided Costs”), subpart b) (“Avoided Capacity Costs”).

For the foregoing reasons, the Commission will adopt the following language:

- b. Must buy: The utility must buy all the energy offered for sale by the DG customer selling the power. Utilities that are full requirements customers of wholesale suppliers may need to require the wholesale supplier to assume this obligation in order to abide by contractual requirements with their wholesale supplier.*
- c. Customer options: Customer may sell all the DG energy to the utility, “sell” all the DG energy to itself, or self-generate part of its needs and sell the remaining energy to the utility.*
- d. Transactions outside the tariff: DG owners and utilities may pursue reasonable transactions outside the DG tariff. However, such transactions are beyond the scope of the work group.*

3. List of supply services to be priced

The Rate Work Group report recommends that the guidelines include the following list of supply services that a utility must offer to DG customers at tariffed rates:

- a. Energy and capacity.*
- b. Scheduled maintenance service (energy, or energy and capacity, supplied by the utility during scheduled maintenance of the customer’s non-utility source of electric energy supply).*

- c. *Unscheduled outages (energy, or energy and capacity, supplied by the utility during unscheduled outages of the customer's non-utility source of electric energy supply).*
- d. *Supplemental service (electric energy, or energy and capacity, supplied by the utility to the DG customer when the customer's non-utility source of electricity is insufficient to meet the customer's own load).*

While the DG Coalition approves of this language, the Regulated Electric Utilities recommend that the guidelines include a more extensive list of services that utilities provide to DG customers, including interconnection services, supply services and delivery services.

The Commission is mindful that the purpose of the docket is to adopt guidelines for utilities to use in developing tariffs. The fact that something is not included within the guidelines does not require the item to be excluded from the tariffs. Nevertheless, to dispel any implication to the contrary, the Commission will clarify that a utility's tariff may include other services deemed necessary.

Consequently, the Commission will adopt the language of the Rate Work Group report, and add to it the following:

- e. *Other services deemed necessary.*

4. and 5. Principles for Setting Rates for Services Provided by DG Customers to Utilities

The Rate Work Group report recommends the following principles for setting rates for services provided by DG customers to utilities:

- 4. *Rates should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions or for costs avoided on the generation, transmission, and/or distribution system.*
- 5. *Rates should reflect the costs the utility expects to avoid. To the extent practical, these costs should reflect seasonal and peak/off-peak differences in costs.*

No party has expressed opposition to this language. Finding it reasonable, the Commission will adopt the language of the Rate Work Group report.

6. Calculation of Avoided Costs

a. Avoided Energy Costs

Energy is the capacity to do work. Energy costs reflect the cost of fuel and the efficiency of the generator that converts the fuel energy into electrical energy, or the terms of a purchased power agreement. Guideline #4, discussed above, implies that a utility should compensate a DG customer to the extent that the customer permits the utility to avoid energy costs.

The Rate Work Group report recommends the following language regarding avoided energy costs:

Using a production cost model the following steps are used to calculate the marginal energy rates:

- a. System-wide hourly marginal energy costs are calculated with a production model for each hour of the future year.*
- b. Based on those costs, the average on-peak and off-peak marginal energy costs are calculated for each month.*
- c. The on-peak monthly rate is set at the average monthly on-peak marginal energy costs. The off-peak monthly energy rate is set at the average monthly off-peak marginal costs. Thus, there are 24 rates set for the year, with an on-peak and off-peak rate set for every month.*
- d. A trial period is proposed to see whether, in practice, utilities are able to forecast these energy prices sufficiently well. Depending on the trial results, a lump sum true-up may be used at the end of each year to reflect the difference between actual and estimated energy bills.*

MMUA objects to the proposed language on the grounds that cooperatives and municipalities that buy all of their power rather than generate it would have no basis for calculating avoided energy costs. As a remedy, the MMUA asks that guidelines provide for a utility that is a “full requirements” customer of a wholesale supplier to use the supplier’s rate schedule to determine avoided energy costs. The DG Coalition supports this position.

While acknowledging that there are many methods of calculating avoided cost, the Regulated Electric Utilities defend the formula included in the Working Group report, noting that it basically conforms to the calculations used for their annual Cogeneration and Small Power Production filings. Because this is such a well-understood formula, the Regulated Electric Utilities argue, there is no need for the trial period provided in subpart iv. Moreover, the amount of error that would likely accrue over a one-year period would simply not justify the administrative burdens of auditing how much energy cost they avoided and retroactively adjusting their bills (providing a “true-up”), the Regulated Electric Utilities argue.

The Department defends the use of a true-up. The Department shares the interest of the Regulated Electric Utilities in minimizing administrative costs, but argues that the benefit of ensuring accurate cost calculations justifies the burden of reconciling monthly actual energy costs with forecasted marginal energy costs.

The Regulated Electric Utilities suggest changes to another aspect of this section of the Work Group report. Specifically, they argue that the listed steps for determining avoided energy costs may not be appropriate in every circumstances. As a remedy, the Regulated Electric Utilities ask that the guidelines not restrict them to following the steps set forth in subparts i. to iv., but rather provide for them to follow “equivalent” steps.

The Commission is persuaded that the language of the Work Group report reflects appropriate measures for determining avoided energy costs, and therefore the Commission will adopt this language generally.

While the Regulated Electric Utilities argue that the avoided cost formula is too familiar and predictable to warrant a true-up, prudence leads the Commission to retain the true-up provision. The Legislature directed the Commission to adopt guidelines to facilitate the development of small generators, balancing the interests of the generators with the interests of the utilities and their ratepayers. This balance depends on correctly identifying the benefits that these generators provide to the electric system, including the extent to which a generator permits a utility to avoid energy costs. A true-up provides assurance to both the utility and the small generator that they will receive the appropriate benefits of their arrangement.

The Commission is not persuaded of the wisdom of directing utilities to adopt a distributed generation tariff by following the guideline's steps "or equivalent steps," given the degree of ambiguity in what constitutes "equivalence." After the Commission adopts these guidelines, each utility will file its distributed generation tariffs; the resulting docket will provide the appropriate forum for evaluating the extent to which the tariff adequately fulfill the purposes of these guidelines.

However, the Commission is persuaded to again modify the language of the Work Group report to accommodate the concerns of "full requirements" customers of wholesale suppliers. There is little point in asking such distribution utilities to calculate avoided cost on the basis of data they do not possess, and that would be of indirect relevance to the utility anyway. Consequently, the Commission will adopt the language of the Rate Work Group report, but substitute the following preamble:

Distribution utilities that are full requirements customers of wholesale suppliers may use their suppliers' rate schedules to determine avoided energy costs. Other utilities should follow these steps:

b. Avoided Capacity Costs

"Capacity" refers to the pace at which energy can be generated or delivered. Capacity costs generally reflect the cost of the generator and related plant. Guideline #4, above, implies that a utility should compensate a DG customer to the extent that the customer permits the utility to reduce or delay expenditures for securing needed capacity. But commentators disagree about many details.

The Rate Work Group report recommends the following language for calculating avoided capacity costs:

- i. Calculate the installed capital cost plus fixed O&M costs plus startup costs (\$/kW-year). If the next (marginal) unit is from a competitive bid, the utility must estimate these costs and fully defend the estimate.*

- ii. Calculate the Levelized Annual Revenue Requirements (LARR) (\$/kW-year).
 - iii. Divide the amount in (ii) for the next year by twelve to get the capacity marginal costs (\$/kW-month).
 - iv. These marginal costs must be escalated annually by the expected inflation rate.
- (1) The need for capacity is established in the utility's most recent integrated resource plan (IRP). A need exists if the utility shows a deficit at any year of the 15-year planning period.
 - (2) Capacity payments should be made for the total DG capacity that is accredited by MAPP's URGE test, regardless of when the power is delivered to the system.
 - (3) The normal "life" of a capacity addition is assumed to be 30 years.
 - (4) If the contract to purchase power from a DG source begins at the time the utility needs the capacity, then the full capacity payment is made, adjusting only as needed for the length of the contract (i.e., there is no discount for adding capacity sooner than it is needed).
 - (5) The formula for adjustments to capacity payments is:

$$A2 = \frac{(1+i)^m - 1}{(1+i)^n - 1} * \frac{(1+i)^{n-a} - (1+e)^{n-a}}{(1+i)^m - (1+e)^m} * A1$$

Where:

A1 = Levelized annual value of a capacity purchase at the time of need.

A2 = Levelized annual value of the capacity paid for in a power purchase contract.

m = Expected lifetime of ordinary (alternative) future capacity addition.

n = Length of power purchase contract.

i = Utility Cost of Capital.

e = Escalation rate affecting value of new capacity additions.

a = Length of time between beginning of contract and time of need for capacity.

This language provokes a number objections from the parties.

The Regulated Electric Utilities object to the language of subparts 6.b.iv.(2) and (3). The amount that a utility would pay for generating capacity would reflect both the new generator's capacity and the generator's anticipated operating life; these subparts are designed to answer the questions "How much capacity does the new generator have?" and "How long will the new generator last?"

Subparts 6.b.iv.(3) states that the capacity of the generator should be determined by the URGE test administered by the Mid-continent Area Power Pool (MAPP). The Regulated Electric Utilities argue that the URGE test is not the only relevant test for determining a generator's capacity. At hearing, no party objected to changing this language to say that a utility would pay for a DG facility's "total fully accredited DG capacity" instead.

Subpart 6.b.iv.(4) states that a generator is assumed to have an operating life of 30 years. The Regulated Electric Utilities argue that this assumption will prove less accurate than the estimate of operating lives that a utility will produce as part of its integrated resource plan (IRP). The Department acknowledges this point. At hearing, no party objected to changing this language to say that a utility would estimate the operating life of a capacity addition based on the estimate in the utility's most recently approved IRP.

The MMUA argues that much of this language does not reflect the circumstances of electric cooperatives and municipal electric utilities. For example, whereas subpart b.iv. often refers to a utility's IRP, many cooperatives and municipal utilities do not develop such plans. The Department acknowledges this concern, but notes that the docket's purpose is merely to generate guidelines. Inevitably the guidelines will not conform to every utility's circumstances, and questions about how they will apply to any given utility will have to be addressed in subsequent – and more narrowly focused – dockets.

But the largest dispute about the Work Group report language involves the extent to which a utility should pay for capacity that it is not actually using and for which it does not have any current need.

The Regulated Electric Utilities initially argued that they should not have to pay for capacity from a DG customer until it is needed, noting the general prohibition on ratepayers paying for plant that has not been proven "used and useful." But CWAA, the DG Coalition, the Green Institute, NAWO and Windustry argue that this policy would discriminate against non-utility generators. When a utility builds a new generator, these commentators note, the utility will begin paying all the costs of the new plant, even if it will be years before the plant's entire generating capacity is needed. These commentators ask for comparable treatment for distributed generators. And they note that the Work Group Report's formula discounts the amount that a utility would pay for future capacity to reflect the fact that the benefits are not expected to accrue until the future; the more remote the need, the greater the discount. Given these considerations, the Department and the DG Coalition support the Work Group Report language at 6.b.iv.(1) which provides for utilities to begin compensating DG customers when they forecast a need for new capacity within the next 15 years.

The Regulated Electric Utilities now acknowledge some benefit to having a DG customer's capacity on hand even before any need is anticipated, but they continue to object to paying for the capacity 15 years before it is needed. They argue that a policy of paying 15 years in advance violates that principle that each generation of ratepayers should pay for the plant that benefits itself, not for plant that will only benefit future ratepayers. And in the evolving world of energy policy, they argue, a 15-year forecast is simply too speculative to warrant this kind of financial commitment. They note that some DG projects would not even last 15 years, nullifying any future advantage ratepayers might hope to gain from subsidizing current DG projects. As a compromise,

the Regulated Electric Utilities propose that they contribute to a DG customer's capacity costs only when the utility's forecasts show that the utility will need additional capacity within the next *five* years, rather than fifteen.

The Commission finds the proposed changes to subparts 6.b.iv.(2) and (3) to be an appropriate refinement to the Work Group report language.

The Commission finds the reasoning of the Regulated Electric Utilities persuasive. Having generators available to call upon in an emergency benefits utilities and their customers, even though the utility does not anticipate an emergency arising. But the magnitude of the benefit will increase as the difference between forecasted demand and forecasted capacity decreases. Precisely when the benefit becomes large enough to warrant payment is a matter of judgment. The Commission concludes that the value that ratepayers receive from having reserve capacity 15 years before any anticipated need is too slight to warrant compensation. But the value that ratepayers receive from having reserve capacity five years before need is anticipated is sufficiently definite to warrant compensation.

Consequently the Commission will approve the Work Group language with the following substitute language at subpart 6.b.iv:

- (1) The need for capacity is established in the utility's most recent integrated resource plan (IRP). A need exists if the utility shows a deficit at any year of the five-year planning period.*
- (2) Capacity payments should be made for the total fully accredited DG capacity, regardless of when the power is delivered to the system.*
- (3) The expected life of a capacity addition is the expected life of the specific capacity addition from the utility's most recently approved integrated resource plan.*

7. Standby Rates

While a DG customer may intend to generate all the electricity it requires, it may desire to have the utility provide back-up power in emergencies. A utility will incur some costs to meet this need, and commentators generally agree that rates for such "standby" service must reflect these costs. But the commentators disagree about many of the details.

In particular, the DG Coalition, Hennepin County and the Regulated Electric Utilities agree that these guidelines do not contemplate every circumstance in which a party might desire standby service from a utility. The DG Coalition asks that the Commission address this issue further in a separate proceeding.

Again, the Commission notes that this docket's purpose is merely to generate guidelines. Questions about how they will apply to any given utility will be addressed as each utility files its proposed tariff conforming to these guidelines. Consequently, the Commission will decline to initiate another industry-wide proceeding at this time.

a. General

The Rate Work Group report recommends the following language for establishing a DG customer's right not to buy standby power.

- i. *DG customers do not have to buy standby power. However, if standby power is not purchased, it may not be available.*
- ii. *DG customers do not have to buy as much standby power as necessary to equal the full amount of their own DG capacity. However, if, for example, the customer has a 5 MW DG facility and buys only 2 MW of standby power, there must be a guarantee that the facility will never take more than 2 MW of standby service.*

Both the DG Coalition and the Regulated Electric Utilities recommend adoption of this language, and no commentor opposed this language specifically. The Commission finds the language reasonable, and will adopt it.

b. Firm Service

Firm service refers to the utility's most reliable, constant electric service; a utility would interrupt the supply of electricity to a firm service customer only as a last resort. The cost of firm service includes the cost of generating, transmitting and distributing electricity. The Rate Work Group developed guideline language for each of these components.

i. Generation

An electric utility must acquire sufficient generating capacity to meet the anticipated needs of its customers. To maintain the reliability of the system, the utility must also have an additional amount of capacity held in reserve for unanticipated circumstances such as the failure of a generator or a transmission line, often in the range of 15-18% of anticipated demand. The cost of maintaining this reserve is built into the utility's rates, including the rates for firm service.

The cost of energy generally reflects the cost of fuel used to power the generators or the price of a purchased power contract; this cost is also reflected in rates.

The Rate Work Group report recommends the following language for establishing the terms for generating firm standby service for a DG customer.

Generation (both energy and capacity): The monthly reservation fees are equal to the percentage of the planned reserve margin of the utility times the applicable energy and capacity tariffed rates. As such, there is a discount of 82 to 85 percent of the generation charge.

This language reflects the idea that a utility must maintain additional capacity to provide firm standby service, but for each 100 kilowatt (kW) of standby power the DG customer would require, the utility would incur the cost of only an additional 15-18 kW.

The Regulated Electric Utilities object to this language. First, they note that the 15-18% figure derives from Xcel's reserve margins; they claim that other utilities have somewhat different margins, making the 82-85% discount figures inappropriate as a general guideline. Second, the Regulated Electric Utilities argue that the discount should apply only to the capacity component of the firm standby charge, not the energy component. Of course, a utility would incur no energy costs to serve a DG customer that never actually used any standby energy. But when the customer did use standby power, the utility would incur energy costs to serve that need, and it would be appropriate to pass through all of those costs to the customer.

Neither the DG Coalition nor the Green Institute opposed the Regulated Electric Utilities' suggestions.

The Commission finds the Rate Work Group report provides a reasonable framework for addressing the generation component of firm standby service for a DG customer, but is also persuaded of the need to modify that framework consistent with the arguments of the Regulated Electric Utilities. Consequently, the Commission will omit from this part of the guidelines any references to energy costs or the specific 82-85% discount figures, and will instead adopt the following language:

Generating Capacity: The monthly reservation fees are equal to the percentage of the planned reserve margin of the utility times the applicable capacity tariffed rates.

ii. Transmission

The Rate Work Group report recommends the following language for establishing the terms for transmitting firm standby service to a DG customer.

Transmission: The monthly charges are equal to the utility's planned reserve margin percentage times the applicable transmission charge. Thus, there is a discount of 82 to 85 percent of the transmission charge.

Similar to the preceding discussion of generation, the Regulated Electric Utilities object to the use of Xcel's reserve margin figures for use in industry-wide guidelines. Moreover, they and MMUA argue that no discount is warranted for transmission costs. Unlike energy costs, transmission costs largely reflect cost for plant; these costs do not vary with the amount of usage. And unlike a generator, which can send the benefit of its electricity throughout the grid, a transmission line's benefits are restricted primarily to adjacent areas; the existence of remote transmission lines will be of limited use to a DG customer that must call on standby power. Consequently, these commentators argue that a DG customer should bear all of the cost of the transmission facilities needed to provide standby power. Those terms would be set forth in an Open Access Transmission Tariff established by the utility, or by the Midwest Independent System Operator (MISO) or successor organizations approved by FERC.

The Commission finds the Rate Work Group report provides a reasonable framework for addressing the transmission component of firm standby service for a DG customer, but is also persuaded of the need to modify that framework consistent with the arguments of MMUA and the

Regulated Electric Utilities. Consequently, the Commission will omit from this part of the guidelines any references to the specific 82-85% discount figures, and will instead adopt the following language:

Transmission: Terms, conditions and charges for transmission service are subject to the individual utilities' or MISO's Open Access Transmission Tariffs or their successors as approved by the FERC.

iii. -iv. Distribution

The Rate Work Group report recommends the following language for establishing the terms for distributing firm standby service to a DG customer.

iii. Bulk Distribution: The monthly charges equal the monthly charge under the applicable distribution charge. That is, there is no discount in the "bulk" distribution charge.

iv. Non-Bulk (Local) Distribution: The monthly charges equal the monthly charge under the applicable distribution charge. There is no discount in the "local" distribution charge.

The DG Coalition supports this language.

But the Cooperatives, the Department, MMUA and the Regulated Electric Utilities argue that distribution plant should not be subject to the same discounts as generation capacity. The reasons for denying a discount for the transmission component of firm standby service apply with greater force to the distribution component, they argue. The utility's cost to distribute standby electricity to a DG customer does not vary with the customer's amount of usage, they assert, and the facilities cannot readily be used to benefit other customers. Because a customer that demands firm standby service will cause the utility to incur these costs, and because the utility will have few if any other means of recouping these costs, these commentators argue that the utility must recover all these costs from the customer.

The Cooperatives, the Department and the Regulated Electric Utilities also oppose having separate treatment for bulk and non-bulk distribution. According to the Department, the distinction is ill-defined, and arising merely from differences in the terminology used in various utilities' tariffs. In any event, the guidelines recommend identical treatment for the two categories, making the distinction superfluous.

The Commission finds the Rate Work Group report provides a reasonable framework for addressing the distribution component of firm standby service for a DG customer. The Commission will decline to incorporate a discount for the distribution component of these costs, for the same reasons the Commission declined to discount the transmission component. But the Commission is persuaded of the need to modify that framework consistent with the arguments of the Cooperatives, the Department and the Regulated Electric Utilities. Consequently, the Commission will eliminate from this part of the guidelines the distinction between bulk and non-bulk distribution, and will instead adopt the following language:

Local Distribution: The monthly rates equal the monthly charge under the applicable distribution charges. That is, there is no discount on the distribution charge.

c. Non-Firm Service

Non-firm service refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service customers at the moment. Customers that are willing to endure power outages or that have their own back-up sources of energy may prefer to subscribe for non-firm standby service because it is less expensive than firm service. Similar to firm service, the Rate Work Group report contains guideline language for the generation, transmission and distribution components of this service, as follows:

- i. Generation (energy and capacity): There are no monthly reservation fees for energy and capacity for a non-firm DG customer.*
- ii. Transmission: There are no monthly reservation fees for transmission for a non-firm DG customer.*
- iii. Bulk and Non-Bulk Distribution: The monthly rates equal the monthly charge under the applicable distribution charges. That is, there is no discount on the distribution charge.*

This language reflects the idea that the only plant that a utility would build specifically for a non-firm customer is distribution plant, and consequently non-firm customers would not bear the fixed cost of other plant.

While the Regulated Electric Utilities support this language, the DG Coalition argues that there should be no bulk distribution fee for non-firm standby service. But the Cooperatives, the Department and MMUA disagree, reasoning that distribution plant dedicated to serving a DG customer must be recovered from that customer, and that the cost of the plant is not usage-sensitive and therefore should be recovered through non-usage-sensitive charges such as a fixed monthly charge.

The Commission finds the Rate Work Group report provides a reasonable framework for addressing non-firm standby service for a DG customer, and finds commentors' arguments supporting that subpart of the report's language to be persuasive. Consequently, that language will be adopted.

d. Physical Assurance

A DG customer that established an automated means to restrict the flow of electricity from the utility to the customer could qualify as a "physical assurance customer." The Rate Work Group report proposes the following guideline language:

A physical assurance customer is a customer who agrees not to require standby services and has a mechanical device to insure that standby service is not taken. The cost of the mechanical device, which must be reasonable, is to be paid by the DG customer.

Like a non-firm customer, a physical assurance customer would not pay a reservation charge for generation or transmission service. Moreover, physical assurance customers would have an option either to pay up-front for stranded distribution facilities that they will not use or to pay for distribution service, through the standby charge, for the entire amount of load.

The DG Coalition and the Green Institute argue that a physical assurance customer should not have to pay a fixed charge for bulk distribution. Additionally, to the extent that a physical assurance customer pays for the distribution plant connecting it to the grid, they argue that the customer should be able to earn some compensation from the utility if the customer is able to resell that distribution plant to other customers. Finally, if an existing customer installs a small generator and elects to become a physical assurance customer, the DG Coalition argues that this customer should not have to pay any fixed distribution charge because the necessary plant would already be in place.

The Regulated Electric Utilities continue their opposition to providing distribution without a facilities charge. Also, they note administrative burdens that could arise from DG customers paying up-front for distribution plant and then acquiring some type of ownership rights in that plant. More generally, the Regulated Electric Utilities ask for leeway in addressing this matter in their tariffs.

While the Commission finds the Rate Work Group report provides a reasonable framework for addressing the physical assurance customer service for a DG customer, the Commission also finds merit in the Regulated Electric Utilities' request. The record cites no examples of when this Commission has encountered a physical assurance-type tariff before. Given the degree of novelty in this suggestion, the Commission will not attempt to draft detailed directions for this matter, and will adopt the following language instead:

A physical assurance customer is a customer who agrees not to require standby services and has a mechanical device to insure that standby service is not taken. The cost of the mechanical device, which must be reasonable, is to be paid by the DG customer. A utility's tariff may deal with other issues not addressed here.

e. Maximum Size to Avoid Standby Charge

For sufficiently small generators, the burden of paying and administering standby charges exceeds any benefit to ratepayers. Certain "qualifying facilities" with generating capacity of 40 kW or less have the discretion to interconnect with a public utility without incurring standby charges.⁴ However, the Commission had previously directed Xcel to adopt a DG tariff that exempted DG customers with capacity of 100 kW or less from paying such charges.

The Rate Work Group report contains guideline language as follows:

⁴ See the federal Public Utility Regulatory Policies Act of 1978, as amended, 16 U.S.C. § 2601 *et seq.*; 18 C.F.R. § 292.101 *et seq.*; see also Minn. Stat. § 216B.164.

A DG facility of 100 kW or less is exempted from paying any standby charges.

The Cooperatives, MMUA and the Regulated Electric Utilities all oppose this guideline as violating the principle of Guideline #4 that ratepayers should not be forced to subsidize DG facilities. These commentors favor setting the threshold at the 40 kW level already established by law. While Xcel's tariff had included a more generous standard, the parties argue that the tariff resulted from a stop-gap Order designed to put DG terms in place temporarily pending the outcome of the current docket;⁵ significantly, the Commission stated that the Xcel terms should not be regarded as precedent for this docket.⁶

On the other hand, CWAA, the Department, the Green Institute and the DG Coalition favor the Work Group report language. Given that Minnegasco currently fuels microturbines up to 60 kW in size, the DG Coalition argues that a 40 kW limit is arbitrarily low. Acknowledging that the Work Group report language would create a subsidy, the Department nevertheless supports the 100 kW exemption as a means of promoting distributed generation. However, the Department also favors tracking the amount of the resulting subsidies and reconsidering the issue in the future.

The resolution of this issue, like prior ones, is a matter of judgment. Where the burdens of standby charges will exceed the benefits to ratepayers, those burdens should be removed; the only question is establishing the threshold. Consistent with its Order establishing Xcel's initial DG tariff, the Commission will not regard that tariff as establishing a relevant precedent for the current case. On the basis of the entire record, the Commission is persuaded that a 60 kW exemption threshold is reasonable. While this level will result in ratepayers bearing some additional cost, it will enable existing microturbines to potentially benefit from the exemption while ensuring that larger generators bear all of their own costs.

⁵ While the Commission declined to consolidate Xcel's DG docket with the current generic docket,

the Commission appreciates the parties' concerns for administrative efficiency, and will therefore make some accommodation. While the Commission declines to refer all issues in the current docket to the generic docket, it will refer some. Specifically, the Commission will adopt some form of DG tariff in the current docket, but contentious issues will be referred to the generic docket. NSP may need to modify its DG tariff once the generic standards are adopted, but that is not a sufficient basis to deprive generators of the benefit of some form of DG tariff in the meantime. No matter how imperfect NSP's tariff may seem in retrospect, it will be better than no tariff at all.

In the Matter of Northern States Power Company's Petition for Approval of a Distributed Generation Energy Tariff, Docket No. E-002/M-01-937 ORDER APPROVING TARIFF WITH MODIFICATIONS (July 29, 2002) at 3-4.

⁶ "NSP's tariff shall not constitute precedent for distributed generation energy tariffs or guidelines being developed in Docket No. E-999/CI-01-1023 [the current docket]." *Id.* at 8.

The Commission also sees the merits of the Department's suggestion to monitor the consequences of this policy and to revisit it with the benefit of greater experience. Consequently the Commission will adopt the following language:

A DG facility of 60 kW or less is exempted from paying any standby charges. The Commission will review this guideline within 24 months.

8. Credits

a. General

As noted above, Guideline #4 states that a utility's rates should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions or for costs avoided on the generation, transmission or distribution system. The Rate Work Group report elaborates on this principle as follows:

Credits should be given to a DG customer if the installation of a DG facility reduces the utility's costs of providing the service. These lower costs could be generation, transmission or distribution related costs.

The Work Group report then addresses a variety of desirable attributes a small generator might bring to an electric system – geographic distribution, diversity, proximity to load, renewable fuels, reduced emissions, and enhanced reliability – and the circumstances under which credits may or may not be warranted for each attribute. CWAA, the DG Coalition and the Regulated Electric Utilities generally favor this language. But MWEA and NAWO recommend that DG customers be able to earn credits for providing other benefits as well, including enhanced security, local economic development, and other social, environmental and long-term economic benefits.

Generators have myriad attributes. The benefits of some attributes may be too slight or speculative to lend themselves to quantification, whereas other benefits – such as economic development – are beyond the scope of the docket. Ultimately the choice of which attributes warrant compensation is a matter of judgment.

The Work Group Report identifies six attributes for consideration based on their potential for helping a utility avoid generation-, transmission- or distribution-related costs. The Commission finds these attributes worthy of consideration. The Commission will decline the suggestion of the commentators to expand the scope of its analysis further at this time. The Commission's choice not to include a topic in these guidelines, however, does not limit the power of a utility to address the topic in its DG tariff, or of anyone else to comment on those tariffs.

Finding the Work Group report language reasonable, the Commission will approve it.

b. Distribution Credits

When a customer chooses to build a generator at a given location, this choice may permit the local utility to avoid or delay additional investments in distribution plant in that area. The parties agree that the utility should pass through the benefit of these cost savings to the DG customer.

i. Magnitude of Credit

The Rate Work Group report contains proposed guideline language as follows:

Distribution credits to a DG customer should equal the utility's avoided distribution costs resulting from the installation of the DG facility.

The Cooperatives and the Regulated Electric Utilities favor guidelines that would establish when the level of avoided distribution costs was so small as to no longer warrant further investigation; the Cooperatives suggest that no generators of less than one MW should warrant a distribution credit. Nevertheless, both the Regulated Electric Utilities and the DG Coalition could accept the Work Group report language as it is.

While larger generators clearly have a larger effect on a distribution system, the Commission is not persuaded that smaller generators have no effect. Of course, the smaller the generator, the smaller the credit it could earn. Finding the Rate Work Group report's language reasonable, the Commission will adopt it.

ii. Publicizing of Criteria

The Rate Work Group report contains proposed guideline language as follows:

Each utility should publish on the Internet its annually conducted distribution capacity planning study that identifies capacity needs, upgrades and load growth on area distribution feeders.

Commentors acknowledge the need to permit potential DG customers to learn where additional generating capacity would benefit the system. Security concerns, however, prompt the Cooperatives, the DG Coalition, MMUA and the Regulated Electric Utilities to express reservations about publicizing where the electrical system is most vulnerable to failure. MMUA also objects that the need to constantly update data on the Internet would become burdensome. Finally, MMUA and the Regulated Electric Utilities note that some utilities would be unable to comply with this guideline because they do not conduct an annual distribution capacity planning study.

Instead, the Department and the DG Coalition propose that a utility file the relevant information with Commission and the Department, and make the information available to potential DG customers upon request. The Regulated Electric Utilities agree that a utility could simply provide the information upon request. And the DG Coalition and the Regulated Electric

Utilities agree that the relevant information consists of a list of substation areas or feeders that could be likely candidates for distribution credits; the Regulated Electric Utilities suggest that any utility would develop such a list as part of its normal distribution planning process.

The Commission finds merit in the commentors' concerns about publicizing system vulnerabilities, and will therefore decline to adopt the Rate Work Group report language. Instead, the Commission will adopt the commentors' recommendation that utilities make the necessary information available upon request, as follows:

Each utility should provide, upon request, a list of substation areas or feeders that could be likely candidates for distribution credits as determined through the utility's normal distribution planning process.

iii. and iv. Conducting Studies and Allocating Costs

The Rate Work Group report contains proposed guideline language as follows:

- iii. Upon receiving a DG application, the utility will perform an initial screening study to determine if the DG project has the potential to receive distribution credits. The DG customer is responsible for the cost of such a screening study.*
- iv. If the utility's study shows that there exists potential for distribution credits, the utility must, at its own cost, pursue further study to determine the distribution credit, as part of its annual distribution capacity study.*

Commentors generally support this language, although the Regulated Electric Utilities argue that the guideline should identify which party should pay for the studies necessary to determine the magnitude of a distribution credit when, for whatever reason, those studies are not part of a utility's annual distribution capacity study.

The Commission finds the Rate Work Group report language reasonable and will adopt it. To the extent that the guidelines do not resolve a question, that question may be addressed in the context of the utility's DG tariff filing.

c. Diversity Credits

The DG Coalition claims that smaller generators are less likely to suffer an unexpected outage, and consequently a utility should be able to reduce the amount of reserve capacity it requires to back up a supply of electricity from smaller generators. The DG Coalition argues that a DG customer should receive the benefit that the utility accrues from reducing its reserve capacity requirements.

The Regulated Electric Utilities disagree. However much a smaller generator may benefit system reliability, the Regulated Electric Utilities argue that those benefits are offset when the DG customer contracts for standby service. The utility must be prepared to serve the standby DG customer when the customer's generator fails. To serve that customer, the utility must rely on securing power from its overall system without the benefit of the customer's small generator. Moreover, the Regulated Electric Utilities argue, a utility's reserve margin is set by MAPP based

studies that mainly reflect the threat to the system posed by the failure of large generators. Small generators have little influence on the calculation of a utility's reserve margin.

The Rate Work Group report incorporates the Regulated Electric Utilities' views into its proposed guideline language as follows:

No additional diversity credits for energy and capacity should be given to DG customers who contract for standby service.

The Commission finds this language reasonable, and will adopt it.

d. Line Loss Credits

To serve a customer that consumes 1000 kWh of electricity each day, a utility must generate more than 1000 kWh. The utility needs to generate enough electricity to serve the customers needs, as well as enough to offset all the current that is lost in transmission and distribution. The DG Coalition argues that a DG customer should be compensated for the amount of energy costs that he or she permits the utility to avoid, including the "line loss" amounts.

The Regulated Electric Utilities argue that the proposed generation and transmission credits will typically incorporate and reflect these line loss savings, and so no additional credits are warranted. They concede, however, that some circumstances could produce additional line loss savings depending on the location and operation of the generator.

The Rate Work Group report incorporates the Regulated Electric Utilities' views into its proposed guideline language as follows:

No additional line loss credits (above the credits already included in the avoided cost calculations) should be paid to a DG customer with the following exception: A DG customer may request the utility to provide a specific line loss study and receive additional line loss credits if the study supports such credits. The DG customer is responsible for the cost of the study regardless of the study's outcome.

The Commission finds this language reasonable, and will adopt it.

e. Renewable Credits

Where a utility has an obligation to acquire electricity from renewable or otherwise environmentally sound sources ("green power")⁷ and the utility relies on a DG customer's generator to fulfill that obligation, commentators agree that the DG customer should be compensated

⁷ For example, many utilities need to acquire green power to serve the needs of customers that order green power from the utilities' tariffs. Also, Minnesota Statutes § 216B.1691 directs Minnesota's investor-owned electric utilities, generation and transmission cooperatives, and municipal power agencies to make good faith efforts to obtain enough electricity from qualifying renewable energy technologies to represent 10% of total retail electric sales by the year 2015.

at the utility's avoided cost of meeting its green power needs. Both the DG Coalition and the Regulated Electric Utilities support the language of the Rate Work Group report, below:

A DG customer who installs a renewable DG facility should be paid the avoided cost of "green power" to the extent that installation of the DG facility allows the utility to avoid the need to purchase "green power" elsewhere. Otherwise a renewable DG facility should be paid the utility's regular avoided costs.

ME3 argues that small-scale DG projects powered by renewable and emissions-free technologies produce public benefits beyond helping a utility meet its needs, and that those benefits should be reflected in the utility's DG tariff. More specifically, the DG Coalition and Windustry argue that a DG customer that provides green power should be compensated at the utility's retail rate for green power minus some amount to cover the utility's administrative costs. In a similar vein, NAWO argues that utilities should pay DG providers of green power a premium equal to the premium that retail customers pay the utility for green power. But the Regulated Electric Utilities oppose this suggestion. They argue that the retail premium for green power is not simply added profit, but reflects the higher cost of securing green power and delivering it to customers.

Commentors also disagree about who should have the right to claim the use of the DG customer's green power. Green power is desirable because it displaces the need to generate power from more polluting sources; the resulting electricity, however, is indistinguishable from other electricity. Consequently, the question of which customer is using green power is a matter of interpretation, not physics. NAWO and Windustry argue that a DG customer should have the right to sell to the highest bidder the right to claim to be using the DG customer's green power. This right is valuable to utilities that need to demonstrate compliance with a legal obligation to provide green power.

The Commission finds the language of the Rate Work Group report reasonable and will adopt it. That language reflects the general consensus of the comments, and the Commission will decline to incorporate other requirements into the guidelines at this time. Again, where these guidelines leave matters unresolved, the parties may address them in the context of a utility's DG tariff filing.

f. Emission Credits

Emissions cause utilities to bear additional costs. For example—

- The federal Clean Air Act⁸ limits the amount of sulfur dioxide (SO₂) that each utility may emit, but permits the utilities to buy and sell their respective rights to emit SO₂. Consequently, each additional amount of SO₂ a utility emits causes the utility to incur the cost of another SO₂ allowance, or to forego the opportunity to sell an allowance.
- When a regulated utility requires additional generating capacity, it may need to select the capacity with the lowest societal costs (including environmental costs) rather than the lowest

⁸ 42 U.S.C. § 7651 *et seq.*

costs to the utility.⁹ In effect, the utility may need to incur additional cost to avoid the higher emissions that might have resulted from a cheaper generating source.

- Minnesota's "renewable energy objective" directs each of Minnesota's investor-owned electric utilities, generation and transmission cooperatives, and municipal power agencies to make good faith efforts to obtain enough electricity from qualifying renewable energy technologies to represent 10% of total retail electric sales by the year 2015.¹⁰ If this statute causes utilities to acquire more electricity from low-emission energy technologies, and if that electricity is more expensive than other electricity the utilities might have acquired, then again the utility will need to incur additional cost to avoid causing greater emissions.

As noted above, Guideline #4 states that rates the utility pays to the DG customer should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions. To the extent that a DG customer permits a utility to avoid emissions-related costs, that customer should receive the benefit. The Rate Work Group report proposes the following language:

- Tradable Emissions: For tradable emissions such as SO₂, if a low emission DG facility allows the utility to capture the value of the emission credit, then the DG owner should receive the credit revenues.*
- Non-Tradable Emissions: DG owners should receive emission credits equal to the utility's avoided emission costs, calculated as the emission per kWh of the next unit the utility plans to construct or purchase less the emission per kWh of the DG facility.*

A DG customer may get green credit or an emission credit, but not both.

The Commission's policy regarding the renewable energy objective may affect the question of whether it is reasonable for utilities to pay a credit for renewable power at the approved green-price premium even if a utility does not need the green power.

Commentors generally support this language as a logical extension of Guideline #4 – when a DG customer permits a utility to avoid costs, the DG customer should get the benefit.

But GRE and the Regulated Electric Utilities oppose paragraph ii. They argue that the principle of

⁹ Minn. Stat. § 216B.2422, subd. 3; Minn. Rules pt. 7843.0400; *In the Matter of the Quantification of Environmental Costs Pursuant to Laws of Minnesota 1993, Chapter 356, Section 3*, Docket No. E-999/CI-93-583 ORDER ESTABLISHING ENVIRONMENTAL COST VALUES (January 3, 1997) and updated pursuant to *In the Matter of the Investigation into Environmental and Socioeconomic Costs*, Docket No. E-999/CI-00-1636, ORDER UPDATING EXTERNALITY VALUES AND AUTHORIZING COMMENT PERIODS ON CO₂, PM_{2.5}, AND APPLICATION OF EXTERNALITY VALUES TO POWER PURCHASES (May 3, 2001).

¹⁰ Minn. Stat. § 216B.1691.

Guideline #4 does not support the policy in paragraph ii because a utility has no avoided costs related to non-tradable emissions. The Regulated Electric Utilities acknowledge that the Commission has quantified the costs related to certain emissions and directs public utilities to consider these costs in selecting resource options. But the Regulated Electric Utilities note that the Commission never directed that the utilities make payments on this basis. Such payments would create a perverse incentive for electric utilities: By increasing the incremental cost of using low-emitting sources, a utility would tend to rely on those sources less often, thereby reducing their environmental benefits.

The Commission finds the arguments of GRE and the Regulated Electric Utilities persuasive. Where a DG customer permits a utility to avoid emissions-related costs, the DG customer should accrue the benefit. But where the Commission has merely directed utilities to impute emissions-related costs, without any actual revenue stream to correlate with the imputed costs, then it is inappropriate and counter-productive to direct utilities to create a revenue stream to low-emission DG customers on that basis.

Consequently, the Commission will approve the language of the Rate Work Group, but without paragraph ii.

g. Reliability Credits

A collection of twenty 50 kW generators may not supply any more electricity than a single 1 MW generator, but they may supply it more reliably. Whenever the 1 MW plant fails, the electric system loses 1 MW of capacity instantly. The collection of smaller generators would never cause the same adverse consequence unless all twenty generators were to fail simultaneously – a very unlikely event. Thus, in addition to compensating DG customers for the energy and capacity they provide, the DG Coalition asks that DG customers be compensated for the increased reliability that they bring to a utility's system.

The Regulated Electric Utilities, however, regard this issue as comparable to the Diversity Credits issue. Small generators have little influence on the calculation of a utility's reserve margin, they argue, because a utility's reserve margin is set by MAPP based on the threat to the system posed by the failure of large generators. Consequently, the Regulated Electric Utilities argue that no reliability credit is warranted for standby DG customers.

The Rate Work Group report incorporates the Regulated Electric Utilities' views into its proposed guideline language as follows:

DG owners should receive no reliability credit beyond what is already incorporated in the standby tariffs.

The Commission is persuaded by the Regulated Electric Utilities' arguments. Finding the language of the Rate Work Group report to be reasonable, the Commission will adopt it.

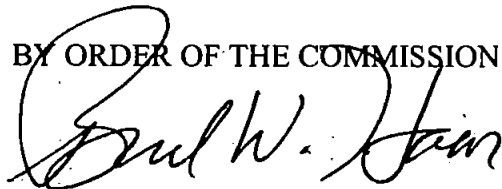
V. Conclusion

For the foregoing reasons, the Commission will approve the guidelines described herein for distributed generation tariffs. Utilities shall file conforming tariffs within 90 days.

ORDER

1. The July 27, 2004 joint proposal, as amended herein and attached as Attachments 1 through 5, shall constitute guidelines for establishing process and technical requirements for interconnecting generators with no more than 10 MW of capacity to the electrical grid.
2. The February 3, 2003, Rate Work Group report, as amended herein and attached as Attachment 6, shall constitute guidelines for establishing the financial relationship between an electric utility and a qualified generator with no more than 10 MW of capacity.
3. Retail electric public utilities shall file a distribution tariff consistent with the guidelines adopted in this Order within 90 days, pursuant to Minnesota Statutes § 216B.1611, subdivision 3.
4. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION



Burl W. Haar
Executive Secretary

(SEAL)

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State of Minnesota
**Interconnection Process
for Distributed Generation Systems**

Introduction

This document has been prepared to explain the process established in the State of Minnesota, to interconnect a Generation System with the Area Electrical Power System (Area EPS). This document covers the interconnection process for all types of Generation Systems which are rated 10MW's or less of total generation Nameplate Capacity; are planned for interconnection with the Area EPS's Distribution System; are not intended for wholesale transactions and aren't anticipated to affect the transmission system. This document does not discuss the interconnection Technical Requirements, which are covered in the "State of Minnesota Distributed Generation Interconnection Requirements" document. This other interconnection requirements document also provides definitions and explanations of the terms utilized within this document. To interconnect a Generation System with the Area EPS, there are several steps that must be followed. This document outlines those steps and the Parties' responsibilities. At any point in the process, if there are questions, please contact the Generation Interconnection Coordinator at the Area EPS. Since this document has been developed to provide an interconnection process which covers a very diverse range of Generation Systems, the process appears to be very involved and cumbersome. For many Generation Systems the process is streamlined and provides an easy path for interconnection.

The promulgation of interconnection standards for Generation Systems by the Minnesota Public Utilities Commission (MPUC) must be done in the context of a reasonable interpretation of the boundary between state and federal jurisdiction. The Federal Energy Regulatory Commission (FERC) has asserted authority in the area, at least as far as interconnection at the transmission level is concerned. This, however, leaves open the question of jurisdiction over interconnection at the distribution level. The Midwest Independent System Operator's (MISO) FERC Electric Tariff, (first revised volume 1, August 23, 2001) Attachment R (Generator Interconnection Procedures and Agreement) states in section 2.1 that "Any existing or new generator connecting at transmission voltages, sub-transmission voltages, or distribution voltages, planning to engage in the sale for resale of wholesale energy, capacity, or ancillary services requiring transmission service under the Midwest ISO OATT must apply to the Midwest ISO for interconnection service". Further in section 2.4 it states that "A Generator not intending to engage in the sale of wholesale energy, capacity, or ancillary services under the Midwest ISO OATT, that proposes to interconnect a new generating facility to the distribution system of a Transmission Owner or local distribution utility interconnected with the Transmission System shall apply to the Transmission Owner or local distribution utility for interconnection". It goes on further to state "Where facilities under the control of the Midwest ISO are affected by such interconnection, such interconnections may be subject to the planning and operating protocols of the Midwest ISO...."

Through discussions with MISO personnel and as a practical matter, if the Generation System Nameplate Capacity is not greater in size than the minimum expected load on the distribution substation, that is feeding the proposed Generation System, and Generation System's energy is not being sold on the wholesale market, then that installation may be considered as not "affecting" the transmission system and the interconnection may be considered as governed by this process. If the Generation System will be selling energy on the wholesale market or the Generation System's total Nameplate Capacity is greater than the expected distribution substation minimum load, then the Applicant shall contact MISO (Midwest Independent System Operator) and follow their procedures.

GENERAL INFORMATION

A) Definitions

- 1) "Applicant" is defined as the person or entity who is requesting the interconnection of the Generation System with the Area EPS and is responsible for ensuring that the Generation System is designed, operated and maintained in compliance with the Technical Requirements.
- 2) "Area EPS" is defined as an electric power system (EPS) that serves Local EPS's. Note. Typically, an Area EPS has primary access to public rights-of-way, priority crossing of property boundaries, etc.
- 3) "Area EPS Operator" is the entity who operates the Area EPS.
- 4) "Dedicated Facilities" is the equipment that is installed due to the interconnection of the Generation System and not required to serve other Area EPS customers.
- 5) "Distribution System" is the Area EPS facilities which are not part of the Area EPS Transmission System or any Generation System.
- 6) "Extended Parallel" means the Generation System is designed to remain connected with the Area EPS for an extended period of time.
- 7) "Generation" is defined as any device producing electrical energy, i.e., rotating generators driven by wind, steam turbines, internal combustion engines, hydraulic turbines, solar, fuel cells, etc.; or any other electric producing device, including energy storage technologies.
- 8) "Generation Interconnection Coordinator" is the person or persons designated by the Area EPS Operator to provide a single point of coordination with the Applicant for the generation interconnection process.
- 9) "Generation System" is the interconnected generator(s), controls, relays, switches, breakers, transformers, inverters and associated wiring and cables, up to the Point of Common Coupling.
- 10) "Interconnection Customer" is the party or parties who will own/operate the Generation System and are responsible for meeting the requirements of the agreements and Technical Requirements. This could be the Generation System applicant, installer, owner, designer, or operator.
- 11) "Local EPS" is an electric power system (EPS) contained entirely within a single premises or group of premises.
- 12) "Nameplate Capacity" is the total nameplate capacity rating of all the Generation included in the Generation System. For this definition the "standby" and/or maximum rated kW capacity on the nameplate shall be used.
- 13) "Open Transfer" is a method of transferring the local loads from the Area EPS to the generator such that the generator and the Area EPS are never connected together.

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- 14) "Point of Common Coupling" is the point where the Local EPS is connected to an Area EPS.
- 15) "Quick Closed" is a method of generation transfer which does not parallel or parallels for less than 100msec with the Area EPS and has utility grade timers which limit the parallel duration to less than 100msec with the Area EPS.
- 16) "Technical Requirements" "is the State of Minnesota Distributed Generation Interconnection Requirements."
- 17) "Transmission System" means those facilities as defined by using the guidelines established by the Minnesota State Public Utilities Commission; "In the Matter of Developing Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions," Docket No. E-015/M-99-1002.

B) Dispute Resolution

The following is the dispute resolution process to be followed for problems that occur with the implementation of this process.

- 1) Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably and in a good faith manner.
- 2) In the event a dispute arises under this process, and if it cannot be resolved by the Parties within thirty (30) days after written notice of the dispute to the other Party, the Parties shall submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in the State of Minnesota. The Parties agree to participate in good faith in the mediation for a period of 90 days. If the parties are not successful in resolving their disputes through mediation, then the Parties may refer the dispute for resolution to the Minnesota Public Utilities Commission, which shall maintain continuing jurisdiction over this process

C) Area EPS Generation Interconnection Coordinator.

Each Area EPS Operator shall designate a Generation Interconnection Coordinator(s) and this person or persons shall provide a single point of contact for an Applicant's questions on this Generation Interconnection process. Some Area EPS Operators may have several Generation Interconnection Coordinators assigned, due to the geographical size of their electrical service territory or the amount of interconnection applications. This Generation Interconnection Coordinator will typically not be able to directly answer or resolve all of the issues involved in the review and implementation of the interconnection process and standards, but shall be available to provide coordination assistance with the Applicant

D) Engineering Studies

During the process of design of a Generation System interconnection between a Generation System and an Area EPS, there are several studies which many need to be undertaken. On the Local EPS (Customers side of the interconnection) the addition of a Generation System may increase the fault current levels, even if the generation is never interconnected with the Area EPS's system. The Interconnection Customer may need to conduct a fault current analysis of the Local EPS in conjunction with adding the Generation System. The addition of the Generation System may also affect the Area EPS and special engineering studies may need to be undertaken looking at the Area EPS with the Generation System included. Appendix D, lists some of the issues that may need to receive further analysis for the Generation System interconnection.

While, it is not a straightforward process to identify which engineering studies are required, we can at least develop screening criteria to identify which Generation Systems may require further analysis. The following is the basic screening criteria to be used for this interconnection process.

- 1) Generation System total Nameplate Capacity does not exceed 5% of the radial circuit expected peak load. The peak load is the total expected load on the radial circuit when the other generators on that same radial circuit are not in operation.
- 2) The aggregate generation's total Nameplate Capacity, including all existing and proposed generation, does not exceed 25% of the radial circuit peak load and that total is also less than the radial circuit minimum load.
- 3) Generation System does not exceed 15% of the Annual Peak Load for the Line Section, which it will interconnect with. A Line Section is defined as that section of the distribution system between two sectionalizing devices in the Area EPS.
- 4) Generation System does not contribute more than 10% to the distribution circuit's maximum fault current at the point at the nearest interconnection with the Area EPS's primary distribution voltage.
- 5) The proposed Generation System total Nameplate Capacity, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment to exceed 85 percent of the short circuit interrupting capability.
- 6) If the proposed Generation System is to be interconnected on a single-phase shared secondary, the aggregate generation Nameplate Capacity on the shared secondary, including the proposed generation, does not exceed 20kW.
- 7) Generation System will not be interconnected with a "networked" system

E) Scoping Meeting

During Step 2 of this process, the Applicant or the Area EPS Operator has the option to request a scoping meeting. The purpose of the scoping meeting shall be to discuss the Applicant's interconnection request and review the application filed. This scoping meeting is to be held so that each Party can gain a better understanding of the issues involved with the requested interconnection. The Area EPS and Applicant shall bring to the meeting personnel, including system engineers, and other resources as may be reasonably required, to accomplish the purpose of the meeting. The Applicant shall not expect the Area EPS to complete the preliminary review of the proposed Generation System at the scoping meeting. If a scoping meeting is requested, the Area EPS shall schedule the scoping meeting within the 15 business day review period allowed for in Step 2. The Area EPS shall then have an additional 5 days, after the completion of the scoping meeting, to complete the formal response required in Step 2. The Application fee shall cover the Area EPS's costs for this scoping meeting. There shall be no additional charges imposed by the Area EPS for this initial scoping meeting.

F) Insurance

- 1) At a minimum, in connection with the Interconnection Customer's performance of its duties and obligations under this Agreement, the Interconnection Customer shall maintain, during the term of the Agreement, general liability insurance, from a qualified insurance agency with a B+ or better rating by "Best" and with a combined single limit of not less than:
 - a) Two million dollars (\$2,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is greater than 250kW.
 - b) One million dollars (\$1,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is between 40kW and 250kW.
 - c) Three hundred thousand (\$300,000) for each occurrence if the Gross Nameplate Rating of the Generation System is less than 40kW.
 - d) Such general liability insurance shall include coverage against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of the Interconnection Customer's ownership and/or operating of the Generation System under this agreement.
- 2) The general liability insurance required shall, by endorsement to the policy or policies, (a) include the Area EPS Operator as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that the Area EPS Operator shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to the Area EPS Operator prior to cancellation, termination, alteration, or material change of such insurance.
- 3) If the Generation System is connected to an account receiving residential service from the Area EPS Operator and its total generating capacity is smaller than 40kW, then the endorsements required in Section F.2 shall not apply.

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- 4) The Interconnection Customer shall furnish the required insurance certificates and endorsements to the Area EPS Operator prior to the initial operation of the Generation System. Thereafter, the Area EPS Operator shall have the right to periodically inspect or obtain a copy of the original policy or policies of insurance
- 5) Evidence of the insurance required in Section F.1. shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by the Area EPS Operator.
- 6) If the Interconnection Customer is self-insured with an established record of self-insurance, the Interconnection Customer may comply with the following in lieu of Section F.1 – 5:
- 7) Interconnection Customer shall provide to the Area EPS Operator, at least thirty (30) days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under section F.1
- 8) If Interconnection Customer ceases to self-insure to the level required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of it's ability to self-insure, the Interconnection Customer agrees to immediately obtain the coverage required under section F.1.
- 9) Failure of the Interconnection Customer or Area EPS Operator to enforce the minimum levels of insurance does not relieve the Interconnection Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.

G) Pre-Certification

The most important part of the process to interconnect generation with Local and Area EPS's is safety. One of the key components of ensuring the safety of the public and employees is to ensure that the design and implementation of the elements connected to the electrical power system operate as required. To meet this goal, all of the electrical wiring in a business or residence, is required by the State of Minnesota to be listed by a recognized testing and certification laboratory, for its intended purpose. Typically we see this as "UL" listed. Since Generation Systems have tended to be uniquely designed for each installation they have been designed and approved by Professional Engineers. This process has been set up to be able to deal with these uniquely designed systems. As the number of Generation Systems installed increase, vendors are working towards creating equipment packages which can be tested in the factory and then will only require limited field testing. This will allow us to move towards "plug and play" installations. For this reason, this interconnection process recognizes the efficiency of "pre-certification" of Generation System equipment packages that will help streamline the design and installation process.

An equipment package shall be considered certified for interconnected operation if it has been submitted by a manufacture, tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous utility interactive operation in compliance with the applicable codes and standards. Presently generation paralleling equipment that is listed by a nationally recognized testing laboratory as having met the applicable type-testing requirements of UL 1741 and IEEE 929 shall be acceptable for interconnection without additional protection system requirements. An "equipment package" shall include all interface components including switchgear, inverters, or other interface devices and may include an integrated generator or electric source. If the equipment package has been tested and listed as an integrated package which includes a generator or other electric source, it shall not required further design review, testing or additional equipment to meet the certification requirements for interconnection. If the equipment package includes only the interface components (switchgear, inverters, or other interface devices), then the Interconnection Customer shall show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and consistent with the testing and listing specified for the package. Provided the generator or electric source combined with the equipment package is consistent with the testing ad listing performed by the nationally recognized testing and certification laboratory, no further design review, testing or additional equipment shall be required to meet the certification requirements of this interconnection procedure. A certified equipment package does not include equipment provided by the Area EPS.

The use of Pre-Certified equipment does not automatically qualify the Interconnection Customer to be interconnected to the Area EPS. An application will still need to be submitted and an interconnection review may still need to be performed, to determine the compatibility of the Generation System with the Area EPS.

H) Confidential Information

Except as otherwise agreed, each Party shall hold in confidence and shall not disclose confidential information, to any person (except employees, officers, representatives and agents, who agree to be bound by this section). Confidential information shall be clearly marked as such on each page or otherwise affirmatively identified. If a court, government agency or entity with the right, power, and authority to do so, requests or requires either Party, by subpoena, oral disposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirements(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. In the absence of a protective order or waiver the Party shall disclose such confidential information which, in the opinion of its counsel, the party is legally compelled to disclose. Each Party will use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded any confidential information so furnished.

I) Non-Warranty.

Neither by inspection, if any, or non-rejection, nor in any other way, does the Area EPS Operator give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Applicant or leased by the Applicant from third parties, including without limitation the Generation System and any structures, equipment, wires, appliances or devices pertinent thereto.

J) Required Documents

The chart below lists the documents required for each type and size of Generation System proposed for interconnection.

Find your type of Generation System interconnection, across the top, then follow the chart straight down, to determine what documents are required as part of the interconnection process.

GENERATION INTERCONNECTION DOCUMENT SUMMARY					
Open Transfer	Quick Closed Transfer	Soft Loading Transfer	Extended Parallel Operation		
			QF facility <40kW	Without Sales	With Sales
Interconnection Process (This document)					
State of Minnesota Distributed Generation Interconnection Requirements					
Generation Interconnection Application (Appendix B)					
		Engineering Data Submittal (Appendix C)			
		Interconnection Agreement (Appendix E)			
		MISO / FERC			
		PPA			

Interconnection Process = "State of Minnesota Interconnection Process for Distributed Generation Systems." (This document)

State of Minnesota Distributed Generation Interconnection Requirements = "State of Minnesota Distributed Generation Interconnection Requirements"

Generation Interconnection Application = The application form in Appendix B of this document.

Engineering Data Submittal = The Engineering Data Form/Agreement, which is attached as Appendix C of this document.

Interconnection Agreement = "Minnesota State Interconnection Agreement for the Interconnection of Extended Parallel Distributed Generation Systems with Electric Utilities", which is attached as Appendix E to this document.

MISO = Midwest Independent System Operator, www.midwestiso.org

FERC = Federal Energy Regulatory Commission, www.ferc.gov

PPA = Power Purchase Agreement.

Process for Interconnection

Step 1 Application (By Applicant)

Once a decision has been made by the Applicant, that they would like to interconnect a Generation System with the Area EPS, the Applicant shall supply the Area EPS with the following information:

- 1) Completed Generation Interconnection Application (Appendix C), including;
 - a) One-line diagram showing;
 - i) Protective relaying.
 - ii) Point of Common Coupling.
 - b) Site plan of the proposed installation.
 - c) Proposed schedule of the installation.
- 2) Payment of the application fee, according to the following sliding scale.

Generation Interconnection Application Fees

Interconnection Type	≤ 20kW	>20kW & ≤250kW	>250kW & ≤500kW	> 500 kW & ≤1000kW	>1000 kW
Open Transfer	\$0	\$0	\$0	\$100	\$100
Quick Closed	\$0	\$100	\$100	\$250	\$500
Soft Loading	\$100	\$250	\$500	\$500	\$1000
Extended Parallel (Pre Certified System)	\$0	\$250	\$1000	\$1000	\$1500
Other Extended Parallel Systems	\$100	\$500	\$1500	\$1500	\$1500

This application fee is to contribute to the Area EPS Operator's labor costs for administration, review of the design concept and preliminary engineering screening for the proposed Generation System interconnection.

For the Application Fees chart, above;

The size (kW) of the Generation System is the total maximum Nameplate Capacity of the Generation System.

Step 2 Preliminary Review (By Area EPS)

Within 15 business days of receipt of all the information listed in Step 1, the Area EPS Generation Interconnection Coordinator shall respond to the Applicant with the information listed below. (If the information required in Step 1 is not complete, the Applicant will be notified, within 10 business days of what is missing and no further review will be completed until the missing information is submitted. The 15-day clock will restart with the new submittal)

As part of Step 2 the proposed Generation System will be screened to see if additional Engineering Studies are required. The base screening criteria is listed in the general information section of this document.

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- 1) A single point of contact with the Area EPS Operator for this project. (Generation Interconnection Coordinator)
- 2) Approval or rejection of the generation interconnection request.
 - a) Rejection – The Area EPS shall supply the technical reasons, with supporting information, for rejection of the interconnection Application.
 - b) Approval - An approved Application is valid for 6 months from the date of the approval. The Area EPS Generation Interconnection Coordinator may extend this time if requested by the Applicant
- 3) If additional specialized engineering studies are required for the proposed interconnection, the following information will be provided to the Applicant. Typical Engineering Studies are outlined in Appendix D. The costs to the Applicant, for these studies shall be not exceed the values shown in the following table for pre-certified equipment.

Generation System Size	Engineering Study Maximum Costs
<20kW	\$0
20kW – 100kW	\$500
100kW – 250kW	\$1000
>250kW or not pre-certified equipment	Actual costs

- a) General scope of the engineering studies required.
 - b) Estimated cost of the engineering studies.
 - c) Estimated duration of the engineering studies.
 - d) Additional information required to allow the completion of the engineering studies.
 - e) Study authorization agreement.
- 4) Comments on the schedule provided.
 - 5) If the rules of MISO (Midwest Independent System Operator) require that this interconnection request be processed through the MISO process, the Generation Interconnection Coordinator will notify the Applicant that the generation system is not eligible for review through the State of Minnesota process.

Step 3 Go-No Go Decision for Engineering Studies (By Applicant)

In this step, the Applicant will decide whether or not to proceed with the required engineering studies for the proposed generation interconnection. If no specialized engineering studies are required by the Area EPS Operator, the Area EPS Operator and the Applicant will automatically skip this step.

If the Applicant decides NOT to proceed with the engineering studies, the Applicant shall notify the Area EPS Generation Interconnection Coordinator, so other generation interconnection requests in the queue are not adversely impacted. Should the Applicant decide to proceed, the Applicant shall provide the following to the Area EPS Generation Interconnection Coordinator:

- 1) Payment required by the Area EPS Operator for the specialized engineering studies.
- 2) Additional information requested by the Area EPS Operator to allow completion of the engineering studies.

Step 4 Engineering Studies (By Area EPS)

In this step, the Area EPS Operator will be completing the specialized engineering studies for the proposed generation interconnection, as outlined in Step 2. These studies should be completed in the time frame provided in step 2, by the Area EPS. It is expected that the Area EPS Operator shall make all reasonable efforts to complete the Engineering Studies within the time frames shown below. If additional time is required to complete the engineering studies the Generation Interconnection Coordinator shall notify the Applicant and provide the reasons for the time extension. Upon receipt of written notice to proceed, payment of applicable fee, and receipt of all engineering study information requested by the Area EPS Operator in step 2, the Area EPS Operator shall initiate the engineering studies.

Generation System Size	Engineering Study Completion
<20kW	20 working days
20kW – 250kW	30 working days
250kW – 1MW	40 working days
> 1MW	90 working days

Once it is known by the Area EPS Operator that the actual costs for the engineering studies will exceed the estimated amount by more the 25%, then the Applicant shall be notified. The Area EPS Operator shall then provide the reason(s) for the studies needing to exceed the original estimated amount and provide an updated estimate of the total cost for the engineering studies. The Applicant shall be given the option of either withdrawing the application, or paying the additional estimated amount to continue with the engineering studies.

Step 5 Study Results and Construction Estimates (By Area EPS)

Upon completion of the specialized engineering studies, or if none was necessary, the following information will be provided to the Applicant.

- 1) Results of the engineering studies, if needed.
- 2) Monitoring & control requirements for the proposed generation.
- 3) Special protection requirements for the Generation System interconnection.
- 4) Comments on the schedule proposed by the Applicant.
- 5) Distributed Generation distribution constrained credits available
- 6) Interconnection Agreement (if applicable).
- 7) Cost estimate and payment schedule for required Area EPS work, including, but not limited to;
 - a) Labor costs related to the final design review.
 - b) Labor & expense costs for attending meetings
 - c) Required Dedicated Facilities and other Area EPS modification(s).
 - d) Final acceptance testing costs.

Step 6 Final Go-No Go Decision (By Applicant)

In this step, the Applicant shall again have the opportunity to indicate whether or not they want to proceed with the proposed generation interconnection. If the decision is NOT to proceed, the Applicant will notify the Area EPS Generation Interconnection Coordinator, so that other generation interconnections in the queue are not adversely impacted. Should the Applicant decide to proceed, a more detailed design, if not already completed by the Applicant, must be done, and the following information is to be supplied to the Area EPS Generation Interconnection Coordinator:

- 1) Applicable up-front payment required by the Area EPS, per Payment Schedule, provided in Step 5. (if applicable)
- 2) Signed Interconnection Agreement (if applicable).
- 3) Final proposed schedule, incorporating the Area EPS comments. The schedule of the project should include such milestones as foundations poured, equipment delivery dates, all conduit installed, cutover (energizing of the new switchgear/transfer switch), Area EPS work, relays set and tested, preliminary vendor testing, final Area EPS acceptance testing, and any other major milestones.
- 4) Detailed one-line diagram of the Generation System, including the generator, transfer switch/switchgear, service entrance, lockable and visible disconnect, metering, protection and metering CT's / VT's, protective relaying and generator control system.
- 5) Detailed information on the proposed equipment, including wiring diagrams, models and types.
- 6) Proposed relay settings for all interconnection required relays.
- 7) Detailed site plan of the Generation System.
- 8) Drawing(s) showing the monitoring system (as required per table 5A and section 5 of the "State of Minnesota Distributed Generation Interconnection Requirements". Including a drawing which shows the interface terminal block with the Area EPS monitoring system.
- 9) Proposed testing schedule and initial procedure, including:
 - a) Time of day (after-hours testing required?).
 - b) Days required.
 - c) Testing steps proposed.

Step 7 Final Design Review (By Area EPS)

Within 15 business days of receipt of the information required in Step 6, The Area EPS Generation Interconnection Coordinator will provide the Applicant with an estimated time table for final review. If the information required in Step 6 is not complete, the Applicant will be notified, within 10 business days of what information is missing. No further review may be completed until the missing information is submitted. The 15-business day clock will restart with the new submittal. This final design review shall not take longer than 15 additional business days to complete, for a total of 30 business days.

During this step, the Area EPS shall complete the review of the final Generation System design. If the final design has significant changes from the Generation System proposed on the original Application which invalidate the engineering studies or the preliminary engineering screening, the Generation System Interconnection Application request may be rejected by the Area EPS Operator and the Applicant may be requested to reapply with the revised design.

Upon completion of this step the Generation Interconnection Coordinator shall supply the following information to the Applicant.

- 1) Requested modifications or corrections of the detailed drawings provided by the Applicant.
- 2) Approval of and agreement with the Project Schedule. (This may need to be interactively discussed between the Parties, during this Step)
- 3) Final review of Distributed Generation Credit amount(s) (where applicable).
- 4) Initial testing procedure review comments. (Additional work on the testing process will occur during Step 8, once the actual equipment is identified)

Step 8 Order Equipment and Construction (By Both Parties)

The following activities shall be completed during this step. For larger installations this step will involve much interaction between the Parties. It is typical for approval drawings to be supplied by the Applicant to the Area EPS for review and comments. It is also typical for the Area EPS to require review and approval of the drawings that cover the interconnection equipment and interconnection protection system. If the Area EPS also requires remote control and/or monitoring, those drawings are also exchanged for review and comment.

By the Applicant's personnel:

- 1) Ordering of Generation System equipment.
- 2) Installing Generation System.
- 3) Submit approval drawings for interconnection equipment and protection systems, as required by Area EPS Operator.
- 4) Provide final relay settings provided to the Area EPS Operator.
- 5) Submit Completed and signed Engineering Data Submittal form.
- 6) Submit proof of insurance, as required by the Area EPS tariff(s) or interconnection agreements.
- 7) Submit required State of Minnesota electrical inspection forms ("blue Copy) filed with the Area EPS Operator.
- 8) Inspecting and functional testing Generation System components.
- 9) Work with the Area EPS personnel and equipment vendor(s) to finalize the installation testing procedure.

By Area EPS personnel:

- 1) Ordering any necessary Area EPS equipment.
- 2) Installing and testing any required equipment.
 - a) Monitoring facilities.
 - b) Dedicated Equipment.
- 3) Assisting Applicant's personnel with interconnection installation coordination issues
- 4) Providing review and input for testing procedures.

Step 9 Final Tests (By Area EPS / Applicant)

(Due to equipment lead times and construction, a significant amount of time may take place between the execution of Step 8 and Step 9.) During this time the final test steps are developed and the construction of the facilities are completed.

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Final acceptance testing will commence when all equipment has been installed, all contractor preliminary testing has been accomplished and all Area EPS preliminary testing of the monitoring and dedicated equipment is completed. One to three weeks prior to the start of the acceptance testing of the generation interconnection the Applicant shall provide, a report stating;

- that the Generation System meets all interconnection requirements.
- all contractor preliminary testing has been completed.
- the protective systems are functionally tested and ready.
- and provides a proposed date that the Generation System will be is ready to be energized and acceptance tested.

For non-type certified systems a Professional Electrical Engineer registered in the State of Minnesota is required to provide this formal report.

For smaller systems scheduling of this testing may be more flexible, as less testing time is required than for larger systems.

In many cases, this testing is done after hours to ensure no typical business-hour load is disturbed. If acceptance testing occurs after hours, the Area EPS Operator's labor will be billed at overtime wages. During this testing, the Area EPS Operator will typically run three different tests. These tests can differ depending on which type of communication / monitoring system(s) the Area EPS Operator decides to install at the site.

For, problems created by Area EPS or any Area EPS equipment that arise during testing, the Area EPS will fix the problem as soon as reasonably possible. If problems arise during testing which are caused by the Applicant or Applicant's vendor or any vendor supplied or installed equipment, the Area EPS will leave the project until the problem is resolved. Having the testing resume will then be subject to Area EPS personnel time and availability.

Step 10 (By Area EPS)

After all Area EPS Operator's acceptance testing has been accomplished and all requirements are met, the Area EPS Operator shall provide written approval for normal operation of the Generation System interconnection, within 3 business days of successful completion of the acceptance tests..

Step 11 (By Applicant)

Within two (2) months of interconnection, the Applicant shall provide the Area EPS with updated drawings and prints showing the Generation System as it were when approved for normal operation by the Area EPS Operator. The drawings shall include all changes which were made during construction and the testing process.

ATTACHMENT I PROCESS

Attachments:

Attached are several documents which may be required for the interconnection process. They are as follows;

Appendix A:

Flow chart showing summary of the interconnection process.

Appendix B:

Generation Interconnection Application Form.

Appendix C:

Engineering Data Submittal Form.

Appendix D:

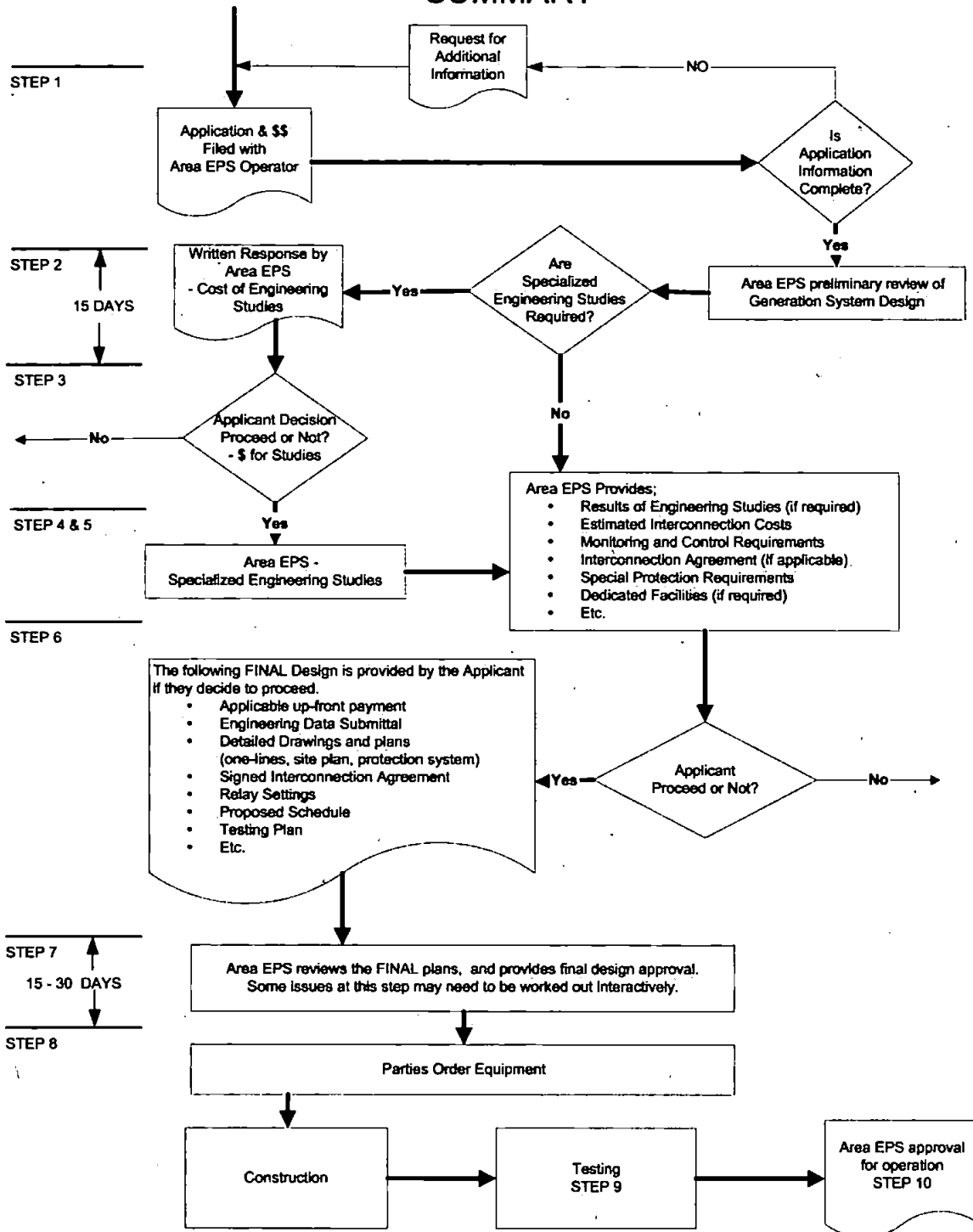
Engineering Studies: Brief description of the types of possible Engineering Studies that may be required for the review of the Generation System interconnection.

Appendix E:

State of Minnesota Interconnection Agreement for the Interconnection of Extended Paralleled Distributed Generation Systems with Electric Utilities.

APPENDIX A

DISTRIBUTED GENERATION INTERCONNECTION PROCESS SUMMARY



APPENDIX B

**INSERT
INTERCONNECTION
APPLICATION
FORM**

APPENDIX C

**INSERT
ENGINEERING DATA
SUBMITTAL
FORM**

APPENDIX D

Engineering Studies

For the engineering studies there are two main parts of the study: 1. Does the distributed generator cause a problem? and 2. What would it cost to make a change to handle the problem.? The first question is relatively straightforward to determine as the Area EPS Engineer reviews the proposed installation. The second question typically has multiple alternatives and can turn into an iterative process. This iterative process can become quite large for more complex generation installations. For the Engineer there is no "cook book" solution which can be applied.

For some of the large generation installations and/or the more complex interconnections the Area EPS Operator may suggest dividing up the engineering studies into the two parts; identify the scope of the problems and attempt to identify solutions to resolve the problems. By splitting the engineering studies into two steps, it will allow for the Applicant to see the problems identified and to provide the Applicant the ability to remove the request for interconnection if the problems are too large and expensive to resolve. This would then save the additional costs to the Applicant for the more expensive engineering studies; to identify ways to resolve the problem(s).

This appendix provides an overview of some of the main issues that are looked at during the engineering study process. Every interconnection has its unique issues, such as relative strength of the distribution system, ratio of the generation size to the existing area loads, etc. Thus many of the generation interconnections will require further review of one or several of the issues listed.

- Short circuit analysis – the system is studied to make sure that the addition of the generation will not over stress any of the Area EPS equipment and that equipment will still be able to clear during a fault. It is expected that the Applicant will complete their own short circuit analysis on their equipment to ensure that the addition of the generation system does not overstress the Applicant's electrical equipment.
- Power Flow and Voltage Drop
 - Reviews potential islanding of the generation
 - Will Area EPS Equipment be overloaded
 - Under normal operation?
 - Under contingent operation? With backfeeds?
- Flicker Analysis –
 - Will the operation of the generation cause voltage swings?
 - When it loads up? When it off loads?
 - How will the generation interact with Area EPS voltage regulation?
 - Will Area EPS capacitor switching affect the generation while on-line?
- Protection Coordination
 - Reclosing issues – this is where the reclosing for the distribution system and transmission system are looked at to see if the Generation System protection can be set up to ensure that it will clear from the distribution system before the feeder is reenergized.
 - Is voltage supervision of reclosing needed?
 - Is transfer-trip required?
 - Do we need to modify the existing protection systems? Existing settings?
 - At which points do we need "out of sync" protection?
 - Is the proposed interconnection protection system sufficient to sense a problem on the Area EPS?
 - Are there protection problems created by the step-up transformer?

ATTACHMENT 1 PROCESS

- Grounding Reviews
 - Does the proposed grounding system for the Generation System meet the requirements of the NESC? "National Electrical Safety Code" published by the Institute of Electrical and Electronics Engineers (IEEE)
- System Operation Impact.
 - Are special operating procedures needed with the addition of the generation?
 - Reclosing and out of sync operation of facilities.
 - What limitations need to be placed on the operation of the generation?
 - Operational VAR requirements?

APPENDIX E

INSERT

**STATE OF MINNESOTA
INTERCONNECTION AGREEMENT**

FOR THE

**INTERCONNECTION OF EXTENDED PARALLELED DISTRIBUTION
GENERATION SYSTEMS**

WITH

ELECTRIC UTILITIES

STATE OF MINNESOTA DISTRIBUTED GENERATION INTERCONNECTION REQUIREMENTS

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Foreword

Electric distribution system connected generation units span a wide range of sizes and electrical characteristics. Electrical distribution system design varies widely from that required to serve the rural customer to that needed to serve the large commercial customer. With so many variations possible, it becomes complex and difficult to create one interconnection standard that fits all generation interconnection situations.

In establishing a generation interconnection standard there are three main issues that must be addressed; Safety, Economics and Reliability.

The first and most important issue is safety; the safety of the general public and of the employees working on the electrical systems. This standard establishes the technical requirements that must be met to ensure the safety of the general public and of the employees working with the Area EPS. Typically designing the interconnection system for the safety of the general public will also provide protection for the interconnected equipment.

The second issue is economics; the interconnection design must be affordable to build. The interconnection standard must be developed so that only those items, that are necessary to meet safety and reliability, are included in the requirements. This standard sets the benchmark for the minimum required equipment. If it is not needed, it will not be required.

The third issue is reliability; the generation system must be designed and interconnected such that the reliability and the service quality for all customers of the electrical power systems are not compromised. This applies to all electrical systems not just the Area EPS.

Many generation interconnection standards exist or are in draft form. The IEEE, FERC and many states have been working on generation interconnection standards. There are other standards such as the National Electrical Code (NEC) that, establish requirements for electrical installations. The NEC requirements are in addition to this standard. This standard is designed to document the requirements where the NEC has left the establishment of the standard to "the authority having jurisdiction" or to cover issues which are not covered in other national standards.

This standard covers installations, with an aggregated capacity of 10MW's or less. Many of the requirements in this document do not apply to small, 40kW or less generation installations. As an aid to the small, distributed generation customer, these small unit interconnection requirements have been extracted from this full standard and are available as a separate, simplified document titled: "Standards for Interconnecting Generation Sources, Rated Less than 40kW with Minnesota Electric Utilities"

1. Introduction

This standard has been developed to document the technical requirements for the interconnection between a Generation System and an area electrical power system "Utility system or Area EPS". This standard covers 3 phase Generation Systems with an aggregate capacity of 10 MW's or less and single phase Generation Systems with a aggregate capacity of 40kW or less at the Point of Common Coupling. This standard covers Generation Systems that are interconnected with the Area EPS's distribution facilities. This standard does not cover Generation Systems that are directly interconnected with the Area EPS's Transmission System, Contact the Area EPS for their Transmission System interconnection standards.

While, this standard provides the technical requirements for interconnecting a Generation System with a typical radial distribution system, it is important to note that there are some unique Area EPS, which have special interconnection needs. One example of a unique Area EPS would be one operated as a "networked" system. This standard does not cover the additional special requirements of those systems. The Interconnection Customer must contact the Owner/operator of the Area EPS with which the interconnection is intended, to make sure that the Generation System is not proposed to be interconnected with a unique Area EPS. If the planned interconnection is with a unique Area EPS, the Interconnection Customer must obtain the additional requirements for interconnecting with the Area EPS.

The Area EPS operator has the right to limit the maximum size of any Generation System or number of Generation Systems that, may want to interconnect, if the Generation System would reduce the reliability to the other customers connected to the Area EPS.

This standard only covers the technical requirements and does not cover the interconnection process from the planning of a project through approval and construction. Please read the companion document "State of Minnesota Interconnection Process for Distributed Generation Systems" for the description of the procedure to follow and a generic version of the forms to submit. It is important to also get copies of the Area EPS's tariff's concerning generation interconnection which will include rates, costs and standard interconnection agreements. The earlier the Interconnection Customer gets the Area EPS operator involved in the planning and design of the Generation System interconnection the smoother the process will go.

A) Definitions

The definitions defined in the "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems" (1547 Draft Ver. 11) apply to this document as well. The following definitions are in addition to the ones defined in IEEE 1547 , or are repeated from the IEEE 1547 standard.

- i) "Area EPS" an electric power system (EPS) that serves Local EPS's. Note. Typically, an Area EPS has primary access to public rights-of-way, priority crossing of property boundaries, etc.
- ii) "Generation" any device producing electrical energy, i.e., rotating generators driven by wind, steam turbines, internal combustion engines, hydraulic turbines, solar, fuel cells, etc.; or any other electric producing device, including energy storage technologies.
- iii) "Generation System" the interconnected Distributed Generation(s), controls, relays, switches, breakers, transformers, inverters and associated wiring and cables, up to the Point of Common Coupling.
- iv) "Interconnection Customer" the party or parties who are responsible for meeting the requirements of this standard. This could be the Generation System applicant, installer, designer, owner or operator.
- v) "Local EPS" an electric power system (EPS) contained entirely within a single premises or group of premises.
- vi) "Point of Common Coupling" the point where the Local EPS is connected to an Area EPS.
- vii) "Transmission System", are those facilities as defined by using the guidelines established by the Minnesota State Public Utilities Commission; "In the Matter of Developing Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions." Docket No. E-015/M-99-1002.
- viii) "Type-Certified" Generation paralleling equipment that is listed by an OSHA listed national testing laboratory as having met the applicable type testing requirement of UL 1741. At the time is document was prepared this was the only national standard available for certification of generation transfer switch equipment. This definition does not preclude other forms of type-certification if agreeable to the Area EPS operator.

B) Interconnection Requirements Goals

This standard defines the minimum technical requirements for the implementation of the electrical interconnection between the Generation System and the Area EPS. It does not define the overall requirements for the Generation System. The requirements in this standard are intended to achieve the following:

- i) Ensure the safety of utility personnel and contractors working on the electrical power system.
- ii) Ensure the safety of utility customers and the general public.
- iii) Protect and minimize the possible damage to the electrical power system and other customer's property.

- iv) Ensure proper operation to minimize adverse operating conditions on the electrical power system.

C) Protection

The Generation System and Point of Common Coupling shall be designed with proper protective devices to promptly and automatically disconnect the Generation from the Area EPS in the event of a fault or other system abnormality. The type of protection required will be determined by:

- i) Size and type of the generating equipment.
- ii) The method of connecting and disconnecting the Generation System from the electrical power system.
- iii) The location of generating equipment on the Area EPS.

D) Area EPS Modifications

Depending upon the match between the Generation System, the Area EPS and how the Generation System is operated, certain modifications and/or additions may be required to the existing Area EPS with the addition of the Generation System. To the extent possible, this standard describes the modifications which could be necessary to the Area EPS for different types of Generation Systems. For some unique interconnections, additional and/or different protective devices, system modifications and/or additions will be required by the Area EPS operator; In these cases the Area EPS operator will provide the final determination of the required modifications and/or additions. If any special requirements are necessary they will be identified by the Area EPS operator during the application review process.

E) Generation System Protection

The Interconnection Customer is solely responsible for providing protection for the Generation System. Protection systems required in this standard, are structured to protect the Area EPS's electrical power system and the public. The Generation System Protection is not provided for in this standard. Additional protection equipment may be required to ensure proper operation for the Generation System. This is especially true while operating disconnected, from the Area EPS. The Area EPS does not assume responsibility for protection of the Generation System equipment or of any portion Local EPS.

F) Electrical Code Compliance

Interconnection Customer shall be responsible for complying with all applicable local, independent, state and federal codes such as building codes, National Electric Code (NEC), National Electrical Safety Code (NESC) and noise and emissions standards. As required by Minnesota State law, the Area EPS will require proof of complying with the National Electrical Code before the interconnection is made, through installation approval by an electrical inspector recognized by the Minnesota State Board of Electricity.

The Interconnection Customer's Generation System and installation shall comply with latest revisions of the ANSI/IEEE standards applicable to the installation, especially IEEE 1547; "Standard for Interconnecting Distributed Resources with Electric Power Systems". See the reference section in this document for a partial list of the standards which apply to the generation installations covered by this standard.

2. References

The following standards shall be used in conjunction with this standard. When the stated version of the following standards is superseded by an approved revision then that revision shall apply.

IEEE Std 100-2000, "IEEE Standard Dictionary of Electrical and Electronic Terms"

IEEE Std 519-1992, "IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems"

IEEE Std 929-2000, "IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems"

IEEE Std 1547, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems"

IEEE Std C37.90.1-1989 (1995), "IEEE Standard Surge Withstand Capability (SEC) Tests for Protective Relays and Relay Systems"

IEEE Std C37.90.2 (1995), "IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers"

IEEE Std C62.41.2-2002, "IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits"

IEEE Std C62.42-1992 (2002), "IEEE Recommended Practice on Surge Testing for Equipment Connected to Low Voltage (1000V and less) AC Power Circuits"

ANSI C84.1-1995, "Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)"

ANSI/IEEE 446-1995, "Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications"

ANSI/IEEE Standard 142-1991, "IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems – Green Book"

UL Std. 1741 "Inverters, Converters, and Controllers for use in Independent Power Systems"

NEC – "National Electrical Code", National Fire Protection Association (NFPA), NFPA-70-2002

NESC – "National Electrical Safety Code". ANSI C2-2000, Published by the Institute of Electrical and Electronics Engineers, Inc.

3. Types of Interconnections

A) The manner in which the Generation System is connected to and disconnected from the Area EPS can vary. Most transfer systems normally operate using one of the following five methods of transferring the load from the Area EPS to the Generation System.

B) If a transfer system is installed which has a user accessible selection of several transfer modes, the transfer mode that has the greatest protection requirements will establish the protection requirements for that transfer system.

i) Open Transition (Break-Before-Make) Transfer Switch – With this transfer switch, the load to be supplied from the Distributed Generation is first disconnected from the Area EPS and then connected to the Generation. This transfer can be relatively quick, but voltage and frequency excursions are to be expected during transfer. Computer equipment and other sensitive equipment will shut down and reset. The transfer switch typically consists of a standard UL approved transfer switch with mechanical interlocks between the two source contactors that drop the Area EPS source before the Distributed Generation is connected to supply the load.

(1) To qualify as an Open Transition switch and the limited protective requirements, mechanical interlocks are required between the two source contacts. This is required to ensure that one of the contacts is always open and the Generation System is never operated in parallel with the Area EPS. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch.

(2) As a practical point of application, this type of transfer switch is typically used for loads less than 500kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending up the Area EPS's stiffness this level may be larger or smaller than the 500kW level.

(3) Figure 1 at the end of this document provides a typical one-line of this type of installation.

ii) Quick Open Transition (Break-Before-Make) Transfer Switch – The load to be supplied from the Distributed Generation is first disconnected from the Area EPS and then connected to the Distributed Generation, similar to the open transition. However, this transition is typically much faster (under 500 ms) than the conventional open transition transfer operation. Voltage and frequency excursions will still occur, but some computer equipment and other sensitive equipment will typically not be affected with a properly designed system. The transfer switch consists of a standard UL approved transfer switch, with mechanical interlocks between the two source contacts that drop the Area EPS source before the Distributed Generation is connected to supply the load.

(1) Mechanical interlocks are required between the two source contacts to ensure that one of the contacts is always open. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch

(2) As a practical point of application this type of transfer switch is typically used for loads less than 500kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending up the Area EPS's stiffness this level may be larger or smaller than the 500kW level.

(3) Figure 2 at the end of this document provides a typical one-line of this type of installation

and shows the required protective elements.

iii) Closed Transition (Make-Before-Break) Transfer Switch – The Distributed Generation is synchronized with the Area EPS prior to the transfer occurring. The transfer switch then parallels with the Area EPS for a short time (100 msec. or less) and then the Generation System and load is disconnect from the Area EPS. This transfer is less disruptive than the Quick Open Transition because it allows the Distributed Generation a brief time to pick up the load before the support of the Area EPS is lost. With this type of transfer, the load is always being supplied by the Area EPS or the Distributed Generation.

- (1) As a practical point of application this type of transfer switch is typically used for loads less than 500kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending up the Area EPS's stiffness this level may be larger or smaller than the 500kW level.
- (2) Figure 2 at the end of this document provides a typical one-line of this type of installation and shows the required protective elements. The closed transition switch must include a separate parallel time limit relay, which is not part of the generation control PLC and trips the generation from the system for a failure of the transfer switch and/or the transfer switch controls.

iv) Soft Loading Transfer Switch

- (1) With Limited Parallel Operation – The Distributed Generation is paralleled with the Area EPS for a limited amount of time (generally less than 1-2 minutes) to gradually transfer the load from the Area EPS to the Generation System. This minimizes the voltage and frequency problems, by softly loading and unloading the Generation System.
 - (a) The maximum parallel operation shall be controlled, via a parallel timing limit relay (62PL). This parallel time limit relay shall be a separate relay and not part of the generation control PLC.
 - (b) Protective Relaying is required as described in section 6.
 - (c) Figure 3 at the end of this document provide typical one-line diagrams of this type of installation and show the required protective elements.
- (2) With Extended Parallel Operation – The Generation System is paralleled with the Area EPS in continuous operation. Special design, coordination and agreements are required before any extended parallel operation will be permitted. The Area EPS interconnection study will identify the issues involved.
 - (a) Any anticipated use in the extended parallel mode requires special agreements and special protection coordination.
 - (b) Protective Relaying is required as described in section 6.
 - (c) Figure 4 at the end of this document provides a typical one-line for this type of interconnection. It must be emphasized that this is a typical installations only and final installations may vary from the examples shown due to transformer connections, breaker configuration, etc.

v) Inverter Connection

This is a continuous parallel connection with the system. Small Generation Systems may utilize inverters to interface to the Area EPS. Solar, wind and fuel cells are some examples of Generation which typically use inverters to connect to the Area EPS. The design of such inverters shall either contain all necessary protection to prevent unintentional islanding, or the

ATTACHMENT 2 REQUIREMENTS

Interconnection Customer shall install conventional protection to affect the same protection. All required protective elements for a soft-loading transfer switch apply to an inverter connection. Figure 5 at the end of this document, shows a typical inverter interconnection.

- (1) Inverter Certification – Prior to installation, the inverter shall be Type-Certified for interconnection to the electrical power system. The certification will confirm its anti-islanding protection and power quality related levels at the Point of Common Coupling. Also, utility compatibility, electric shock hazard and fire safety are approved through UL listing of the model. Once this Type Certification is completed for that specific model, additional design review of the inverter should not be necessary by the Area EPS operator.
- (2) For three-phase operation, the inverter control must also be able to detect and separate for the loss of one phase. Larger inverters will still require custom protection settings, which must be calculated and designed to be compatible with the specific Area EPS being interconnected with.
- (3) A visible disconnect is required for safely isolating the Distributed Generation when connecting with an inverter. The inverter shall not be used as a safety isolation device.
- (4) When banks of inverter systems are installed at one location, a design review by the Area EPS must be performed to determine any additional protection systems, metering or other needs. The issues will be identified by the Area EPS during the interconnection study process

4. Interconnection Issues and Technical Requirements

A) General Requirements - The following requirements apply to all interconnected generating equipment. The Area EPS shall be the source side and the customer's system shall be the load side in the following interconnection requirements.

- i) Visible Disconnect - A disconnecting device shall be installed to electrically isolate the Area EPS from the Generation System. The only exception for the installation of a visible disconnect is if the generation is interconnected via a mechanically interlocked open transfer switch and installed per the NEC (702.6) "so as to prevent the inadvertent interconnection of normal and alternate sources of supply in any operation of the transfer equipment."

The visible disconnect shall provide a visible air gap between Interconnection Customer's Generation and the Area EPS in order to establish the safety isolation required for work on the Area EPS. This disconnecting device shall be readily accessible 24 hours per day by the Area EPS field personnel and shall be capable of padlocking by the Area EPS field personnel. The disconnecting device shall be lockable in the open position.

The visible disconnect shall be a UL approved or National Electrical Manufacture's Association approved, manual safety disconnect switch of adequate ampere capacity. The visible disconnect shall not open the neutral when the switch is open. A draw-out type circuit breaker can be used as a visual open.

The visible disconnect shall be labeled, as required by the Area EPS Operator to inform the Area EPS field personnel.

- ii) Energization of Equipment by Generation System - The Generation System shall not energize a de-energized Area EPS. The Interconnection Customer shall install the necessary padlocking (lockable) devices on equipment to prevent the energization of a de-energized electrical power system. Lock out relays shall automatically block the closing of breakers or transfer switches on to a de-energized Area EPS.

- iii) Power Factor - The power factor of the Generation System and connected load shall be as follows;

- (1) Inverter Based interconnections - shall operate at a power factor of no less than 90% at the inverter terminals.
- (2) Limited Parallel Generation Systems, such as closed transfer or soft-loading transfer systems shall operate at a power factor of no less than 90%, during the period when the Generation System is parallel with the Area EPS, as measured at the Point of Common Coupling.
- (3) Extended Parallel Generation Systems shall be designed to be capable of operating between 90% lagging and 95% leading. These Generation Systems shall normally operate near unity power factor (+/-98%) or as mutually agreed between the Area EPS operator and the Interconnection Customer.

- iv) Grounding Issues

- (1) Grounding of sufficient size to handle the maximum available ground fault current shall be designed and installed to limit step and touch potentials to safe levels as set forth in "IEEE Guide for Safety in AC Substation Grounding", ANSI/IEEE Standard 80.

- (2) It is the responsibility of the Interconnection Customer to provide the required grounding

ATTACHMENT 2 REQUIREMENTS

for the Generation System. A good standard for this is the IEEE Std. 142-1991 "Grounding of Industrial and Commercial Power Systems"

(3) All electrical equipment shall be grounded in accordance with local, state and federal electrical and safety codes and applicable standards

v) Sales to Area EPS or other parties – Transportation of energy on the Transmission system is regulated by the area reliability council and FERC. Those contractual requirements are not included in this standard. The Area EPS will provide these additional contractual requirements during the interconnection approval process.

B) For Inverter based, closed transfer and soft loading interconnections - The following additional requirements apply:

i) Fault and Line Clearing - The Generation System shall be removed from the Area EPS for any faults, or outages occurring on the electrical circuit serving the Generation System

ii) Operating Limits in order to minimize objectionable and adverse operating conditions on the electric service provided to other customers connected to the Area EPS, the Generation System shall meet the Voltage, Frequency, Harmonic and Flicker operating criteria as defined in the IEEE 1547 standard during periods when the Generation System is operated in parallel with the Area EPS.

If the Generation System creates voltage changes greater than 4% on the Area EPS, it is the responsibility of the Interconnection Customer to correct these voltage sag/swell problems caused by the operation of the Generation System. If the operation of the interconnected Generation System causes flicker, which causes problems for others customer's interconnected to the Area EPS, the Interconnection Customer is responsible for correcting the problem.

iii) Flicker - The operation of Generation System is not allowed to produce excessive flicker to adjacent customers. See the IEEE 1547 standard for a more complete discussion on this requirement.

The stiffer the Area EPS, the larger a block load change that it will be able to handle. For any of the transfer systems the Area EPS voltage shall not drop or rise greater than 4% when the load is added or removed from the Area EPS. It is important to note, that if another interconnected customer complains about the voltage change caused by the Generation System, even if the voltage change is below the 4% level, it is the Interconnection Customer's responsibility to correct or pay for correcting the problem. Utility experience has shown that customers have seldom objected to instantaneous voltage changes of less than 2% on the Area EPS, so most Area EPS operators use a 2% design criteria

iv) Interference - The Interconnection Customer shall disconnect the Distributed Generation from the Area EPS if the Distributed Generation causes radio, television or electrical service interference to other customers, via the EPS or interference with the operation of Area EPS. The Interconnection Customer shall either effect repairs to the Generation System or reimburse the Area EPS Operator for the cost of any required Area EPS modifications due to the interference.

v) Synchronization of Customer Generation-

- (1) An automatic synchronizer with synch-check relaying is required for unattended automatic quick open transition, closed transition or soft loading transfer systems.
- (2) To prevent unnecessary voltage fluctuations on the Area EPS, it is required that the synchronizing equipment be capable of closing the Distributed Generation into the Area EPS within the limits defined in IEEE 1547 . Actual settings shall be determined by the Registered Professional Engineer establishing the protective settings for the installation.
- (3) Unintended Islanding – Under certain conditions with extended parallel operation, it would be possible for a part of the Area EPS to be disconnected from the rest of the Area EPS and have the Generation System continue to operate and provide power to a portion of the isolated circuit. This condition is called "islanding". It is not possible to successfully reconnect the energized isolated circuit to the rest of the Area EPS since there are no synchronizing controls associated with all of the possible locations of disconnection. Therefore, it is a requirement that the Generation System be automatically disconnected from the Area EPS immediately by protective relays for any condition that would cause the Area EPS to be de-energized. The Generation System must either isolate with the customer's load or trip. The Generation System must also be blocked from closing back into the Area EPS until the Area EPS is reenergized and the Area EPS voltage is within Range B of ANSI C84.1 Table 1 for a minimum of 1 minute. Depending upon the size of the Generation System it may be necessary to install direct transfer trip equipment from the Area EPS source(s) to remotely trip the generation interconnection to prevent islanding for certain conditions

vi) Disconnection – the Area EPS operator may refuse to connect or may disconnect a Generation System from the Area EPS under the following conditions:

- (1) Lack of approved Standard Application Form and Standard Interconnection Agreement.
- (2) Termination of interconnection by mutual agreement.
- (3) Non-Compliance with the technical or contractual requirements.
- (4) System Emergency or for imminent danger to the public or Area EPS personnel (Safety).
- (5) Routine maintenance, repairs and modifications to the Area EPS. The Area EPS operator shall coordinate planned outages with the Interconnection Customer to the extent possible.

5. Generation Metering, Monitoring and Control

Metering, Monitoring and Control – Depending upon the method of interconnection and the size of the Generation System, there are different metering, monitoring and control requirements Table 5A is a table summarizing the metering, monitoring and control requirements..

Due to the variation in Generation Systems and Area EPS operational needs, the requirements for metering, monitoring and control listed in this document are the expected maximum requirements that the Area EPS will apply to the Generation System. It is important to note that for some Generation System installations the Area EPS may wave some of the requirements of this section if they are not needed. An example of this is with rural or low capacity feeders which require more monitoring then larger capacity, typically urban feeders.

Another factor which will effect the metering, monitoring and control requirements will be the tariff under which the Interconnection Customer is supplied by the Area EPS. Table 5A has been written to cover most application, but some Area EPS tariffs may have greater or less metering, monitoring and control requirements then, as shown in Table 5A. .

TABLE 5A Metering, Monitoring and Control Requirements			
Generation System Capacity at Point of Common Coupling	Metering	Generation Remote Monitoring	Generation Remote Control
< 40 kW with all sales to Area EPS	Bi-Directional metering at the point of common coupling	None Required	None Required
< 40 kW with Sales to a party other than the Area EPS	Recording metering on the Generation System and a separate recording meter on the load	Interconnection Customer supplied direct dial phone line.	None Required
40 – 250kW with limited parallel	Detented Area EPS Metering at the Point of Common Coupling	None Required	None Required
40 – 250kW with extended parallel	Recording metering on the Generation System and a separate recording meter on the load	Interconnection Customer supplied direct dial phone line. Area EPS to supply it's own monitoring equipment	None Required
250 – 1000 kW with limited parallel	Detented Area EPS Metering at the Point of Common Coupling	Interconnection Customer supplied direct dial phone line and monitoring points available. See B (i)	None Required
250 – 1000 kW With extended parallel operation	Recording metering on the Generation System and a separate recording meter on the load.	Required Area EPS remote monitoring system See B (i)	None Required
>1000 kW With limited parallel Operation	Detented Area EPS Metering at the Point of Common Coupling	Required Area EPS SCADA monitoring system. See B (i)	None required
>1000 kW With extended parallel operation	Recording metering on the Generation System and a separate recording meter on the load.	Required Area EPS SCADA monitoring system See B (i)	Direct Control via SCADA by Area EPS of interface breaker.

"Detented" = A meter which is detented will record power flow in only one direction.

A) Metering

- i) As shown in Table 5A the requirements for metering will depend up on the type of generation and the type of interconnection. For most installations, the requirement is a single point of metering at the Point of Common Coupling. The Area EPS Operator will install a special meter that is capable of measuring and recording energy flow in both directions, for three phase installations or two detented meters wired in series, for single phase installations.. A dedicated - direct dial phone line may be required to be supplied to the meter for the Area EPS's use to read the metering. Some monitoring may be done through the meter and the dedicated - direct dial phone line, so in many installations the remote monitoring and the meter reading can be done using the same dial-up phone line.
- ii) Depending upon which tariff the Generation System and/or customer's load is being supplied under, additional metering requirements may result. Contact the Area EPS for tariff requirements. In some cases, the direct dial-phone line requirement may be waived by the Area EPS for smaller Generation Systems.
- iii) All Area EPS's revenue meters shall be supplied, owned and maintained by the Area EPS. All voltage transformers (VT) and current transformers (CT), used for revenue metering shall be approved and/or supplied by the Area EPS. Area EPS's standard practices for instrument transformer location and wiring shall be followed for the revenue metering.
- iv) For Generation Systems that sell power and are greater then 40kW in size, separate metering of the generation and of the load is required. A single meter recording the power flow at the Point of Common Coupling for both the Generation and the load, is not allowed by the rules under which the area transmission system is operated. The Area EPS is required to report to the regional reliability council (MAPP) the total peak load requirements and is also required to own or have contracted for, accredited generation capacity of 115% of the experienced peak load level for each month of the year. Failure to meet this requirement results in a large monetary penalty for the Area EPS operator.
- v) For Generation Systems which are less then 40kW in rated capacity and are qualified facilities under PURPA (Public Utilities Regulatory Power Act – Federal Gov. 1978), net metering is allowed and provides the generation system the ability to back feed the Area EPS at some times and bank that energy for use at other times. Some of the qualified facilities under PURPA are solar, wind, hydro, and biomass. For these net-metered installations, the Area EPS may use a single meter to record the bi-directional flow or the Area EPS Operator may elect to use two detented meters, each one to record the flow of energy in one direction.

B) Monitoring (SCADA) is required as shown in table 5A. The need for monitoring is based on the need of the system control center to have the information necessary for the reliable operation of the Area EPS's. This remote monitoring is especially important during periods of abnormal and emergency operation.

The difference in Table 5A between remote monitoring and SCADA is that SCADA typically is a system that is in continuous communication with a central computer and provides updated values and status, to the Area EPS operator, within several seconds of the changes in the field. Remote monitoring on the other hand will tend to provide updated values and status within minutes of the change in state of the field. Remote monitoring is typically less expensive to install and operate.

- i) Where Remote Monitoring or SCADA is required, as shown in Table 5A, the following monitored and control points are required:

- (1) Real and reactive power flow for each Generation System (kW and kVAR). Only required if separate metering of the Generation and the load is required, otherwise #4 monitored at

the point of Common Coupling will meet the requirements.

- (2) Phase voltage representative of the Area EPS's service to the facility.
- (3) Status (open/close) of Distributed Generation and interconnection breaker(s) or if transfer switch is used, status of transfer switch(s).
- (4) Customer load from Area EPS service (kW and kVAR).
- (5) Control of interconnection breaker - if required by the Area EPS operator.

When telemetry is required, the Interconnection Customer must provide the communications medium to the Area EPS's Control Center. This could be radio, dedicated phone circuit or other form of communication. If a telephone circuit is used, the Interconnection Customer must also provide the telephone circuit protection. The Interconnection Customer shall coordinate the RTU (remote terminal unit) addition with the Area EPS. The Area EPS may require a specific RTU and/or protocol to match their SCADA or remote monitoring system.

6. Protective Devices and Systems

A) Protective devices required to permit safe and proper operation of the Area EPS while interconnected with customer's Generation System are shown in the figures at the end of this document. In general, an increased degree of protection is required for increased Distributed Generation size. This is due to the greater magnitude of short circuit currents and the potential impact to system stability from these installations. Medium and large installations require more sensitive and faster protection to minimize damage and ensure safety.

If a transfer system is installed which has a user accessible selection of several transfer modes, the transfer mode which has the greatest protection requirements will establish the protection requirements for that transfer system.

The Interconnection Customer shall provide protective devices and systems to detect the Voltage, Frequency, Harmonic and Flicker levels as defined in the IEEE 1547 standard during periods when the Generation System is operated in parallel with the Area EPS. The Interconnection Customer shall be responsible for the purchase, installation, and maintenance of these devices. Discussion on the requirements for these protective devices and systems follows:

i) Relay settings

- (1) If the Generation System is utilizing a Type-Certified system, such as a UL listed inverter a Professional Electrical Engineer is not required to review and approve the design of the interconnecting system. If the Generation System interconnecting device is not Type-Certified or if the Type-Certified Generation System interconnecting device has additional design modifications made, the Generation System control, the protective system, and the interconnecting device(s) shall be reviewed and approved by a Professional Electrical Engineer, registered in the State of Minnesota.
- (2) A copy of the proposed protective relay settings shall be supplied to the Area EPS operator for review and approval, to ensure proper coordination between the generation system and the Area EPS.

ii) Relays

- (1) All equipment providing relaying functions shall meet or exceed ANSI/IEEE Standards for protective relays, i.e., C37.90, C37.90.1 and C37.90.2.
- (2) Required relays that are not "draw-out" cased relays shall have test plugs or test switches installed to permit field testing and maintenance of the relay without unwiring or disassembling the equipment. Inverter based protection is excluded from this requirement for Generation Systems <40kW at the Point of Common Coupling.
- (3) Three phase interconnections shall utilize three phase power relays, which monitor all three phases of voltage and current, unless so noted in the appendix one-lines.
- (4) All relays shall be equipped with setting limit ranges at least as wide as specified in IEEE 1547 , and meet other requirements as specified in the Area EPS interconnect study. Setting limit ranges are not to be confused with the actual relay settings required for the proper operation of the installation. At a minimum, all protective systems shall meet the requirements established in IEEE 1547 .

(a) Over-current relays (IEEE Device 50/51 or 50/51V) shall operate to trip the protecting

ATTACHMENT 2 REQUIREMENTS

breaker at a level to ensure protection of the equipment and at a speed to allow proper coordination with other protective devices. For example, the over-current relay monitoring the interconnection breaker shall operate fast enough for a fault on the customer's equipment, so that no protective devices will operate on the Area EPS. 51V is a voltage restrained or controlled over-current relay and may be required to provide proper coordination with the Area EPS.

(b) Over-voltage relays (IEEE Device 59) shall operate to trip the Distributed Generation per the requirements of IEEE 1547 .

(c) Under-voltage relays (IEEE Device 27) shall operate to trip the Distributed Generation per the requirements of IEEE 1547

(d) Over-frequency relays (IEEE Device 81O) shall operate to trip the Distributed Generation off-line per the requirements of IEEE 1547 .

(e) Under-frequency relay (IEEE Device 81U) shall operate to trip the Distributed Generation off-line per the requirements of IEEE 1547 . For Generation Systems with an aggregate capacity greater than 30kW, the Distributed Generation shall trip off-line when the frequency drops below 57.0-59.8 Hz. typically this is set at 59.5 Hz, with a trip time of 0.16 seconds, but coordination with the Area EPS is required for this setting.

The Area EPS will provide the reference frequency of 60 Hz. The Distributed Generation control system must be used to match this reference. The protective relaying in the interconnection system will be expected to maintain the frequency of the output of the Generation.

(f) Reverse power relays (IEEE Device 32) (power flowing from the Generation System to the Area EPS) shall operate to trip the Distributed Generation off-line for a power flow to the system with a maximum time delay of 2.0 seconds.

(g) Lockout Relay (IEEE Device 86) is a mechanically locking device which is wired into the close circuit of a breaker or switch and when tripped will prevent any close signal from closing that device. This relay requires that a person manually resets the lockout relay before that device can be reclosed. These relays are used to ensure that a deenergized system is not reenergized by automatic control action, and prevents a failed control from auto-reclosing an open breaker or switch.

(h) Transfer Trip – All Generation Systems are required to disconnect from the Area EPS when the Area EPS is disconnected from its source, to avoid unintentional islanding. With larger Generation Systems, which remain in parallel with the Area EPS, a transfer trip system may be required to sense the loss of the Area EPS source. When the Area EPS source is lost, a signal is sent to the Generation System to separate the Generation from the Area EPS. The size of the Generation System vs the capacity and minimum loading on the feeder will dictate the need for transfer trip installation. The Area EPS interconnection study will identify the specific requirements.

If multiple Area EPS sources are available or multiple points of sectionalizing on the Area EPS, then more than one transfer trip system may be required. Area EPS interconnection study will identify the specific requirements. For some installations the alternate Area EPS source(s) may not be utilized except in rare occasions. If this is the situation, the Interconnection Customer may elect to have the Generation System locked out when the alternate source(s) are utilized, if agreeable to the Area EPS operator.

ATTACHMENT 2 REQUIREMENTS

- (i) Parallel limit timing relay (IEEE Device 62PL) set at a maximum of 120 seconds for soft transfer installations and set no longer than 100ms for quick transfer installations, shall trip the Distributed Generation circuit breaker on limited parallel interconnection systems. Power for the 62 PL relay must be independent of the transfer switch control power. The 62PL timing must be an independent device from the transfer control and shall not be part of the generation PLC or other control system.

**TABLE 6A
SUMMARY OF RELAYING REQUIREMENTS**

Type of Interconnection	Over-current (50/51)	Voltage (27/59)	Frequency (81 O/U)	Reverse Power (32)	Lockout (86)	Parallel Limit Timer	Sync-Check (25)	Transfer Trip
Open Transition Mechanically Interlocked (Fig. 1)	—	—	—	—	—	—	—	—
Quick Open Transition Mechanically Interlocked (Fig. 2)	—	—	—	—	Yes	Yes	Yes	—
Closed Transition (Fig. 2)	—	—	—	—	Yes	Yes	Yes	—
Soft Loading Limited Parallel Operation (Fig. 3)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	—
Soft Loading Extended Parallel < 250 kW (Fig. 4)	Yes	Yes	Yes	—	Yes	—	Yes	—
Soft Loading Extended Parallel >250kW (Fig.4)	Yes	Yes	Yes	—	Yes	—	Yes	Yes
Inverter Connection (Fig. 5)								
< 40 kW	Yes	Yes	Yes	—	Yes	—	—	—
40 kW – 250kW	Yes	Yes	Yes	—	Yes	—	—	—
> 250 kW	Yes	Yes	Yes	—	Yes	—	—	Yes

7. Agreements

A) Interconnection Agreement – This agreement is required for all Generation Systems that parallel with the Area EPS. Each Area EPS's tariffs contain standard interconnection agreements. There are different interconnection agreements depending upon the size and type of Generation System. This agreement contains the terms and conditions upon which the Generation System is to be connected, constructed and maintained, when operated in parallel with the Area EPS. Some of the issues covered in the interconnection agreement are as follows;

- i) Construction Process
- ii) Testing Requirements
- iii) Maintenance Requirements
- iv) Firm Operating Requirements such as Power Factor
- v) Access requirements for the Area EPS personnel
- vi) Disconnection of the Generation System (Emergency and Non-emergency)
- vii) Term of Agreement
- viii) Insurance Requirements
- ix) Dispute Resolution Procedures

B) Operating Agreement – For Generation Systems that normally operate in parallel with the Area EPS, an agreement separate from the interconnection agreement, called the "operating agreement", is usually created. This agreement is created for the benefit of both the Interconnection Customer and the Area EPS operator and will be agreed to between the Parties. This agreement will be dynamic and is intended to be updated and reviewed annually. For some smaller systems, the operating agreement can simply be a letter agreement for larger and more intergraded Generation Systems the operating agreement will tend to be more involved and more formal. The operating agreement covers items that are necessary for the reliable operation of the Local and Area EPS. The items typically included in the operating agreement are as follows;

- i) Emergency and normal contact information for both the Area EPS operations center and for the Interconnection Customer
- ii) Procedures for periodic Generation System test runs.
- iii) Procedures for maintenance on the Area EPS that effect the Generation System.
- iv) Emergency Generation Operation Procedures

8. Testing Requirements

A) Pre-Certification of equipment

The most important part of the process to interconnect generation with Local and Area EPS's is safety. One of the key components of ensuring the safety of the public and employees is to ensure that the design and implementation of the elements connected to the electrical power system operate as required. To meet this goal, all of the electrical wiring in a business or residence, is required by the State of Minnesota to be listed by a recognized testing and certification laboratory, for its intended purpose. Typically we see this as "UL" listed. Since Generation Systems have tended to be uniquely designed for each installation they have been designed and approved by Professional Engineers. As the number of Generation Systems installed increase, vendors are working towards creating equipment packages which can be tested in the factory and then will only require limited field testing. This will allow us to move towards "plug and play" installations. For this reason, this standard recognizes the efficiency of "pre-certification" of Generation System equipment packages that will help streamline the design and installation process.

An equipment package shall be considered certified for interconnected operation if it has been submitted by a manufacture, tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous utility interactive operation in compliance with the applicable codes and standards. Presently generation paralleling equipment that is listed by a nationally recognized testing laboratory as having met the applicable type-testing requirements of UL 1741 and IEEE 929, shall be acceptable for interconnection without additional protection system requirements. An "equipment package" shall include all interface components including switchgear, inverters, or other interface devices and may include an integrated generator or electric source. If the equipment package has been tested and listed as an integrated package which includes a generator or other electric source, it shall not required further design review, testing or additional equipment to meet the certification requirements for interconnection. If the equipment package includes only the interface components (switchgear, inverters, or other interface devices), then the Interconnection Customer shall show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and consistent with the testing and listing specified for the package. Provided the generator or electric source combined with the equipment package is consistent with the testing ad listing performed by the nationally recognized testing and certification laboratory, no further design review, testing or additional equipment shall be required to meet the certification requirements of this interconnection procedure. A certified equipment package does not include equipment provided by the Area EPS.

The use of Pre-Certified equipment does not automatically qualify the Interconnection Customer to be interconnected to the Area EPS. An application will still need to be submitted and an interconnection review may still need to be performed, to determine the compatibility of the Generation System with the Area EPS.

B) Pre-Commissioning Tests

i) Non-Certified Equipment

(1) Protective Relaying and Equipment Related to Islanding

- (a) Distributed generation that is not Type-Certified (type tested), shall be equipped with protective hardware and/or software designed to prevent the Generation from being connected to a de-energized Area EPS.

**ATTACHMENT 2
REQUIREMENTS**

- (b) The Generation may not close into a de-energized Area EPS and protection provided to prevent this from occurring. It is the Interconnection Customer's responsibility to provide a final design and to install the protective measures required by the Area EPS. The Area EPS will review and approve the design, the types of relays specified, and the installation. Mutually agreed upon exceptions may at times be necessary and desirable. It is strongly recommended that the Interconnection Customer obtain Area EPS written approval prior to ordering protective equipment for parallel operation. The Interconnection Customer will own these protective measures installed at their facility.
- (c) The Interconnection Customer shall obtain prior approval from the Area EPS for any revisions to the specified relay calibrations.

C) Commissioning Testing

The following tests shall be completed by the Interconnection Customer. All of the required tests in each section shall be completed prior to moving on to the next section of tests. The Area EPS operator has the right to witness all field testing and to review all records prior to allowing the system to be made ready for normal operation. The Area EPS shall be notified, with sufficient lead time to allow the opportunity for Area EPS personnel to witness any or all of the testing.

- i) Pre-testing The following tests are required to be completed on the Generation System prior to energization by the Generator or the Area EPS. Some of these tests may be completed in the factory if no additional wiring or connections were made to that component. These tests are marked with a ***
 - (1) Grounding shall be verified to ensure that it complies with this standard, the NESC and the NEC.
 - (2) * CT's (Current Transformers) and VT's (Voltage Transformers) used for monitoring and protection, shall be tested to ensure correct polarity, ratio and wiring
 - (3) CT's shall be visually inspected to ensure that all grounding and shorting connections have been removed where required.
 - (4) Breaker / Switch tests – Verify that the breaker or switch cannot be operated with interlocks in place or that the breaker or switch cannot be automatically operated when in manual mode. Various Generation Systems have different interlocks, local or manual modes etc. The intent of this section is to ensure that the breaker or switches controls are operating properly.
 - (5) * Relay Tests – All Protective relays shall be calibrated and tested to ensure the correct operation of the protective element. Documentation of all relay calibration tests and settings shall be furnished to the Area EPS operator.
 - (6) Trip Checks - Protective relaying shall functionally tested to ensure the correct operation of the complete system. Functional testing requires that the complete system is operated by the injection of current and/or voltage to trigger the relay element and proving that the relay element trips the required breaker, lockout relay or provides the correct signal to the next control element. Trip circuits shall be proven through the entire scheme (including breaker trip)

For factory assembled systems, such as inverters the setting of the protective elements may occur at the factory. This section requires that the complete system including the wiring and the device being tripped or activated is proven to be in working condition through the injection of current and/or voltage.

ATTACHMENT 2 REQUIREMENTS

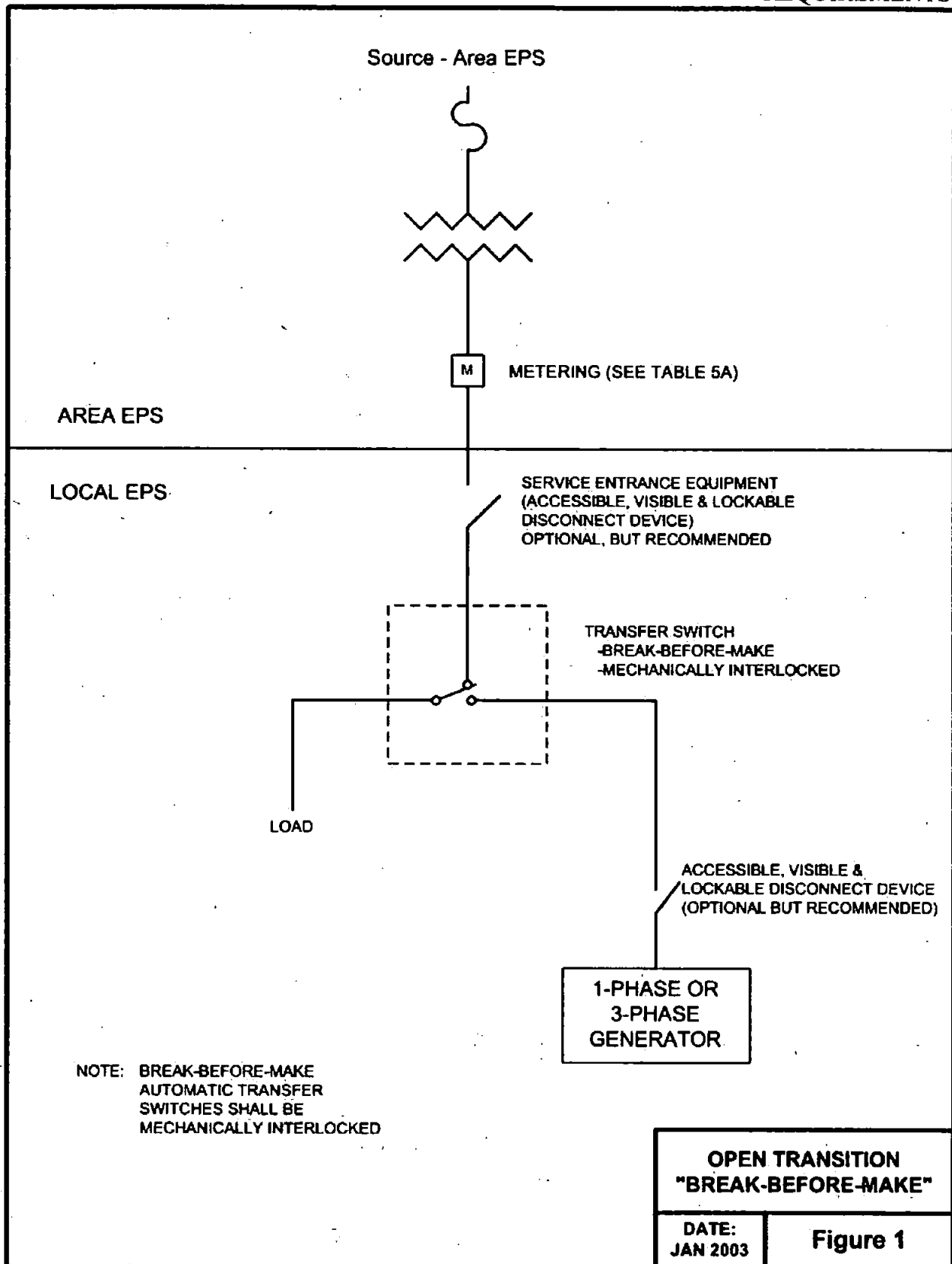
- (7) Remote Control, SCADA and Remote Monitoring tests – All remote control functions and remote monitoring points shall be verified operational. In some cases, it may not be possible to verify all of the analog values prior to energization. Where appropriate, those points may be verified during the energization process
- (8) Phase Tests – the Interconnection Customer shall work with the Area EPS operator to complete the phase test to ensure proper phase rotation of the Generation and wiring.
- (9) Synchronizing test – The following tests shall be done across a open switch or racked out breaker. The switch or breaker shall be in a position that it is incapable of closing between the Generation System and the Area EPS for this test. This test shall demonstrate that at the moment of the paralleling-device closure, the frequency, voltage and phase angle are within the required ranges, stated in IEEE 1547 . This test shall also demonstrate that is any of the parameters are outside of the ranges stated; the paralleling-device shall not close. For inverter-based interconnected systems this test may not be required unless the inverter creates fundamental voltages before the paralleling device is closed.
- ii) On-Line Commissioning Test – the following tests will proceed once the Generation System has completed Pre-testing and the results have been reviewed and approved by the Area EPS operator. For smaller Generation Systems the Area EPS may have a set of standard interconnection tests that will be required. On larger and more complex Generation Systems the Interconnection Customer and the Area EPS operator will get together to develop the required testing procedure. All on-line commissioning test shall be based on written test procedures agreed to between the Area EPS operator and the Interconnection Customer.

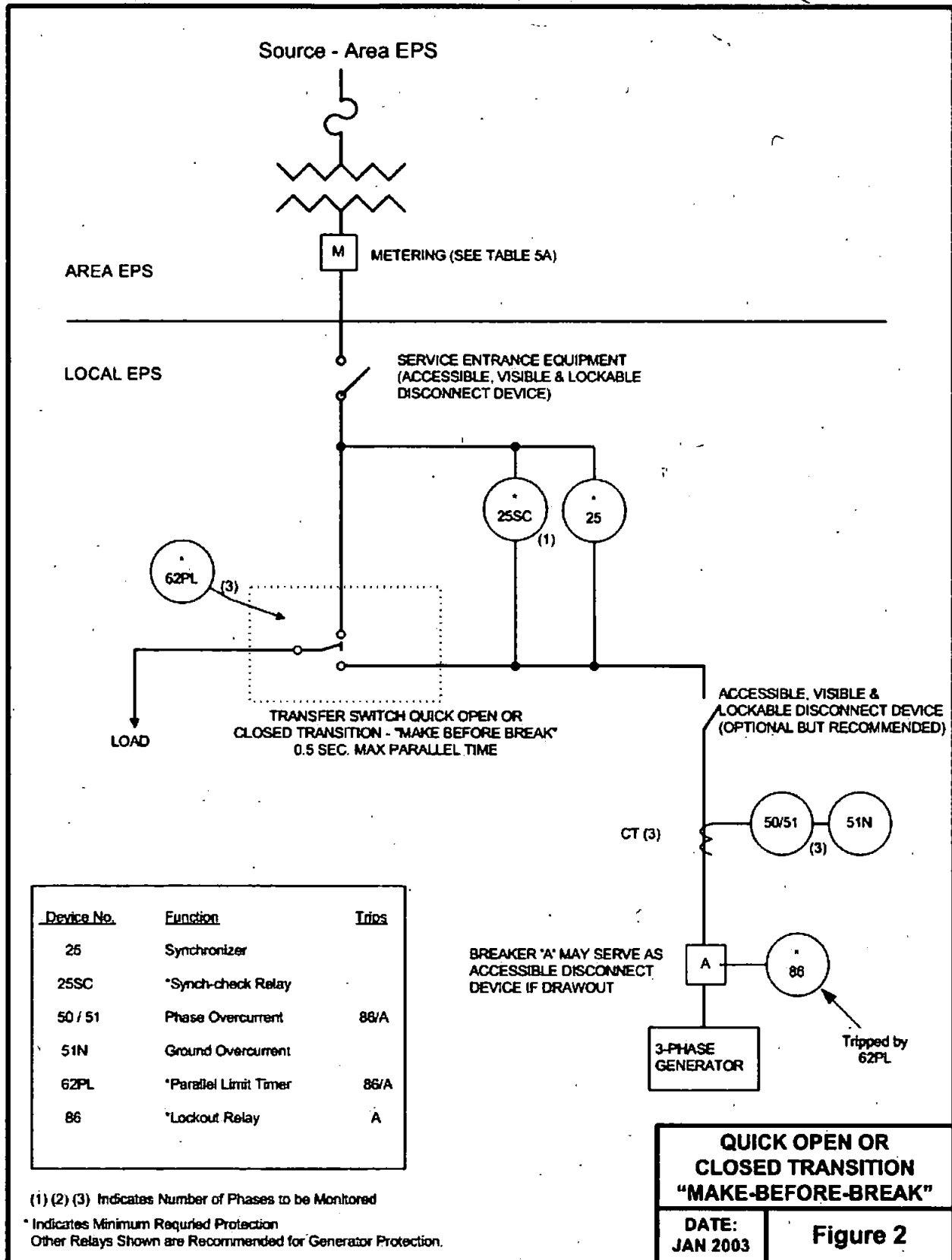
Generation System functionally shall be verified for specific interconnections as follows:

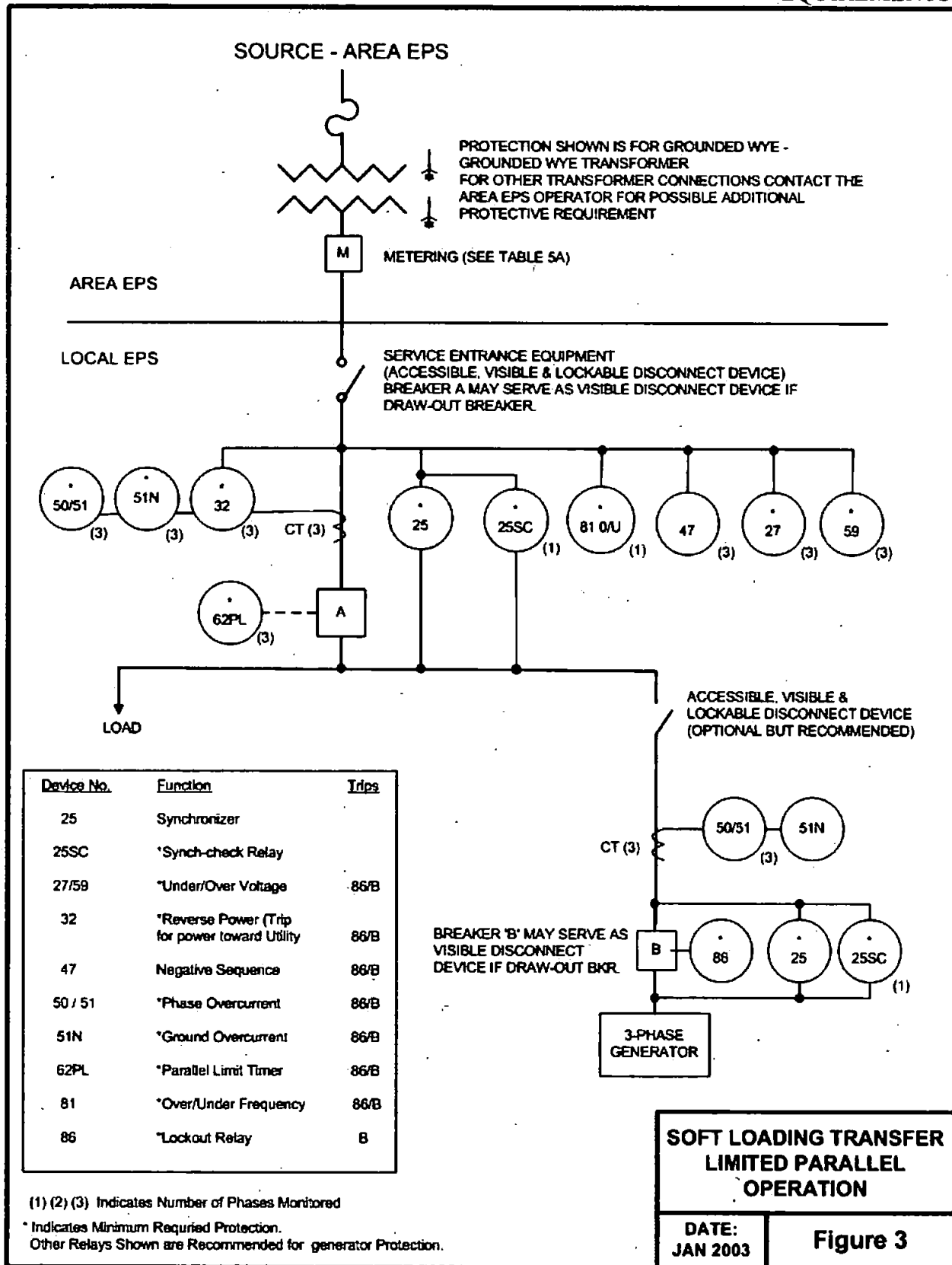
- (1) Anti-Islanding Test – For Generation Systems that parallel with the utility for longer then 100msec.
 - (a) The Generation System shall be started and connected in parallel with the Area EPS source
 - (b) The Area EPS source shall be removed by opening a switch, breaker etc.
 - (c) The Generation System shall either separate with the local load or stop generating
 - (d) The device that was opened to remove the Area EPS source shall be closed and the Generation System shall not reparallel with the Area EPS for at least 5 minutes.
- iii) Final System Sign-off.
 - (1) To ensure the safety of the public, all interconnected customer owned generation systems which do not utilize a Type-Certified system shall be certified as ready to operate by a Professional Electrical Engineer registered in the State of Minnesota, prior to the installation being considered ready for commercial use.
- iv) Periodic Testing and Record Keeping

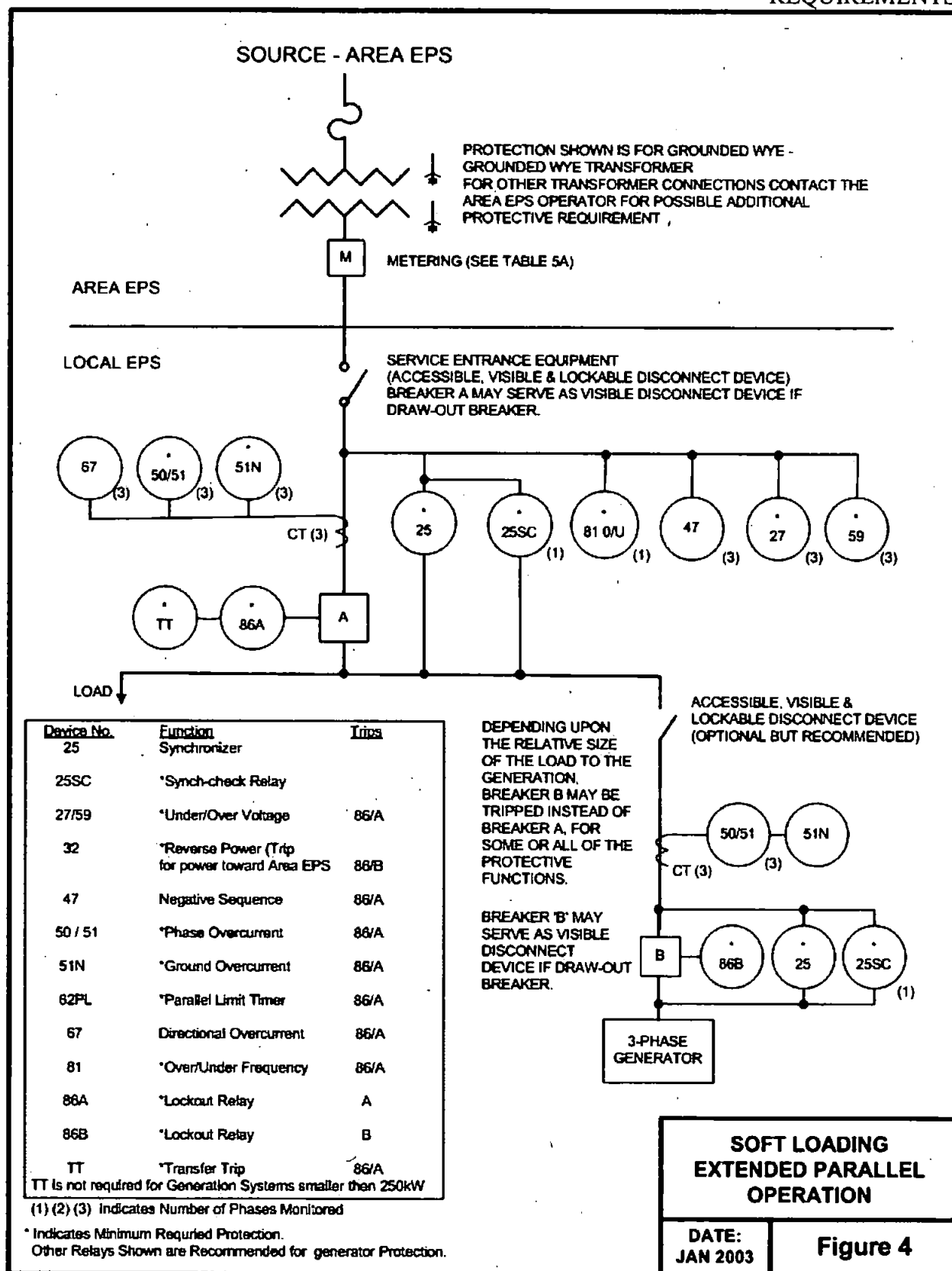
ATTACHMENT 2 REQUIREMENTS

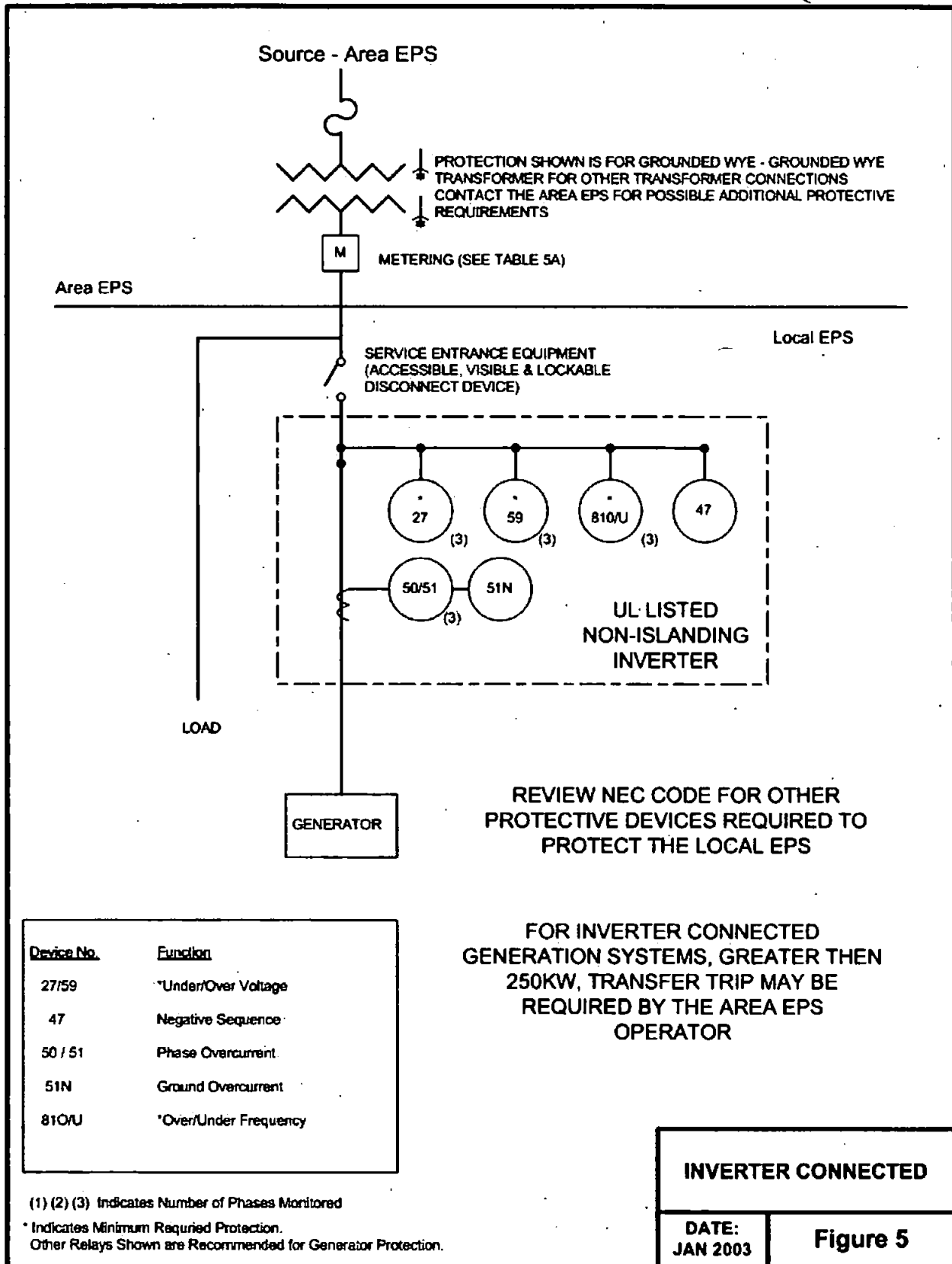
- (1) Any time the interface hardware or software, including protective relaying and generation control systems are replaced and/or modified, the Area EPS operator shall be notified. This notification shall, if possible, be with sufficient warning so that the Area EPS personnel can be involved in the planning for the modification and/or witness the verification testing. Verification testing shall be completed on the replaced and/or modified equipment and systems. The involvement of the Area EPS personnel will depend upon the complexity of the Generation System and the component being replaced and/or modified. Since the Interconnection Customer and the Area EPS operator are now operating an interconnected system. It is important for each to communicate changes in operation, procedures and/or equipment to ensure the safety and reliability of the Local and Area EPSs.
- (2) All interconnection-related protection systems shall be periodically tested and maintained, by the Interconnection Customer, at intervals specified by the manufacture or system integrator. These intervals shall not exceed 5 years. Periodic test reports and a log of inspections shall be maintained, by the Interconnection Customer and made available to the Area EPS operator upon request. The Area EPS operator shall be notified prior to the period testing of the protective systems, so that Area EPS personnel may witness the testing if so desired.
 - (a) Verification of inverter connected system rated 15kVA and below may be completed as follows; The Interconnection Customer shall operate the load break disconnect switch and verify the Generator automatically shuts down and does not restart for at least 5 minutes after the switch is close
 - (b) Any system that depends upon a battery for trip/protection power shall be checked and logged once per month for proper voltage. Once every four years the battery(s) must be either replaced or a discharge test performed. Longer intervals are possible through the use of "station class batteries" and Area EPS operator approval.











Generation Interconnection Application

WHO SHOULD FILE THIS APPLICATION: Anyone expressing interest to install generation which will interconnect with the Area EPS (Local electric utility). This application should be completed and returned to the Area EPS Generation Interconnection Coordinator, in order to begin processing the request.

INFORMATION: This application is used by the Area EPS Operator to perform a preliminary interconnection review. The Applicant shall complete as much of the form as possible. The fields in BOLD are required to be completed to the best of the Applicant's ability. The Applicant will be contacted if additional information is required. The response may take up to 15 business days after receipt of all the required information.

COST: A payment to cover the application fee shall be included with this application. The application fee amount is outlined in the "State of Minnesota Interconnection Process for Distributed Generation Systems".

OWNER/APPLICANT		
Company / Applicant's Name:		
Representative:	Phone Number:	FAX Number:
Title:		
Mailing Address:		
Email Address:		
LOCATION OF GENERATION SYSTEM INTERCONNECTION		
Street Address, legal description or GPS coordinates:		
PROJECT DESIGN / ENGINEERING (if applicable)		
Company:		
Representative:	Phone:	FAX Number:
Mailing Address:		
Email Address:		
ELECTRICAL CONTRACTOR (if applicable)		
Company:		
Representative:	Phone:	FAX Number:
Mailing Address:		
Email Address:		
GENERATOR		
Manufacturer:		Model:
Type (Synchronous Induction, Inverter, etc):		Phases: 1 or 3
Rated Output (Prime kW):	(Standby kW):	Frequency:
Rated Power Factor (%):	Rated Voltage (Volts):	Rated Current (Amperes):
Energy Source (gas, steam, hydro, wind, etc.)		
TYPE OF INTERCONNECTED OPERATION		
Interconnection / Transfer method:		
☐ Open ☐ Quick Open ☐ Closed ☐ Soft Loading ☐ Inverter		
Proposed use of generation: (Check all that may apply)		Duration Parallel:
☐ Peak Reduction ☐ Standby ☐ Energy Sales ☐ Cover Load		☐ None ☐ Limited ☐ Continuous
Pre-Certified System: Yes / No (Circle one)		Exporting Energy Yes / No (Circle one)

ESTIMATED LOAD INFORMATION

The following information will be used to help properly design the interconnection. This Information is not intended as a commitment or contract for billing purposes.

Minimum anticipated load (generation not operating):

kW:

kVA:

Maximum anticipated load (generation not operating):

kW:

kVA:

ESTIMATED START/COMPLETION DATES

Construction start date:

Completion (operational) date:

DESCRIPTION OF PROPOSED INSTALLATION AND OPERATION

Attach a single line diagram showing the switchgear, transformers, and generation facilities. Give a general description of the manner of operation of the generation (cogeneration, closed-transition peak shaving, open-transition peak shaving, emergency power, etc.). Also, does the Applicant intend to sell power and energy or ancillary services and/or wheel power over Area EPS facilities. If there is an intent to sell power and energy, also define the target market.

SIGN OFF AREA:

With this Application, we are requesting the Area EPS Operator to review the proposed Generation System Interconnection. We request that the Area EPS identifies the additional equipment and costs involved with the interconnection of this system and to provide a budgetary estimate of those costs. We understand that the estimated costs supplied by the Area EPS Operator, will be estimated using the information provided. We also agree that we will supply, as requested, additional information, to allow the Area EPS Operator to better review this proposed Generation System interconnection. We have read the "State of Minnesota Distributed Generation Interconnection Requirements" and will design the Generation System and interconnection to meet those requirements.

Applicant Name (print):

Applicant Signature:

Date:

**SEND THIS COMPLETED & SIGNED APPLICATION AND ATTACHMENTS TO THE
AREA EPS GENERATION INTERCONNECTION COORDINATOR**

State of Minnesota

ENGINEERING DATA SUBMITTAL
For the Interconnection of Distributed Generation

Page 1

WHO SHOULD FILE THIS SUBMITTAL: Anyone in the final stages of interconnecting a Generation System with the Area EPS. This submittal shall be completed and provided to the Area EPS Generation Interconnection Coordinator during the design of the Generation System, as established in the "State of Minnesota Interconnection Process for Distributed Generation Systems".

INFORMATION: This submittal is used to document the interconnected Generation System. The Applicant shall complete as much of the form as applicable. The Applicant will be contacted if additional information is required.

OWNER / APPLICANT

Company / Applicant:

Representative:

Phone Number:

FAX Number:

Title:

Mailing Address:

Email Address:

PROPOSED LOCATION OF GENERATION SYSTEM INTERCONNECTION

Street Address, Legal Description or GPS coordinates:

PROJECT DESIGN / ENGINEERING (if applicable)

Company:

Representative:

Phone:

FAX Number:

Mailing Address:

Email Address:

ELECTRICAL CONTRACTOR (if applicable)

Company:

Representative:

Phone:

FAX Number:

Mailing Address:

Email Address:

TYPE OF INTERCONNECTED OPERATION

Interconnection / Transfer method:

☐ Open☐ Quick Open☐ Closed☐ Soft Loading☐ Inverter

Proposed use of generation: (Check all that may apply)

☐ Peak Reduction ☐ Standby ☐ Energy Sales☐ Cover Load

Duration Parallel:

☐ None☐ Limited☐ Continuous

Pre-Certified System: Yes / No (Circle one)

Exporting Energy Yes / No (Circle one)

State of Minnesota

ENGINEERING DATA SUBMITTAL
For the Interconnection of Distributed Generation

Page 2

GENERATION SYSTEM OPERATION / MAINTENANCE CONTACT INFORMATION		
Maintenance Provider:	Phone #:	Pager #:
Operator Name:	Phone #:	Pager #:
Person to Contact before remote starting of units		
Contact Name:	Phone #:	Pager #:
	24hr Phone #:	

GENERATION SYSTEM OPERATING INFORMATION	
Fuel Capacity (gals):	Full Fuel Run-time (hrs):
Engine Cool Down Duration (Minutes):	Start time Delay on Load Shed signal:
Start Time Delay on Outage (Seconds):	

ESTIMATED LOAD		
The following information will be used to help properly design the interconnection. This Information is not intended as a commitment or contract for billing purposes.		
Minimum anticipated load (generation not operating):	kW:	kVA:
Maximum anticipated load (generation not operating):	kW:	kVA:

REQUESTED CONSTRUCTION START/COMPLETION DATES	
Design Completion:	
Construction Start Date:	
Footings in place:	
Primary Wiring Completion:	
Control Wiring Completion:	
Start Acceptance Testing:	
Generation operational (In-service):	

State of Minnesota

ENGINEERING DATA SUBMITTAL
For the Interconnection of Distributed Generation

Page 3

(Complete all applicable items, Copy this page as required for additional generators)

SYNCHRONOUS GENERATOR (if applicable)

Unit Number:	Total number of units with listed specifications on site:		
Manufacturer:	Type:	Phases: 1 or 3	
Serial Number (each)	Date of manufacture:	Speed (RPM):	Freq. (Hz):
Rated Output (each unit) kW Standby:	kW Prime:	kVA:	
Rated Power Factor (%):	Rated Voltage(Volts):	Rated Current (Amperes):	
Field Voltage (Volts):	Field Current (Amperes):	Motoring Power (kW):	
Synchronous Reactance (X_d):	% on	kVA base	
Transient Reactance (X'_d):	% on	kVA base	
Subtransient Reactance (X''_d):	% on	kVA base	
Negative Sequence Reactance (X_s):	% on	kVA base	
Zero Sequence Reactance (X_o):	% on	kVA base	
Neutral Grounding Resistor (if applicable):			
I^2t or K (heating time constant):			
Exciter data:			
Governor data:			
Additional Information:			

INDUCTION GENERATOR (if applicable)

Rotor Resistance (R_r):	Ohms	Stator Resistance (R_s):	Ohms
Rotor Reactance (X_r):	Ohms	Stator Reactance (X_s):	Ohms
Magnetizing Reactance (X_m):	Ohms	Short Circuit Reactance (X_d''):	Ohms
Design Letter:	Frame Size:		
Exciting Current:	Temp Rise (deg C°):		
Rated Output (kW):			
Reactive Power Required:		k Vars (no Load)	kVars (full load)
If this is a wound-rotor machine, describe any external equipment to be connected (resistor, rheostat, power converter, etc.) to rotor circuit, and circuit configuration. Describe ability, if any, to adjust generator reactive output to provide power system voltage regulation.			
Additional Information:			

PRIME MOVER (Complete all applicable items)

Unit Number:	Type:		
Manufacturer:			
Serial Number:	Date of Manufacture:		
H.P. Rated:	H.P. Max:	Inertia Constant:	lb.-ft. ²
Energy Source (hydro, steam, wind, wind etc.):			

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INTERCONNECTION (STEP-UP) TRANSFORMER (If applicable)

Manufacturer:		kVA:	
Date of Manufacture:		Serial Number:	
High Voltage: kV	Connection: delta wye	Neutral solidly grounded?	
Low Voltage: kV	Connection: delta wye	Neutral solidly grounded?	
Transformer Impedance (Z):	% on	kVA base	
Transformer Resistance (R):	% on	kVA base	
Transformer Reactance (X):	% on	kVA base	
Neutral Grounding Resistor (if applicable)			

TRANSFER SWITCH (If applicable)

Model Number:	Type:
Manufacturer:	Rating(amps):

INVERTER (If applicable)

Manufacturer:		Model:	
Rated Power Factor (%):	Rated Voltage (Volts):	Rated Current (Amperes):	
Inverter Type (ferroresonant, step, pulse-width modulation, etc.):			
Type of Commutation: forced line	Minimum Short Circuit Ratio required:		
Minimum voltage for successful commutation:			
Current Harmonic Distortion	Maximum Individual Harmonic (%):		
	Maximum Total Harmonic Distortion (%):		
Voltage Harmonic Distortion	Maximum Individual Harmonic (%):		
	Maximum Total Harmonic Distortion (%):		
Describe capability, if any, to adjust reactive output to provide voltage regulation:			
NOTE: Attach all available calculations, test reports, and oscillographic prints showing inverter output voltage and current waveforms.			

POWER CIRCUIT BREAKER (if applicable)

Manufacturer:		Model:			
Rated Voltage (kilovolts):		Rated Ampacity (Amperes):			
Interrupting Rating (Amperes):		BIL Rating:			
Interrupting Medium (vacuum, oil, gas, etc.)		Insulating Medium (vacuum, oil, gas, etc.)			
Control Voltage (Closing):	(Volts)	AC	DC		
Control Voltage (Tripping):	(Volts)	AC	DC	Battery	Charged Capacitor
Close Energy (circle one):	Spring	Motor	Hydraulic	Pneumatic	Other
Trip Energy (circle one):	Spring	Motor	Hydraulic	Pneumatic	Other
Bushings Current Transformers (Max. ratio):				Relay Accuracy Class:	
CT'S Multi Ratio? (circle one); No / Yes: (Available taps):					

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MISCELLANEOUS (Use this area and any additional sheets for applicable notes and comments)**SIGN OFF AREA**

This Engineering Data Submittal documents the equipment and design of the Generation System. We agree to supply the Area EPS Operator with an updated Engineering Data Submittal any time significant changes are made in the equipment used or the design of the proposed Generation System. The Applicant agrees to design, operate and maintain the Generation System within the requirements set forth by the "State of Minnesota Distributed Generation Interconnection Requirements".

Applicant Name (print):

Applicant Signature:

Date:

**SEND THIS COMPLETED & SIGNED ENGINEERING DATA SUBMITTAL AND ANY ATTACHMENTS TO THE
AREA EPS GENERATION INTERCONNECTION COORDINATOR**

State of Minnesota
Interconnection Agreement
**For the Interconnection of Extended Parallel Distributed
Generation Systems With Electric Utilities**

This Generating System Interconnection Agreement is entered into by and between the Area Electrical Power System Operator (Area EPS Operator) "_____" and the Interconnection Customer "_____". The Interconnection Customer and Area EPS are sometimes also referred to in this Agreement jointly as "Parties" or individually as "Party".

In consideration of the mutual promises and obligations stated in this Agreement and its attachments, the Parties agree as follows:

I. SCOPE AND PURPOSE

- A) Establishment of Point of Common Coupling. This Agreement is intended to provide for the Interconnection Customer to interconnect and operate a Generation System with a total Nameplate Capacity of 10MWs or less in parallel with the Area EPS at the location identified in Exhibit C and shown in the Exhibit A one-line diagram.
- B) This Agreement governs the facilities required to and contains the terms and condition under which the Interconnection Customer may interconnect the Generation System to the Area EPS. This Agreement does not authorize the Interconnection Customer to export power or constitute an agreement to purchased or wheel the Interconnection Customer's power. Other services that the Interconnection Customer may require from the Area EPS, or others, may be covered under separate agreements.
- C) To facilitate the operation of the Generation System, this agreement also allows for the occasional and inadvertent export of energy to the Area EPS. The amount, metering, billing and accounting of such inadvertent energy exporting shall be governed by Exhibit D (Operating Agreement). This Agreement does not constitute an agreement by the Area EPS Operator to purchase or pay for any energy, inadvertently or intentionally exported, unless expressly noted in Exhibit D or under a separately executed power purchase agreement (PPA).
- D) This agreement does not constitute a request for, nor the provision of any transmission delivery service or any local distribution delivery service.
- E) The Technical Requirements for interconnection are covered in a separate Technical Requirements document know as, the "State of Minnesota Distributed Generation Interconnection Requirements", a copy of which as been made available to the Interconnection Customer and incorporated and made part of this Agreement by this reference

II. DEFINITIONS

- A) "Area EPS" is an electric power system (EPS) that serves Local EPS's. Note: Typically, an Area EPS has primary access to public rights-of-way, priority crossing of property boundaries, etc.

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- B) "Area EPS Operator" is the entity that operates the Area EPS.
- C) "Dedicated Facilities" are the equipment that is installed due to the interconnection of the Generation System and not required to serve other Area EPS customers.
- D) "EPS" (Electric Power System) are facilities that deliver electric power to a load. Note: This may include generation units.
- E) "Extended Parallel" means the Generation System is designed to remain connected with the Area EPS for an extended period of time.
- F) "Generation" is any device producing electrical energy, i.e., rotating generators driven by wind, steam turbines, internal combustion engines, hydraulic turbines, solar, fuel cells, etc.; or any other electric producing device, including energy storage technologies.
- G) "Generation Interconnection Coordinator" is the person or persons designated by the Area EPS Operator to provide a single point of coordination with the Applicant for the generation interconnection process.
- H) "Generation System" is the interconnected generator(s), controls, relays, switches, breakers, transformers, inverters and associated wiring and cables, up to the Point of Common Coupling.
- I) "Interconnection Customer" is the party or parties who will own/operate the Generation System and are responsible for meeting the requirements of the agreements and Technical Requirements. This could be the Generation System applicant, installer, owner, designer, or operator.
- J) "Local EPS" is an electric power system (EPS) contained entirely within a single premises or group of premises.
- K) "Nameplate Capacity" is the total nameplate capacity rating of all the Generation included in the Generation System. For this definition the "standby" and/or maximum rated kW capacity on the nameplate shall be used.
- L) "Point of Common Coupling" is the point where the Local EPS is connected to an Area EPS
- M) "Point of Delivery" is the point where the energy changes possession from one party to the other. Typically this will be where the metering is installed but it is not required that the Point of Delivery is the same as where the energy is metered
- N) "Technical Requirements" "is the State of Minnesota Requirements for Interconnection of Distributed Generation."

III. DESCRIPTION OF INTERCONNECTION CUSTOMER'S GENERATION SYSTEM

- A) A description of the Generation System, including a single-line diagram showing the general arrangement of how the Interconnection Customer's Generation System is interconnected with the Area EPS's distribution system, is attached to and made part of this Agreement as Exhibit A. The single-line diagram shows the following:
- 1) Point of Delivery (if applicable)
 - 2) Point of Common Coupling
 - 3) Location of Meter(s)
 - 4) Ownership of the equipment.
 - 5) Generation System total Nameplate Capacity _____ kW
 - 6) Scheduled operational (on-line) date for the Generation System.

IV. RESPONSIBILITIES OF THE PARTIES

- A) The Parties shall perform all obligations of this Agreement in accordance with all applicable laws and regulations, operating requirements and good utility practices.
- B) Interconnection Customer shall construct, operate and maintain the Generation System in accordance with the applicable manufacturer's recommended maintenance schedule, the Technical Requirements and in accordance with this Agreement
- C) The Area EPS Operator shall carry out the construction of the Dedicated Facilities in a good and workmanlike manner, and in accordance with standard design and engineering practices.

V. CONSTRUCTION

The Parties agree to cause their facilities or systems to be constructed in accordance with the laws of the State of Minnesota and to meet or exceed applicable codes and standards provided by the NESC (National Electrical Safety Code), ANSI (American National Standards Institute), IEEE (Institute of Electrical and Electronic Engineers), NEC (National Electrical Code), UL (Underwriter's Laboratory), Technical Requirements and local building codes and other applicable ordinances in effect at the time of the installation of the Generation System.

A) Charges and payments

The Interconnection Customer is responsible for the actual costs to interconnect the Generation System with the Area EPS, including, but not limited to any Dedicated Facilities attributable to the addition of the Generation System, Area EPS labor for

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installation coordination, installation testing and engineering review of the Generation System and interconnection design. Estimates of these costs are outlined in Exhibit B. While estimates, for budgeting purposes, have been provided in Exhibit B, the actual costs are still the responsibility of the Interconnection Customer, even if they exceed the estimated amount(s). All costs, for which the Interconnection Customer is responsible for, must be reasonable under the circumstances of the design and construction.

1) Dedicated Facilities

- a) During the term of this Agreement, the Area EPS Operator shall design, construct and install the Dedicated Facilities outlined in Exhibit B. The Interconnection Customer shall be responsible for paying the actual costs of the Dedicated Facilities attributable to the addition of the Generation System.
- b) Once installed, the Dedicated Facilities shall be owned and operated by the Area EPS owner and all costs associated with the operating and maintenance of the Dedicated Facilities, after the Generation System is operational, shall be the responsibility of the Area EPS Operator, unless otherwise agreed.
- c) By executing this Agreement, the Interconnection Customer grants permission for the Area EPS Operator to begin construction and to procure the necessary facilities and equipment to complete the installation of the Dedicated Facilities, as outlined in Exhibit B. If for any reason, the Generation System project is canceled or modified, so that any or all of the Dedicated Facilities are not required, the Interconnection Customer shall be responsible for all costs incurred by the Area EPS, including, but not limited to the additional costs to remove and/or complete the installation of the Dedicated Facilities. The Interconnection Customer may, for any reason, cancel the Generation System project, so that any or all of the Dedicated Facilities are not required to be installed. The Interconnection Customer shall provide written notice to the Area EPS Operator of cancellation. Upon receipt of a cancellation notice, the Area EPS Operator shall take reasonable steps to minimize additional costs to the Interconnection Customer, where reasonably possible.

2) Payments

- a) The Interconnection Customer shall provide reasonable adequate assurances of credit, including a letter of credit or personal guaranty of payment and performance from a creditworthy entity acceptable under the Area EPS Operators credit policy and procedures for the unpaid balance of the estimated amount shown in Exhibit B.
- b) The payment for the costs outlined in Exhibit B, shall be as follows;
 - i. 1/3 of estimated costs, outlined in Exhibit B, shall be due upon execution of this agreement.
 - ii. 1/3 of estimated costs, outlined in Exhibit B, shall be due prior to initial energization of the Generation System, with the Area EPS.
 - iii. Remainder of actual costs, incurred by the Area EPS, shall be due within 30 days from the date the bill is mailed by the Area EPS after project completion.

VI. DOCUMENTS INCLUDED WITH THIS AGREEMENT.

- A) This agreement includes the following exhibits, which are specifically incorporated herein and made part of this Agreement by this reference: *(if any of these Exhibits are deemed not applicable for this Generation System installation they may be omitted from the final Agreement by the Area EPS Operator.)*
- 1) Exhibit A – Description of Generation System and single-line diagram. This diagram shows all major equipment, including, visual isolation equipment, Point of Common Coupling, Point of Delivery for Generation Systems that intentionally export, ownership of equipment and the location of metering.
 - 2) Exhibit B – Estimated installation and testing costs payable by the Interconnection Customer. Included in this listing shall be the description and estimated costs for the required Dedicated Facilities being installed by the Area EPS Operator for the interconnection of the Generation System and a description and estimate for the final acceptance testing work to be done by the Area EPS Operator.
 - 3) Exhibit C – Engineering Data Submittal – A standard form that provides the engineering and operating information about the Generation System.
 - 4) Exhibit D – Operating Agreement – This provides specific operating information and requirements for this Generation System interconnection. This Exhibit has a separate signature section and may be modified, in writing, from time to time with the agreement of both parties.
 - 5) Exhibit E – Maintenance Agreement – This provides specific maintenance requirements for this Generation System interconnection. This Exhibit has a separate signature section and may be modified, in writing, from time to time with the agreement of both parties.

VII. TERMS AND TERMINATION

- A) This Agreement shall become effective as of the date when both the Interconnection Customer and the Area EPS Operator have both signed this Agreement. The Agreement shall continue in full force and effect until the earliest date that one of the following events occurs:
- 1) The Parties agree in writing to terminate the Agreement; or
 - 2) The Interconnection Customer may terminate this agreement at any time, by written notice to the Area EPS Operator, prior to the completion of the final acceptance testing of the Generation System by the Area EPS Operator. Once the Generation System is operational then VII.A.3 applies. Upon receipt of a cancellation notice, the Area EPS Operator shall take reasonable steps to minimize additional costs to the Interconnection Customer, where reasonably possible.
 - 3) Once the Generation System is operational the Interconnection Customer may terminate this agreement after 30 days written notice to the Area EPS Operator, unless otherwise agreed to within the Exhibit D, Operating Agreement; or

- 4) The Area EPS Operator may terminate this agreement after 30 days written notice to the Interconnection Customer if:
 - a) The Interconnection Customer fails to interconnect and operate the Generation System per the terms of this Agreement; or
 - b) The Interconnection Customer fails to take all corrective actions specified in the Area EPS's written notice that the Generation System is out of compliance with the terms of this Agreement, within the time frame set forth in such notice, or
 - c) If the Interconnection Customer fails to complete the Area EPS Operator's final acceptance testing of the generation system within 24 months of the date proposed under section III.A.5.
- B) Upon termination of this Agreement the Generation System shall be disconnected from the Area EPS. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing, at the time of the termination.

VIII. OPERATIONAL ISSUES

Each Party will, at its own cost and expense, operate, maintain, repair and inspect, and shall be fully responsible for, the facilities which it now or hereafter may own, unless otherwise specified.

- A) Technical Standards: The Generation System shall be installed and operated by the Interconnection Customer consistent with the requirements of this Agreement; the Technical Requirements; the applicable requirements located in the National Electrical Code (NEC); the applicable standards published by the American National Standards Institute (ANSI) and the Institute of Electrical and Electronic Engineers (IEEE); and local building and other applicable ordinances in effect at the time of the installation of the Generation System.
- B) Right of Access: At all times, the Area EPS Operator's personnel shall have access to the disconnect switch of the Generation System for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement, to meet its obligation to operate the Area EPS safely and to provide service to its customers. If necessary for the purposes of this Agreement, the Interconnection Customer shall allow the Area EPS Operator access to the Area EPS's equipment and facilities located on the premises.
- C) Electric Service Supplied: The Area EPS will supply the electrical requirements of the Local EPS that are not supplied by the Generation System. Such electric service shall be supplied, to the Interconnection Customer's Local EPS, under the rate schedules applicable to the Customer's class of service as revised from time to time by the Area EPS.
- D) Operation and Maintenance: The Generation System shall be operated and maintained, by the Interconnection Customer in accordance with the Technical Standards and any additional requirements of Exhibit D and Exhibit E, attached to this document, as amended, in writing, from time to time.

- E) Cooperation and Coordination: Both the Area EPS Operator and the Interconnection Customer shall communicate and coordinate their operations, so that the normal operation of the Area EPS does not unduly effect or interfere with the normal operation of the Generation System and the Generation System does not unduly effect or interfere with the normal operation of the Area EPS. Under abnormal operations of either the Generation System or the Area EPS system, the responsible Party shall provide reasonably timely communication to the other Party to allow mitigation of any potentially negative effects of the abnormal operation of their system.
- F) Disconnection of Unit: The Area EPS Operator may disconnect the Generation System as reasonably necessary, for termination of this Agreement; non-compliance with this Agreement; system emergency, imminent danger to the public or Area EPS personnel; routine maintenance, repairs and modifications to the Area EPS. When reasonably possible the Area EPS Operator shall provide prior notice to the Interconnection Customer explaining the reason for the disconnection. If prior notice is not reasonably possible the Area EPS Operator shall after the fact, provide information to the Interconnection Customer as to why the disconnection was required. It is agreed that the Area EPS Operator shall have no liability for any loss of sales or other damages, including all consequential damages for the loss of business opportunity, profits or other losses, regardless of whether such damages were foreseeable, for the disconnection of the Generation System per this Agreement. The Area EPS Operator shall expend reasonable effort to reconnect the Generation System in a timely manner and to work towards mitigating damages and losses to the Interconnection Customer where reasonably possible.
- G) Modifications to the Generation System – When reasonably possible the Interconnection Customer shall notify the Area EPS Operator, in writing, of plans for any modifications to the Generation System interconnection equipment, including all information needed by the Area EPS Operator as part of the review described in this paragraph, at least twenty (20) business days prior to undertaking such modification(s). Modifications to any of the interconnection equipment, including, all interconnection required protective systems, the generation control systems, the transfer switches/breakers, interconnection protection VT's & CT's, and Generation System capacity, shall be included in the notification to the Area EPS Operator. When reasonably possible the Interconnection Customer agrees not to commence installation of any modifications to the Generating System until the Area EPS Operator has approved the modification, in writing, which approval shall not be unreasonably withheld. The Area EPS Operator shall have a minimum of five (5) business days to review and respond to the planned modification. The Area EPS Operator shall not take longer then a maximum of ten (10) business days, to review and respond to the modification after the receipt of the information required to review the modifications. When it is not reasonably possible for the Interconnection Customer to provide prior written notice, the Interconnection Customer shall provide written notice to the Area EPS Operator as soon as reasonably possible, after the completion of the modification(s).
- H) Permits and Approvals: The Interconnection Customer shall obtain all environmental and other permits lawfully required by governmental authorities prior to the construction of the Generation System. The Interconnection Customer shall also maintain these applicable permits and compliance with these permits during the term of this Agreement.

IX. LIMITATION OF LIABILITY

- A) Each Party shall at all times indemnify, defend, and save the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury or

ATTACHMENT 5 AGREEMENT

death of any person or damage to property, costs and expenses, reasonable attorneys' fees and court costs, arising out of or resulting from the Party's performance of its obligations under this agreement, except to the extent that such damages, losses or claims were caused by the negligence or intentional acts of the other Party.

- B) Each Party's liability to the other Party for failure to perform its obligations under this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any punitive, incidental, indirect, special, or consequential damages of any kind whatsoever, including for loss of business opportunity or profits, regardless of whether such damages were foreseen.
- C) Notwithstanding any other provision in this Agreement, with respect to Area EPS Operator's provision of electric service to any customer including the Interconnection Customer, the Area EPS Operator's liability to such customer shall be limited as set forth in the Area EPS Operator's tariffs and terms and conditions for electric service, and shall not be affected by the terms of this Agreement.

X. DISPUTE RESOLUTION

- A) Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably and in a good faith manner.
- B) In the event a dispute arises under this Agreement, and if it cannot be resolved by the Parties within thirty (30) days after written notice of the dispute to the other Party, the Parties agree to submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in the State of Minnesota. The Parties agree to participate in good faith in the mediation for a period of 90 days. If the parties are not successful in resolving their disputes through mediation, then the Parties may refer the dispute for resolution to the Minnesota Public Utilities Commission (MPUC), which shall maintain continuing jurisdiction over this Agreement.

XI. INSURANCE

- A) At a minimum, in connection with the Interconnection Customer's performance of its duties and obligations under this Agreement, the Interconnection Customer shall maintain, during the term of the Agreement, general liability insurance, from a qualified insurance agency with a B+ or better rating by "Best" and with a combined single limit of not less than:
 - 1) Two million dollars (\$2,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is greater than 250kW.
 - 2) One million dollars (\$1,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is between 40kW and 250kW.
 - 3) Three hundred thousand (\$300,000) for each occurrence if the Gross Nameplate Rating of the Generation System is less than 40kW.
 - 4) Such general liability insurance shall include coverage against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of the Interconnection Customer's ownership and/or operating of the Generation System under this agreement.

**ATTACHMENT 5
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- B) The general liability insurance required shall, by endorsement to the policy or policies, (a) include the Area EPS Operator as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that the Area EPS Operator shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to the Area EPS Operator prior to cancellation, termination, alteration, or material change of such insurance.
- C) If the Generation System is connected to an account receiving residential service from the Area EPS Operator and its total generating capacity is smaller than 40kW, then the endorsements required in Section XI.B shall not apply.
- D) The Interconnection Customer shall furnish the required insurance certificates and endorsements to the Area EPS Operator prior to the initial operation of the Generation System. Thereafter, the Area EPS Operator shall have the right to periodically inspect or obtain a copy of the original policy or policies of insurance
- E) Evidence of the insurance required in Section XI.A. shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by the Area EPS Operator.
- F) If the Interconnection Customer is self-insured with an established record of self-insurance, the Interconnection Customer may comply with the following in lieu of Section XI.A – E:
 - 1) Interconnection Customer shall provide to the Area EPS Operator, at least thirty (30) days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under section XI.A
 - 2) If Interconnection Customer ceases to self-insure to the level required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of it's ability to self-insure, the Interconnection Customer agrees to immediately obtain the coverage required under Section XI.A.
- G) Failure of the Interconnection Customer or Area EPS Operator to enforce the minimum levels of insurance does not relieve the Interconnection Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.
- H) All insurance certificates, statements of self-insurance, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

Your Friendly Area EPS
Attention: Manager of Generation Insurance
12345 Utility Drive.
Anytown, MN 55000

XII. MISCELLANEOUS

A) FORCE MAJEURE

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- 1) An event of Force Majeure means any act of God, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. An event of Force Majeure does not include an act of negligence or intentional wrongdoing. Neither Party will be considered in default as to any obligation hereunder if such Party is prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations hereunder
- 2) Neither Party will be considered in default of any obligation hereunder if such Party is prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations hereunder. .

B) NOTICES

- 1) Any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person or sent by first class mail, postage prepaid, to the person specified below:
 - a) If to Area EPS Operator
Your Friendly Area EPS
Attention: Generation Interconnection Coordinator
12345 Utility Drive.
Anytown, MN 55000
 - b) If to Interconnection Customer
A Friendly Interconnection Customer
Attention: Generation Coordinator
12345 Interconnection Drive.
Anytown, MN 55000
- 2) A Party may change its address for notices at any time by providing the other Party written notice of the change, in accordance with this Section.
- 3) The Parties may also designate operating representatives to conduct the daily communications which may be necessary or convenient for the administration of this Agreement. Such designations, including names, addresses, and phone numbers may be communicated or revised by one Party's notice to the other Party.

C) ASSIGNMENT

The Interconnection Customer shall not assign its rights nor delegate its duties under this Agreement without the Area EPS Operator's written consent. Any assignment or delegation the Interconnection Customer makes without the Area EPS Operator's written consent shall not be valid. The Area EPS Operator shall not unreasonably withhold its consent to the Generating Entities assignment of this Agreement.

D) NON-WAIVER

None of the provisions of this Agreement shall be considered waived by a Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

E) GOVERNING LAW AND INCLUSION OF AREA EPS OPERATOR'S TARIFFS AND RULES.

- 1) This Agreement shall be interpreted, governed and construed under the laws of the State of Minnesota as if executed and to be performed wholly within the State of Minnesota without giving effect to choice of law provisions that might apply to the law of a different jurisdiction.
- 2) The interconnection and services provided under this Agreement shall at all times be subject to the terms and conditions set forth in the tariff schedules and rules applicable to the electric service provided by the Area EPS Operator, which tariff schedules and rules are hereby incorporated into this Agreement by this reference.
- 3) Notwithstanding any other provisions of this Agreement, the Area EPS Operator shall have the right to unilaterally file with the MPUC, pursuant to the MPUC's rules and regulations, an application for change in rates, charges, classification, service, tariff or rule or any agreement relating thereto.

F) AMENDMENT AND MODIFICATION

This Agreement can only be amended or modified by a writing signed by both Parties.

G) ENTIRE AGREEMENT

This Agreement, including all attachments, exhibits, and appendices, constitutes the entire Agreement between the Parties with regard to the interconnection of the Generation System of the Parties at the Point(s) of Common Coupling expressly provided for in this Agreement and supersedes all prior agreements or understandings, whether verbal or written. It is expressly acknowledged that the Parties may have other agreements covering other services not expressly provided for herein, which agreements are unaffected by this Agreement. Each party also represents that in entering into this Agreement, it has not relied on the promise, inducement, representation, warranty, agreement or other statement not set forth in this Agreement or in the incorporated attachments, exhibits and appendices.

H) CONFIDENTIAL INFORMATION

Except as otherwise agreed or provided herein, each Party shall hold in confidence and shall not disclose confidential information, to any person (except employees, officers, representatives and agents, who agree to be bound by this section). Confidential information shall be clearly marked as such on each page or otherwise affirmatively identified. If a court, government agency or entity with the right, power, and authority to do so, requests or requires either Party, by subpoena, oral disposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirements(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. In the absence of a protective order or waiver the Party shall disclose such confidential information which,

in the opinion of its counsel, the party is legally compelled to disclose. Each Party will use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded any confidential information so furnished

I) NON-WARRANTY

Neither by inspection, if any, or non-rejection, nor in any other way, does the Area EPS Operator give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Interconnection Customer or leased by the Interconnection Customer from third parties, including without limitation the Generation System and any structures, equipment, wires, appliances or devices appurtenant thereto.

J) NO PARTNERSHIP.

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

XIII. SIGNATURES

IN WITNESS WHEREOF, the Parties hereto have caused two originals of this Agreement to be executed by their duly authorized representatives. This Agreement is effective as of the last date set forth below.

Interconnection Customer

By: _____

Name: _____

Title: _____

Date: _____

Area EPS Operator

By: _____

Name: _____

Title: _____

Date: _____

EXHIBIT A

**GENERATION SYSTEM DESCRIPTION
AND SINGLE-LINE DIAGRAM**

EXHIBIT B

SUMMARY OF AREA EPS COSTS AND DESCRIPTION OF DEDICATED FACILITIES BEING INSTALLED BY THE AREA EPS OPERATOR FOR THE INTERCONNECTION OF THE GENERATION SYSTEM

This Exhibit shall provide the estimated total costs, that will be the responsibility of the Interconnection Customer. It is assumed that the Initial application has been filed and the engineering studies have been paid for and completed. So those costs are not included on this listing.

What is listed below is a general outline of some of the major areas where costs could occur. Other costs than those listed below may be included by the Area EPS, provided that those costs are a direct result from the request to interconnect the Generation System. The following list is only a guideline and each Area EPS Operator, for each installation will be creating a unique Exhibit B, that is tailored for that specific Generation System interconnection.

- A) Dedicated Facilities (equipment, design and installation labor)
- B) Monitoring & Control System (equipment, design and installation labor)
- C) Design Coordination and Review
- D) Construction Coordination labor costs
- E) Testing (development of tests and physical testing)
- F) Contingency

EXHIBIT C
ENGINEERING DATA SUBMITTAL

Attach a completed Engineering Data Submittal form from Appendix C of "State of Minnesota Interconnection Process for Distributed Generation Systems".

EXHIBIT D

OPERATING AGREEMENT

Each Generation System interconnection will be unique and will require a unique Operating Agreement. The following is a listing of some of the possible areas that will be covered in a operating agreement. The following has not been developed into a standard agreement due to the unique nature of each Generation System. It is envisioned that this Exhibit will be tailored by the Area EPS Operator for each Generation System interconnection. It is also intended that this Operating Agreement Exhibit will be reviewed and updated periodically, to allow the operation of the Generation System, to change to meet the needs of both the Area EPS Operator and the Interconnection Customer, provided that the change does not negatively affect the other Party. There may also be operating changes required by outside issues, such as changes in FERC and MISO requirements and/or policies which will require this Operating Agreement to be modified.

The following items are provided to show the general types of items which may be included in this Operating Agreement. The items included in the Operating Agreement shall not be limited to the items shown on this list.

- A) Applicable Area EPS Tariffs – discussion on which tariffs are being applied for this installation and possibly how they will be applied.
- B) Var Requirements – How will the Generation System be required to operate so as to control the power factor of the energy flowing in either direction across the interconnection?
- C) Inadvertent Energy – This Operating Agreement needs to provide the method(s) that will be used to monitor, meter and account for the inadvertent energy used or supplied by the Generation System. Tariffs and operating rules that apply for this Generation System interconnection shall be discussed in this Operating Agreement.
- D) Control Issues - Starting and stopping of the generation, including the remote starting and stopping, if applicable.
- E) Dispatch of Generation Resources - What are the dispatch requirements for the Generation System, Can it only run during Peak Hours? Are there a limited number of hours that it can run? Is it required to have met an availability percentage? This will greatly depend upon the PPA and other requirements. Is the Interconnection Customer required to coordinate outages of the Generation System, with the Area EPS?
- F) Outages of Distribution System – How are emergency outages handled? How are other outages scheduled? If the Interconnection Customer requires the Area EPS Operator to schedule the outages during after-hours, who pays for the Area EPS Operator's overtime?
- G) Notification / Contacts - Who should be notified? How should they be notified? When should they be notified? For what reasons, should the notification take place?

- 1) Starting of the Generation

- 2) Dispatching of Generation
 - 3) Notification of failures (both Area EPS and Generation System failures)
- H) Documentation of Operational Settings – How much fuel will the generation System typically have on hand? How long can it run with this fuel capacity? How is the generation system set to operate for a power failure? These may be issues that should be documented in the Operating Agreement. The following are a couple of examples:
- 1) "The Generation System will monitor the Area EPS phase voltage and after 2 seconds of any phase voltage below 90% the generation will be started and the load transferred to the generator, if the generation is not already running."
 - 2) "The Generation System will wait for 30 minutes after it senses the return of the Area EPS frequency and voltage, before it will automatically reconnect to the Area EPS"
- I) Cost of testing for future failures – If a component of the Generation System fails or needs to be replaced, which effects the interconnection with the Area EPS, what is the process for retesting, and for replacement? Who pays for the additional costs of the Area EPS to work with the Interconnection Customer to resolve these problems and/or to complete retesting of the modified equipment?
- J) Right of Access: At all times, the Area EPS Operator shall have access to the disconnect switch of the Generation System for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement, to meet its obligation to operate the Area EPS safely and to provide service to its customers, at all times. If necessary for the purposed of this Agreement, the Interconnection Customer shall allow the Area EPS Operator access to the Area EPS's equipment and facilities located on the premises.

Add Signature Section -The Operating Agreement should be set up so that it is individually signed and dated by both parties.

EXHIBIT E

MAINTENANCE AGREEMENT

Each Generation System interconnection will be unique and will require a unique Maintenance Agreement. It is envisioned that this Exhibit will be tailored for each Generation System interconnection. It is also intended that this Maintenance Agreement Exhibit will be reviewed and updated periodically, to allow the maintenance of the Generation System be allowed to change to meet the needs of both the Area EPS Operator and the Interconnection Customer, provided that change does not negatively affect the other Party. There may also be changes required by outside issues; such as changes in FERC and MISO requirements and/or policies which will require this agreement to be modified.

A) Routine Maintenance Requirements –

- 1) Who is providing maintenance – Contact information
- 2) Periods of maintenance

B) Modifications to the Generation System - The Interconnection Customer shall notify the Area EPS Operator, in writing of plans for any modifications to the Generation System interconnection equipment at least twenty (20) business days prior to undertaking such modification. Modifications to any of the interconnection equipment, including all required protective systems, the generation control systems, the transfer switches/breakers, VT's & CT's, generating capacity and associated wiring shall be included in the notification to the Area EPS Operator. The Interconnection Customer agrees not to commence installation of any modifications to the Generating System until the Area EPS Operator has approved the modification, in writing. The Area EPS shall have a minimum of five (5) business days and a maximum of ten (10) business days, to review and respond to the modification, after the receipt of the information required to review the modifications.

Add signature Section

State of Minnesota
**Guidelines for Establishing the Terms of the Financial Relationship Between
an Electric Utility and a Distributed Generation Customer
with No More Than 10 MW of Capacity**

1. AVAILABILITY

The DG customer must connect in parallel to the utility distribution system.

2. QUALIFICATIONS

- a. The DG facility must be an operable, permanently installed or mobile generation facility serving the customer receiving retail electric service at the same site.
- b. Must buy: The utility must buy all the energy offered for sale by the DG customer selling the power. Utilities that are full requirements customers of wholesale suppliers may need to require the wholesale supplier to assume this obligation in order to abide by contractual requirements with their wholesale supplier.
- c. Customer options: Customer may sell all the DG energy to the utility, "sell" all the DG energy to itself, or self-generate part of its needs and sell the remaining energy to the utility.
- d. Transactions outside the tariff: DG owners and utilities may pursue reasonable transactions outside the DG tariff. However, such transactions are beyond the scope of the work group.

3. LIST OF SUPPLY SERVICES TO BE PRICED

- a. Energy and capacity.
- b. Scheduled maintenance service (energy, or energy and capacity, supplied by the utility during scheduled maintenance of the customer's non-utility source of electric energy supply).
- c. Unscheduled outages (energy, or energy and capacity, supplied by the utility during unscheduled outages of the customer's non-utility source of electric energy supply).
- d. Supplemental service (electric energy, or energy and capacity, supplied by the utility to the DG customer when the customer's non-utility source of electricity is insufficient to meet the customer's own load).
- e. Other services deemed necessary.

ATTACHMENT 6 RATES

4. PRINCIPLE OF SETTING RATES FOR SERVICES PROVIDED BY DG CUSTOMERS TO UTILITIES

Rates should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions or for costs avoided on the generation, transmission, and/or distribution system.

5. PRINCIPLE OF SETTING RATES

Rates should reflect the costs the utility expects to avoid. To the extent practical, these costs should reflect seasonal and peak/off-peak differences in costs.

6. CALCULATION OF AVOIDED COSTS

a. Avoided Energy Costs

Distribution utilities that are full requirements customers of wholesale suppliers may use their suppliers' rate schedules to determine avoided energy costs. Other utilities should follow these steps:

- i. System-wide hourly marginal energy costs are calculated with a production model for each hour of the future year.
- ii. Based on those costs, the average on-peak and off-peak marginal energy costs are calculated for each month.
- iii. The on-peak monthly rate is set at the average monthly on-peak marginal energy costs. The off-peak monthly energy rate is set at the average monthly off-peak marginal costs. Thus, there are 24 rates set for the year, with an on-peak and off-peak rate set for every month.
- iv. A trial period is proposed to see whether, in practice, utilities are able to forecast these energy prices sufficiently well. Depending on the trial results, a lump sum true-up may be used at the end of each year to reflect the difference between actual and estimated energy bills.

b. Avoided Capacity Costs

- i. Calculate the installed capital cost plus fixed O&M costs plus startup costs (\$/kW-year). If the next (marginal) unit is from a competitive bid, the utility must estimate these costs and fully defend the estimate.
- ii. Calculate the Levelized Annual Revenue Requirements (LARR) (\$/kW-year).

ATTACHMENT 6
RATES

iii. Divide the amount in (ii) for the next year by twelve to get the capacity marginal costs (\$/kW-month).

iv. These marginal costs must be escalated annually by the expected inflation rate.

- (1) The need for capacity is established in the utility's most recent integrated resource plan (IRP). A need exists if the utility shows a deficit at any year of the 5-year planning period.
- (2) Capacity payments should be made for the total fully accredited DG capacity, regardless of when the power is delivered to the system.
- (3) The expected life of a capacity addition is the expected life of the specific capacity addition from the utility's most recently approved integrated resource plan.
- (4) If the contract to purchase power from a DG source begins at the time the utility needs the capacity, then the full capacity payment is made, adjusting only as needed for the length of the contract (i.e., there is no discount for adding capacity sooner than it is needed).
- (5) The formula for adjustments to capacity payments is:

$$A2 = \frac{(1+i)^m - 1}{(1+i)^n - 1} * \frac{(1+i)^{n-a} - (1+e)^{n-a}}{(1+i)^m - (1+e)^m} * A1$$

Where:

A1= Levelized annual value of a capacity purchase at the time of need.

A2=Levelized annual value of the capacity paid for in a power purchase contract.

m=Expected lifetime of ordinary (alternative) future capacity addition.

n= Length of power purchase contract.

i= Utility Cost of Capital.

e= Escalation rate affecting value of new capacity additions.

a= Length of time between beginning of contract and time of need for capacity.

7. STANDBY RATES

a. General

- i. DG customers do not have to buy standby power. However, if standby power is not purchased, it may not be available.
- ii. DG customers do not have to buy as much standby power as necessary to equal the full amount of their own DG capacity. However, if, for example, the customer has a 5 MW DG facility and buys only 2 MW of standby power, there must be a guarantee that the facility will never take more than 2 MW of standby service.

b. Firm Service

- i. Generation (capacity): The monthly reservation fees are equal to the percentage of the planned reserve margin of the utility times the applicable capacity tariffed rates.
- ii. Transmission: Terms, conditions and charges for transmission service are subject to the individual utilities' or MISO's Open Access Transmission Tariffs or their successors as approved by the FERC.
- iii. Local Distribution: The monthly charges equal the monthly charge under the applicable distribution charge. There is no discount in the local distribution charge.

c. Non-Firm Service

- i. Generation (energy and capacity): There are no monthly reservation fees for energy and capacity for a non-firm DG customer.
- ii. Transmission: There are no monthly reservation fees for transmission for a non-firm DG customer.
- iii. Local Distribution: The monthly rates equal the monthly charge under the applicable distribution charges. That is, there is no discount on the distribution charge.

d. Physical Assurance Customer

A physical assurance customer is a customer who agrees not to require standby services and has a mechanical device to insure that standby service is not taken. The cost of the mechanical device, which must be reasonable, is to be paid by the DG customer. A utility's tariff may deal with other issues not addressed here.

e. Maximum Size to Avoid Standby Charge

A DG facility of 60 kW or less is exempted from paying any standby charges. The Commission will review this guideline within 24 months.

8. CREDITS

a. General

Credits should be given to a DG customer if the installation of a DG facility reduces the utility's costs of providing the service. These lower costs could be generation, transmission or distribution related costs.

b. Distribution Credits

- i. Distribution credits to a DG customer should equal the utility's avoided distribution costs resulting from the installation of the DG facility.
- ii. Each utility should provide, upon request, a list of substation areas or feeders that could be likely candidates for distribution credits as determined through the utility's normal distribution planning process.
- iii. Upon receiving a DG application, the utility will perform an initial screening study to determine if the DG project has the potential to receive distribution credits. The DG customer is responsible for the cost of such a screening study.
- iv. If the utility's study shows that there exists potential for distribution credits, the utility must, at its own cost, pursue further study to determine the distribution credit, as part of its annual distribution capacity study.

c. Diversity Credit

No additional diversity credits for energy and capacity should be given to DG customers who contract for standby service.

d. Line Loss Credits

No additional line loss credits (above the credits already included in the avoided cost calculations) should be paid to a DG customer with the following exception: A DG customer may request the utility to provide a specific line loss study and receive additional line loss credits if the study supports such credits. The DG customer is responsible for the cost of the study regardless of the study's outcome.

e. Renewable Credits

A DG customer who installs a renewable DG facility should be paid the avoided cost of "green power" to the extent that installation of the DG facility allows the utility to avoid the need to purchase "green power" elsewhere. Otherwise a renewable DG facility should be paid the utility's regular avoided costs.

f. Emission Credits

Tradable Emissions: For tradable emissions such as SO₂, if a low emission DG facility allows the utility to capture the value of the emission credit, then the DG owner should receive the credit revenues.

A DG customer may get green credit or an emission credit, but not both.

The Commission's policy regarding the renewable energy objective may affect the question of whether it is reasonable for utilities to pay a credit for renewable power at the approved green-price premium even if a utility does not need the green power.

g. Reliability Credits

DG owners should receive no reliability credit beyond what is already incorporated in the standby tariffs.

STATE OF MINNESOTA)
COUNTY OF RAMSEY)SS

AFFIDAVIT OF SERVICE

I, Margie DeLaHunt, being first duly sworn, deposes and says:

That on the 28th day of September, 2004 she served the attached

ORDER ESTABLISHING STANDARDS.

MNPUC Docket Number: E-999/CI-01-1023

XX By depositing in the United States Mail at the City of St. Paul, a true and correct copy thereof, properly enveloped with postage prepaid

XX By personal service

XX By inter-office mail

to all persons at the addresses indicated below or on the attached list:

Commissioners
Carol Casebolt
Peter Brown
Ann Pollack
Eric Witte
Al Bierbaum
Janet Gonzalez
AG
Clark Kaml
David Jacobson
Stuart Mitchell
Mary Swoboda
Jessie Schmoker
Sharon Ferguson - DOC
Julia Anderson - OAG
Curt Nelson - OAG

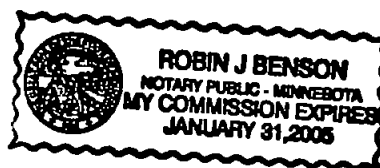
Margie DeLaHunt

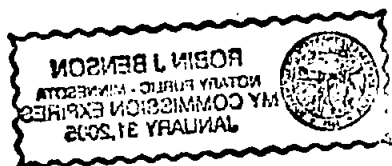
Subscribed and sworn to before me,

a notary public, this 29 day of

September, 2004

Robin J Benson
Notary Public





In the Matter of All Electric
companies establishing generic
standards for utility tariffs for
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Grand Marais Public Utilities Comm. Russell Good Mgr. 15 Broadway N. PO Box 600 Grand Marais MN 55604	<i>Electric 242</i>	Grand Rapids Public Utilities Commission A.T. Ward General Manager Village Hall PO Box 658 Grand Rapids MN 55744	<i>Electric 243</i>	Granite Falls Munic. Elec. Light & Water Dept. W. P. Lavin City Mgr. 885 Prentice St. Granite Falls MN 56241-1598	<i>Electric 244</i>

Grove City Electric Dept. Sharon Larsen Clerk City Hall PO Box 98 Grove City MN 56243	<i>Electric 245</i>	Halstad Municipal Utilities David Meyer Supt. 405 2nd Ave. W. Halstad MN 56548	<i>Electric 246</i>	Hamlin (HD) Electric Coop. Janice Nordseth Office Mgr. Clear Lake SD 57226	<i>Electric 152</i>
Harmony Water & Light Chris Johnson Harmony MN 55939	<i>Electric 247</i>	Hastings Public Utilities Commission James Heusser 1225 Progress Drive Hastings MN 55033	<i>Electric 6364</i>	Hawley Public Utilities Comm. - Electric Kevin Berg PO Box 69 Hawley MN 56549-0069	<i>Electric 249</i>
Henning Power & Light D. Hagen Mgr. PO Box 55 Henning MN 56551	<i>Electric 250</i>	Hibbing Public Utilities-Electric James Kochevar Gen. Mgr. 19th St. & 6th Ave. E PO Box 249 Hibbing MN 55745	<i>Electric 251</i>	Hutchinson Utilities Commission - Electric Patrick Spethman General Manager 225 Michigan St. S.E. Hutchinson MN 55350	<i>Electric 252</i>
Interstate Power & Light Company - Electric D. H. Berentsen Alliant Energy G0-9 200 1st Street S.E. P. O. Box 351 Cedar Rapids IA 52406-0351	<i>Electric 001</i>	Iowa Lakes Rural Electric Terry L. Burns Gen. Mgr. 702 S 1st St Estherville IA 51334	<i>Electric 151</i>	Itasca-Mantrap Coop. Electric Assn. Patrick E. O'Brien Manager PO Box 192 Park Rapids MN 56470	<i>Electric 117</i>
Jackson Electric Light Dept. J. Lutz Supt 80 West Ashley St Jackson MN 56143	<i>Electric 253</i>	Janesville Municipal Utilities Clinton Rogers City Administrator 101 North Mott St. PO Box O Janesville MN 56048-0617	<i>Electric 254</i>	Kandiyohi Power Cooperative David J. George Mgr. 1311 Hwy 71 NE Willmar MN 56201	<i>Electric 118</i>
Kandiyohi Public Utilities Mike Seiler PO Box 276 Kandiyohi MN 56251	<i>Electric 255</i>	Kasota Electric Light Dept. Rosie Sickler Clerk/Treasurer P. O. Box 218 Kasota MN 56050	<i>Electric 256</i>	Kasson Municipal Electric Dept. Lynne Erickson Finance Coordinator 401 - 5th St. SE Kasson MN 55944	<i>Electric 257</i>
Keewatin Public Utilities Roger Heil P.O. Box 190 Keewatin MN 55753	<i>Electric 258</i>	Kenyon Municipal Utilities Randy Eggert Supt. 709 2nd Street Kenyon MN 55946	<i>Electric 260</i>	Lake Country Power Richard Lemonds General Manager Grand Rapids Service Center 2810 Elida Drive Grand Rapids MN 55744	<i>Electric 106</i>
Lake Crystal Public Utilities Commission Robert Hauge City Administrator 100 E. Robinson Street PO Box 86 Lake Crystal MN 56055-0086	<i>Electric 262</i>	Lake Park Utilities Don Qualley Utility Supt. PO Box 239 Lake Park MN 56554	<i>Electric 263</i>	Lake Region Coop. Electrical Assn. David Weaklend Gen. Mgr. 12 5th Ave. N. E. P. O. Box 643 Pelican Rapids MN 56572-0643	<i>Electric 119</i>
Lakefield Public Utilities Jim Koep Supt. PO Box 1023 Lakefield MN 56150	<i>Electric 264</i>	Lanesboro Public Utilities Commission Barbara Hoyhtya City Admin. PO Box 333 Lanesboro MN 55949	<i>Electric 265</i>	LeSueur Municipal Utilities Rick Almich Supt. PO Box 176 LeSueur MN 56058-0176	<i>Electric 266</i>
Litchfield Public Utilities Commission Leslie Valiant PO Box 521 Litchfield MN 55355	<i>Electric 267</i>	Luverne Municipal Utilities Red Arndt Utilities Coordinator 203 East Main PO Box 659 Luverne MN 56156	<i>Electric 268</i>	Lyon-Lincoln Electric Cooperative, Inc. West Highway 14 PO Box 639 Tyler MN 56178-0639	<i>Electric 125</i>

Mabel Public Utilities J. Narum Clerk Box 425 Mabel MN 55954	<i>Electric 269</i>	Madelia Municipal Light & Power Dept. Steve Moses Supt. 24 Abbott Avenue SW Madelia MN 56062	<i>Electric 270</i>	Madison Municipal Utilities Harold Hodge Superintendent 616 8th st Madison MN 56256	<i>Electric 271</i>
Marshall Municipal Utilities Greg Sherman General Manager 113 South 4th Street PO Box 3575 Marshall MN 56258	<i>Electric 272</i>	McKinley Public Utilities Dan Kodroski McKinley MN 55761	<i>Electric 335</i>	McLeod Cooperative Power Assn. Randall Owen Gen. Mgr. 1231 Ford Avenue, PO Box 70 Glencoe MN 55336-0070	<i>Electric 120</i>
Meeker Light & Power Assn. Timothy Mergen Mgr. PO Box 522 503 East Hwy 12 Litchfield MN 55355	<i>Electric 121</i>	Melrose Public Utilities Tracy Ekola Director 225 E First St N PO Box 216 Melrose MN 56352-0216	<i>Electric 274</i>	Mille Lacs Electric Coop. (E) Ralph Mykkanen Gen. Mgr. PO Box 230 Aitkin MN 56431	<i>Electric 122</i>
Minnesota Municipal Utilities Association Greg Oxley Government Relations 12805 Highway 55, suite 212 Plymouth MN 55441-3859	<i>Electric</i>	Minnesota Power Mark Schober Controller 30 West Superior Street Duluth MN 55802	<i>Electric 015</i>	Minnesota Rural Electric Association Lee Sundberg 11640 73rd Ave., North Maple Grove MN 55369	<i>Electric</i>
Minnesota Valley Coop. Light & Power Assn. Patrick C. Carruth Gen. Mgr. PO Box 717 Montevideo MN 56265	<i>Electric 123</i>	Minnesota Valley Electric Cooperative Jeannie Robbins Office Manager P. O. Box 125 Jordan MN 55352	<i>Electric 124</i>	Moorhead Public Service Dept. (E) B. Schwandt General Mg 500 Center Ave. PO Box 779 Moorhead MN 56560	<i>Electric 275</i>
Moose Lake Water & Light Comm. Leland Johnson Supt. PO Box 418 Moose Lake MN 55767	<i>Electric 276</i>	Mora Public Utilities Commission Bob Jagusch 117 S.E. Railroad Ave. Mora MN 55051	<i>Electric 277</i>	Mountain Iron Light & Water Dept. Craig J. Wainio City Administrator 8586 Enterprise Drive South Mountain Iron MN 55768	<i>Electric 278</i>
Mountain Lake Municipal Utilities Luayn Murphy Clerk 1015 2nd Avenue Drawer C Mountain Lake MN 56159	<i>Electric 279</i>	Nashwauk Public Utilities Dept. E. Bolf Manager 301 Central Avenue Nashwauk MN 55769	<i>Electric 280</i>	New Prague Utilities Commission Dennis Seuer Public Works Director 118 Central Ave. N. New Prague MN 56071	<i>Electric 281</i>
New Ulm Public Utilities Comm. - Electric Bob Stevenson Supt. 310 1st. Street N. PO Box 355 New Ulm MN 56073	<i>Electric 282</i>	Newfolden Electric Dept. Grace Lindquist Clerk P.O. Box 188 Newfolden MN 56738	<i>Electric 284</i>	Nielsville Municipal Utility Stephanie Abentroth Clerk Nielsville MN 56568	<i>Electric 285</i>
Nobles Cooperative Electric R. G. Burud Mgr. Highway 59N PO Box 788 Worthington MN 56187	<i>Electric 126</i>	North Branch Light & Power Comm. B.C. Walters Supt. PO Box 176 North Branch MN 55056	<i>Electric 286</i>	North Itasca Electric Cooperative, Inc. J. Ortman Mgr. PO Box 227 Bigfork MN 56628	<i>Electric 127</i>
North St. Paul Utility Dept. Jim Bowers Elec. Supt 2526 East 7th Avenue North St. Paul MN 55109	<i>Electric 287</i>	North Star Electric Cooperative, Inc. Dan Hoskins General Manager 441 St. Hwy. 172 NW P. O. Box 719 Baudette MN 56623	<i>Electric 129</i>	Northern States Power Company dba Xcel Mark Hervey Gen. Manager Rev. Req. 414 Nicollet Mall Minneapolis MN 55401	<i>Electric 002</i>

Northwestern Wisconsin Electric Co. Mark F. Dahlberg President PO Box 9 Grantsburg WI 54840-0009	<i>Electric 016</i>	Olivia Municipal Water & Light Dept. Robert Zeug Supt. 1009 West Lincoln Avenue Olivia MN 56277	<i>Electric 288</i>	Ortonville Light & Water Dept. Roman Taffe Supt. 315 Madison Avenue Ortonville MN 56278	<i>Electric 289</i>
Otter Tail Power Company Jeff Legge Controller P.O. Box 496 215 South Cascade Street Fergus Falls MN 56538-0496	<i>Electric 017</i>	Owatonna Municipal Public Utilities - Electric Stephen Shurts General Manager 208 South Walnut PO Box 800 Owatonna MN 55060	<i>Electric 290</i>	Peoples Coop. Power Assn. Of Olmsted Frank Welter General Mgr. 3935 Hwy 14 East PO Box 339 Rochester MN 55903	<i>Electric 132</i>
Peterson Electric Dept. P. Benson PO Box 94 Peterson MN 55962	<i>Electric 292</i>	Pierz Municipal Utilities Jeff Hasert Supt. PO Box 367 Pierz MN 56364	<i>Electric 293</i>	PKM Electric Cooperative Assn. Charles Riesen Mgr. 406 North Minnesota Street PO Box 108 Warren MN 56762	<i>Electric 131</i>
Preston Public Utilities F. Nagle Admin. PO Box 657 Preston MN 55965	<i>Electric 294</i>	Princeton Public Utilities Commission John Dunham Gen. Mgr. 907 1st Street Princeton MN 55371	<i>Electric 295</i>	Proctor Public Utilities Comm. Carol Lind Commission Secretary 100 Pionk Drive Proctor MN 55810	<i>Electric 296</i>
Randall Electric Light Company Gerald Peterschick Admin. Randall MN 56475	<i>Electric 297</i>	Red Lake Electric Coop. R.M. Kennedy Mgr. PO Box 430 Red Lake Falls MN 56750	<i>Electric 133</i>	Red River Valley Coop. Power Assn. Loren Brorby Manager P. O. Box 358 Halstad MN 56548-0358	<i>Electric 134</i>
Redwood Electric Cooperative Betty Wilhelmi Office Mgr. PO Box 15 Clements MN 56224	<i>Electric 135</i>	Redwood Falls Public Utilities Charles Heins Supt. 333 S. Washington Street Redwood Falls MN 56283	<i>Electric 298</i>	Renville-Sibley Cooperative Power Dale Christensen CEO PO Box 68 Danube MN 56230	<i>Electric 136</i>
Rochester Public Utilities Larry Koshire Mgr. 4000 East River Rd NE Rochester MN 55906-2813	<i>Electric 299</i>	Roseau Electric Coop., Inc. Michael Adams Manager PO Box 100 Roseau MN 56751	<i>Electric 137</i>	Roseau Munic. Power Plant Jim Vieckaryous Supt 100 2nd Avenue PO Box 307 Roseau MN 56751	<i>Electric 300</i>
Round Lake Municipal Utility Sandy Consoer Clerk PO Box 72 Round Lake MN 56167-0072	<i>Electric 301</i>	Runestone Electric Assn. William Banke, Jr. Gen. Mgr. 7th & Fillmore PO Box 9 Alexandria MN 56308	<i>Electric 138</i>	Rushford Electric Dept. Larry Bartelson Admin. PO Box 430 Rushford MN 55971	<i>Electric 302</i>
Rushmore Electric Dept. Gloria Long Village Clerk PO Box 227 Rushmore MN 56168	<i>Electric 303</i>	Sauk Centre Light & Power Comm. Marty Sunderman Supt. 101 South Main Street PO Box 128 Sauk Centre MN 56378	<i>Electric 308</i>	Shakopee Public Utilities Commission Lou Van Hout Mgr. 1030 East 4th Avenue Shakopee MN 55379	<i>Electric 309</i>
Shelly Electric Dept. Jodean Neil Clerk PO Box 126 Shelly MN 56581	<i>Electric 310</i>	Sleepy Eye Public Utilities Commission David Logue Supt. 130 2nd Avenue NW Sleepy Eye MN 56085	<i>Electric 311</i>	South Central Electric Assn. T. Malone Mgr. PO Box 150 County Road 57 West St. James MN 56081	<i>Electric 139</i>

Electric 140

Southwestern Minnesota Coop. Electric
Kathy Nepp Sioux Valley-Southwestern Electric
PO Box 216
Accounts Payable
Colman SD 57017

Electric 313

Springfield Public Utilities
Scott Johnson Supt.
14 North Marshall Avenue
Springfield MN 56087

Electric 306

St. Peter Municipal Utilities
L.G. Geisking Dir. Public Works
227 S. Front Street
St. Peter MN 56082

Electric 142

Steele Waseca Coop. Electric
Gerald J. Mikel General Mgr.
2411 W. Bridge St.
PO Box 485
Owatonna MN 55060-0485

Electric 143

Todd Wadena Electric Coop.
D. Hendrickson General Mgr
PO Box 431
Wadena MN 56482

Electric 318

Truman Municipal Light Plant
Robert Grefe Mgr.
118 North 1st Avenue
PO Box 147
Truman MN 56088

Electric 321

Virginia Dept. Of Public Utilities - Electric
Terry Leoni General Manager
620 2nd St. S.
PO Box 1048
Virginia MN 55792

Electric 324

Warroad Munic. Light & Power Dept.
D. Anderson Supt
PO Box 50
Warroad MN 56763

Electric 327

Westbrook Light & Power Commission
Dennis Jutting Supt.
PO Box 308
Westbrook MN 56183-0308

Electric 329

Willmar Munic. Utilities Comm.
Michael F. Nitchals Gen. Mgr.
704 West Litchfield Avenue
PO Box 937
Willmar MN 56201

Spring Grove Munic. Utility
Lyn Solberg Deputy Clerk
118 1st Ave NW
Spring Grove MN 55974

St. Charles Light & Water Dept.
Sandra Pasche Accounts Payable
830 Whitewater Avenue
St. Charles MN 55972

Staples Munic. Water & Light Dept.
G. Brever Manager
Staples Government Center
611 Iowa Ave. NE
Staples MN 56479

Stephen Electric Light Dept.
Dwayne Rud Superintendent
PO Box 630
Stephen MN 56757

Traverse Electric Coop., Inc.
Donald O'Leary Manager
TH 27 & 17th Street
Wheaton MN 56296

Two Harbors Water & Light Dept.- Electric
Steve Blettner Supt.
522 First Avenue
Two Harbors MN 55792

Wadena Light & Water Dept.
Vernell Roberts Supt.
104 Jefferson Street North
Wadena MN 56482

Waseca Electric Utility
Julie Linnihan Finance Dept.
508 South State Street
Waseca MN 56093

Whalan, City of
Lolly Melander Clerk-Treasurer
RR2 Box 2105
Lanesboro MN 55949

Windom Municipal Utilities
Marv Grunig
444 9th Street
Windom MN 56101

*Electric 312**Electric 304**Electric 315**Electric 316**Electric 144**Electric 319**Electric 322**Electric 325**Electric 328**Electric 330**Electric 314*

Spring Valley Public Utilities Comm.
Stu Smith Supt.
104 South Section Avenue
Spring Valley MN 55975

Electric 305

St. James Light & Water Dept.
J. Bechthold Supt.
124 Armstrong Blvd S
St. James MN 56081

Electric 141

Stearns Electric Assn:
Rick Banke Mgr.
900 E. Kraft Drive
P. O. Box 40
Melrose MN 56352

Electric 317

Thief River Falls Water & Light Dept.
A. Rude Director
123 Main Avenue North
PO Box 528
Thief River Falls MN 56701

Electric 145

Tri-County Electric Coop.
Brian Krambeer President, CEO
210 West Jessie Street
PO Box 626
Rushford MN 55971-0626

Electric 320

Tyler Munic. Light & Power Dept.
Jason Maxwell City Adm
PO Box 398
Tyler MN 56178

Electric 323

Warren Light & Power Dept. - Electric
Dan DeWall Supt.
120 E. Bridge Ave.
Warren MN 56762

Electric 326

Wells Public Utilities Commission
Ray Wigern Supt.
101 1st St SE
PO Box 96
Wells MN 56097-0096

Electric 147

Wild Rice Electric Coop.
S. J. Haaven Mgr.
PO Box 438
Mahnomon MN 56557

Electric 155

Winnebago Rural Electric
Sauer
PO Box 65
Thompson IA 50478

Electric 331

Winthrop Municipal Electric Plant
S. Shult City Clerk
305 North Main Street
Winthrop MN 55396

Worthington Public Utilities
Donald Habicht City Adm.
318 Ninth St.
PO Box 458
Worthington MN 56187

Electric 332

Wright Hennepin Coop. Electric Assn.
M. Vogt President & CEO
PO Box 330
6800 Electric Drive
Rockford MN 55373

Electric 148