Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date:	June 12, 2014	**Agenda Item **# 5**

Company: All Rate Regulated Electric Utilities

Docket No. **E999/CI-13-720**

In the Matter of a Commission Inquiry into Ownership of Renewable Energy Credits Used to Meet Minnesota Requirements

Issue: Should the Commission issue a decision on the ownership of Renewable Energy Credits?

Staff:		
	Michelle Rebholz	(651) 201-2206
	Janet Gonzalez	201-2231
	Andrew Twite	201-2245

Relevant Documents

Powerfully Green, Comments.	January 27, 2014
Otter Tail Power, Initial Comments.	February 6, 2014
Dairyland Power Cooperative, Comments.	February 7, 2014
Minnkota Power Cooperative, Comments	February 7, 2014
Minnesota Power, Initial Comments.	February 7, 2014
Department of Commerce, Initial Comments	February 7, 2014
Environmental Law and Policy Center, et al, Initial Comments	February 7, 2014
Xcel Energy, Initial Comments.	February 7, 2014
Metropolitan Council, Comments	February 10, 2014
Center for Resource Solutions, Comments	February 10, 2014
Innovative Power Systems, Comments.	February 10, 2014
Solar Energy Industries Association, Initial Comments	February 10, 2014
Otter Tail Power Company, Reply Comments.	February 21, 2014
Xcel Energy, Reply Comments	February 21, 2014
Wal-Mart Stores East, LP, Comments	February 21, 2014
Environmental Law and Policy Center, et al, Reply Comments	February 21, 2014
Sundial Solar, Reply Comments.	February 24, 2014
Solar Energy Industries Association, Reply Comments.	February 24, 2014
Powerfully Green, Supplemental Reply Comments.	May 28, 2014
Dairyland Power Coop, Response to Information Request.	June 2, 2014

The attached materials are workpapers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

Statement of the issue

Should the Commission issue a decision on the ownership of Renewable Energy Credits?

If so, for which types of facilities and transactions:

- Net-metered facilities of less than 40 kW receiving payments for excess generation at the utility's average retail energy rate?[1]
- Other facilities and arrangements covered under Minn. Stat. §216B.164 and other Minnesota statutes?

Background

Public Utilities Regulatory Policies Act (PURPA)

The federal Public Utilities Regulatory Policies Act (PURPA) was enacted in 1978, as part of a larger package of national energy legislation to deal with the aftermath of the 1973-4 oil embargo, natural gas shortages, and the ongoing "energy crisis." PURPA itself has six titles; the part relevant to these briefing papers is Title II, Sections 201 and 210. The purpose of these sections was to promote independent small power production (generally from renewable sources) and cogeneration by requiring utilities to purchase the output from such facilities. These facilities are known as qualifying facilities (QFs).

PURPA[2] delegates the responsibility to implement many aspects of the statute, within the framework of the federal law and FERC rules, to state regulatory commissions and non-regulated utilities, including setting the rates at which utilities must purchase generation from QFs. Utilities must purchase from QFs at "the incremental cost to the electric utility of electric energy or capacity or both which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source." This is generally referred to as ***avoided cost.***

The Minnesota Public Utilities Commission began a state-level rulemaking process to implement PURPA in 1980. Minn. Stat. §216B.164 was enacted in 1981 to provide a clear state framework for implementing PURPA, with significant additions in 1983. The Commission's rules, now known as Minn. Rules, Chapter 7835, became effective in 1983. Minn. Stat. §216B.164 states that the statute, and the Commission's rules promulgated thereunder, apply to cooperative and municipal utilities as well as public utilities.

Net Metering

---

[1] Some commenters recommend limiting the Commission's decision to this circumstance. One commenter challenges the Commission's jurisdiction to determine even this issue for cooperatives.

[2] While PURPA contains 5 other Titles and numerous sections, in these briefing papers we will use PURPA as shorthand for the provisions in Title II, Sections 201 and 210, relating to cogeneration and small power production.

The 1983 amendments to Minn. Stat. §216B.164 added the requirement that QFs under 40 kW be given the option to be net-metered, and to be compensated for net input into the utility's system at the "average retail utility energy rate," a concept that had already been developing in the Commission's proposed rules. Minnesota was the first state to pass net metering legislation. Approximately 47 jurisdictions in the United States now have some form of net metering. PURPA does not require net-metering; in fact, such a term is not used in PURPA nor FERC implementing rules.

Renewable Energy Statute

Minnesota's Renewable Energy Statute, Minn. Stat. §216B.1691, requires sixteen (16) utilities to procure certain percentages of renewable energy in certain years. The Commission is the agency charged with enforcing the statute.

Minn. Stat. §216B.1691 subd. 4, referenced later in these briefing papers, required the Commission to establish a program for tradable renewable energy credits by January 1, 2008. The subdivision states that once a credit tracking system is in place, the Commission shall issue an order establishing protocols for trading credits.

Renewable Energy Credits (RECs)

A Renewable Energy Credit (REC) represents 1 MWh of renewable energy. Retirement of RECs is the only means for utilities to show compliance with Minnesota's Renewable Energy Standard (RES) and Solar Energy Standard (SES). RECs must be registered in M-RETS (Midwest Renewable Energy Tracking System) to be used toward Minnesota compliance.[3]

With limited exceptions,[4] Minnesota Statutes do not address REC ownership. The Commission has only addressed the issue in Docket E002/M-08-440 (the "silent REC" docket), which involved a request by Xcel Energy for the Commission to decide REC ownership for certain older Power Purchase Agreements (PPAs) which allegedly did not specify such ownership.[5] REC ownership has not gained much attention since then, until the passage of the 2013 legislation on solar and distributed generation prompted stakeholders to ask the Commission if it would be issuing decisions on REC ownership.

[3] See: Minn. Stat. §216B.1691, Subd. 4; various Commission orders in Dockets 03-869 and 04-1616.

[4] Minnesota Laws 2013, Chapter 85, specifies that utilities own RECs if a Value of Solar rate is in place, or if Made in Minnesota incentives are used.

[5] On September 9, 2010, the Commission issued its ORDER DETERMINING OWNERSHIP OF RENEWABLE ENERGY CREDITS FOR POWER PURCHASE AGREEMENTS MADE PURSUANT TO STATE WIND AND BIOMNASS STATUTES AND THE FEDERAL PUBLIC UTLITY REGULATRY POLICY ACT in Docket E002/M-08-440.

In Docket E002/M-13-642—an Xcel filing to update various sections of its Distributed Generation tariff to reflect 2013 statutory changes—the Commission declined to decide REC ownership and instead referred the issue to the current docket. The issue of REC ownership has also been raised in comments in the pending cogeneration/small power production rulemaking Docket, E-999/R-13-729 and in regard to Xcel's Solar*Rewards program.

On December 30, 2013, the Commission issued a notice in the instant docket, asking for comments on:

- What categories of Renewable Energy Credits (RECs) need clarity on ownership?
- Who owns the RECs from net metered customers? Does it matter whether the QF is being paid the average retail rate or avoided cost rate?
- Who owns the RECs if a third party owns the PV equipment and leases to the homeowner/business?
- Are there special considerations on REC ownership related to REC aggregators/marketers?
- What factors should the Commission take into account when determining REC ownership?
- Should the Commission make decisions on REC ownership?
- If the Commission should issue decisions on REC ownership, for which utilities or parties to a transaction should the Commission's decision apply?

Jurisdiction

<u>Party Comments</u>

Most parties agree that the Commission has the authority to determine REC ownership and therefore staff has not repeated the arguments shared by multiple commenters. As Dairyland points out, the Federal Energy Regulatory Commission (FERC) issued a decision in 2003 making clear that RECs are a state creation and therefore ownership is to be decided by states; the Commission made the same finding in a 2008 docket, discussed later in these briefing papers.

Minnkota, however, did not share the position of other commenters and stated, "Minnkota does not believe it is necessary and the determination of personal property ownership rights may not be within the jurisdiction of the PUC."[6] Minnkota did not elaborate on the reasoning for its position.

In a May 21 supplemental filing in response to a staff inquiry, Dairyland clarified that while it agrees that state may make the decision on REC ownership, the Commission may be limited on which utilities it applies that decision to. Staff will address this position in the next section.

---

[6] Minnkota February 7, 2014 comments, page 2.

Staff Comment

FERC has stated that states, not FERC, may determine REC ownership:

> RECs are relatively recent creations of the States…They exist outside the confines of PURPA. PURPA thus does not address the ownership of RECs. And the contracts for sales of QF capacity and energy entered into pursuant to PURPA, likewise do not control the ownership of the RECs (absent an express provision in the contract).[7]

The Commission has previously found in the "Silent REC" docket that it had jurisdiction to determine REC ownership for approximately 46 Xcel PPAs where REC ownership was silent or ambiguous. In that docket, the Commission stated:

> After consideration, the Commission concludes it has the authority to determine who owns the renewable energy credits arising under the power purchase agreements in this docket. In this, the Commission shares the view of the Federal Energy Regulatory Commission (FERC), that states, in creating renewable energy credits, have the power to determine who owns the RECs in the initial instance, and how they may be sold or traded.
>
> …Renewable energy credits are creatures of statute, and are heavily imbued with the public interest. They are central to state energy regulatory policy, and exist only to serve critical state energy goals. They were created as a regulatory tool for measuring and monitoring utilities' compliance with their statutory obligations to secure specific percentages of generation supplies from renewable sources. As such, they are part of a complex and detailed regulatory regime established by statute and under Commission control and guidance long after the PPAs in question in this docket were executed.
>
> RECs, therefore, are not creatures of contract, conferring free-standing property rights…Parties lack the authority to remove the issue of REC ownership from the regulatory process.[8]

Based upon this ruling and FERC reasoning, it appears clear that the Commission retains the authority to determine REC ownership.

[7] FERC Docket EL-03-133-000, Order Granting Petition for Declaratory Ruling. American Ref-Fuel Co. et al, (October 1, 2003).

[8] Docket E002/M-08-440, issued September 9, 2010, pp. 4-5.

Transactions Needing Commission Guidance

Party Comments

While parties largely agreed that the Commission has the authority to determine the ownership of RECs, they were more divided over what types of transactions the Commission's decision should apply to.

The Department suggests that for net metering transactions, the Commission should decide REC ownership if there is not otherwise a contract in place.[9]

Minnkota states that the Commission should not overrule existing PPAs on REC ownership.

Nearly all commenters recommend that the Commission make a decision on REC ownership in the context of net metering. However, Minnesota Power (MP) stated that the Commission should also clarify ownership of RECs for energy generated and consumed onsite, while Dairyland stated that the Commission's decision should only apply to net excess generation (NEG) from customer-sited generation.

Otter Tail Power (OTP) stated the Commission should only clarify ownership in the context of the REO-RES.[10] The company also stated it was indifferent to a Commission decision on historical projects.

Staff Comment

Staff suggests that at a minimum the Commission make a determination on REC ownership in the context of net metering. Staff also agrees that PPAs are a different matter not requiring a Commission decision; as seen in the Silent REC docket, if a utility or QF is party to a PPA that is unclear on REC ownership, they can bring that specific PPA to the Commission for a determination.

The Commission could also choose to make a determination for non-net metered PURPA transactions under 100 kW and those over 100 kW who provide firm power and choose to use the utility's standard offer. (Under PURPA, utilities are required to make available a "standard offer" to QFs under 100 kW. Under Commission rules, QFs over 100 kW may negotiate contracts with utilities, or those who provide firm power may choose the standard rate offer.)

---

[9] Staff presumes the Department is referring to third party contracts that explicitly address REC ownership, because all net metered installations smaller than 40 kW fall under the standard contract, which does not address REC ownership. (Xcel's Solar*Rewards contract does specify REC ownership due to the incentive provided to the customer; the current iteration of the program and contract is pending in Docket E002/M-13-1015, due to be heard by the Commission in late June.)

[10] Staff is not clear on the specifics of OTP's recommendation.

It may not be necessary to make a more detailed decision on the historical application of the Commission's decision.

A related issue not commented on by parties (except by Dairyland in response to a staff inquiry) is to which utilities a Commission decision would apply. The Commission could make a decision that applies only to investor-owned utilities. However, Minnesota's renewable energy statute, which gave rise to RECs, applies to a total of 16 entities: these include not only to the IOUs, but also municipal power agencies, generation and transmission cooperatives, public power districts, and indirectly to distribution members of these entities.

Dairyland, one of the utilities subject to Minnesota's RES, states that its rate rider with its member distribution cooperatives already grants it the RECs. Staff issued an Information Request to Dairyland. Dairyland provided the relevant page of its rate rider showing it claims ownership of RECs under net metering arrangements; that rider is now in the record for Commission review.

At page 7 of its initial comments, Dairyland states, "Dairyland acknowledges FERC's conclusion that the issue of REC ownership is not governed by PURPA and is a matter of state law and policy." However, Dairyland's supplemental filing claims that a Commission ruling on REC ownership, which Dairyland addresses in its rate rider, amounts to rate regulation, and the Commission does not have the requisite authority over Dairyland or its member distribution cooperatives to regulate its rates.

Staff disagrees that simply because Dairyland addresses REC ownership in its rate rider that the issue can be characterized as impermissible rate regulation. The issue noticed in this docket relates to ownership of the REC, not rates.[11]

Dairyland also incorrectly characterizes the issue as one not delegated to the Commission, when the Renewable Energy Statute makes clear that the Commission can issue decisions related to RECs:

> 216B.1691, Subd. 4. Renewable energy credits.
>
> (a) To facilitate compliance with this section, the commission, by rule or order, shall establish by January 1, 2008, a program for tradable renewable energy credits for electricity generated by eligible energy technology. The credits must represent energy produced by an eligible energy technology, as defined in subdivision 1. Each kilowatt-hour of renewable energy credits must be treated the same as a kilowatt-hour of eligible energy technology generated or procured by an electric utility if it is produced by an eligible energy technology. The program

[11] In addition, while staff does not believe any action taken in this docket amounts to rate regulation, staff notes that under Minn. Stat. §216B.164 and Minnesota Rules Chapter 7835, the Commission does have authority over cooperative distribution utilities' net metering rates.

> must permit a credit to be used only once. The program must treat all eligible energy technology equally and shall not give more or less credit to energy based on the state where the energy was generated or the technology with which the energy was generated. The commission must determine the period in which the credits may be used for purposes of the program.
>
> (b) In lieu of generating or procuring energy directly to satisfy the eligible energy technology objective or standard of this section, an electric utility may utilize renewable energy credits allowed under the program to satisfy the objective or standard.
>
> (c) The commission shall facilitate the trading of renewable energy credits between states.
>
> (d) The commission shall require all electric utilities to participate in a commission-approved credit-tracking system or systems. Once a credit-tracking system is in operation, the commission shall issue an order establishing protocols for trading credits.

The statute quoted here gives the jurisdiction over the 16 utilities subject to the RES, including generation and transmission cooperatives such as Dairyland, and clearly contemplates that the Commission will need to make decisions related to RECs. In fact, Dairyland itself characterized RECs as a regulatory tool subject to Commission reach in the Silent REC docket:

> RECs originated as a method to track renewable generation for purposes of compliance with State renewable portfolio standards, and to avoid double-counting. They are an accounting device which simply quantifies the renewable attributes of the renewable-fuel generated electricity. [Citation omitted.] The creation of, and resulting market for *RECs are solely a consequence of regulatory action that permits trading of RECs* […][12]

Arguments on REC Ownership

For net metering, parties' positions on REC ownership can be divided into two general categories: some—including Dairyland, Minnkota, MP, OTP, and Xcel—contend that the rate at which generators are reimbursed should determine ownership, with generators retaining RECs when compensated at avoided cost and purchasers acquiring RECs when compensating at a rate above avoided cost. Others—including CRS, EO, SEIA, and Wal-Mart, Inc.—assert that the rate of compensation should *not* be the sole determinant of REC ownership. The parties provided a number of grounds for their positions; for ease of readability and analysis, staff has divided the parties' comments on REC ownership by topic.

[12] Dairyland May 22, 2008 comments in Docket E002/M-08-440 (Silent REC docket). Emphasis added.

Is the Net Metering Rate an Avoided Cost Rate?

One of the main subjects in comments is previous decisions on REC ownership based on the price paid for the energy. Many parties cited to a FERC decision and the Commission's Silent REC decision, as summarized below.

In their comments, multiple parties reference a 2003 ruling by FERC pertaining to REC ownership in preexisting PURPA PPAs.[13] In the case, FERC concluded that: "avoided cost regulations did not contemplate the existence of RECs and that the avoided cost rates for capacity and energy sold under contracts entered into pursuant to PURPA do not convey the RECs, in the absence of an express contractual provision."[14] In its ruling, FERC acknowledges that RECs are a creation of states' legislation. As they exist "outside the confines of PURPA," states have the power to determine REC ownership as they see fit.[15]

Several parties—including Dairyland, Minnkota, MP, and Xcel—contend that FERC's reasoning suggests that the RECs associated with any net energy generation (NEG) purchased at the end of a relevant period should be transferred to the purchaser. These parties argue that under net metering in Minnesota, where QFs are compensated at the retail energy rate, utilities pay a premium over the avoided cost rate; accordingly, the ratepayers who funded that premium should reap its benefits by receiving the RECs.[16]

The EO take issue with this position, arguing that the retail energy rate is neither a premium nor an incentive. Rather, EO claim "net-metering is a legislatively-determined structure that is deemed fair compensation for the benefits provided by distributed generation."[17]

In their comments, many parties cite a recent Commission order on the "Silent REC" docket.[18] The docket was initiated by Xcel's petition requesting a Commission ruling on 46 PPAs whose terms allegedly did not specify ownership of RECs. The PPAs were entered into pursuant to either PURPA or Minnesota's 1994 Wind or Biomass Mandates. In the docket, Xcel and other utilities argued that the utilities purchasing the energy should acquire the RECs, while others maintained that the generators should retain REC ownership. Ultimately, the Commission sided with the Department, declaring that generators retain ownership under PURPA PPAs, but purchasers acquire RECs for PPAs entered into under the Wind and Biomass Mandate. The Commission found that Wind and Biomass Mandate PPAs "have already been treated as

---

[13] FERC Docket No. EL-03-133-000, *Order Granting Petition for Declaratory Ruling*. American Ref-Fuel Co. et. al., 105 FERC ¶ 61, 005-61,004 (October 1, 2003).

[14] Ibid, at paragraph 18.

[15] Ibid, at paragraph 23.

[16] See, e.g., Dairyland February 7, 2014 comments, at pages 7-8.

[17] EO February 7, 2014 comments, at page 6.

[18] Docket No. E002/M-08-440, issued September 9, 2010.

renewable PPAs," noting that they "almost invariably carried extra costs associated with generating renewable energy, and both buyers and [sellers] knew that the only reason Xcel was paying a premium for renewable energy, as opposed to paying less for fossil-fuel energy, was so that it could claim this energy as fulfilling statutory renewable energy obligations."[19]

Some parties, such as DOC and EO, assert that the reasoning in the Silent REC docket suggests that generators should retain RECs under net metering. DOC, for example, notes that the Commission granted REC ownership to generators under PURPA PPAs. In addition, as EO point out, while the Commission did rule that Xcel should acquire RECs for Wind and Biomass mandate PPAs, the Commission found that in those cases the purchaser was paying a premium over the avoided cost rate. And, as argued above, EO do not believe the net metering rate constitutes a premium. Therefore, EO contends, under the Silent REC precedent, RECs pursuant to net metering should belong to the generator.

In its consideration of the Silent REC docket, Xcel comes to a different conclusion. The Company highlights the order's discussion of rates: "The Commission agreed with the position of DOC that if the Company paid more than avoided cost to purchase the power, it would appear that the Company purchased, and ratepayers paid for, more than energy."[20] Thus, the Company concludes, because it is paying more than the avoided cost rate for net metered generation, it purchased more than just energy, and it is entitled to the RECs.

Minnesota Statute

In its initial comments, SEIA cites Minnesota statute, which states that the net metering rules are intended to, "give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public."[21] REC ownership, SEIA argues, is an integral part of financing for DG installations; thus, as EO argue, granting REC ownership to generators would send a positive signal to financers and provide additional encouragement to cogeneration.

Dairyland, on the other hand, emphasizes the sentence's qualifying language, highlighting the clause, "consistent with protection of the ratepayers and the public." Dairyland asserts that it is the ratepayers who will ultimately bear the cost of the RECs, so requiring the utilities to pay an additional amount for the transfer of RECs amounts to making the ratepayers pay for them twice.[22] Xcel concurs, stating, "if we purchase renewable energy for customers on our system, we believe all our customers should receive the benefit of all attributes of that energy – including RECs."[23]

---

[19] Ibid, at page 8.

[20] Xcel February 7, 2014 comments, at page 4.

[21] Minn. Stat. § 216B.164, subd. 1

[22] Dairyland February 7, 2014 comments, at pages 6-8.

[23] Xcel February 21, 2014 comments, at page 2.

In its comments, DOC also references this section of state law. In the Department's words, "Minn. Stat. §216B.164 was not revised to indicate that the RECs transferred to the utility under net metering, even though other changes were made to the statute regarding ownership of RECs."[24] DOC points to the Value of Solar (VOS) and Made in Minnesota solar incentive legislation, each of which transfers REC ownership to the purchaser. The Department concludes that this suggests REC ownership should remain with the generators.[25]

Xcel, however, interprets the implications of recent legislation differently. Specifically, the Company cites the VOS statute, which establishes the utility's applicable retail rate, "as the floor for a VOS rate for the first three years and transfers the RECs to the Company at that rate." Thus, the Company concludes, "it is unclear why additional payments would be required when offering the same retail rate outside of the VOS tariff."[26]

On-site consumption

While many parties take the position that RECs for any NEG purchased at the end of the relevant period should be transferred to the purchaser, at least two parties, MP and Xcel, believe that purchasers should also own RECs pertaining to energy that is consumed on-site. Xcel notes that the energy consumed on-site is also compensated at the retail energy rate through a bill reduction, and so the ratepayers who are paying a premium for the energy should reap the benefit of the RECs.[27] MP contends that the monthly service charges paid by net metered customers are "insufficient to cover the utility's fixed cost and investment," and so "[e]ven if Minnesota Power were to never reimburse a DG customer for excess generation, if the DG provides a significant portion of the onsite needs, the cost of serving the DG customer will be shifted to the rest of the customer base."[28]

---

[24] Department February 7, 2014 comments, at page 3.

[25] One small solar installation owner commented that she has intentionally foregone participation in her utility's incentive programs under the assumption that she then would retain ownership of the RECs (Public comment of Elizabeth Oppenheimer, January 31, 2014). In response, Xcel notes that participation in any of its programs that transfer REC ownership is voluntary. In the Company's words, "a customer has the option to forgo an incentive payment or select service under a tariff that may provide a lower price for energy but would allow the customer to retain REC ownership" (Xcel February 21, 2014 comments, at page 3). Staff notes that, under Commission rules, QFs have the option to take service under either the Simultaneous Purchase and Sale Rate (see Minn. Rules, Part 7835.3400) or the Time of Day Purchase Rate (see Minn. Rules, Part 7835.3500), each of which is lower than the retail energy rate.

[26] Xcel February 7, 2014 comments, at page 7, referring to Minn. Stat. § 216B.164, subd. 10 (j).

[27] Xcel February 21, 2014 comments, at page 4.

[28] MP February 7, 2014 comments, at page 2.

Third-party ownership

On the question of REC ownership when a third party owns the PV equipment and leases it to the homeowner or business, there was considerable variation among the parties. In all cases, however, the rationale behind the positions was similar to that employed above. Accordingly, here staff simply lays out the parties' positions.

Some parties, including Minnkota and MP, believe that RECs should be transferred to the purchaser regardless of the rate of compensation. Others, including Xcel and OTP, believe the rate paid should determine ownership.[29] Several parties, including CRS, EO, the Metropolitan Council, SEIA, and Wal-Mart believe the RECs should remain with the owner of the generation.

Staff Comment

Staff provides an analysis of two general topics. First, staff provides an analysis of the main arguments made by parties. Second, staff presents the results of its own survey of state commission decisions on REC ownership.

Arguments on REC Ownership

It is noteworthy that most parties, even those who disagree on who should own the RECs, agree that if the price paid for energy is avoided cost, the customer-generator should receive the RECs. What the parties disagree on is whether the rate for net metered facilities under 40kW is, in fact, avoided cost.

Both the Silent REC decision and FERC decisions are instructional in this situation. As the Department notes, the Commission in the Silent REC docket found that for transactions entered into pursuant to PURPA, the generator owns the RECs. This was because PURPA requires the utility to purchase energy and capacity at rates equal to the utility's avoided cost. The standard avoided cost calculation does not specifically take the renewable aspect of a facility into account; a wind QF or a natural gas cogeneration QF are paid the same rate. However, FERC decisions recognize that it is permissible to have different avoided costs depending on the generating type, firmness of power provided, and other quantifiable elements.[30]

---

[29] Consistent with their earlier positions, Xcel suggested that the RECs should be transferred from the owner to the purchaser if the purchaser paid a premium over avoided cost, and OTP recommended a dual pricing system in which one price would transfer the RECs to the purchaser and at another they would stay with the system owner.

[30] See for example *California Public Utilities Commission,* 133 FERC ¶ 61,059 (2010) October 21, 2010 Order Granting Clarification and Dismissing Rehearing. In particular, footnote 53 states in part, "thus, a state may appropriate recognize procurement segmentation by making separate avoided cost calculations." (Quoting *Accord Signal Shasta*, 41 FERC ¶ 61,120 at 61,294, where FERC declined to find that the California Commission's implementation of four standard offer contracts containing different avoided costs was inconsistent with PURPA or FERC regulations.)

The arguments for utilities to automatically receive the RECs associated with net excess generation from QFs under 40 kW who receive compensation at the average retail energy rate rests on the assertion that the purchase rate is in excess of avoided cost. Staff disagrees. In Docket E999/R-80-500, the Commission adopted rules governing cogeneration and small power production. While the Commission did require an average retail energy rate to be used for net metered facilities under 40 kW, that rate was used as a proxy for avoided cost given the differences attributable to small facilities.[31] Avoided cost does not have to be a single calculation or rate; rather, a method that allows for some judgment in how the rate is to be set.

Staff agrees with the EO position that the net metering rate does not include a premium for the REC. The requirement that utilities offer QFs of less than 40 kW the average retail energy rate for net input into the system was added to Minn. Stat. §216B.164 in 1983,[32] and implemented through Commission rules adopted that same year.[33] This net metering compensation rate was set long before RECs were created or likely even contemplated. In adopting the specific calculation methodology for average retail energy rates, the Commission discussed a number of considerations, including the potential aggregate value of capacity from small QFs, smaller capacity increments, and shorter lead times. These factors are included in FERC rules[34] as factors to be considered when determining purchase rates, and the Commission has also identified simplicity and customer understanding. The average retail energy rate set out in legislation and the Commission's rules for over 30 years is a reasonable estimate of avoided costs for small facilities, consistent with Federal and state law. To illustrate the point further, staff has provided, as Attachment A, Xcel's annual filing of its DG facilities from Docket 13-10. The DG units listed on the attachment, whether they be wind, solar, or gas, are all paid the same rate if they are under 40kW. This supports the staff's and EO's point that the under 40 kW rate includes no premium for the renewable nature of the generation; it is simply a different rate due to the different considerations listed above. Because there appears to be differences of opinion on whether the net metering rate is an avoided cost rate or not, the Commission may want to consider making a finding that this rate is avoided cost.

---

[31] For investor owned utilities, net metering continues to apply for facilities above 40 kW but utilities must only pay the standard avoided cost rate. Staff presumes that utilities agree the customer would own the RECs in that situation.

[32] Minnesota laws, 1983, Chapter 301, §167. The statute was first enacted in 1981. Several significant amendments, including the average retail rate compensation for small QFs, were added in 1983.

[33] The Commission's Order Adopting Rules *In the Matter of the Proposed Adoption of Rules of the Minnesota Public Utilities Commission Governing Cogeneration and Small Power Production*, Docket E-999/R-80-560 was issued on March 7, 1983. The Commission's initial draft proposed rules were issued in 1981 and the hearing process in mid-1982. Several parts of the 1981 legislation and the 1983 legislative amendments adopted concepts set out in the draft rules, including the concept of compensating small facilities at the utility's retail energy rate.

[34] See 18 C.F.R. §292.304.

Additionally, under state legislation passed in 2013, the utilities own the RECs for generation from facilities that receive Made in Minnesota production incentive payments for the time period those payments are received.[35] It would render that provision of the law essentially meaningless if the utility were to own the RECs even in absence of such payments.

Should the Commission use this rationale and decide that RECs do not belong to the utility, it may not need to decide whether the customer or a third party (if a third party is part of the transaction) owns the RECs. If a third party has entered into a contract with the customer, the contract can govern who owns the RECs.

Should the Commission also choose to decide REC ownership for non-net metered customer transactions under PURPA, staff suggests a slightly different decision. For customers under 100 kW, PURPA requires the utility to make a standard offer. Under Commission rules, QFs of 100 kW and over may also choose the standard offer if they provide firm power, or may negotiate an agreement. The Commission could decide that the default decision is the RECs are owned by the customer but that ownership may change in negotiations.[36]

Overall, staff suggests that the Commission could find that generators own the RECs unless: 1) a different arrangement is agreed to by the generator and utility in a contract; 2) state law specifies a different outcome; or 3) specific Commission orders or rules specify a different outcome.

Survey of other states' policies

In their initial comments, EO claim that the vast majority of states grant ownership of RECs to the customer-generators. Specifically, they argue that 23 of the 27 states that have adopted REC ownership policies assign "initial ownership" of RECs to customer-generators.[37]

However, staff believes this to be an oversimplification. For example, in at least three of the states cited by EO—California, New Hampshire, and North Dakota—utilities own any RECs associated with the purchase of any NEG remaining at the end of a given 12-month period, and in at least three others—Colorado, Nevada, and Oregon—utilities own the RECs if they subsidize the system.[38] Moreover, many of the remaining states' policies are not comparable to

---

[35] See Minn. Stat. § 216C.414.

[36] Staff sees no merit in the argument that utilities may even be entitled to the RECs from generation consumed on-site by net-metered QFs under 40 kW. Even if the Commission were to decide that RECs from net excess generation belonged to utilities, it is difficult to see how energy consumed by customer from his/her own generation somehow belongs to the utility. The FERC has determined that net metering is not a method of determining avoided cost, and no mandatory purchase and sale is taking place when on-site consumption is less than total consumption during the normal (generally monthly) billing period.

[37] EO February 7, 2014 comments, at page 4.

[38] According to the website cited by EO: Database of State Incentives for Renewables & Efficiency (DSIRE), "Net Metering for Renewable Energy." Accessed April 23, 2014 from www.dsireusa.org/incentives/index.cfm?SearchType=Net&&EE=0&RE=1

Minnesota's because they either carry NEG over indefinitely or, at the end of the given 12-month period, they require utilities to reimburse the customer-generator for NEG at an avoided cost rate.[39] Thus, staff concludes that there is no clear consensus among states when it comes to REC ownership policies for net metering.

Below is a summary of the rationale employed by two commissions—the California Public Utilities Commission and North Carolina Utilities Commission—that came to significantly different conclusions in their consideration of REC ownership for net metering, followed by a brief summary of Minnesota's neighboring states' policies.

California

Until 2009, California's net metering policy required any NEG remaining at the end of its annual 12-month cycle to be forfeited to utilities. Assembly Bill 920 changed this, offering customers two options: carry any NEG forward to the next 12-month period or be compensated by the utility for any NEG at a rate determined by the California Public Utilities Commission (CPUC). The legislation stipulated that sale of any NEG to a utility would also transfer REC ownership.[40] Thus, the legislation presented the CPUC with a task that "mirrored" the Commission's: rather than deciding whether REC ownership is transferred under a given rate, the CPUC was to determine an appropriate rate given that REC ownership was to be transferred.

In its ruling, the CPUC determined that NEG was to be compensated at an avoided cost rate[41] with an adder for the renewable attributes.[42] Notably, the statute did not mandate compensation for the value of the renewable attributes, but the CPUC determined that the NEG had a value over and above the energy produced. In calculating the adder, the CPUC preferred "a market-based valuation" method, noting that, conceptually, the adder would ideally equal the average REC trading price over the 12-month period.[43]

---

[39] In fact, staff's review of the website (DSIRE) cited by EO suggests that there is not a single state with a net metering policy that is directly comparable to Minnesota.

[40] State of California (2011), "Net Surplus Compensation (AB 920)." Accessed April 22, 2014 from http://www.cpuc.ca.gov/PUC/energy/DistGen/netsurplus.htm

[41] The selected avoided cost rate was derived from the rolling average of the hourly day-ahead electricity market price (roughly comparable to MISO's day-ahead LMPs) from 7 a.m. to 5 p.m.

[42] California Public Utilities Commission Decision 11-06-016, June 9, 2011. Accessed April 22, 2014 from http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/137431.htm

[43] Ibid, at 6.3 Value of renewable attributes. Because RECs were not publicly traded at the time, the Decision adopted a different, interim rate as a proxy for the REC trading price.

North Carolina

The North Carolina Utilities Commission (NCUC) considered REC ownership in a series of orders issued between 2005 and 2009.[44] In its rulings, the NCUC argued that net metering potentially subsidizes customer-generators, but also has benefits that could potentially offset any subsidies.[45] Under its rulings, the NCUC did not allow utilities to "charge participating customers any additional standby, metering, or other charges."[46] In return, the NCUC determined that any NEG remaining at the end of the summer or winter billing seasons—and the corresponding RECs—should be transferred to the utility without compensation. In the NCUC's words, this compromise, "reasonably balances numerous factors while attempting to limit the potential for abuse. Net metering is specifically designed for owners of small-scale renewable generation installed for the customer's own use, not for sale to the utility."[47]

In its third relevant net metering order, the NCUC offered customer-generators a choice in REC ownership: those who take service under a time-of-use demand rate schedule would retain REC ownership for all generation, while those who chose to be credited at the retail rate would transfer RECs for all generation (not simply the NEG) to the utility with no additional compensation.[48]

Neighboring states

While none of the four states that adjoin Minnesota have a clearly established, universal REC ownership policy for net metering, three have issued orders with REC ownership implications. In North and South Dakota, the respective Commissions have each approved similar tariffs for OtterTail Power (OTP). In each state, OTP purchases any NEG remaining at the end of the 12-month period at the avoided cost rate plus a REC compensation adder (equal to 0.2 and 0.3 cents per kWh in North Dakota and South Dakota, respectively).[49] Similarly, in Wisconsin Xcel Energy reimburses residual NEG at the avoided cost rate, and the Public Service Commission allows the parties to negotiate a "renewable credit rate" that would also transfer the associated RECs.[50]

---

[44] State of North Carolina Utilities Commission, Docket No. E-100, SUB 83, orders: October 20, 2005; July 6, 2006; and March 31, 2009.

[45] Ibid, in October 2005 order. These benefits included: "a reduction in peak demand; lessening the consumption of fossil fuels; reducing pollution and avoiding environmental damage; reducing line losses and improving efficiency of the grid; and avoiding upgrades to transmission and distribution facilities" (page 2).

[46] Ibid, in July 2006 order.

[47] Ibid, in October 2005 order.

[48] Ibid, in March 2009 order.

[49] See South Dakota Public Utilities Commission Docket EL09-026, and North Dakota Public Service Commission Case Number PU-05-193, approved October 18, 2005.

[50] Wisconsin Public Service Commission, Docket 4220-UR-117, filled December 22, 2011.

Elsewhere in the Midwest, five states have explicit REC ownership policies for net metering.[51] Four of the five—Illinois, Michigan, Nebraska, and Ohio—grant RECs to customer-generators, unless the parties have entered into a contract that explicitly transfers ownership. At the end of a given 12-month period, utilities in Illinois, Nebraska, and Ohio purchase remaining NEG at the avoided cost rate, and in Michigan, NEG credits carry over indefinitely. In Kansas, on the other hand, the utility owns all RECs associated with net metering. Notably, monthly NEG is carried over at the retail rate, but at the end of the 12-month period, any remaining NEG is forfeited to the utility.[52]

Next Steps After REC Ownership Decision

Some commenters brought up additional issues that may need to be addressed as the result of a REC ownership decision.

In its comments, OTP suggested an alternative that would make DG owners' options for REC ownership more explicit. The Company suggests a dual pricing mechanism, wherein the Commission would establish two net metering compensation rates, one of which would transfer ownership and the other would not. This would allow customers to select the compensation structure they prefer. OTP also recommends that the uniform statewide contract be revised.

MP suggests two items. First, MP suggests that the utilities' corresponding tariffs be modified to reflect clarifications issued through this process.

MP also suggests that a standardized process be formalized through which utilities are notified of REC aggregation.[53] A standardized process will foster transparency of REC transfers and aggregations. Creating this process will provide a clear picture of how RECs are being utilized in Minnesota and will eliminate the risk of double counting or other possible errors.

The Metropolitan Council recommends that utilities stand ready and are allowed to bid for RECs when offered by facility owners on an ongoing basis rather than through a specific RFP process, thus having the utilities compete for RECs instead of developers competing to sell the RECs to a utility.

Staff Comment

Staff agrees that one option is for utilities to change their tariffs to reflect the Commission's decision on REC ownership; the Commission may also wish to direct changes to the uniform

---

[51] DSIRE, "Net Metering for Renewable Energy." Accessed April 23, 2014 from www.dsireusa.org/incentives/index.cfm?SearchType=Net&&EE=0&RE=1

[52] Kansas Corporation Commission, "Net Metering in Kansas." Accessed April 22, 2014 from http://kcc.ks.gov/energy/net_metering_faq.htm

[53] MP February 7, 2014 comments, at page 3.

statewide contract as well, which is part of the Commission's rules in Chapter 7835, currently part of a rulemaking.

The concept of a dual pricing tariff as proposed by Otter Tail, or a mandated REC auction, as suggested by the Metropolitan Council, may require significant additional development and resources. Any utility is free to propose a dual pricing tariff if it chooses to do so. Staff presumes there could be significant debate over the REC price set in the tariff, and some might argue that a REC price would need to be revisited periodically[54]. However, if a utility wishes to pursue this option, it can voluntarily file a tariff.

REC auctions occur in some states already. Staff has inquired about the Massachusetts S-REC auction and has learned that it is a very robust mechanism with many very specific timelines and requirements. A REC auction in Minnesota would likely require considerable Commission resources; in addition, the Commission would need to consider the policy implications of an auction.

There are other options that would allow a REC market to occur for these smaller net metering facilities without a tariff or auction. REC aggregators operate in Minnesota and the Midwest. Once the Commission clarifies REC ownership, aggregators can approach REC owners and negotiate the purchase and sale of these credits.

Minnesota Power's concern over the tracking of RECs and preventing double counting is an important one. Smaller, less sophisticated customers who own RECs may not be familiar with the state law's prohibition on double counting and in some cases may not remember whether they have transferred their RECs to a third party. Because the Commission has designated M-RETS as the tracking system for Minnesota, and because M-RETS is working on similar issues, staff suggests MP initiate contact with M-RETS to ensure its needs are met.

Decision Options

A) REC ownership

1) Net metering: net energy generation (NEG)

a. Find that *utilities* own RECs corresponding to all NEG.

b. Find that *generators* own RECs corresponding to all NEG.

[54] In the Xcel Community Solar Garden proceeding, Docket E002/M-13-867, the Commission did set a price for RECs generated from Community Solar Gardens (CSGs). However, that determination was based upon the specifics of the CSG statute and record, and a different set of considerations would be involved in REC pricing for net metering. For example, net metering can be for any type of renewable generation, and it would likely be argued that different REC prices would be appropriate for solar versus other renewable generation.

c. Find that *generators* own RECs corresponding to NEG if the rate of compensation is the standard offer avoided cost rate, and *utilities* own RECs corresponding to NEG if the rate of compensation is the average retail utility energy rate.

d. Take no action on REC ownership for NEG.

2) Non-net metered PURPA transactions

a. Find that *utilities* own RECs for non-net metered PURPA transactions under the standard offer.

b. Find that *generators* own RECs for non-net metered PURPA transactions under the standard offer.

c. Take no action on REC ownership for non-net metered PURPA transactions under the standard offer. (*Staff note*: Decision options A.2. a-c use the term "standard offer" because that is the term used by FERC. In essence, Decision option A.2.b would have the effect of stating that for non-net metered transactions at the avoided cost rate, the generator owns the RECs.)

B) Average retail rate for net metered facilities under 40kW

1) Find that the average retail rate for net metered facilities under 40 kW is an avoided cost rate. OR;

2) Take some other action.

C) Scope of Ruling

1) Dictate that the findings in section A) or B) applies to::

a. Rate-regulated utilities only;

b. Utilities subject to Minnesota Statutes §216B.1691, Minnesota's renewable energy statute; (Staff note: this would apply to the 16 utilities subject to the RES.)

c. Utilities subject to Minnesota Statutes §216B.164.

D) Further Action

1) Require utilities to modify corresponding tariffs to reflect the ruling in A) or B).
2) Direct that revision of the uniform statewide contract to incorporate the ruling in A) or B) be considered in the Commission's pending rulemaking docket, Docket E999/R-13-729, or other relevant proceeding.
3) Take no further action.

414 Nicollet Mall
Minneapolis, Minnesota 55401

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

March 1, 2013

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: DISTRIBUTED GENERATION INTERCONNECTIONS - ANNUAL REPORT
DOCKET NOS. E002/M-04-2055 &
E999/PR-13-10

Dear Dr. Haar:

Enclosed is our annual report submitted pursuant to Minn. Stat. 216B.1611. This report provides information on interconnection applications and discontinued distributed generation on our system during the 2012 calendar year.

Portions of our filing contain trade secret information as defined under Minn. Stat. § 13.37. As such, this data is protected from public disclosure and has been marked accordingly.

We appreciate the opportunity to present this information. We are available to provide any additional information or respond to any questions you may have. Please feel free to contact me at paul.lehman@xcelenergy.com or 612-330-7529.

SINCERELY,

/S/

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE AND FILINGS

Enclosures
c. Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL REPORT ON DISTRIBUTED GENERATION INTERCONNECTIONS

DOCKET NOS. E002/M-04-2055 & E999/PR-13-10
ANNUAL REPORT

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits our annual filing on distributed generation (DG) interconnections in compliance with the Commission's July 14, 2006 Order in this docket. This report provides information on interconnection applications and discontinued distributed generation on our system during the 2012 calendar year. In addition, this report provides an update on the Company's DG tariff energy and capacity payments, as well as DG system renewable resource credits and tradable emissions credits.

OVERVIEW

During 2012, we received 347 interconnection applications for distributed generation systems with a total capacity of about 38,267 kW. Of the applications received in 2012, about eight percent were for non-Solar*Rewards® systems, 81 percent were for Solar*Rewards® systems, one percent were for wind, and nine percent other systems (diesel, gas or biomass). The disposition column of Attachments A and B constitutes the status of each project.

A summary of DG interconnection applications over the past three years follows:

Summary Table						
	2010[1]		2011		2012	
Type	**# of Apps**	**kW**	**# of Apps**	**kW**	**# of Apps**	**kW**
Wind	11	220	11	150	4	101
Solar	33	366	9	205	29	1,931
Solar*Rewards®[1]	166	1,057	140	1,496	282[2]	4,180
Other (e.g. Diesel)	15	13,975	23	26,530	32	32,055
Total	226	15,377	183	28,381	347	38,267

[1] Solar*Rewards® was not available prior to 2010.
[2] Nineteen of these applications were part of the Minnesota Bonus program, which provides $21 million over five years (fiscal years 2011 – 2015) from the Company's Renewable Development Fund program to provide rebates of up to $5.00 per watt for Solar*Rewards® projects using solar PV modules that are either manufactured or assembled in Minnesota.

As the summary table indicates, a majority of the 2012 applications were in conjunction with the Company's Solar*Rewards® program. The Commission approved the Solar*Rewards® contract tariff on February 16, 2010 in Docket No. E002/M-09-1167, APPROVAL OF A SOLAR REWARDS CONTRACT, and the Company launched the three-year program on March 1, 2010. Solar*Rewards® provides Minnesota customers with an incentive payment of $2.25 per watt for the installation of solar PV systems under 40 kW.[1] However, most of the energized capacity was in conjunction with "Other" projects such as back-up diesel generators.

I. Background

In 2001, the Minnesota Legislature enacted Minn. Stat. 216B.1611, which requires each Minnesota electric utility to maintain records concerning applications received for generation interconnection and parallel operation. Specifically, Minn. Stat. 216B.1611 Subd. 4(b) states:

> *Every electric utility shall file with the commissioner a distributed generation interconnection report for the preceding calendar year that identifies each distributed generation facility interconnected with the utility's distribution system. The report must list the new distributed generation facilities interconnected with the system since the previous year's report, any distributed generation facilities no longer interconnected with the utility's system since the previous report, the capacity of each facility, and the feeder or other point on the company's utility system where the facility is connected. The annual report must also identify all applications for interconnection received during the previous one-year period, and the disposition of the applications.*

---

[1] The incentive payment was reduced from $2.25 to $1.50 per watt at the February 20, 2013 Commission Agenda Meeting (Order pending) in Docket No. E002/M-10-1278. All payments made for new installations in the 2012 reporting year were made at the original $2.25 incentive level.

On December 27, 2004, the Company filed a petition (Docket No. E002/M-04-2055) requesting approval of a DG tariff and standby service rider. On July 14, 2006, the Commission issued its Order (July 2006 Order) in this docket approving its DG tariff and standby service rider with revisions. In addition, the Commission's July 2006 Order specifies that Xcel Energy shall make an annual compliance filing to include the following:

- An updated energy payment schedule if different from the previous year;
- An updated capacity payment schedule if different from the previous year;
- An updated renewable resource credit schedule if different from the previous year;
- The average tradable emissions credit for the previous year, and
- A discussion of and support for any and all changes in the schedules.

The Order also specifies that Xcel Energy shall provide calculations and the prices it charged during the year for the renewable resource credit and address distributed generation metering, and whether and to what extent there were complaints or concerns that the metering issues was a barrier to development of DG.

II. Program Report

This is Xcel Energy's ninth annual filing in compliance with the Commission's July 2006 Order. Portions of this report are marked non-pubic as the information is considered trade secret or security data. For national security reasons, information about feeder connections is protected from disclosure. Also, customer service data (names and addresses) is not included and not required as part of this compliance report.

Ordering Paragraph #7. New generator interconnections, facilities no longer interconnected, the capacity of each facility, and the location of the facility on the Company's distribution system.

Attachment A lists the 2012 applications received along with the capacity and location of each facility for distributed generation interconnections other than those resulting from the Company's Solar*Rewards® program. Attachment B lists the same information for 2012 Solar*Rewards® program applications. The disposition column in each attachment constitutes the status of each project.

As mentioned in our previous reports, there are ongoing challenges in collecting the required information. There are instances when customers interconnect without the Company's knowledge and therefore have not submitted an application. Also, the Company is not always aware of, or notified, when a customer chooses to no longer be interconnected. Xcel Energy will continue to act diligently to collect and maintain the required information acknowledging that some of the information is, and will remain to be, out of our direct control.

In past annual reports, we included customers that interconnected with the system but were not identified or included in a prior annual report. Due to our system improvements, we have no "newly discovered" customers to report that were inadvertently omitted from a previous DG interconnection annual filing. Further, the Company has not identified any customers that were previously interconnected with the Company's system and terminated that connection in 2012.

Ordering Paragraph #8. An updated energy and capacity payment schedule if different from the previous year. An updated renewable resource credit schedule if different from the previous year. The average tradable emissions credit for the previous year.

<u>Payment Schedule</u>: The Distributed Generation standard interconnection and power purchase tariff in the Company's Minnesota Electric Rate Book, Section 10, has been updated since our last annual report on DG was filed. Tariff sheets 10-1 through 10-72 were initially established in 1998 and 2002 and were available to DG installations of 2.0 MW or less. Subsequent processes lead to the establishment of the identically titled Distributed Generation Standard Interconnection and Power Purchase Tariff on tariff sheets 10-73 through 10-162, available to DG installations of 10.0 MW or less. These pages encompass the information included in tariff sheets 10-1 through 10-72, therefore sheets 10-1 through 10-72 were cancelled effective September 1, 2012 (Docket No. E002/GR-10-971). Section 10, Sheet Nos. 76 and 77 apply to retail electric customers at distribution voltages who operate a qualifying DG facility with a nameplate rating of 10,000 kW or less and operate in parallel with the Company's distribution system.

The payment schedule for energy delivered to the Company under Section 10, Sheet No. 76 is based on monthly expected on and off peak average marginal energy costs of the year. The capacity payment under Section 10, Sheet No. 77 is based on the Company's avoided cost and the Company's capacity need based on the 5-year planning period as reported in the most recent integrated resource plan. For DG facilities over 10 MW, energy and capacity payment prices are on a negotiated basis subject to the Company's system need at the time.

Resource Credit Schedule: If a customer installs a renewable resource DG system that allows the Company to avoid the need to purchase renewable energy elsewhere, then the purchase of such renewable energy and capacity shall equal the avoided cost of renewable purchases. However, the Company does not have any customers in this situation. There has been no change from the previous year.

Tradable Emissions Schedule: As set forth in Section 10, Sheet No. 76 of the DG Tariff, if the purchase of energy and capacity from the DG customer's facility results in the Company receiving an economic value associated with tradable emissions, such tradable emissions credits shall be provided to the DG customer. Again, we do not have any customers under this provision. There has been no change from the previous year.

Ordering Paragraph #9. Provide calculations and the prices it charged during the year for the renewable resource credit and address distributed generation metering; and whether and to what extent there were complaints or concerns that metering issues were a barrier to the development of DG.

Since we have not made any changes to our renewable resource credit in the past year, we do not have any updated calculations or prices to submit at this time. In our 2011 annual report, we reported one Solar*Rewards customer complaint involving a metering issue. The customer subsequently withdrew the complaint.

CONCLUSION

Xcel Energy respectfully requests that the Commission accept our report on distributed generation interconnections. We would be pleased to discuss any of the data in this report and provide any additional information requested by the Commission or the Department of Commerce – Division of Energy Resources.

Dated: March 1, 2013

Northern States Power Company

Respectfully submitted by:

/s/

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE & FILINGS

DG Interconnection Applications Received in 2012

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins...
Bloomington	500	Solar	Energized	
Bloomington	500	Solar	Energized	
Buffalo	23	Diesel	Energized	
Center City	10	Solar	Energized	
Chisago City	1.68	Solar	Energized	
Cottage Grove	20	Wind	In Progress	
Cottonwood	39.9	Wind	In Progress	
Eagle Lake	19.74	Solar	Energized	
Eagle Lake	12	Solar	Energized	
Eden Prairie	600	Diesel	Energized	
Eden Prairie	500	Diesel	Energized	
Edina	5	Solar	Energized	
Hastings	6.72	Solar	Energized	
Inver Grove Heights	2.2	Solar	Energized	
Lake Elmo	7.31	Solar	Energized	
Lakeville	200	Solar	Energized	
Mahtomedi	20	Diesel	Energized	
Maplewood	1.7	Solar	In Progress	
Minneapolis	240	Diesel	Energized	
Minneapolis	240	Diesel	Energized	
Minneapolis	1000	Diesel	In Progress	
Minneapolis	280	Diesel	Energized	
Minneapolis	20000	Gas	In Progress	
Minneapolis	13.25	Solar	Energized	
Minneapolis	5.57	Solar	Energized	
Minneapolis	7.3	Solar	Energized	

…Trade Secret Data Ends]

DG Interconnection Applications Received in 2012

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins...
Minneapols	90	Solar	In Progress	
Minneiska	3.6	Solar	Energized	
Minnetonka	1500	Diesel	Energized	
Minnetonka	600	Diesel	Energized	
Minnetonka	1.29	Solar	Energized	
Monticello	5	Gas	Energized	
Morton	80	Gas	Energized	
Mound	1.4	Solar	Energized	
Mound	1.5	Wind	Energized	
Pipestone	39.9	Wind	In Progress	
Plymouth	100	Diesel	Energized	
Red Wing	2.16	Solar	Energized	
Rosemount	400	Diesel	Energized	
Roseville	500	Diesel	Energized	
Sabin	10	Diesel	Energized	
Shoreview	500	Diesel	Energized	
St. Cloud	1.52	Solar	Energized	
St. Joseph	130	Diesel	Energized	
St. Paul	350	Diesel	Energized	
St. Paul	500	Diesel	Energized	
St. Paul	250	Diesel	Energized	
St. Paul	3.44	Solar	Energized	
St. Paul	2.58	Solar	Energized	
St. Paul		Solar	In Progress	
St. Paul	175	Diesel	Energized	
St. Paul	2.115	Solar	Energized	

...Trade Secret Data Ends]

DG Interconnection Applications Received in 2012

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins...
St. Paul	500	Solar	In Progress	
St. Paul	5	Solar	Energized	
Starbuck	102	Diesel	Energized	
Waconia	600	Diesel	In Progress	
Waseca	14.1	Solar	Energized	
Waseca	12	Solar	Energized	
Wayzata	500	Diesel	Energized	
Wayzata	180	Diesel	Energized	
West St. Paul	600	Diesel	Energized	
White Bear Lake	10	Diesel	Energized	
Woodbury	60	Diesel	Energized	
Woodbury	1000	Diesel	In Progress	
Woodbury	1000	Diesel	In Progress	
	34,088			

…Trade Secret Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins…
Afton	12.48	Solar	Complete	
Afton	9.18	Solar	Complete	
Apple Valley	38.66	Solar	Complete	
Arden Hills	39.12	Solar	Complete	
Bloomington	39.968	Solar	Complete	
Bloomington	39.806	Solar	Complete	
Bloomington	39.56	Solar	Complete	
Bloomington	32.452	Solar	Complete	
Bloomington	35.628	Solar	Complete	
Bloomington	39.96	Solar	Complete	
Bloomington	5.46	Solar	Complete	
Brooklyn Center	19.206	Solar	Complete	
Brooklyn Center	32.274	Solar	Complete	
Brooklyn Center	3.9	Solar	Complete	
Brooklyn Center	38.25	Solar	Complete	
Brooklyn Center	38.25	Solar	Complete	
Brooklyn Park	4.392	Solar	Complete	
Brooklyn Park	8	Solar	Complete	
Brooklyn Park	2.73	Solar	Complete	
Brooklyn Park	36.432	Solar	Complete	
Brooklyn Park	5.4	Solar	Complete	
Brooklyn Park	1.4	Solar	Complete	
Brooklyn Park	3.06	Solar	Complete	
Burnsville	14.4	Solar	Complete	
Carver	5.124	Solar	Complete	
Center City	4.5	Solar	Complete	
				…Trade Secret
				Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins…
Center City	40	Solar	Complete	
Champlin	5.52	Solar	Complete	
Chisago City	8.775	Solar	Complete	
Cokato	38.87	Solar	Complete	
Columbia Heights	39.69	Solar	Complete	
Columbia Heights	4.095	Solar	Complete	
Corcoran	8.25	Solar	Complete	
Crystal	1.4	Solar	Complete	
Dodge Center	29.64	Solar	Complete	
Dodge Center	24.7	Solar	Complete	
Eagan	12.76	Solar	Complete	
Eagan	36.72	Solar	Complete	
Eagan	10.64	Solar	Complete	
Eden Prairie	39.772	Solar	Complete	
Eden Prairie	7.98	Solar	Complete	
Eden Prairie	2.08	Solar	Complete	
Eden Prairie	6.24	Solar	Complete	
Eden Prairie	7.215	Solar	Complete	
Eden Prairie	4.08	Solar	Complete	
Eden Prairie	11.52	Solar	Complete	
Eden Prairie	9.6	Solar	Complete	
Edina	5.7	Solar	Complete	
Edina	27.495	Solar	Complete	
Edina	8.25	Solar	Complete	
Edina	5.76	Solar	Complete	
Edina	25.214	Solar	Complete	
				…Trade Secret
				Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins...
Edina	29.588	Solar	Complete	
Falcon Heights	39.92	Solar	Complete	
Faribault	2.16	Solar	Complete	
Farmington	17.84	Solar	Complete	
Farmington	17.48	Solar	Complete	
Farmington	18.31	Solar	Complete	
Farmington	17.47	Solar	Complete	
Fridley	39.96	Solar	Complete	
Fridley	39.96	Solar	Complete	
Fridley	39.96	Solar	Complete	
Golden Valley	4.94	Solar	Complete	
Golden Valley	4.08	Solar	Complete	
Golden Valley	37.824	Solar	Complete	
Golden Valley	36.54	Solar	Complete	
Hamel	15.84	Solar	Complete	
Hastings	37.8	Solar	Complete	
Hopkins	1.76	Solar	Complete	
Inver Grove Heights	5.64	Solar	Complete	
Janesville	8.82	Solar	Complete	
Janesville	8.16	Solar	Complete	
La Crescent	38.4	Solar	Complete	
La Crescent	7.6	Solar	Complete	
LaCrescent	28.8	Solar	Complete	
Lake City	34.56	Solar	Complete	
Lakeville	9.57	Solar	Complete	
Lakeville	6	Solar	Complete	
				...Trade Secret
				Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins…
Lindstrom	22.815	Solar	Complete	
Lindstrom	23.4	Solar	Complete	
Lindstrom	22.815	Solar	Complete	
Lino Lakes	2.98	Solar	Complete	
Lino Lakes	2.09	Solar	Complete	
Lowry	9.12	Solar	Complete	
Mahtomedi	6.24	Solar	Complete	
Mankato	39.97	Solar	Complete	
Mankato	7.138	Solar	Complete	
Mankato	12.48	Solar	Complete	
Mankato	24.96	Solar	Complete	
Maple Grove	12	Solar	Complete	
Maplewood	39.96	Solar	Complete	
Maplewood	5.5	Solar	Complete	
Maplewood	5	Solar	Complete	
Maplewood	38.88	Solar	Complete	
Maplewood	9.31	Solar	Complete	
Marine on St. Croix	7.52	Solar	Complete	
Marine on St. Croix	8.64	Solar	Complete	
Mazeppa	8.46	Solar	Complete	
Medicine Lake	8.17	Solar	Complete	
Minneapolis	39.96	Solar	Complete	
Minneapolis	3.5	Solar	Complete	
Minneapolis	5.28	Solar	Complete	
Minneapolis	5.46	Solar	Complete	
Minneapolis	2	Solar	Complete	
				…Trade Secret
				Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins...
Minneapolis	2.115	Solar	Complete	
Minneapolis	39.82	Solar	Complete	
Minneapolis	6.16	Solar	Complete	
Minneapolis	24.872	Solar	Complete	
Minneapolis	4.725	Solar	Complete	
Minneapolis	2.73	Solar	Complete	
Minneapolis	5.025	Solar	Complete	
Minneapolis	39.888	Solar	Complete	
Minneapolis	5.612	Solar	Complete	
Minneapolis	5	Solar	Complete	
Minneapolis	2.25	Solar	Complete	
Minneapolis	2.5	Solar	Complete	
Minneapolis	3.9	Solar	Complete	
Minneapolis	21.6	Solar	Complete	
Minneapolis	2.125	Solar	Complete	
Minneapolis	7.25	Solar	Complete	
Minneapolis	3.5	Solar	Complete	
Minneapolis	3.43	Solar	Complete	
Minneapolis	2.88	Solar	Complete	
Minneapolis	39.75	Solar	Complete	
Minneapolis	3.52	Solar	Complete	
Minneapolis	2.55	Solar	Complete	
Minneapolis	6.045	Solar	Complete	
Minneapolis	3.012	Solar	Complete	
Minneapolis	26.352	Solar	Complete	
Minneapolis	14	Solar	Complete	
				...Trade Secret
				Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins…
Minneapolis	3.675	Solar	Complete	
Minneapolis	5	Solar	Complete	
Minneapolis	5.655	Solar	Complete	
Minneapolis	3.825	Solar	Complete	
Minneapolis	10.32	Solar	Complete	
Minneapolis	9.633	Solar	Complete	
Minneapolis	4.68	Solar	Complete	
Minneapolis	2.73	Solar	Complete	
Minneapolis	4	Solar	Complete	
Minneapolis	7.56	Solar	Complete	
Minneapolis	5.7	Solar	Complete	
Minneapolis	39.715	Solar	Complete	
Minneapolis	39.56	Solar	Complete	
Minneapolis	3.864	Solar	Complete	
Minneapolis	38.4	Solar	Complete	
Minneapolis	19.878	Solar	Complete	
Minneapolis	3.952	Solar	Complete	
MInneapolis	2.928	Solar	Complete	
Minneapolis	6.762	Solar	Complete	
Minneapolis	39.995	Solar	Complete	
Minneapolis	5.5	Solar	Complete	
Minneapolis	3.375	Solar	Complete	
Minneapolis	38.478	Solar	Complete	
Minneapolis	2.25	Solar	Complete	
Minneapolis	3	Solar	Complete	
Minneapolis	19.8	Solar	Complete	
				…Trade Secret
				Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins…
Minneapolis	2.7	Solar	Complete	
Minneapolis	25.15	Solar	Complete	
Minneapolis	3	Solar	Complete	
Minneapolis	36	Solar	Complete	
Minneapolis	10.11	Solar	Complete	
Minneapolis	5.61	Solar	Complete	
Minneapolis	14.25	Solar	Complete	
Minnesota City	0.75	Solar	Complete	
Minnetonka	5.61	Solar	Complete	
Minnetonka	4.68	Solar	Complete	
Minnetonka	2.928	Solar	Complete	
Minnetonka	4.88	Solar	Complete	
Minnetonka	3.8	Solar	Complete	
Minnetonka	4.68	Solar	Complete	
Minnetonka	22.8	Solar	Complete	
Minnetonka	4.56	Solar	Complete	
Minnetonka	6.25	Solar	Complete	
Minnetonka Beach	12.87	Solar	Complete	
Montevideo	7.65	Solar	Complete	
Morgan	39.6	Solar	Complete	
Mound	3.416	Solar	Complete	
New Brighton	2.925	Solar	Complete	
New Brighton	5.4	Solar	Complete	
New Brighton	4.968	Solar	Complete	
North Branch	4.8	Solar	Complete	
Northfield	7.6	Solar	Complete	
				…Trade Secret
				Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins…
Northfield	2.82	Solar	Complete	
Northfield	5	Solar	Complete	
Oakdale	1.35	Solar	Complete	
Oakdale	39.84	Solar	Complete	
Pine Island	8.28	Solar	Complete	
Plato	39.96	Solar	Complete	
Plymouth	39.28	Solar	Complete	
Plymouth	36.416	Solar	Complete	
Plymouth	36.416	Solar	Complete	
Plymouth	38.52	Solar	Complete	
Plymouth	39.6	Solar	Complete	
Plymouth	34.68	Solar	Complete	
Raymond	23.04	Solar	Complete	
Raymond	39.15	Solar	Complete	
Red Wing	2.925	Solar	Complete	
Red Wing	5.46	Solar	Complete	
Red Wing	11.475	Solar	Complete	
Red Wing	11.88	Solar	Complete	
Richfield	6	Solar	Complete	
Richfield	6.08	Solar	Complete	
Richfield	36.562	Solar	Complete	
Richfield	4.08	Solar	Complete	
Richfield	39.56	Solar	Complete	
Richfield	36.54	Solar	Complete	
Rogers	6.65	Solar	Complete	
Rollingstone	39.84	Solar	Complete	
				…Trade Secret
				Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins…
Roseville	7.905	Solar	Complete	
Roseville	2	Solar	Complete	
Roseville	7.98	Solar	Complete	
Roseville	1.47	Solar	Complete	
Roseville	11.31	Solar	Complete	
Roseville	5.85	Solar	Complete	
Sauk Rapids	1	Solar	Complete	
Shafer	6	Solar	Complete	
Shoreview	39.96	Solar	Complete	
Shoreview	5.61	Solar	Complete	
Shoreview	2.82	Solar	Complete	
St Louis Park	5.32	Solar	Complete	
St Louis Park	8.17	Solar	Complete	
St. Cloud	5.865	Solar	Complete	
St. Cloud	3.06	Solar	Complete	
St. Cloud	36.416	Solar	Complete	
St. Louis Park	2.925	Solar	Complete	
St. Michael	38.87	Solar	Complete	
St. Paul	39.84	Solar	Complete	
St. Paul	2	Solar	Complete	
St. Paul	1.96	Solar	Complete	
St. Paul	10.43	Solar	Complete	
St. Paul	3.06	Solar	Complete	
St. Paul	2.964	Solar	Complete	
St. Paul	24.5	Solar	Complete	
St. Paul	5	Solar	Complete	
				…Trade Secret Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins…
St. Paul	4.05	Solar	Complete	
St. Paul	2.7	Solar	Complete	
St. Paul	3.75	Solar	Complete	
St. Paul	2.28	Solar	Complete	
St. Paul	3.04	Solar	Complete	
St. Paul	5.175	Solar	Complete	
St. Paul	17.356	Solar	Complete	
St. Paul	1.95	Solar	Complete	
St. Paul	3.8	Solar	Complete	
St. Paul	7	Solar	Complete	
St. Paul	1.47	Solar	Complete	
St. Paul	11.34	Solar	Complete	
St. Paul	39.96	Solar	Complete	
St. Paul	6.08	Solar	Complete	
St. Paul	2.925	Solar	Complete	
St. Paul	4.08	Solar	Complete	
St. Paul	39.364	Solar	Complete	
St. Paul	1.84	Solar	Complete	
St. Paul	1.71	Solar	Complete	
St. Paul	2.64	Solar	Complete	
St. Paul	6.24	Solar	Complete	
St. Paul	21.06	Solar	Complete	
St. Paul	19.63	Solar	Complete	
St. Paul	6.5	Solar	Complete	
St. Paul	9	Solar	Complete	
St. Paul	3.04	Solar	Complete	
				…Trade Secret
				Data Ends]

DG Interconnection Applications Received in 2012
Solar*Rewards®

City	Capacity (kW)	DG Type	Disposition	Feeder [Trade Secret Data Begins...
St. Paul Park	7	Solar	Complete	
Stillwater	8.19	Solar	Complete	
Stillwater	8.84	Solar	Complete	
Stillwater	22	Solar	Complete	
Watertown	8.784	Solar	Complete	
West Concord	6.49	Solar	Complete	
West Concord	39.95	Solar	Complete	
Winona	28.8	Solar	Complete	
Winona	1.5	Solar	Complete	
Winona	4	Solar	Complete	
Winona	0.5	Solar	Complete	
Winona	6.76	Solar	Complete	
Winona	2.34	Solar	Complete	
Winona	6.21	Solar	Complete	
Woodbury	9.675	Solar	Complete	
Woodbury	5.46	Solar	Complete	
Woodbury	31.864	Solar	Complete	
Woodbury	39.786	Solar	Complete	
Woodbury	38.74	Solar	Complete	
Woodbury	35.15	Solar	Complete	
Young America	8.19	Solar	Complete	
Zumbro Falls	7	Solar	Complete	
	4180.919			**...Trade Secret Data Ends]**