Section 1. Regulatory Aspects of On-Site Electricity Generation

1.1 Federal and State Regulations

Both federal and state regulations and programs have been put in place to encourage the generation of electricity from biomass and other renewable energy sources. The mechanisms used to encourage this generation include the creation of renewable energy markets, favorable tax treatments, and favorable regulatory status. The major applicable regulations and programs are discussed below.

1.1.1 Public Utility Regulatory Policies Act (PURPA) of 1978

Under PURPA, facilities generating their own electricity and meeting certain fuel and efficiency standards (a “Qualified Facility” or QF) are accorded special regulatory qualifications. As initially approved, PURPA required that the local utility purchase all energy sold by the owner of a QF at its avoided cost and provide standby, backup, and maintenance power to the QF. However, EPACT ’05 amended PURPA, such that where the Federal Energy Regulatory Commission (FERC) determines that competitive conditions exist, such as areas that participate in regional transmission markets, a utility is no longer required to buy power from renewable energy and combined heat and power (CHP, or cogeneration) plants, even when such plants can generate power less expensively than the utility, and even when such plants would otherwise meet PURPA standards.

The revised PURPA standards do provide an exception for generating units rated 20 MW or less. Before being relieved of their purchase obligation from units rated 20 MW or less, the local utility must provide a showing that the units have access to competitive power markets. Smaller generating units, such as those at renewable energy plant sites and generating only the plant load, are typically connected at distribution voltage and therefore do not have transmission access to the Regional Transmission Organization (RTO) markets, in this case the Midwest Independent System Operator’s (MISO’s) markets. To receive the full benefit of those parts of PURPA that still apply, a DG facility that cogenerates or utilizes qualifying fuels should be formally registered by the owner as a QF under the PURPA self-certification process. Despite any changes in federal regulations, the state of Minnesota actively encourages the development of distributed generation, as discussed below.
1.1.2 Renewable Energy Credits

Customers who generate their own electricity utilizing qualified renewable fuels, such as biomass or wind, can sell Renewable Energy Credits (RECs) into national and state markets, where such markets exist, even when the electricity is all utilized on-site. However, once sold, the RECs remain with the property of the buyer, who can further trade the RECs. The current market for RECs are small and regional, though evolving, with transactions via over-the-counter trades or bilateral deals. Carbon credits will also have value as greenhouse gas regulations emerge.

1.1.3 Production Tax Credits

Under the Energy Policy Act of 2005 (EPACT ’05), generators of electricity from biomass that is sold for use by others are eligible for a production tax credit (PTC), for the first 10 years of such electricity production. The PTC for 2006 for “open-loop” biomass is about one half of the $0.019/ kWh credit for wind and other renewable energy technologies, with an annual adjustment for inflation. To be eligible for a PTC under the current law, the electricity-generating equipment must be on-line before January 1, 2008. Among other eligibility requirements for the PTCs, the regulations restrict the use of coal in the fuel-to-flame initialization and stabilization, and facilities that use the renewable energy to serve any on-site needs are ineligible. The energy associated with natural gas used in the production of electricity is not eligible for production tax credits, and any electricity produced by "co-mingling" natural gas and renewable fuels would need to be sorted by fuel type.

Similar to PTCs, renewable generation assets owned by tax exempt state and municipal utilities are eligible for renewable energy production incentive (REPI) payments from the federal government.

1.2 Distributed Generation and Utility Regulations

Action has been initiated at both state and federal levels to encourage development of smaller, dispersed generating facilities, called Distributed Generation Facilities (DGs), that supply electricity to the customer owning the generation, and/or supply electricity directly to the utility without the customer taking any of the energy (a wholesale generator). The actions at both levels of government have been aimed at removing barriers typically erected by utility organizations against DGs. DGs can provide benefits of increased grid reliability, reduced investment in transmission facilities, reduced grid system losses, and increased efficiency of energy conversion.

The definition of a DG varies by state and federal jurisdiction. Also, regulations for the interconnection of these facilities with the electricity grid may vary by electric utility. The amount paid by the utility to the DG is stipulated under various rate schedules (tariffs) approved for investor-owned utilities by the state Public Service Commission. (Electric Cooperatives and municipal electric utilities set their policies via their Board of Directors who must comply with state and federal mandates.) The electricity buyback rates may vary based on several factors, including the reliability of the DG supply and the amount of electricity delivered by the DG. DGs with capacities above certain thresholds often have the opportunity to negotiate special buyback rates outside of the tariff.
Units exceeding the state DG size threshold or PURPA applicability threshold would be subject to more lengthy and costly connection and application procedures, as outlined in the RTO or local utility connection rules. These procedures are less precise and may require extensive negotiations after utility completion of special costly interconnection and transmission access studies. However, if generating units at renewable energy plant sites are sized to meet only the plant electric load plus steam requirements, then these units are likely to fall within the DG or PURPA applicability standard.

1.2.1 Minnesota Distributed Generation Rules

On August 1, 2001, Minnesota Stat. 216B.161 became effective. The Minnesota Public Utilities Commission was directed under this statute to implement a proceeding with the following purposes: 1) establish the terms and conditions that govern the interconnection and parallel operation of on-site, distributed generation; 2) provide cost savings and reliability benefits to customers; 3) establish technical requirements that will promote the safe and reliable parallel operation of on-site distributed generation resources; 4) enhance both the reliability of electric service and economic efficiency in the production and consumption of electricity; and 5) promote the use of distributed resources in order to provide electric system benefits during periods of capacity constraints. Subsequently, the Dept of Commerce met with a group of stakeholders to develop a set of regulations meeting the objectives of the Act.

In Minnesota, distributed generation is defined as electricity-producing facilities burning clean fuels and rated 10 MW or less and operating at 35 kV or less. The electricity buyback rates offered by the utilities change annually, and are based on the utility’s expected marginal monthly on-peak and off-peak energy costs as well as avoided capacity costs. The price paid by the utility for its purchase of firm capacity from DGs (the capacity buyback rate) also changes annually, based on the utility’s cost of capital and the remaining life of the DG equipment and the utility’s need to otherwise install its own generating facilities.

The State of Minnesota has developed a document entitled “Distributed Generation Connection Requirements,” which, in addition to specifying the setting of relays and other physical aspects of interconnection, describes the technical requirements for metering, monitoring, and controlling generation. A document describing Xcel Energy’s conformance to the DG regulations can be found at www.xcelenergy.com. The State of Minnesota has also adopted a net metering standard for very small DG’s (less than 40 KW).
1.2.2 Federal (FERC) vs state jurisdiction

DG regulations in Minnesota state:

“...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 (Minnesota) process.” Otherwise, the generating system is likely to be under FERC jurisdiction.

1.2.3 Federal Distributed Generation Rules

Federal regulations promulgating DG standards have been initiated by the Federal Energy Regulatory Commission (FERC) and are stated in FERC Order No. 2006-B which became effective on August 26, 2006. The regulations, which mandate expedited MISO treatment for federal DG units apply to generating units rated 20 MW or less. However, the definition of lower nameplate capacity for DGs by the various states (generally 10 to 15 MW) is currently the operative definition in those states. FERC regulations regarding transmission access and facility interconnection are effective nationwide.

1.2.4 Non-DG Units

In certain cases, the availability of byproduct fuel and other resources will allow the installation of generating units with capacity ratings far in excess of the amount required to operate the plant. Although such units would be too large to qualify for DG or PURPA benefits and would require transmission access, they would meet classification as Independent Power Producers (IPPs) and could register as Exempt Wholesale Generators (EWGs). Registration as an EWG means that they are exempt from conventional utility regulation as long as they do not have majority ownership by an electric utility. An EWG also has the right of access to the transmission grid for purposes of wholesale transactions.

EWGs in Minnesota and Wisconsin must make application via the Midwest Independent System Operator (MISO) to interconnect with the transmission system and to reserve transmission capability required to transmit the output. This is done by following a complicated application procedure to MISO for both the interconnection and any additional transmission capacity accompanied by a substantial study funding payment (to be paid by the EWG) under the MISO Open Access Transmission and Energy Markets Tariff (TEMT). The MISO study results provide the EWG with an interconnection configuration, along with the amount of investment the EWG must make in the transmission grid.

Prices paid for energy to the EWG are based either on MISO market prices (if the EWG becomes a market participant) or on individually negotiated bilateral contracts. EWGs are eligible for the federal PTC.
1.3 Utility Interconnection Requirements and Approvals

Customer on-site generation may be sized to meet some of the plant needs while continuing to purchase remaining plant requirements (such as during peak electricity demand) from the local utility under standard tariffs, meeting all of the plant needs and selling excess power (produced by the DG when its electricity usage is less than its peak usage) off-site, or meeting all of the plant needs and continuously generating excess electricity to the grid, even during peak plant demand. Unless electricity is to be sold off-site to a wholesale entity other than the local utility, connections to the local electrical distribution system are under the rules set by the local utility. If renewable generating facilities are sized to be under the state standard, approval will be under local utility requirements conforming to state DG standards.

Regulations regarding connecting DG facilities to a utility system vary by generator size and interconnection voltage. Details within the regulations include relaying standards, circuit breaker ratings, switch ratings, approved devices, etc. Utilities cannot make interconnection requirements more stringent than the new uniform state and federal regulations without an approved reason.

1.3.1 Applicable Utility Tariffs

When a DGs electricity is utilized on-site, and the DG remains connected to the utility, provisions related to standby, backup, and maintenance power apply. The price for each of these services is stated in the utility tariffs. The applicable Xcel Energy (Minnesota) and Alliant Energy (Wisconsin) rates for these services, as well as pricing for the energy and capacity purchased from the customer-owned generation are discussed below.

Standby power costs are almost always a major cost component for an industrial user, and are currently priced at $2 (WP&L) to $2.25 (NSP) per kW-month at the primary distribution. RTO transmission at approximately $1.70 per kW-month should also be added. Backup generators at a customer’s site may reduce or eliminate standby power costs, in addition to avoiding brownouts or blackouts, and allowing the industrial user to consider the use of interruptible rates from the utility. However, backup generators entail costs and environmental complications, which must be balanced against their advantages.

Buyback rates for energy sold to the grid vary by utility. The current Xcel Energy pricing for energy purchased from DG’s is in the range of $0.03/kWh to $0.125/kWh, depending on time of day and season, plus capacity credits that change annually depending on NSP’s cost of capital and the value of the capacity on the NSP system. The current Alliant Energy (Wisconsin) pricing for DG is $.06/kWh on-peak and $0.025/kWh off-peak. Additional credits may be available from the utility for the supply of energy from renewable fuels.

1.3.2 Metering, Insurance, Applications, etc.

DG regulations also state metering requirements, minimum insurance requirements, application procedures and costs, approval procedures and costs, timelines, contract formats and many other details associated with DG installations. These requirements should be reviewed and taken into account in evaluating the advisability of installing a DG facility. Insurance requirements are in effect in Minnesota for units larger than 100 kW.
1.3.3 Interconnection and Transmission Studies

An engineering study by the host utility may be required for DGs that plan to produce electricity for sale onto the local electric distribution and transmission network ("grid"). The studies can vary in cost, depending on the amount of DG capacity sold to the utility. The study will determine what additional electric infrastructure is required by the utility to accommodate the output of the DG facility, including any upgrades to existing equipment. If the amount of capacity sold does not exceed the expected load of the local substation that is feeding the plant, then the DG may be considered as not affecting the transmission system, and the interconnection procedures of the local utility apply. For DG capacity sold that is greater than the load of the local substation, the procedures of the Midwest Independent System Operator (MISO) and Regional Transmission Operator (RTO) may apply. Developers of large facilities must typically contribute large capital outlays for interconnection facilities and transmission upgrades.

1.3.4 Generating Unit Accreditation

Capacity accreditation by the Mid-Continent Area Power Pool (MAPP), the organization responsible for ensuring adequate regional electric system reliability, or its successor organization, the Midwest Reliability Organization, may be a means of reducing utility standby charges and/or receiving capacity credits for customer-owned generation. Capacity credits are utilized by the local utility to help meet its total capacity requirements, typically equal to peak load plus 15 percent reserve. The MAPP Generation Reserve Sharing Handbook describes the accreditation process (found at www.mapp.org/assets/pdf/GRSP_Handbook_20050311.pdf). Variable capacity unit accreditation is applicable to wind as well as to combined heat and power units for which the amount of power available to the grid may vary and is not dispatchable by the local utility.
1.4 Regulations Summary

Table EPE 1 below provides a summary of the regulations pertaining to the generation of electricity from renewable resources.

<table>
<thead>
<tr>
<th>REGULATION</th>
<th>DESCRIPTION</th>
</tr>
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<tbody>
<tr>
<td>Federal Production Tax Credit</td>
<td>Payment in the form of a tax credit per kWh produced and sold to the grid.</td>
</tr>
<tr>
<td>Renewable Energy Credits</td>
<td>Where market exists, payment by marketers for green energy sales to end-users</td>
</tr>
<tr>
<td>PURPA</td>
<td>Gives standards for regulation of cogeneration facilities, which states may adopt.</td>
</tr>
<tr>
<td>State Distributed Generation Rules</td>
<td>Define interconnection requirements by the size of the generating unit. Address insurance, application, and approval issues.</td>
</tr>
<tr>
<td>Federal Distributed Generation Rules</td>
<td>Provide for uniform regulations from which states cannot be more stringent.</td>
</tr>
<tr>
<td>Utility Tariffs</td>
<td>Rate schedules</td>
</tr>
<tr>
<td>Standby capacity service</td>
<td>Fee for contracted amount of reserve backup capacity.</td>
</tr>
<tr>
<td>Supplemental energy</td>
<td>Standby, maintenance, or supplemental energy are usually supplied under the normal tariff for which the customer qualifies.</td>
</tr>
<tr>
<td>Buyback rates</td>
<td>Payment by a utility to a DG for energy sold to that utility. May be at utility avoided cost (NSP) with premium for renewable energy or at a flat rate (WP&amp;L).</td>
</tr>
<tr>
<td>Interconnection requirement</td>
<td>Addresses voltage, relaying, frequency, devices, metering, monitoring, control of generation, and other technical issues.</td>
</tr>
<tr>
<td>Interconnection study</td>
<td>Electrical engineering study of the effect of supplying additional capacity onto the local electric distribution and transmission network.</td>
</tr>
<tr>
<td>Generating unit accreditation</td>
<td>Recognition of capacity benefit of generation units to the regional electric system network. May help to reduce standby capacity charges.</td>
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Prepared by Larry L Schedin PE, November 1, 2007

Note: Some of the content of this paper has been excerpted from a similar section in a forthcoming report on the use of ethanol coproducts to produce electricity. This report section was also written by Larry L Schedin PE for U of M Professor Vance Morey to be issued shortly.