AGENDA
SHAKOPEE PUBLIC UTILITIES COMMISSION
REGULAR MEETING
APRIL 15, 2019

1. **Call to Order** at 5:00pm in the SPUC Service Center, 255 Sarazin Street.

2. **Approval of Minutes**

3. **Communications**

4. **Approve the Agenda**

5. **Approval of Consent Business**

6. **Bills: Approve Warrant List**

7. **Liaison Report**

8. **Reports: Water Items**
   8a) Water System Operations Report – Verbal
   8b) Nitrate Analysis – Procedure and Protocol
   8c) City of Shakopee Review Comments – SPU/Commission Response

9. **Reports: Electric Items**
   9a) Electric System Operations Report – Verbal
   9b) 2019 Lineworker's Rodeo Overview and Results
   9c) Distributed Generation Mandate and Process Requirements
   9d) Resn. #1243 – Adopting Shakopee Public Utilities Commission's Policy Regarding Distributed Generation Resources and Net Metering and Rules Governing the Interconnection of Cogeneration and Small Power Production Facilities
   9e) Resn. #1244 – Adopting the Shakopee Public Utilities Commission Distributed Energy Resource Interconnection Process
   9f) Resn. #1245 – Approving Shakopee Public Utilities Commission's Cogeneration and Small Power Production Tariff

10. **Reports: Human Resources**

11. **Reports: General**
   11a) MMUA Tom Bovitz Scholarship Essays
   11b) 2018 Audit of Financial Statements - BerganKDV
   11c) 2019 March Financial Results

12. **New Business**

13. **Tentative Dates for Upcoming Meetings**
   - Regular Meeting -- May 6
   - Mid Month Meeting -- May 20
   - Regular Meeting -- June 3
   - Mid Month Meeting -- June 17

14. **Adjourn** to 5/6/19 at the SPU Service Center, 255 Sarazin Street

The MINUTES

OF THE

SHAKOPEE PUBLIC UTILITIES COMMISSION
(Regular Meeting)

Vice President Joos called the regular session of the Shakopee Public Utilities Commission to order at the Shakopee Public Utilities meeting room at 5:00 P.M., April 1, 2019.

MEMBERS PRESENT: Commissioners Joos, Meyer, Clay and Mocol. Also present, Liaison Lehman, Utilities Manager Crooks, Finance Director Schmid, Water Superintendent Schemel and Marketing/Customer Relations Director Walsh. Commissioner Amundson was absent as previously advised.

Motion by Clay, seconded by Meyer to approve the minutes of the March 18, 2019 Commission meeting. Motion carried.

Under Communications, Utilities manager Crooks welcomed Kathi Mocol as our new SPU Commissioner.

Vice President Joos offered the agenda for approval.

Motion by Meyer, seconded by Clay to approve the agenda as presented. Motion carried.

Motion by Mocol, seconded by Clay to approve the Consent Business agenda as presented. Commissioner Meyer asked that Item 8b: Quarterly Nitrate Results be taken off of consent business. Amended motion was accepted and carried.

Vice President Joos stated that the Consent Items were: Item 11a: Website Analytics – Review and 2019 February Financial Results.

The warrant listing for bills paid April 1, 2019 was presented.

Motion by Meyer, seconded by Mocol to approve the warrant listing dated April 1, 2019 as presented. Motion carried.

Liaison Lehman presented his report. Expansion of TIF districts for the Canterbury and old City Hall sites will be discussed at the next City Council meeting. Comments regarding coordination of the City 2040 Comp Plan and SPU's Water Supply Plan will be made during Item 8c: 2019 Water Supply Plan Report.

Water Superintendent Schemel provided a report of current water operations. It was reported that Well #2 and Water Storage Tank #2 are now back in service after completing scheduled maintenance.

Quarterly Nitrate Results were reviewed by Mr. Crooks. The Commission adopted sampling procedure and protocol were discussed. More detailed information will be brought back to the next meeting.

Mr. Crooks presented the DNR (February 15, 2019) approved 2017 Water Supply Plan. Discussion then centered on a letter written to the Commission from the Shakopee City Administrator. The Commissioners received the letter on Saturday March 30. SPU Staff received the letter today. The letter had been forwarded to the Utilities Manager on Sunday. There were 21 comments contained in the letter with requests for information on each item. Staff did not have time to respond to each point. The Commission directed Staff to respond to each of the 21 items in the letter and bring back those responses to the next Commission meeting.

Staff was directed to share the future draft facilities map with the City and to continue exchanging the information necessary to ensure both the City's 2040 Comprehensive Plan and the Commission's 2018 Comprehensive Water System Plan and Commission's Water Supply Plan are in synch and fully coordinated.

Mr. Crooks provided a report of current electric operations. There were two electric outages to review. One was caused when a car knocked down a power pole and the second was a caused by a failed transformer. Construction projects were updated.

Mr. Crooks read the March 2019 MMPA Board Meeting Summary.

Mr. Crooks reviewed the SPU/MMPA Energy Education Program for Shakopee High School students that took place in March.

Item 11a: Website Analytics – Review was received under Consent Business.

Mr. Crooks presented the SPU Governance Handbook for Commission review. Commissioners were asked to sign an acknowledgment page within the document.

Mr. Crooks presented an overview of Commission Meeting Protocol and Procedure.

Vice President Joos announced the 2019 election for officers and officials to the Shakopee Public Utilities Commission. Each officer; President, Vice President and Secretary, are to be elected to a 1-year term.

Mr. Crooks called for nominations for the office of President of the Shakopee Public Utilities Commission.

Motion by Clay to nominate Commissioner Joos for the office of President of the Shakopee Public Utilities Commission. There were no further nominations.

Mr. Crooks moved to close the nominations and move to Commission vote. Vote was unanimous. Motion carried.

Mr. Crooks acknowledged the vote and Commissioner Joos was elected unanimously to the office of President of the Shakopee Public Utilities Commission.

Mr. Crooks called for nominations for the office of Vice President of the Shakopee Public Utilities Commission.

Motion by Meyer to nominate Commissioner Amundson for the office of Vice President of the Shakopee Public Utilities Commission. There were no other nominations.

Mr. Crooks moved to close the nominations and move to Commission vote. Vote was unanimous. Motion carried.

Mr. Crooks acknowledged the vote and Commissioner Amundson was elected unanimously to the office of Vice President of the Shakopee Public Utilities Commission.

Mr. Crooks called for nominations for the office of Secretary to the Shakopee Public Utilities Commission.

Motion by Joos to nominate Utilities Manager Crooks for the office of Secretary to the Shakopee Public Utilities Commission. There were no further nominations.

Mr. Crooks moved to close the nominations and move to Commission vote. Vote was unanimous. Motion carried

The vote was acknowledged and Mr. Crooks was elected unanimously for the office of Secretary to the Shakopee Public Utilities Commission.

President Joos then set to make the appointment for the Representative to the Minnesota Municipal Power Agency (MMPA) for the Shakopee Public Utilities Commission. Utilities Manager Crooks was re-appointed as Representative to MMPA for the Shakopee Public Utilities Commission.

President Joos then set to make the appointment for the Alternate Representative to MMPA for the Shakopee Public Utilities Commission. Commissioner Amundson was re-appointed as Alternate Representative to MMPA for the Shakopee Public Utilities Commission.

Item 11f: 2019 February Financial Results was received under Consent Business.

The tentative commission meeting dates of April 15 and May 6 were noted.

Motion by Meyer, seconded by Clay to adjourn to the April 15, 2019 meeting. Motion carried.

Commission Secretary: John R. Crooks

SHAKOPEE PUBLIC UTILITIES
MEMORANDUM

TO: SHAKOPEE PUBLIC UTILITIES COMMISSION

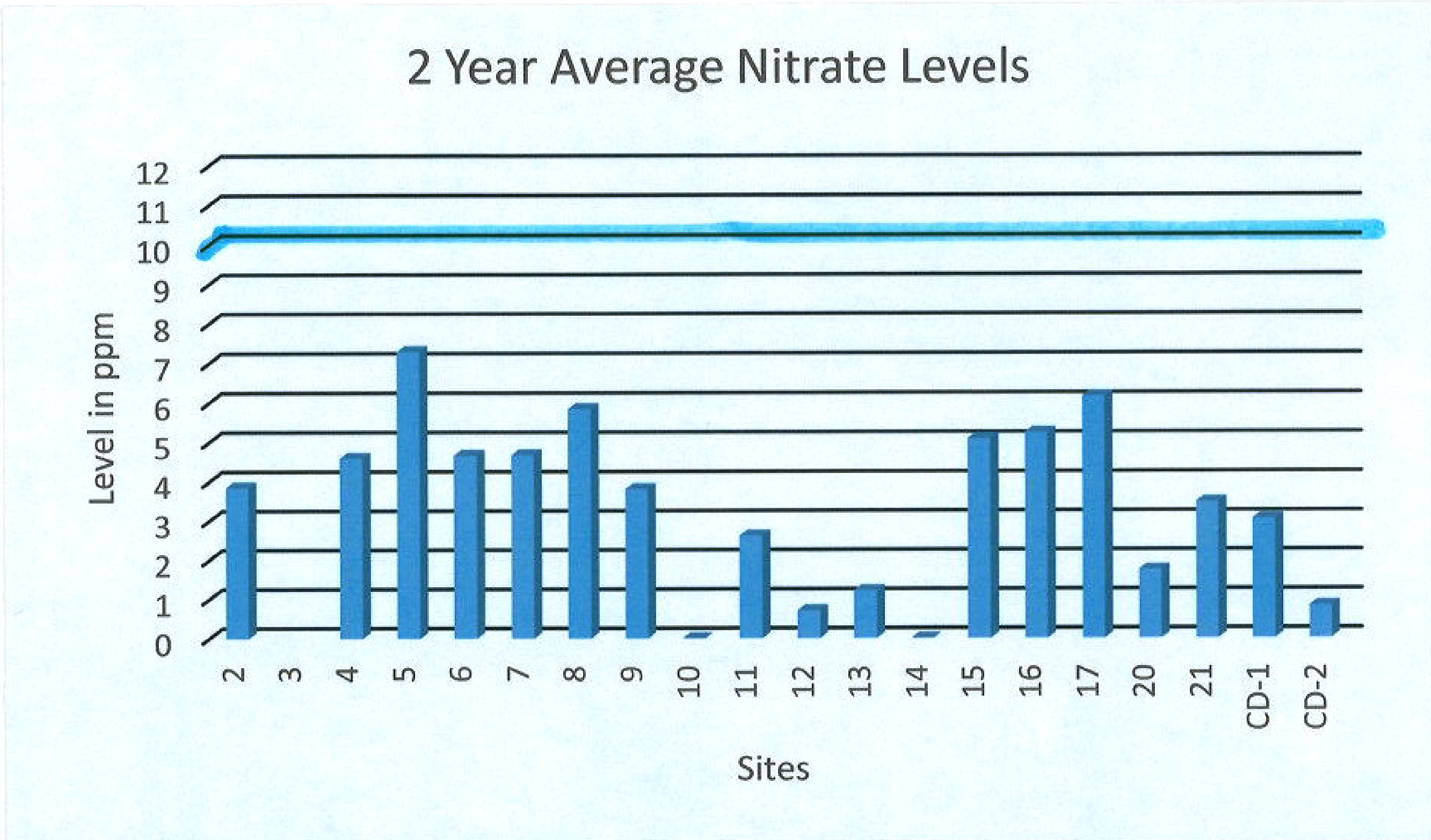
FROM: JOHN R. CROOKS, UTILITIES MANAGER JRC

SUBJECT: NITRATE ANALYSIS – PROCEDURE AND PROTOCOL

DATE: APRIL 12, 2019

Following up on discussion that took place during the April 1 Commission meeting, Staff would like to review the existing Nitrate sampling procedures and protocol. The Commission first adopted these requirements in 1998 and the last update to the policy was 2005.

As indicated in the quarterly Nitrate results that are provided to the Commission, trending levels are much better the last 2 years which are better than past 10 and 20 years. A graph has been supplied to show that each well is well below the Minnesota Department of Health's maximum contaminant level MCL of 10 mg/l.


2 Year Average Nitrate Levels
Level in ppm
0
1
2
3
4
5
6
7
8
9
10
11
12
2
3
4
5
6
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20
21
CD-1
CD-2
Sites

SHAKOPEE PUBLIC UTILITIES – WATER DEPARTMENT
INTERNAL OPERATING PROTOCOL – NITRATES

The "Standard Testing and Operational Procedures - Nitrates Levels", as adopted by the Commission November 1998, requires compliance with all health regulations and restricts the operations of wells between 10 mg/l and 5 mg/l. With the wealth of data collected since 1998 it has been determined an update is required and is contained within this document. This internal operating protocol will be as stringent where water demand allows.

TESTING PROTOCOL

Testing protocol has been slightly modified from current SPUC policy "Testing and Operational Procedures – Nitrate Levels". These changes reflect the additions of wells (15 through 21) to the system and also Well 2 being sealed off from the MTS/H formation. This testing is the minimum baseline for all wells and is listed in the following table labeled Testing Protocol. Additional testing may be required as indicated in the Internal Operational Procedures chart.

This monitoring frequency is much more stringent than required by the MN Department of Health (MDH). According to Minnesota Safe Drinking Water Rules, quarterly sampling is required only when NO3 levels are above 5.4 mg/l (50% of the Maximum Contaminant Level of 10 mg/l).

OPERATIONAL PROTOCOL

Operational protocol is based on the latest test results received from the MDH and/or the private laboratory being used by SPUC for nitrate analysis. No restrictions are placed upon wells having NO3 levels below 5 mg/l, which is 50% of the Maximum Contaminant Level (MCL) of 10 mg/l. Nitrate MCL violation criteria states there is a violation when the MDH confirmation average exceeds 10.4 mg/l. SPUC Operating restrictions begin to take place when lab results show a well's nitrate level over 5 mg/l. This protocol can be seen in the chart labeled Internal Operational Procedures For All Wells. Operating restrictions are identified for wells with NO3 levels between 5 mg/l and 7.5 mg/l (50% to 75% of the MCL). Further restrictions are given for levels over 7.5 mg/l and again at levels over 9.0 mg/l.

This protocol is set to assure public safety when nitrates levels begin to approach upper limits. This is the ultimate priority of the Utilities. The public must be confident safeguards are in place as to not allow nitrates above the MCL to enter the water supply.

ACTION LEVELS

A change in action level to a more restrictive operation will be made as soon as possible after a report of a nitrate level calling for a more restrictive Action Level.

A change in action level to a less restrictive operation will not be made until 2 consecutive follow -up test results are at a lower Action Level.

Sharp increases in nitrate levels may call for changes in action levels. If a test result calls for an increase of more than one step in Action Level, the Action Level will be designated as 1 additional Action Level above the test result.

For example: for Well 5, operating at an action level of "below 5.00" a test of 7.56 mg/l would be two action levels steps – but add one additional step to designate the Action Level in the "9.00 and over" range.

TIMING OF REPORTING AND CONFERRED RESPONSE

When the conditions call for the need to confer, the Water Superintendent and Utilities Manager will make every effort to meet the following timelines:

Before - changing to a less restrictive operation

ASAP - upon receiving test report showing water pumped into the system exceeding 10 mg/l

ASAP – if a well had to be run on "hand" operation for an emergency condition, regardless of nitrate levels

Within 1 day – after an emergency condition, if a well was not run for some reason

Within 1 day – of a test result calling for a more restrictive Action Level

Each workday – when operating under an exemption to Internal Operating Protocol

As needed – for routine review of current Action Levels on various wells

RETESTING SAMPLES and INVESTIGATIONS OF RESULTS

Certain samples tested by our private laboratory will be retested to verify the reliability of our results. Retests will be routinely done when test results exceed the following levels contained on the following table. A resample of the well will also be required in conjunction with the retest.

The Superintendent will order retests without waiting to discuss with the Utilities Manager, but will advise that a retest has been requested. The Superintendent may order other retests whenever needed.

In specific instances when results indicate a significant change the Water Superintendent will meet with the Utilities Manager to discuss an investigations to determine the possible cause of the nitrate increase. It may be determined the best course of action will fall outside the scope of specified procedure. In this case the course of action will be approved by the Utilities Manager.

EXEMPTIONS

Operations will be as described under this Internal Operating Protocol unless specific exemption is directed by the Utilities Manager.

Adopted 5/3/05

SHAKOPEE PUBLIC UTILITIES – WATER DEPARTMENT
TESTING AND OPERATIONAL PROCEDURES – NITRATES

TESTING SCHEDULE FOR ALL WELLS:

NITRATE LEVEL:	TESTING FREQUENCY:
2.5 mg/l and below	Quarterly testing
2.5 mg/l and above	Monthly testing
8.5 mg/l and above	72 hours of pumping

This monitoring frequency is much more stringent than required by the MN Department of Health (MDH). According to Minnesota Safe Drinking Water Rules, quarterly sampling is required only when NO3 levels are above 5.4 mg/l (50% of the Maximum Contaminant Level of 10 mg/l).

The prior 13-months of NO3 results will be provided to Commission every month.

OPERATIONAL PROCEDURES – NORMAL, SHORTAGE, EMERGENCY

NORMAL CONDITIONS -

Regular pumping from a well will be immediately suspended upon receiving test result above 10.0 mg/l.
Wells taken out of service for nitrate levels will be tested before being put back in service. Regular pumping will not resume until test results are below 10.0 mg/l for two consecutive weeks.

SHORTAGE CONDITIONS -

A "shortage" is defined as a condition where water pressures or storage tanks are below levels desired, but not so extreme as to constitute an emergency. Examples would be a prolonged drought, pump failure, or storage tank being out of service.
Under shortage conditions the preferred action is the imposition of restrictions on water usage by sprinkling restrictions or similar conservation measures. As an alternative response, wells previously taken out of service due to elevated nitrate levels may be placed in operation in conjunction with other wells to blend water. Blended water will be monitored to determine that the nitrate level of water supplied to the public is 10.0 mg/l or below.
If blended water of 10.0 mg/l is not exceeded, public notification is not required by the MN Department of Health.
Utility Commissioners will be advised of the event.

EMERGENCY CONDITIONS –

An "emergency" is defined as an extreme condition where a threat to life and safety is reasonably seen. Examples would be a shortage of water pressure due to fire-fighting use, or to low water storage levels giving inadequate fire protection.

Under emergency conditions, wells taken out of service due to elevated nitrate levels may be placed in operation at the discretion of the appropriate utilities staff personnel, normally the Water Superintendent, or as directed by the Utilities Manager.

In the event that wells with high nitrate levels are run under the emergency conditions, public notification is required by the MN Department of Health and SPUC emergency procedures will be followed. SPUC will take appropriate action to assure suitable water is available as required by various customers.

Utilities Commissioners will be advised of an emergency event.

This policy is set to assure public safety when nitrates levels begin to approach upper limits. This is the ultimate priority of the Utilities. The public must be confident safeguards are in place as to not allow nitrates above the MCL to enter the water supply.

General Notes to the Testing Schedule and Operational Procedures:

1. When four consecutive repeat samples that are reliably and consistently below a given schedule threshold, the testing frequency will revert to the average of the four latest tests.

2. SPUC testing schedule will meet or exceed state and federal requirements.

3. Water quality standard and public notification procedures will comply with state and federal SDWA requirements.

4. Water pumped to waste (not for public consumption) is not subject to the testing schedule or the operational procedures.

Adopted 5/3/05

8c

SHAKOPEE PUBLIC UTILITIES
MEMORANDUM

TO: SHAKOPEE PUBLIC UTILITIES COMMISSION

FROM: JOHN R. CROOKS, UTILITIES MANAGER

SUBJECT: SPU RESPONSE TO MARCH 25 LETTER FROM THE SHAKOPEE CITY ADMINISTRATOR.

DATE: APRIL 12, 2019

Attached to this memo is the original letter dated March 25, 2019 and received March 30, 2019. I have provided responses to each of the 21 comments and their requests for further information.

Since the letter was addressed to the SPU Commission and not myself or Staff, it is appropriate the responses be reviewed by Commissioners before writing the cover letter and returning the attachments back to the City Administrator.

SHAKOPEE
PLANNING AND DEVELOPMENT

March 25, 2019

Shakopee Public Utilities Commission
255 Sarazin Street
Shakopee, MN 55379

RE: City of Shakopee Review Comments for SPUC Comprehensive Water System Plan and Water Supply Plan

City staff have been able to review SPUC's Comprehensive Water System Plan and have the following comments which will need to be addressed prior to Metropolitan Council approval. First set of comments are in response to the Comprehensive Water System Plan, dated September 13, 2018.

1. Current Shakopee population is incorrect. Stated as "approximately 37,000", this number reflects 2010 census data. This number should be the latest Metropolitan Council estimate for 2017, which is 41,519.

2. On page 13, Table 3-2 "Projected Population Data" is not consistent with revised City or Met Council projections for city population, please refer to the following table for consistent information.

City of Shakopee Population Forecasts				
	2010	2020	2030	2040
Population	36,946	47,800	55,900	62,600
Households	12,722	16,300	19,400	22,100
Employment	18,831	25,700	29,100	32,800

3. Existing and projected land use maps and table should be revised to remain consistent with the City's 2040 Comprehensive Plan land use maps and tables.

   Table B-1 through B-5 "Projected Water Consumption by Land Use" need to be revised to reflect correct planned land use categories as defined in the 2040 Comprehensive Plan and correct full build out acreage for these planned categories. Information on these tables appears to be from the 2030 Comprehensive Plan which will not be in effect once the 2040 Plan is adopted.

   Figure 2-3 "Existing Water System Model Map" and Figure 3-1 "Existing Land Use" do not include the new Windermere development, this should be included in both maps.

4. Page ES-1 – The Existing Facilities inventory does not match the Water Supply Plan inventory in Table 5 of that plan.

5. Page ES-1 – 8 million gallons in well capacity plus 11.25 MG in storage is a substantial amount over the historic maximum day demand.

6. Recommend to include a more detailed discussion about the history and master planning for a water treatment plant, referencing any past studies that have been completed, etc.

7. Appendices were not provided for review. Please provide.

8. Page 38 – Suggest including more specific info on Manganese to supplement and support the text in section 5.2.3.2 as there are several wells within the window that should be monitored a little more critically to ensure they do not exceed the .1 mg/L health risk guidance level with mention in a health risk context vs. only discussing the aesthetic nuisances.

9. Page 37, section 5.2.3.1 – While the Nitrate levels as reported in the annual CCR are below the MCL, only barely. A more robust discussion about the timing of the testing from year to year, the historic trends, etc. should be discussed to very explicitly detail the extremely closeness of exceeding the MCL. The discussion of blending water to mitigate the levels should be better discussed. (e.g. since the wells are connected directly into the distribution/transmission system, there is little blending that occurs until further outward into the system; therefore, there could be potential consumers immediate to the higher-level nitrate wells that are receiving the higher levels of nitrates and this should be further disclosed in more detail to consumers if indeed fact. The historical levels of nitrates are concerning with little fluctuation over the years. Are the well head protection initiatives, testing, blending, etc. enough to protect and supply safe drinking water supply relative to Nitrates? It is not certain with the info provided.

Remainder of comments are in response to Water Supply Plan dated December 12, 2018

10. Table 3. Valley Fair is listed as the high drinking water user. This property needs to be better inventoried to confirm meters vs. sanitary sewer meters vs. any possible private wells. There is an auxiliary sewer meter, not certain on the entire story about having this auxiliary meter vs. the SPUC meters.

11. Table 5 – The ground vs. elevated inventory does not match the Comprehensive Plan inventory on page ES-1 of that plan.

12. P. 14, last paragraph – Seems that 125.5 gallons per capita is an extremely high assumption that would lead too much of an overbuild of the system.

13. Table 10 – There are many boxes that are checked where the city is not aware of the indicated coordination as follows:
    a. Lake – the "other" mitigation measure box that is checked, and the "monitored" regular check-in box
    b. Wetland – same comments for the boxes checked under Lake
    c. Trout Stream – same comments for the boxes checked under Lake

14. Table 11 – While the WHP was adopted as indicated on 11/2011, it is apparent from discussions with city staff that there is a lack of adequate coordination with the city pertaining to the well head protection implementation initiatives, issues, etc., most notably when it comes to development and surface water coordination.

15. Table 12 – A 2020 CIP year of Water Treatment Facilities does not reflect the current CIP.

16. Please provide the city a copy of SPUC's Emergency Response Plan dated May 2017.

17. Table 21 – the New Water Conservation Ordinances action taken box is checked "no". It seems as an initiative that dates back to the 2006 plan commitment that this should already be completed. Verify status.

18. Table 23 – Per the table, there are only 300 automated meters. An AMI project is included in the CIP to automate meter reading over the next few years. Please confirm that this project is expected to replace all mechanical meters. The coordination of this is important to better monitor the city's discharge into the sanitary sewer also (e.g. recent event where a water service/line broke, with 280k gallons flowing into the city's sanitary sewer system.

19. Table 26 – Install AMI timeframe indicates "when possible". Suggest to update to match timeline in CIP.

20. Table 30 – Not aware of SPUCs participation in any Rain Barrel initiative with the watersheds.

21. Table 31 – Seemingly very little educational inclusion methodologies are being used.

Find SRF Memorandum No. 11925 attached requesting revised water supply forecasts for the AUAR study currently underway.

The City can provide all required data by request. If there are any questions or concerns about the City's comments, please contact city staff, thank you.

Sincerely,

Bill Reynolds
City Administrator

CC
Michael Kerski, Director Planning and Development
Steve Lillehaug, City Engineer
Shakopee Public Utility Commissioners

SRF

Memorandum

SRF No. 11925

To: Mark Noble, Senior Planner
Planning Division, City of Shakopee

From: Stephanie Falkers, Senior Associate

Date: March 22, 2019

Subject: Jackson Township AUAR – Water System Planning

Jackson Township AUAR

SRF Consulting Group is assisting the City of Shakopee with the development of an Alternative Urban Areawide Review (AUAR) for the areas included within the Jackson Township Orderly Annexation Area to the southwest of the city. The AUAR is a form of environmental review, intended to describe a development scenario and assess potential impacts to environmental and cultural resources. Impacts to public infrastructure services are also assessed, including water and sanitary services and the transportation network.

The Jackson Township AUAR will assess the impacts that result from a full-build scenario of the study area, according to the land uses proposed in the Draft 2040 Comprehensive Plan Update. This scenario includes over 600 acres identified for residential development and over 550 acres of commercial/industrial development (see proposed land uses on the following page).

To assess the potential impacts and need for mitigation, a full build-out of the proposed 2040 land use plan should be used to inform any water and sanitary modeling. The use of the 2040 growth assumptions will result in a more accurate depiction of water needs to support the growing area and will allow for the identification of appropriate mitigation activities within the AUAR.

It is our understanding that the current Comprehensive Water System Plan for the City, includes growth assumptions that align with the growth assumptions proposed in the 2030 Comprehensive Plan. To provide an accurate assessment of the future water system, the modeling should be updated to reflect the growth assumptions included in the Draft 2040 Comprehensive Plan Update.

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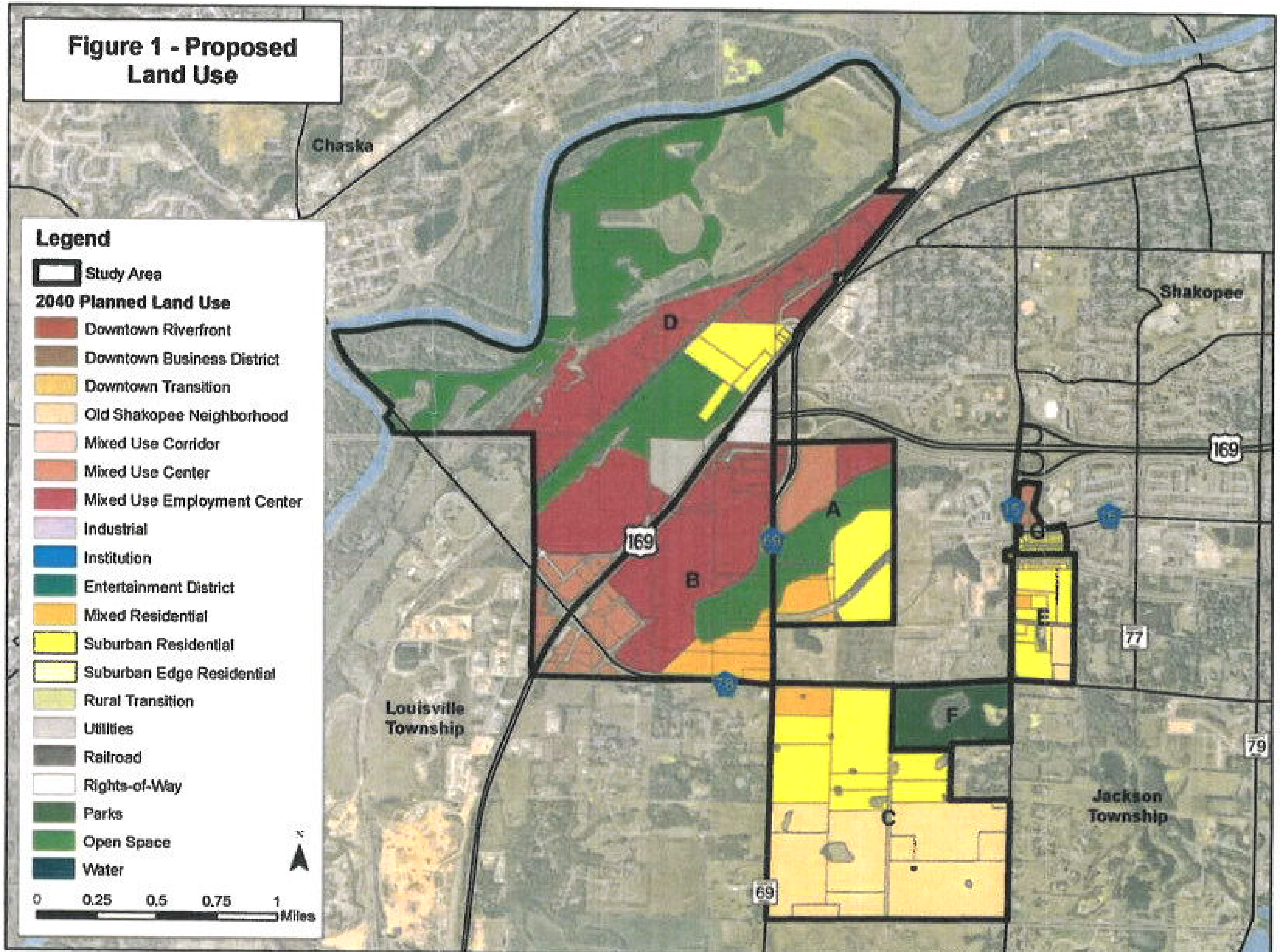
Figure 1 - Proposed Land Use
Chaska
Shakopee
Louisville Township
Jackson Township
A
B
C
D
E
F
G
169
69
78
15
77
79
Legend
Study Area
2040 Planned Land Use
Downtown Riverfront
Downtown Business District
Downtown Transition
Old Shakopee Neighborhood
Mixed Use Corridor
Mixed Use Center
Mixed Use Employment Center
Industrial
Institution
Entertainment District
Mixed Residential
Suburban Residential
Suburban Edge Residential
Rural Transition
Utilities
Railroad
Rights-of-Way
Parks
Open Space
Water
0 0.25 0.5 0.75 1 Miles
N

1. ***Current Shakopee population is incorrect. Stated as "approximately 37,000", this number reflects 2010 census data. This number should be the latest Metropolitan Council estimate for 2017, which is 41,519***

   -This population was listed in a general introduction paragraph, historical population data is reflected in table 3-1 which lists a 2017 population of 41,374, which is consistent with current estimates. Data included in table 3-1 was utilized in the report.

2. ***On page 13, Table 3-2 "Projected Population Data" is not consistent with revised City or Met Council projections for city population, please refer to the following table for consistent information.***

   -At the time of development of this plan, recently provided population information was not available, data from Met Council available at that time was referenced, water use projections will be updated with newly provided population information as needed.

3. ***Existing and projected land use maps and table should be revised to remain consistent with the City's 2040 Comprehensive Plan land use maps and tables.***

   -Maps utilized in the comp water plan were the most current at the time of development - the water plan will be updated to utilize these more recently updated maps as they are available. ***Table B-1 through B-5 "Projected Water Consumption by Land Use" need to be revised to reflect correct planned land use categories as defined in the 2040 Comprehensive Plan and correct full build-out acreage for these planned categories. Information on these tables appears to be from the 2030 Comprehensive Plan which will not be in effect once the 2040 Plan is adopted.***

   -Maps utilized in the comp water plan were the most current at the time of development - the water plan will be updated to utilize these more recently updated maps as they are available. ***Figure 2-3 "Existing Water System Model Map" and Figure 3-1 "Existing Land Use" do not include the new Windermere development, this should be included in both maps.***

   -The existing water system map was developed with current water mapping information at the time of development in 2017. Given the passage of time, new water main has since been added. This additional water main will be included in any updates completed to the comprehensive water plan.

4. ***Page ES-I - The Existing Facilities inventory does not match the Water Supply Plan inventory in Table 5 of that plan.***

   -The water supply plan (DNR) was due in October of 2017 and was completed a year before the comprehensive water plan. Both plans inventory a total storage capacity of 11.25 MGD. The 2017 water supply plan (table 5) listed tank 5 as an elevated tank. Though it functions as an elevated tank with "floating storage", as all tanks in the SPUC system function, it is constructed at grade, connected to its pressure zone via a transmission water main and thus is listed as a ground storage tank in the comprehensive water plan.

5. ***Page ES-1 - 8 million gallons in well capacity plus 11.25 MG in storage is a substantial amount over the historic maximum day demand.***

   -The sizing requirements for supply and storage are provided in great detail within the comprehensive water plan:

   The year 2012 had a maximum day demand of 16.26 MGD. Water supply capacity from wells are sized to satisfy max day demand in each pressure zone, with the two largest wells offline (for the total system, firm capacity is 20.3 mgd vs 24.4 mgd total) The trigger chart provided in section 7.6 of the comprehensive water plan recommends a new well be constructed when max day demand has the potential to approach 20.3 mgd. Given the time it takes to develop and place a new well online (in relation to site and production procurement, permitting, design and commissioning) proactive planning is required.

   With regards to storage, each pressure zone is assessed in relation to the storage needs of that zone. Given the pattern of development with the City first developing at lower elevations and then moving south to higher elevations, additional pressure zones have been created with their own unique storage needs. For many of the water storage performance metrics, higher elevation pressure zones do not have regular access to water stored in lower pressure zones, except if it is pumped from a booster station. The ability of each pressure zone to receive water thorough booster stations from lower pressure zones was accounted for in the storage analysis for each pressure zone. While indeed it could be asserted that SPUC has ample water storage available, the development of expanded pressure zones has additional storage recommendations that are not satisfied by existing storage facilities within lower pressure zones

6. ***Recommend to include a more detailed discussion about the history and master planning for a water treatment plant, referencing any past studies that have been completed, etc.***
   In 2002, SPUC consultant, Bonestroo, completed a detailed analysis of potential water treatment strategies. Several options were reveiwed with technical and financial analysis. This information was used in the 2003 Water Trunk Charge and Connection Analysis Report by SPUC Consultant, Schoell and Madson, recommending funding one or two water treatment plants. Another follow-up letter report in 2006 was completed by Progressive Consulting to re-analyize the data for potential treatment at individual sites, if required.
7. ***Appendices were not provided for review. Please provide.***
   Appendices A through G will be provided.
8. ***Page 38 – Suggest including more specific info on Manganese to supplement and support text in section 5.2.3.2 as there are several wells within the window that should be monitored a little more critically to ensure they do not exceed the .1 mg/l health risk guidance level with mention in a health risk context vs. only discussing the aesthetic nuisances.***
   Information regarding the manganese levels was provided to Mr. Lillehaug on March 15 after discussion at the Joint meeting with City Council. Language concerning the MDH health risk guidance level will be included.
9. ***Page 37, section 5.23.1 – While the Nitrate levels as reported in the annual CCR are below the MCL, only barely. A more robust discussion about the timing of the testing from year to year, the historic trends, etc., should be discussed to very explicitly detail the extreme closeness of exceeding the MCL. The discussion of blending water to mitigate the levels should be better discussed. (e.g. since the wells are connected directly into the distribution system, there is little blending that occurs until further outward into the system; therefore, there could be potential consumers immediate to the higher-level nitrate wells that are receiving the higher levels of nitrates and this should be further disclosed in more detail to consumers if indeed fact. The historic levels of nitrates are concerning with little fluctuation over the years. Are the well head protection initiatives, testing, blending, etc. enough to protect and supply safe drinking water supply relative to Nitrates? It is not certain with the info provided.***
   Shakopee Public Utilities has followed a strict policy set by the Commission for stringent operations and protocol regarding elevated levels of nitrates in Shakopee's public water supply wells. The program is much more detailed than the MDH requirements. The MDH and DNR are fully aware of our practice and have applauded our efforts to monitor the NO3 levels in Shakopee. This policy was adopted in 1998 and followed with several updates due to the expansion of the water system. Staff will take exception to the above statements the levels are below the MCL, only barely and the extreme closeness of exceeding the MCL. This is certainly not the case. Based upon the latest 2 year average of Nitrate levels in water supply wells, Well #5 is below the MCL by 30% (7.189 mg/l), Well #8 by 45% (5.774mg/l) and Well #17 is 40% under the MCL (6.209mg/l). These are the 3 wells with the highest concentration of NO3.There are 2,898 nitrate results on record since 2002. Nitrate results are presented to the Commission on a quarterly basis. The wells are not directly connected to the distribution/transmission system. They come together within the Pumphouse for treatment where they blend together before going to the distribution system, which is a MDH recognized treatment approach.

10. ***Table 3. ValleyFair is listed as the high drinking water user. This property needs to be better inventoried to confirm meters vs. sanitary sewer meters vs. any private wells. There is an auxiliary sewer meter , not certain on the entire story about having this auxilary meter vs. SPUC meters.***
SPUC maintains monthly detailed record keeping in regards to the metering at ValleyFair. Toni Janzig, SAC Technician with the Met Council also conducts an annual review of water use records and has for many years. We provide the Met Council with quarterly data. There are no private wells owned by ValleyFair to our knowledge. The agreement regarding the auxiliary meters was set by the City of Shakopee over 20 years ago. At the time SPUC agreed to the arrangement and have complied with the City's request since that time.
11. ***Table 5 - The ground vs. elevated inventory does not match the Comprehensive Plan inventory on page ES-1 of that plan.***
-The water supply plan (DNR) was due in October of 2017 and was completed a year before the comprehensive water plan. Both plans inventory a total storage capacity of 11.25 MGD, all of which is considered "floating storage" meaning, it can flow to the pressure zone that is served by gravity. The 2017 water supply plan (table 5) listed tank 5 as an elevated tank. Though it functions as an elevated tank with "floating storage", as all tanks in the SPUC system function, it is constructed at grade and thus is listed as a ground storage tank in the comprehensive water plan.
12. ***P. 14, last paragraph- Seems that 125.5 gallons per capita is an extremely high assumption that would lead too much of an overbuild of the system.***
This figure, referenced in table 7 of the water supply plan is a system-wide per capita projection, so this figure accounts for <u>all water use</u> including, commercial, industrial and residential. This per capita figure is consistent with the historical total SPUC water system per capita water use (See table 2 of the water supply plan). With regards to only residential per capita water use, in recent years this figure has been in the range of 62-84 gallons per person per day, which is well within a normal range for residential users. This figure can vary depending on weather conditions which have a large effect on water use trends. A detailed summary of water use projection assumptions is included in the comprehensive water plan. The assumptions are for similar usage patterns to continue forward through ultimate development.
13. ***Table 10 – There are many boxes that are checked where the city is not aware of the indicated coordination as follows:***
    a. ***Lake-the "other' mitigation measure box is checked and "monitored' regular check –in box***
    b. ***Wetland – same comments for the boxes checked under Lake***
    c. ***Trout Stream-same comments for the boxes checked under Lake***
    SPUC Staff will provide examples of the coordination with others.
14. ***Table 11 – While the WHP was adopted as indicated on 11/2011, it is apparent from discussions with city staff that there is a lack of adequate coordination with the city pertaining to the well head protection implementations initiative, issues, etc., most notably when it comes to development and surface water coordination.***
SPUC Staff did work with City Staff with the implementation of the WHPP beginning in the early 2000's, most notably with Bruce Loney and Michael Leek. Staff agrees there has been little coordination with the current City Staff. SPUC will be filing an amendment to the WHPP per statutory mandate in 2020. MDH Staff will be setting up a mandated scoping meeting #1 in the near future (per MDH letter dated March 20, 2019) and it is at that time SPUC is required to submit it's 2 ½ year evaluation of the current WHPP.
15. ***Table 12 – A 2020 CIP of Water Treatment Facilities does not reflect the current CIP.***
This Water Supply Plan was written in the summer of 2017 and submitted in October of 2017, prior to the DNR mandated submission deadline of October 15, 2017. Thus the CIP included in the Water Supply Plan will not reflect the current 5 year Commission accepted CIP. The DNR did not approve the Water Supply Plan until February 19, 2018.

16. ***Please provide the city a copy of SPUC's Emergency Response Plan dated May 2017***
A copy of the Plan will be provided to the City of Shakopee.

17. ***Table 21 – the New Water Conservation Ordinances action taken box is checked "no". It seems as an initiative that dates back to the 2006 plan commitment that this should be already be completed. Verify status.***
Shakopee Public Utilities does not have the authorization to set ordinances. If this is something the City of Shakopee would like to pursue, Staff can be available to coordinate with the City.

18. ***Table 23 – Per the table, there are only 300 automated meters. An AMI project is included in the CIP to automate meter reading over the next few years. Please confirm that this is expected to replace all mechanical meters. The coordination of this is important to better monitor the city's discharge into the sanitary sewer also (e.g. recent event where a warter service/line broke, with 280k gallons flowing into the city's sanitary sewer system.***
The information regarding the current number of automated meters in the system is accurate. These meters were installed as part of a pilot project to gather information in regards to efficiencies, cost savings, reliabilty of the technology, etc. SPUC is moving forward with the AMR/AMI project in 2019 with securing a consultant to assist in developing information with the latest technologies and eventual RFPs. The Project has been listed on the Commissioner's Goals and Objectyives for 2019. The project is currently on a 3 year timeline.

19. **Table 26 – Install AMI timeline indicates "when possible"/Suggest to update to match timeline in CIP.**
Answered above. Once again, the Water Supply Plan was submitted in October of 2017. All pertinent information will be updated.

20. ***Table 31 – Not aware of SPUC's participation in any Rain Barrel initiative with the watersheds.***
At the time of the report, rain barrels as an initiative was in our planning but funding could not be secured from Met Council. SPU participated in the Clean Water Fund Water Efficiency Grant program with Met Council in 2016 and 2017. Met Council lost funding and the program stopped.

21. ***Table 31 – Seemingly very little educational inclusion methodologies are being used.***
SPUC Staff believes the inclusion methodologies are important and adequate. Staff has received no feedback from the DNR and the Met Council that the methodologies are insufficient to satisfy the Water Supply Plan.

9b

SHAKOPEE PUBLIC UTILITIES

"Lighting the Way – Yesterday, Today and Beyond"

April 11, 2019

TO: John Crooks, Utilities Manager

FROM: Greg Drent, Electric Superintendent

Subject: APPA Colorado Springs, Colorado Rodeo 2019

SPU had a great showing at the APPA Line Workers Rodeo in Colorado Springs, Colorado. I cannot thank the commission enough for sending us to the rodeo to represent SPU. This event brings the lineman closer together to represent SPU in the best way possible.

We are blessed to have a group of linemen so dedicated and passionate about their work here at SPU. The two journeyman teams were Mike Enright, Jamie VonBank, Justin Rotert and Brad Carlson, Matt Griebel, Greg Drent. The journeyman events were pole transfer with sticks, underground event, hurt man rescue, arrestor change out, and insulator change out. The three apprentices were Tyler Hanson, Matt Kahle and Jordan Schuettpelz. The apprentice events were fuse change out, hurt man rescue, secondary service hookup, written test and load transfer.

On Friday morning, the competitors and judges checked in at 9:00 am along with a vendor trade show to look at new products. After the check-in, the Rodeo grounds were visited and their equipment was checked out to make sure everything made the trip safe. The judges' meetings started in early afternoon and then the apprentice written test was at 4:00pm.

The day of the competition starts early as we got on the bus at 6:00 a.m. for the 15-minute bus ride to the rodeo grounds. After the opening ceremony at 7:30 the events started. There were 78 journeyman teams and 130 apprentices competing in the Rodeo. We had a fun day to climb as there was a little snow on the ground and mud on our boots but that is what we are used to. In the journeyman team events, we ran clean and had one team finish 15th overall. The other journeyman team had a couple dedications on one event and ran clean the other events. Their practice and dedication to the rodeo showed through with their great performance.

In the apprentice event, we had a great showing I am happy to report that Tyler Hanson of SPU finished 12th overall followed by Jordan Schuettpelz 19th and Matt Kahle 20th. There scores were 492,488 and 488 out of a possible 500. SPU had the top journeyman and top apprentice in Minnesota and we continue to work hard at the events to represent SPU. All the participants at SPU want to thank the Commission and Mr. Crooks for dedicating time and resources to make the rodeo event very successful.

9c

SHAKOPEE PUBLIC UTILITIES
MEMORANDUM

TO: John Crooks, Utilities Manager JRC

FROM: Joseph D. Adams, Planning & Engineering Director JDAdams

SUBJECT: Distributed Generation Mandate and Interconnection Process Requirements

DATE: April 12, 2019

ISSUE

The Commission is required by state statutes to publish a process and update its rules for co-generators and small power producers intending to connect to the utility's distribution system to be consistent with changes in the applicable state statutes, the Commission's wholesale power supply source and available generation technology.

BACKGROUND

State statute requires municipal utilities to adopt rules for co-generators and small power producers intending to connect to the utility's distribution system if the utility chooses to develop their own rules for this purpose. The rules identify the terms and conditions under which the utility will allow customer owned generation sources to be connected to the distribution system and the rates at which power will purchased.

The Commission last adopted rules for co-generators and small power producers in 1985 by Resolution #291, when its wholesale power provider was NSP. Since then, the Commission's power supplier has changed and is now the Minnesota Municipal Power Agency (MMPA). The change in wholesale power suppliers and the differing terms under which the Commission purchases power from MMPA requires a change in the tariff or rate that applies to customer owned generation sources larger than 40 kW. The Commission's retail rates, which apply in net metering installations (those less than 40 kW) have changed too. Consequently, the rate data in Resolution #291 is incorrect and needs to be brought up to date to be consistent with current practice and state statutes.

The cost of small power production equipment, e.g. solar panels and wind turbines have been reduced to the point of being much more realistic for customers to install. Consequently, staff has processed applications more and more frequently over the past several years from customers wanting to install a generation source and interconnect to the SPU distribution system. Staff has been processing these applications using a combination of our (outdated) rules and current statutory requirements.

Presently there are 38 customers with distributed generation resources interconnected to the SPU electric distribution system, plus the MMPA wind turbine at the SPU Service Center. This is the second most number of interconnections among municipal electric utilities in Minnesota. There is a total of 429.67 kW of DG capacity interconnected to our system, which is the third highest combined DG capacity interconnected to municipal utilities in Minnesota.

DISCUSSION

Project Engineer Christian Fenstermacher has been a member of the joint MMUA/MREA working group tasked with developing a state wide guide for public and customer owned utilities to use when adopting their Distributed Energy Resources Process and Policies to conform to the applicable state statutes and he will provide a short presentation to the Commission at their April 15th meeting.

RECOMMENDATION/REQUESTED ACTIONS

Staff recommends and requests the Commission adopt the following resolutions:

Resn. #1243 A Resolution Adopting Shakopee Public Utilities Commission's Policy Regarding Distributed Generation Resources and Net Metering and Rules Governing the Interconnection of Cogeneration and Small Power Production Facilities

Resn. #1244 A Resolution Adopting the Shakopee Public Utilities Commission Distributed Energy Resource Interconnection Process

Resn. #1245 A Resolution Approving Shakopee Public Utilities Commission's Cogeneration and Small Power Production Tariff

RESOLUTION #1243

A RESOLUTION ADOPTING SHAKOPEE PUBLIC UTILITIES COMMISSION'S POLICY REGARDING DISTRIBUTED ENERGY RESOURCES AND NET METERING AND RULES GOVERNING THE INTERCONNECTION OF COGENERATION AND SMALL POWER PRODUCTION FACILITIES

WHEREAS, the Shakopee Public Utilities Commission is committed to providing its customers with reliable and affordable power within its electric service area as assigned by the State of Minnesota.

WHEREAS, the purpose of this Distributed Energy Resources and Net Metering Policy is to establish the qualification criteria and certain responsibilities for the delivery, interconnection, metering, and purchase of electricity from distributed generation facilities.

WHEREAS, this policy, in accordance with Minnesota Statutes §216B.164, shall be implemented to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the utility's ratepayers and the public.

WHEREAS, the purpose of the Cogeneration and Small Power Production Rules is for Shakopee Public Utilities Commission to implement certain provisions of Minnesota Statutes §216B.164, the Public Utility Regulatory Policies Act of 1978, and Federal Energy Regulatory Commission regulations related to customer-owned distributed energy resources.

WHEREAS, the adoption of these rules establishes that the Shakopee Public Utilities Commission is the interpreting body and arbiter of the provisions of Minnesota Statutes §216B.164 for Shakopee Public Utilities Commission.

WHEREAS, Shakopee Public Utilities Commission shall annually adopt a cogeneration and small power production tariff under these rules.

WHEREAS, the cogeneration and small power production tariff shall include a calculation of average retail utility energy rates, standard contracts to be used with qualifying facilities, interconnection process and technical requirements, and Shakopee Public Utilities Commission 's estimated average incremental energy costs and net annual avoided capacity costs.

WHERAS, all filings under these rules shall be maintained at the Shakopee Public Utilities Commission offices and shall be made available for public inspection during normal business hours.

NOW THEREFORE BE IT RESOLVED BY THE SHAKOPEE PUBLIC UTILITIES COMMISSION, that Resolution #226 and Resolution #291 are repealed upon this Resolution taking effect, and

BE IT FURTHER RESOLVED, that the Shakopee Public Utilities Commission adopts the following Policy Regarding Distributed Energy Resources and Net Metering and Rules Governing the Interconnection of Cogeneration and Small Power Production Facilities.

Adopted in regular session of the Shakopee Public Utilities Commission, this 15th day of April, 2019.

____

Commission President: Terrance Joos

ATTEST:

____

Commission Secretary: John R. Crooks

**Shakopee Public Utilities Commission Policy
Regarding Distributed Energy Resources
and Net Metering**

To establish the application procedure and qualification criteria for all customers for the delivery, interconnection, metering and purchase of electricity from distributed energy resource facilities and to comply with applicable laws and rules governing distributed energy resources.

The utility recognizes its obligation to provide interconnection to eligible qualifying facilities and will comply with all applicable laws and rules governing distributed energy resources.

For purposes of this policy, the following terms have the meanings given them:

A. **Average retail energy rate** - the average of the retail energy rates, exclusive of special rates based on income, age, or energy conservation, according to the applicable rate schedule of the utility for sales to the class of customer of which the customer/qualifying facility belongs.
B. **Avoided costs** - the incremental costs to the utility of electric energy or capacity or both which, but for the purchase from the qualifying facility, the utility would generate itself or purchase from another source.
C. **Contract** - the written agreement between the customer/qualifying facility and the utility, as established in the utility's Rules Governing Interconnection of Cogeneration and Small Power Production.
D. **Distributed energy resource (DER)** - a distributed generation system incorporated with or without an electric storage system.
E. **Interconnection application** - the form to be used by the customer to submit its formal request for interconnection to the utility and which shall be substantially similar in form to that contained in the Distributed Energy Resources Interconnection Process adopted by the utility.
F. **Interconnection rules** - any applicable rules developed in accordance with Minnesota Statutes §§216B.164 and 216B.1611. This includes the utility's Rules Governing Interconnection of Cogeneration and Small Power Production. It also includes the utility's Distributed Energy Resources Interconnection Process which includes its Simplified Process, Fast Track Process, and Study Process as well as the technical requirements incorporated therein or any future technical requirements adopted by the utility.
G. **Measured capacity** - for purposes of determining capacity, it shall be measured based on the highest fifteen (15) minute average demand of the unit in any one billing period.
H. **Net metering/net billing** - the process whereby the customer and the utility compensate each other based on the difference in the amount of energy each sells to the other at the net metered facility.
I. **Net metered facility** - an electric generation facility constructed for the purpose of offsetting energy use through the use of renewable energy or high efficiency generation sources with a capacity of less than 40 kilowatts that has elected in writing to be compensated for excess generation through net metering/net billing.
J. **Total generator nameplate capacity** - the nominal voltage (V), current (A), maximum active power (kWac), apparent power (kVA), and reactive power (kvar) at which a distributed energy resource (DER), is capable of sustained operation. For a qualifying facility with multiple units, the total generator capacity is equal to the sum of all individual DER units' nameplate rating in the qualifying facility. The DER system's total generation capacity may,

with the utility's agreement, be limited thought use of control systems, power relays or similar device settings or adjustments as identified in IEEE 1547. The customer must fully, accurately and completely disclose in its interconnection application to the utility, the technical specifications for any capacity limiting device contemplated and the customer shall furnish the utility with any factory manuals or other similar documents requested from the utility regarding such limiting or other control devices which factor into the calculation of total generator capacity.

K. **Qualifying facility** - a cogeneration or small power production facility which satisfies the conditions established in Code of Federal Regulations, title 18, part 292. The qualifying facility must be owned by a customer of the utility and located in the utility service area.

L. **Utility** – Shakopee Public Utilities Commission.

In the event an inconsistency exists between terms in this policy and those established by applicable statute, rule or court order, then the definition so established shall supersede the definition used in this policy and shall govern.

All customers are eligible for distributed generation, interconnection with the utility's distribution system and application of net metering upon the following terms and conditions.

1. The customer must meet the eligibility requirements set forth in the federal Public Utility Regulatory Policies Act of 1978 (PURPA) *18 C.F.R. 292.303, 292.304 and Minnesota's distributed generation laws. Minn. Stat. §216B.164.
2. The customer shall complete, sign and return to utility either the Interconnection Application or the Simplified Process Application in the form prescribed in the utility's Distributed Energy Resources Interconnection Process. The application shall be approved by the utility prior to the customer beginning the project. The customer signature on the application indicates the customer shall follow the steps outlined in the utility's interconnection rules.
3. The customer shall enter into a written contract with the utility using the uniform contract contained in the utility's Rules Governing Interconnection of Cogeneration and Small Power Production.
4. The qualifying facility shall pay the utility for all reasonable costs of interconnection including those costs outlined in Minnesota Statute 216B.164, the utility's DER Interconnection Process, and the State of Minnesota Interconnection Technical Requirements.
5. The qualifying facility's total generator nameplate capacity shall be less than 40 kW and the facility shall operate at a measured capacity of less than 40 kW at all times to qualify for net metering/net billing or roll over credit compensation.
6. The utility may limit the capacity and operating characteristics of qualifying facility single phase generators in a manner consistent with the utility limitations for single phase motors, when necessary to avoid a qualifying facility from causing problems with the service of other customers.
7. The utility may require the qualifying facility to discontinue parallel generation operations when necessary for system safety.

8. The power output from the qualifying facility must be maintained so that frequency and voltage are compatible with normal utility service and do not cause that service to fall outside the prescribed limits of interconnection rules and other standard limitations.
9. The qualifying facility shall keep in force liability insurance against personal or property damage due to the installation, interconnection, and operation of its electric generating facilities. The amount of insurance coverage shall be the maximum amount of said insurance for a qualifying facility or net metered facility as outlined in the utility's DER Interconnection Process.
10. Failure of the qualifying facility to operate its distributed energy resource at a measured capacity below the 40 kW AC capacity limit established by Minn. Stat. §216B.164, Sub. 3 and as contemplated by this policy, shall result in the following. The utility will notify the customer/qualifying facility of the fact that its generating equipment has failed to operate below the 40 kW AC maximum capacity and will provide the customer/qualifying facility with the date, time and kW reading that substantiate this finding.
11. The utility shall compensate the customer/qualifying facility for all metered electricity produced by said qualifying facility during the thirty (30) day period during which the failure occurred, at the utility's wholesale power supplier's avoided cost rate.
12. The utility shall continue to pay the customer/qualifying facility for subsequent electricity produced and delivered pursuant to the contract, at the utility's wholesale power supplier's avoided cost rate until:
    1. The problem with the generator that caused it to operate at or above the statutory maximum capacity has been remedied; and
    2. The utility has been provided documentation adopted by a Minnesota Professional Engineer that confirms the problem with the generator has been remedied.
13. Any customer account eligible for net metering/net billing is not eligible for any other load management discounts unless agreed to by the utility.
14. Payment for the purchase of the qualifying facility's electricity herein shall be in the form of a credit on the customer's monthly billing invoice or paid by check or electronic payment to the customer within fifteen (15) days of the billing date, whichever is selected and indicated in the contract.
15. The customer must be, and continue to be, current with payment on its electric account with utility.
16. The customer must not enter into any arrangement that violates the utility's exclusive right to provide electric service in its service area under Minnesota Statutes §§216B.37-44.
17. In the event that the distributed generator fails to meet the requirements of this policy for a total distributed generation capacity of less than 40 kW AC, and fails to satisfy the corrective requirements set forth in Section 12 above, then the utility will have the right to (1) cancel the contract with the owner of the qualifying facility, and (2) enter into a new contract with the owner of the qualifying facility that, among other changes, adjusts the qualifying facility's rated capacity and specifies avoided cost pricing for the qualifying facility's output. To the extent that the utility does not have the obligation to make purchases from qualifying facilities of 40 kW or greater due to transfer of the obligation to the utility's wholesale supplier that has been approved by the Federal Energy Regulatory Commission, the new agreement will be between the utility's wholesale supplier and the

qualifying facility. In either case, the utility (and, as applicable, the utility's wholesale supplier) and the owner of the qualifying facility will cooperate in the transition from the form of contract set forth in the utility's Rules Governing Interconnection of Cogeneration and Small Power Production to a new form of contract appropriate to a qualifying facility with a capacity of 40 kW or greater.

18. Fully executed interconnection contracts for distributed energy resources may be canceled in the event the distributed energy resource fails to interconnect to the utility's distribution system within twelve (12) months of signing of the interconnection contract by the qualifying facility and the utility.

Rules

Governing the Interconnection of

Cogeneration and Small Power Production Facilities

with

Shakopee Public Utilities Commission

Part A. DEFINITIONS

Subpart 1. Applicability. For purposes of these rules, the following terms have the meanings given them below.

Subp. 2. Average retail utility energy rate. "Average retail utility energy rate" means, for any class of utility customer, the quotient of the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales. The computation shall use data from the most recent 12- month period available.

Subp. 3. Backup power. "Backup power" means electric energy or capacity supplied by the utility to replace energy ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the facility.

Subp. 4. Capacity. "Capacity" means the capability to produce, transmit, or deliver electric energy, and is measured by the number of megawatts alternating current at the point of common coupling between a qualifying facility and the utility's electric system during a 15-minute interval period.

Subp. 5. Capacity costs. "Capacity costs" means the costs associated with providing the capability to deliver energy. The utility capital costs consist of the costs of facilities from the utility and the utility's wholesale provider used to generate, transmit, and distribute electricity and the fixed operating and maintenance costs of these facilities.

Subp. 6. Customer. "Customer" means the person named on the utility electric bill for the premises.

Subp. 7. Energy. "Energy" means electric energy, measured in kilowatt-hours.

Subp. 8. Energy costs. "Energy costs" means the variable costs associated with the production of electric energy. They consist of fuel costs and variable operating and maintenance expenses.

Subp. 9. Firm power. "Firm power" means energy delivered by the qualifying facility to the utility with at least a 65 percent on-peak capacity factor in the month. The capacity factor is based upon the qualifying facility's maximum metered capacity delivered to the utility during the on-peak hours for the month.

Subp. 10. Governing body. "Governing body" means Shakopee Public Utilities Commission.

Subp. 11. Interconnection costs. "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the utility that are directly related to installing and maintaining the physical facilities necessary to permit interconnected operations with a qualifying facility. Costs are considered interconnection costs only to the extent that they exceed the costs the utility would incur in selling electricity to the qualifying facility as a nongenerating customer.

Subp. 12. Interruptible power. "Interruptible power" means electric energy or capacity supplied by the utility to a qualifying facility subject to interruption under the provisions of the utility's tariff applicable to the retail class of customers to which the qualifying facility would belong irrespective of its ability to generate electricity.

Subp. 13. Maintenance power. "Maintenance power" means electric energy or capacity supplied by a utility during scheduled outages of the qualifying facility.

Subp. 14. On-peak hours. "On-peak hours" means either those hours formally designated by the utility as on-peak for ratemaking purposes or those hours for which its typical loads are at least 85 percent of its average maximum monthly loads.

Subp. 15. Point of distributed energy resource (DER) connection. "Point of DER connection" means the point where the qualifying facility's generation system, including the point of generator output, is connected to the customer's electric system and meets the current definition of IEEE 1547.

Subp. 16. Purchase. "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by the utility.

Subp. 17. Qualifying facility. "Qualifying facility" means a cogeneration or small power production facility which satisfies the conditions established in Code of Federal Regulations, title 18, part 292. The initial operation date or initial installation date of a cogeneration or small power production facility must not prevent the facility from being considered a qualifying facility for the purposes of this chapter if it otherwise satisfies all stated conditions. The qualifying facility must be owned by a Customer and located in the utility service area.

Subp. 18. Sale. "Sale" means the sale of electric energy or capacity or both by the utility to a qualifying facility.

Subp. 19a. Standby charge. "Standby charge" means the charge imposed by the utility upon a qualifying facility for the recovery of costs for the provision of standby services necessary to make electricity service available to the qualifying facility.

Subp. 19b. Standby service. "Standby service" means the service to potentially provide electric energy or capacity supplied by the utility to a qualifying facility greater than 40 kW.

Subp. 20. Supplementary power. "Supplementary power" means electric energy or capacity supplied by the utility which is regularly used by a qualifying facility in addition to that which the facility generates itself.

Subp. 21. System emergency. "System emergency" means a condition on the utility's system which is imminently likely to result in significant disruption of service to customers or to endanger life or property.

Subp. 22. Utility. "Utility" means Shakopee Public Utilities Commission.

Part B. SCOPE AND PURPOSE

The purpose of these rules is to implement certain provisions of MinnesotaStatutes, §216B.164; the Public Utility Regulatory Policies Act of 1978, United States Code, title 16, §824a-3; and the Federal Energy Regulatory Commission regulations, Code of Federal Regulations, title 18, part 292. These rules shall be applied in accordance with their intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public.

Part C. FILING REQUIREMENTS

Annually the utility shall file for review and approval, a cogeneration and small power production tariff with the governing body. The tariff must contain schedules 1 – 4.

SCHEDULE 1.

Schedule 1 shall contain the calculation of the average retail utility energy rates to be updated annually.

SCHEDULE 2.

Schedule 2 shall contain all standard contracts to be used with qualifying facilities, containing applicable terms and conditions.

SCHEDULE 3.

Schedule 3 shall contain the utility's adopted interconnection process, safety standards, technical requirements for distributed energy resource systems, required operating procedures for interconnected operations, and the functions to be performed by any control and protective apparatus.

SCHEDULE 4.

Schedule 4 shall contain the estimated average incremental energy costs by seasonal, peak and off-peak periods for the utility's power supplier from which energy purchases are first avoided. Schedule 4 shall also contain the net annual avoided capacity costs, if any, stated per kilowatt-hour and averaged over the on-peak hours and over all hours for the utility's power supplier from which capacity purchases are first avoided. Both the average incremental energy costs and net annual avoided capacity costs shall be increased by a factor equal to 50 percent of the utility and the utility's power supplier's overall line losses due to distribution, transmission and transformation of electric energy.

Part D. AVAILABILITY OF FILINGS

All filings shall be maintained at the utility's general office and any other offices of the utility where rate tariffs are kept. The filings shall be made available for public inspection during normal business hours. The utility shall supply the current year's distributed generation rates, interconnection procedures and application form on the utility website, if practicable, or at the utility office.

Part E. REPORTING REQUIREMENTS

Annually the utility shall report to the governing body for its review and approval an annual report including information in subparts 1-3. The utility shall still comply with other federal and state reporting of distributed generation to federal and state agencies expressly required by statute.

Subpart 1. Summary of average retail utility energy rate. A summary of the qualifying facilities that are currently served under average retail utility energy rate.

Subp. 2. Other qualifying facilities. A summary of the qualifying facilities that are not currently served under average retail utility energy rate.

Subp. 3. Wheeling. A summary of the wheeling undertaken with respect to qualifying facilities.

Part F. CONDITIONS OF SERVICE

Subpart 1. Requirement to purchase. The utility shall purchase energy and capacity from any qualifying facility which offers to sell energy and capacity to the utility and agrees to the conditions in these rules.

Subp. 2. Written contract. A written contract shall be executed between the qualifying facility and the utility.

Part G. ELECTRICAL CODE COMPLIANCE

Subpart 1. Compliance; standards. The interconnection between the qualifying facility and the utility must comply with the requirements in the most recently published edition of the National Electrical Safety Code issued by the Institute of Electrical and Electronics Engineers. The interconnection is subject to subparts 2 and 3.

Subp. 2. Interconnection. The qualifying facility is responsible for complying with all applicable local, state, and federal codes, including building codes, the NationalElectrical Code (NEC), the National Electrical Safety Code (NESC), and noise and emissions standards. The utility shall require proof that the qualifying facility is in compliance with the NEC before the interconnection is made. The qualifying facility must obtain installation approval from an electrical inspector recognized by the Minnesota State Board of Electricity.

Subp. 3. Generation system. The qualifying facility's generation system and installation must comply with the American National Standards Institute/Institute of Electrical and Electronics Engineers (ANSI/IEEE) standards applicable to the installation.

Part H. RESPONSIBILITY FOR APPARATUS

The qualifying facility, without cost to the utility, must furnish, install, operate, and maintain in good order and repair any apparatus the qualifying facility needs in order to operate in accordance with schedule 3.

Part I. TYPES OF POWER TO BE OFFERED; STANDBY SERVICE

Subpart 1. Service to be offered. The utility shall offer maintenance, interruptible, supplementary, and backup power to the qualifying facility upon request.

Subp. 2. Standby service. The utility shall offer a qualifying facility standby power or service at the utility's applicable standby rate schedule.

Part J. DISCONTINUING SALES DURING EMERGENCY

The utility may discontinue sales to the qualifying facility during a system emergency, if the discontinuance and recommencement of service is not discriminatory.

Part K. RATES FOR UTILITY SALES TO A QUALIFYING FACILITY

Rates for sales to a qualifying facility are governed by the applicable tariff for the class of electric utility customers to which the qualifying facility belongs or would belong were it not a qualifying facility. Such rates are not guaranteed and may change from time to time at the discretion of the utility.

Part L. STANDARD RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Subpart 1. Qualifying facilities with 100-kilowatt capacity or less. For qualifying facilities with capacity of 100 kilowatts or less, standard purchase rates apply. The utility shall make available four types of standard rates, described in parts M, N, O, and P. The qualifying facility with a capacity of 100 kilowatts or less must choose interconnection under one of these rates, and must specify its choice in the written contract required in part V. Any net credit to the qualifying facility must, at its option, be credited to its account with the utility or returned by check or comparable electronic payment service within 15 days of the billing date. The option chosen must be specified in the written contract required in part V. Qualifying facilities remain responsible for any monthly service charges and demand charges specified in the tariff under which they consume electricity from the utility.

Subp. 2. Qualifying facilities over 100-kilowatt capacity. A qualifying facility with more than 100-kilowatt capacity has the option to negotiate a contract with the utility or, if it commits to provide firm power, be compensated under standard rates.

Subp. 3. Grid access charge. A qualifying facility shall be assessed a monthly grid access charge to recover the fixed costs not already paid by the customer through the customer's existing billing arrangement. The additional charge shall be reasonable and appropriate for the class of customer based on the most recent cost of service study defining the grid access charge. The cost of service study for the grid access charge shall be made available for review by the customer of the utility upon request.

Part M. AVERAGE RETAIL UTILITY ENERGY RATE

Subpart 1. Applicability. The average retail utility energy rate is available only to customer-owned qualifying facilities with capacity of less than 40 kilowatts which choose not to offer electric power for sale on either a time-of-day basis, a simultaneous purchase and sale basis or roll-over credit basis.

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

Subp. 3. Additional calculations for billing. When the energy generated by the qualifying facility exceeds that supplied by the utility to the customer at the same site during the same billing period, the utility shall compensate the qualifying facility for the excess energy at the average retail utility energy rate.

Part N. SIMULTANEOUS PURCHASE AND SALE BILLING RATE

Subpart 1. Applicability. The simultaneous purchase and sale rate is available only to qualifying facilities with capacity of less than 40 kilowatts which choose not to offer electric power for sale on average retail utility energy rate basis, time-of-day basis or roll- over credit basis.

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

Subp. 3. Compensation to qualifying facility; energy purchase. The utility shall purchase all energy which is made available to it by the qualifying facility. At the option of the qualifying facility, its entire generation must be deemed to be made available to the utility. Compensation to the qualifying facility must be the energy rate shown on schedule 4.

Subp. 4. Compensation to qualifying facility; capacity purchase. If the qualifying facility provides firm power to the utility, the capacity component must be the utility's net annual avoided capacity cost per kilowatt-hour averaged over all hours shown on schedule 4, divided by the number of hours in the billing period. If the qualifying facility does not provide firm power to the utility, no capacity component may be included in the compensation paid to the qualifying facility.

Part O. TIME-OF-DAY PURCHASE RATES

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

Subp. 2. Method of billing. The qualifying facility must be billed for all energy and capacity it consumes during each billing period according to the utility's applicable retail rate schedule.

Subp. 3. Compensation to qualifying facility; energy purchases. The utility shall purchase all energy which is made available to it by the qualifying facility. Compensation to the qualifying facility must be the energy rate shown on schedule 4.

Subp. 4. Compensation to qualifying facility; capacity purchases. If the qualifying facility provides firm power to the utility, the capacity component must be the capacity cost per kilowatt shown on schedule 4 divided by the number of on-peak hours in the billing period. The capacity component applies only to deliveries during on-peak hours. If the qualifying facility does not provide firm power to the utility, no capacity component may be included in the compensation paid to the qualifying facility.

Part P. ROLL-OVER CREDIT PURCHASE RATES

Subpart 1. Applicability. The roll-over credit rate is available only to qualifying facilities with capacity of less than 40 kilowatts which choose not to offer electric power for sale on average retail utility energy rate basis, time-of-day basis or simultaneous purchase and sale basis.

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

Subp. 3. Additional calculations for billing. When the energy generated by the qualifying facility exceeds that supplied by the utility during a billing period, the utility shall apply the excess kilowatt hours as a credit to the next billing period kilowatt hour usage. Excess kilowatt hours that are not offset in the next billing period shall continue to be rolled over to the next consecutive billing period. Any excess kilowatt hours rolled over that are remaining at the end of each calendar year shall cancel with no additional compensation.

Part Q. CONTRACTS NEGOTIATED BY CUSTOMER

A qualifying facility with capacity greater than 100 kilowatts must negotiate a contract with the utility setting the applicable rates for payments to the customer of avoided capacity and energy costs.

Subpart 1. Amount of capacity payments. The qualifying facility which negotiates a contract under part Q must be entitled to the full avoided capacity costs of the utility. The amount of capacity payments will be determined by the utility and the utility's wholesale power provider.

Subp. 2. Full avoided energy costs. The qualifying facility which negotiates a contract under part Q must be entitled to the full avoided energy costs of the utility. The costs must be adjusted as appropriate to reflect line losses.

Part R. WHEELING

Qualifying facilities with capacity of 30 kilowatts or greater, are interconnected to the utility's distribution system and choose to sell the output of the qualifying facility to any other utility, must pay any appropriate wheeling charges to the utility. Within 15 days of receiving payment from the utility ultimately receiving the qualifying facility's output, the utility shall pay the qualifying facility the payment less the charges it has incurred and its own reasonable wheeling costs.

Part S. NOTIFICATION TO CUSTOMERS

Subpart 1. Contents of written notice. Following each annual review and approval by the utility of the cogeneration rate tariffs the utility shall furnish in the monthly newsletter or similar mailing, written notice to each of its customers that the utility is obligated to interconnect with and purchase electricity from cogenerators and small power producers.

Subp. 2. Availability of information. The utility shall make available to all interested persons upon request, the interconnection process and requirements adopted by the utility, pertinent rate schedules and sample contractual agreements.

Part T. DISPUTE RESOLUTION

In case of a dispute between a utility and a qualifying facility or an impasse in the negotiations between them, either party may request the governing body to determine the issue.

Part U. INTERCONNECTION CONTRACTS

Subpart 1. Interconnection standards. The utility shall provide a customer applying for interconnection with a copy of, or electronic link to, the utility's adopted interconnection process and requirements.

Subp. 2. Existing contracts. Any existing interconnection contract executed between the utility and a qualifying facility with capacity of less than 40 kilowatts remains in force until terminated by mutual agreement of the parties or as otherwise specified in the contract. The governing body has assumed all dispute responsibilities as listed in existing interconnection contracts. Disputes are resolved in accordance with Part T.

Subp. 3. Renewable energy credits; ownership. Generators own all renewable energy credits unless other ownership is expressly provided for by a contract between a generator and the utility.

Part V. UNIFORM CONTRACT

The form for uniform contract that shall be used between the utility and a qualifying facility having less than 40 kilowatts of capacity is as shown in subpart 1.

Subpart 1. Uniform Contract for Cogeneration and Small Power Production Facilities. (See attached contract form.)

UNIFORM CONTRACT FOR COGENERATION AND SMALL POWER PRODUCTION FACILITIES

THIS CONTRACT is entered into ____________________, ___, by ________________ ______________________, a municipal utility under Minnesota law, (hereafter called "Utility") and ____ (hereafter called "QF").

RECITALS

The QF has installed electric generating facilities, consisting of ____________________ ______________________________ (Description of facilities), rated at ____kilowatts AC of electricity, on property located at ____ ____.

The QF is a customer of the Utility located within the assigned electric service territory of the Utility.

The QF is prepared to generate electricity in parallel with the Utility.

The QF's electric generating facilities meet the requirements of the rules adopted by the Utility on Cogeneration and Small Power Production and any technical standards for interconnection the Utility has established that are authorized by those rules.

The Utility is obligated under federal and Minnesota law to interconnect with the QF and to purchase electricity offered for sale by the QF.

A contract between the QF and the Utility is required.

AGREEMENTS

The QF and the Utility agree:

1. The Utility will sell electricity to the QF under the rate schedule in force for the class of customer to which the QF belongs.

2. The Utility will buy electricity from the QF under the current rate schedule filed with the city council or city-appointed governing body of the utility. The QF elects the rate schedule category hereinafter indicated:

____ a. Average retail utility energy rate.

- QF capacity must be less than 40 kW.

____ b. Simultaneous purchase and sale billing rate.

- QF capacity must be less than 40 kW.

____ c. Roll-over credits.

- QF capacity must be less than 40 kW.

____ d. Time-of-day purchase rates.

- QF capacity must be 40 kW or more and less than or equal to 100 kW.

A copy of the presently approved rate schedule is attached to this contract.

3. The rates for sales and purchases of electricity may change over the time this contract is in force, due to actions of the Utility or the State of Minnesota, and the QF and the Utility agree that sales and purchases will be made under the rates in effect each month during the time this contract is in force.

4. The Utility will compute the charges and payments for purchases and sales for each billing period. Any net credit to the QF, other than kilowatt-hour credits under clause 2(c), will be made under one of the following options as chosen by the QF.

____ a. Credit to the QF's account with the Utility.
____ b. Paid by check or electronic payment service to the QF within fifteen (15) days of the billing date.

5. Renewable energy credits associated with generation from the facility are owned by:

____.

6. The QF must operate its electric generating facilities within any rules, regulations, and policies adopted by the Utility not prohibited by the rules governing Cogeneration and Small Power Production on the Utility's system which provide reasonable technical connection and operating specifications for the QF and are consistent with the Minnesota Public Utilities Commission's rules on Cogeneration and Small Power Production, as required under Minnesota Statutes §216B.164, subdivision 9.

7. The QF will not enter into an arrangement whereby electricity from the generating facilities will be sold to an end user in violation of the Utility's exclusive right to provide electric service in its service area under Minnesota Statutes, §216B.37-44.

8. The QF will operate its electric generating facilities so that they conform to the national, state, and local electric and safety codes, and will be responsible for the costs of conformance.

9. The QF is responsible for the actual, reasonable costs of interconnection which are estimated to be $___________. The QF will pay the Utility in this way:

____

____.

10. The QF will give the Utility reasonable access to its property and electric generating facilities if the configuration of those facilities does not permit disconnection or testing from the Utility 's side of the interconnection. If the Utility enters the QF's property, the Utility will remain responsible for its personnel.

11. The Utility may stop providing electricity to the QF during a system emergency. The Utility will not discriminate against the QF when it stops providing electricity or when it resumes providing electricity.

12. The Utility may stop purchasing electricity from the QF when necessary for the Utility to construct, install, maintain, repair, replace, remove, investigate, or inspect any equipment or facilities within its electric system. The Utility may stop purchasing electricity from the QF in the event the generating facilities listed in this contract are documented to be causing power quality, safety or reliability issues to the Utility's electric distribution system.

The Utility will notify the QF before it stops purchasing electricity in this way:

____

____.

13. The QF will keep in force general liability insurance against personal or property damage due to the installation, interconnection, and operation of its electric generating facilities. The amount of insurance coverage will be $ ____________. (The amount must be consistent with the distributed generation tariff adopted by the Utility pursuant to Minnesota Statutes §216B.1611, subdivision 3, clause 2.)

14. The QF and the Utility agree to attempt to resolve all disputes arising hereunder promptly and in a good faith manner.

15. The city council or city-appointed body governing the Utility has authority to consider and determine disputes, if any, that arise under this contract in accordance with procedures in the rules it adopts implementing Minnesota Statute §216B.164, pursuant to §216B.164, subdivision 9.

16. This contract becomes effective as soon as it is signed by the QF and the Utility. This contract will remain in force until either the QF or the Utility gives written notice to the other that the contract is canceled. This contract will be canceled thirty (30) days after notice is given. If the listed electric generating facilities are not interconnected to the Utility's distribution system within twelve months of the contract being signed by the QF and the Utility, the contract terminates. The QF and the Utility may delay termination by mutual agreement.

17. Neither the QF nor the Utility will be considered in default as to any obligation if the QF or the Utility is prevented from fulfilling the obligation due to an act of God, labor disturbance, act of public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, an order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or other cause beyond the QF's or Utility's control. However, the QF or Utility whose performance under this contract is hindered by such an event shall make all reasonable efforts to perform its obligations.

18. This contract can only be amended or modified by mutual agreement in writing signed by the QF and the Utility.

19. The QF must notify the Utility prior to any change in the electric generating facilities' capacity size or generating technology according to the interconnection process adopted by the Utility.

20. Termination of this contract is allowed (i) by the QF at any time without restriction; (ii) by Mutual Agreement between the Utility and the QF; (iii) upon abandonment or removal of electric generating facilities by the QF; (iv) by the Utility if the electric generating facilities are continuously non-operational for any twelve (12) consecutive month period; (v) by the Utility if the QF fails to comply with applicable interconnection design requirements or fails to remedy a violation of the interconnection process; or (vi) by the Utility upon breach of this contract by the QF unless cured with notice of cure received by the Utility prior to termination.

21. In the event this contract is terminated, the Utility shall have the rights to disconnect its facilities or direct the QF to disconnect its generating facilities.

22. This contract shall continue in effect after termination to the extent necessary to allow either the Utility or the QF to fulfill rights or obligations that arose under the contract.

23. Transfer of ownership of the generating facilities shall require the new owners and the Utility to execute a new contract. Upon the execution of a new contract with the new owners this contract shall be terminated.

24. The QF and the Utility shall at all times indemnify, defend, and save each other harmless from any and all damages, losses, claims, including claims and actions relating to injury or death of any person or damage to property, costs and expenses, reasonable attorneys' fees and court costs, arising out of or resulting from the QF's or the Utility's performance of its obligations under this contract, except to the extent that such damages, losses or claims were caused by the negligence or intentional acts of the QF or the Utility.

25. The Utility and the QF will each be responsible for its own acts or omissions and the results thereof to the extent authorized by law and shall not be responsible for the acts or omissions of any others and the results thereof.

26. The QF's and the Utility's liability to each other for failure to perform its obligations under this contract shall be limited to the amount of direct damage actually occurred. In no event, shall the QF or the Utility be liable to each other for any punitive, incidental, indirect, special, or consequential damages of any kind whatsoever, including for loss of business opportunity or profits, regardless of whether such damages were foreseen.

27. The Utility does not give any warranty, expressed or implied, to the adequacy, safety, or other characteristics of the QF's interconnected system.

28. This contract contains all the agreements made between the QF and the Utility. The QF and Utility are not responsible other than those stated in this contract.

THE QF AND THE UTILITY HAVE READ THIS CONTRACT AND AGREE TO BE BOUND BY ITS TERMS. AS EVIDENCE OF THEIR AGREEMENT, THEY HAVE EACH SIGNED THIS CONTRACT BELOW ON THE DATE LISTED BY SIGNER.

QF

By: ______________________________

Printed Name: ______________________

DATE: ___________________________

UTILITY

By: ______________________________

Printed Name: ______________________

DATE: ___________________________

Contract Version: *February 2019*

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RESOLUTION #1244

A RESOLUTION ADOPTING THE SHAKOPEE PUBLIC UTILITIES COMMISSION DISTRIBUTED ENERGY RESOURCE INTERCONNECTION PROCESS

WHEREAS, by order on September 28, 2004, the Minnesota Public Utilities Commission adopted Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities; and

WHEREAS, Minnesota Statutes Section 216B.1611, subdivision 3 required municipal utilities to adopt a generation tariff that addressed the issues included in the commission's order; and

WHEREAS, under Minnesota Statutes Section 216B.25, any order of the commission rescinding, altering, amending, or reopening a prior order shall have the same effect as an original order; and

WHEREAS, by order on August 13, 2018, the Minnesota Public Utilities Commission adopted an updated interconnection process for distributed energy resources replacing the standards adopted in 2004; and

WHEREAS, the Shakopee Public Utilities Commission Distributed Energy Resource Interconnection Process addresses the issues included in the commission's 2018 order; and

WHEREAS, this Distributed Energy Resource Interconnection Process functions in concert with the Shakopee Public Utilities Commission Policy Regarding Distributed Energy Resources and Net Metering as well as its Rules Governing the Interconnection of Cogeneration and Small Power Production;

THEREFORE, BE IT RESOLVED that the Shakopee Public Utilities Commission adopts the Shakopee Public Utilities Commission Distributed Energy Resources Interconnection Process.

Adopted in regular session of the Shakopee Public Utilities Commission, this 15th day of April, 2019.

Commission President: Terrance Joos

ATTEST:

Commission Secretary: John R. Crooks

SHAKOPEE PUBLIC UTILITIES
"Lighting the Way – Yesterday, Today and Beyond"

SHAKOPEE PUBLIC UTILITIES COMMISSION

DISTRIBUTED ENERGY RESOURCE INTERCONNECTION PROCESS

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Detroit Lakes Public Utility's 29.3 KW Select Solar Community Solar Garden Detroit Lakes, MN

INTERCONNECTION PROCESS

Process Overview

ABSTRACT

Interconnection Process for Distributed Energy Resources less than 10 megawatt (MW) interconnected to the Distribution System of a Municipal in the State of Minnesota.

Contents

Foreword

The State of Minnesota currently has interconnection process standards in effect to address the interconnection of distributed energy resources (DER) to the distribution grid. Under Minnesota Statute §216B.1611, cooperatives and municipals shall adopt an interconnection process that addresses the same issues as the interconnection process approved by the Minnesota Public Utilities Commission. The Municipal Minnesota Distributed Energy Resources Interconnection Process (Interconnection Process or M-MIP) applies to any DER no larger than 10-megawatt (MW) AC interconnecting to and operating in parallel with Shakopee Public Utilities Commission's distribution system in Minnesota. This interconnection process document is designed to be customer-centric when explaining the steps and details to interconnect DER systems to the distribution grid.

The interconnection process document is broken into five parts: Process Overview, Simplified Process, Fast Track Process, Study Process and Interconnection Agreement. For the majority of DER interconnection, only the Process Overview and the Simplified Process parts will apply. For larger and more complex DER interconnections, the Fast Track Process and the Study Process may apply.

In addition to the interconnection process documents, interconnection agreement(s) are to be executed prior to the DER system being interconnected to the distribution grid. For most DER interconnection, the Shakopee Public Utilities Commission Contract for Cogeneration and Small Power Production Facilities (Uniform Contract) will be used. For DER systems that do not fall under the terms of the Uniform Contract, the M-MIP Interconnection Agreement will apply.

The process to interconnect a DER system to the distribution grid starts with the submission of an Interconnection Application. Each track has different information that is requested in the application and the non-refundable interconnection application fees will vary. Both the electric utility and the interconnecting customer have timelines that are enforced to ensure a timely application review, contract execution and interconnection commissioning.

The key to a successful interconnection of a DER system is communication between all parties. Timely submission of the Interconnection Application prior to the purchase and installation of a DER system is strongly recommended. The Utility encourages customers to ask questions throughout the interconnection process. Interconnecting DER system to the distribution grid is not an effortless process, but it does not need to be a problematic process either.

1 Key Terminology

1.1. Distributed Energy Resource

Distributed Energy Resources, DER, was often referred to in past interconnection processes as Distributed Generation, DG, and on occasion also interchanged with the term Qualifying Facility, QF. This Interconnection Process uses the term DER to address all types of generation and energy resources that can be interconnected to the electric distribution system. DER technologies can include photovoltaic solar systems, wind turbines, storage batteries or diesel generators and are not limited to renewable types of technologies.

1.2. Point of Coupling/Connection

DER systems often reside behind the utility's revenue meter of a residence or business. The meter is normally the point of demarcation between the utility-owned equipment and the customer-owned equipment. The term Point of Common Coupling, PCC, is the demarcation location between the utility and the customer.

The Point of DER Connection, PoC, can be different from the PCC. The PoC is the location where a DER system(s) would interconnect to the electrical system normally owned by the customer. For example, the PoC for a rooftop photovoltaic solar system may the main electrical panel in a customer's home.

1.3. Capacity

Throughout the Interconnection Process will be references to capacity of the DER system. In most cases, the capacity listed is referring to the Nameplate Capacity of the DER system. All capacity reference will be in alternating current, AC.

There can be multiple DER systems with different PoCs that all have the same PCC submitted on a single interconnection application. The capacity for this type of interconnection would be the aggregate Nameplate Capacity of all DER systems at the individual PoCs. Additional examples of DER system arrangements can be seen in Section 13 under the definition of Point of Common Coupling.

2 Roles

2.1. Overview

During the interconnection process for a proposed DER system, there are multiple entities involved in the application, approval and commissioning processes. The main entities that are involved during the Interconnection Process for a proposed DER system are the Interconnection Customer, the Application Agent and the DER

Interconnection Coordinator. Official definitions of each entity are defined in the Glossary (Section 13). Additional details are explained in the subsections below.

2.2. DER Interconnection Coordinator

The utility is referred to as the Area Electric Power Supply Operator in this Interconnection Process. The Area EPS Operator shall designate a DER Interconnection Coordinator(s) to serve as a single point of contact from which general information on the application process may be obtained. The DER Interconnection Coordinator shall be available to provide coordination assistance with the Interconnection Customer but is not responsible to directly answer or resolve all of the issues involved in review and implementation of the interconnection process and standards.

The contact information of the DER Interconnection Coordinator will be posted on the Area EPS Operator's website when feasible.

2.3. Interconnection Customer

The owner of the proposed DER system and the entity requesting interconnection to the distribution system.

2.4. Application Agent

The Interconnection Customer may designate, on the Interconnection Application or in writing after the application has been submitted, an Application Agent to serve as a single point of contact to coordinate with the DER Interconnection Coordinator on their behalf. Designation of an Application Agent does not absolve the Interconnection Customer from signing application documents and the responsibilities outlined in the Interconnection Process or in interconnection agreements. DER vendors, project managers or electricians are common entities that the Interconnection Customer may designate to perform this role.

2.5. Engineering Roles

Either party may designate a specific person to be a single point of contact to provide technical expertise during the Interconnection Process for their organization. The person to supply engineering expertise may be a third party such as an engineering consultant or manufacturer's engineer.

3 Processes

3.1. Overview

The Interconnection Process applies to any DER no larger than 10 MW AC interconnecting to and operating in parallel with an Area EPS distribution system in

Minnesota. Interested parties with plans to interconnect DER systems larger than 10 MW AC to the distribution system should contact the Area EPS Operator for the specific interconnection process. Federal Energy Regulatory Commission's (FERC) interconnection process will supersede any interconnection process the Area EPS Operator has for DER system interconnections that fall under the jurisdiction of FERC.

The Interconnection Process for DER is broken into three different tracks; the Simplified Process, the Fast Track Process, and the Study Process. The general classification of each track is summarized in Table 3.1 below.

Table 3.1. Interconnection Process Tracks

Track	DER Technology	Size Limitations
Simplified Process	Certified Inverter only	20 kW AC
Fast Track Process	All types	5 MW AC
Study Process	All types	10 MW AC

If engineering screens are failed during the application process, a proposed DER interconnection may be moved into a different track. When a proposed DER interconnection is moved into a different track, additional information may be requested and additional fees may apply.

3.2. Importance of Process Timelines

It is very important to pay attention to timelines listed for each process track. The timelines exist for an orderly and efficient process to interconnect DER systems to the Distribution System. If a timeline is missed by an Interconnection Customer, without the Interconnection Customer requesting a Timeline Extension explained in Section 10, the Interconnection Application will be deem withdrawn by the Area EPS Operator.

The Area EPS Operator also need to abided to the timelines listed for each process track. The process for an Area EPS Operator to request Timeline Extensions is also addressed in Section 10.

Unless otherwise state, all time frames are measured in Business Days. For purpose of measuring these time intervals, the time shall be computed so as to exclude the first and include the last day of the prescribed duration of time. Any communication sent or received after 4:30 p.m. Central Prevailing Time or on a Saturday, Sunday or Holiday shall be considered to be sent on the next Business Day.

3.3. Simplified Process

An application to interconnect a certified[1], inverter-based DER system no larger than 20 kilowatts (kW) shall be evaluated under the Simplified Process. A common form of DER inverter certification is UL 1741. Proposed DER systems that require Area EPS system modifications to accommodate the interconnection do not qualify for the Simplified Process. A transformer change, fusing upgrades or line extensions are common examples of Area EPS system modification. Simplified Process eligibility does not imply or indicate the Interconnection Application will pass the initial review screens. Failure to pass the screens will route the Interconnection Application to the Fast Track Process.

3.4. Fast Track Process

An application to interconnect a DER shall be evaluated under the Fast Track Process if the eligibility requirements are not exceeded in Table 3.2 and the application does not qualify for the Simplified Process. Fast Track eligibility for DERs is determined based upon the generator type, the size of the generator, voltage of the line, and the location of and the type of line at the Point of Common Coupling, (PCC). All synchronous and induction machines must be no larger than 2 MW to be eligible for Fast Track Process consideration.

Table 3.2. Fast Track Eligibility for DER

Line Voltage	Fast Track Eligibility[2] Regardless of Location	Fast Track Eligibility for certified, inverter-based DER on a Mainline[3] and ≤ 2.5 Electrical Circuit Miles from Substation[4]
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 30 kV	≤ 2 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

In addition to the size threshold, the Interconnection Customer's proposed DER must meet the codes, standards and certification requirements found in Section 15 and Section 14.

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[1] Additional information regarding certified equipment is found in Section 15 and Section 14.

[2] Synchronous and induction machine eligibility is limited to no more than 2 MW even when line voltage is greater than 15 kV.

[3] For purposes of this table, a Mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 266 kcmil, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[4] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report described in Section 5.

3.5. Study Process

An application to interconnect a DER that does not meet the Simplified Process or Fast Track Process eligibility requirements or does not pass the review as described in either process, shall be evaluated under the Study Process.

3.6. Process Assistance

Prior to submitting an Interconnection Application, the Interconnection Customer may ask the Area EPS Operator's DER Interconnection Coordinator which process track a proposed interconnection is subject to and additional details on each process track.

An Interconnection Customer can obtain, through an informal request, general information about the interconnection process and on Affected System(s) for a proposed interconnection at a specific location. Upon request, the existing electric system information provided to the Interconnection Customer should include relevant system study results, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Area EPS Operator's System. Information will be provided to the extent such provision does not violate the privacy policies of the Area EPS Operator, confidentiality provisions of prior agreements or critical infrastructure requirements. The Area EPS Operator shall comply with reasonable requests for such information.

4 Interconnection Application

4.1. Overview

Each process track has different information that needs to be provided to the Area EPS Operator. Table 4.1 indicates which application is to be completed in its entirety and submitted to the Area EPS Operator to start the interconnection process for the proposed DER system.

Table 4.1. Interconnection Application

Process Track	Application
Simplified	Simplified Interconnection Application
Fast Track	Standard Interconnection Application
Study	Standard Interconnection Application

The Area EPS Operator will provide all necessary Interconnection Applications, Interconnection Process documents and sample interconnection agreements on its website if possible. The Area EPS Operator will also accept Interconnection Applications submitted electronically either through a web portal or to an email address specified by the Area EPS Operator. The Area EPS Operator may allow the Interconnection Application to be submitted with an electronic signature.

4.2. Availability of Information

The Area EPS Operator will provide all necessary Interconnection Applications, Interconnection Process documents and sample interconnection agreements on its website if possible. If a website is not available, the applicable documents will be readily available at the Area EPS Operator's main office.

The Area EPS Operator will establish a public queue of active interconnection applications on its website once the Area EPS Operator has received at least 40 completed Interconnection Applications in a year. The public queue will be updated, at minimum, on a monthly basis.

4.3. Interconnection Application Process Fees

Each Interconnection Application submitted to the Area EPS Operator must include the appropriate interconnection application process fee prior to the Area EPS Operator reviewing the Interconnection Application. The required process fee for each process track is listed in Table 4.2.

Table 4.2. Interconnection Application Process Fee

Process Track		Process Fee
Simplified		\$100
Fast Track	Certified[5] System	\$100 + \$1/kW
	Non-Certified System	\$100 + \$2/kW
Study		\$1,000 + \$2/kW down payment. Additional study fees may apply.

4.4. Application Review Timelines

The Interconnection Application shall be date- and time-stamped upon initial, and if necessary, resubmission receipt. The Area EPS Operator shall notify the Interconnection Customer if the Interconnection Application is deemed incomplete within ten (10) Business Days. This notification shall include a written list detailing all information that must be provided to complete the Interconnection Application. Depending on the process track the Interconnection Customer has between five (5) and ten (10) Business Days to provide the missing information unless additional time is

[5] Additional information regarding certified equipment is found in Section 15 and Section 14.

requested with valid reasons. Failure to submit the requested information within the stated timeline will result in the Interconnection Application being withdrawn.

An Interconnection Application will be deemed complete upon submission to the Area EPS Operator when all documents, fees and information required with the Interconnection Application adhering to Minnesota Technical Requirements is included. The time- and date- stamp of the completed Interconnection Application shall be accepted as the qualifying date for purposes of establishing a queue position as described in Section 4.7.

Depending on the process track the Area EPS Operator has either a total of twenty (20) Business Days or twenty-five (25) Business Days to complete the Interconnection Application review and submit notice back to the Interconnection Customer stating the proposed DER system may proceed with the interconnection process or the proposed DER system requires additional engineering studies. The period of time when waiting for the Interconnection Customer to provide missing information is not included in the Area EPS Operator's twenty (20) Business Days or twenty-five (25) Business Days review timeline.

4.5. Comparability

The Area EPS Operator shall receive, process and analyze all Interconnection Applications in a timely manner. The Area EPS Operator shall use the same Reasonable Efforts in processing and analyzing Interconnection Applications from all Interconnection Customers.

4.6. Changing Process Queues

During the review of the initially submitted Interconnection Application for the proposed DER system, the Area EPS Operator may determine the proposed DER system should be in a different process track. For proposed DER systems that are moved into a different process track after submittal of the initial application, the difference between the originally submitted processing fee and the current process track's processing fee will be assessed. In addition, the Area EPS Operator may request the Interconnection Customer to provide additional information regarding the proposed DER system.

4.7. Queue Position

The Area EPS Operator shall maintain a single, administrative queue and may manage the queue by geographical region. The queue position of each completed Interconnection Application is used to determine the engineering review. The queue position is also used to determine the cost responsibility for system upgrades necessary to accommodate the interconnection.

An Interconnection Application will retain its queue number even when it is moved into a different process track. An Interconnection Application can lose its queue position if the Interconnection Customer misses timelines in the applicable process track. The Interconnection Customer and Area EPS Operator have the opportunity to request timeline extensions which are explained in detail in Section 10.

4.8. Site Control

Documentation of site control must be submitted with the Interconnection Application. Site control may be demonstrated by any of the following:

- Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the DER system.

- An option to purchase or acquire a leasehold site for constructing the DER system.

- An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for constructing the DER system.

For DER in the Simplified Process, proof of site control may be demonstrated by the site owner's signature on the Simplified Interconnection Application.

5 Pre-Application Report

5.1. Pre-Application Report Requests

The Interconnection Customer may submit a Pre-Application Report Request, including a non-refundable fee of $300, for a Pre-Application Report on a proposed project at a specific site. The Interconnection Customer must fill out the Pre-Application Request form as completely as possible. The Area EPS Operator shall provide the readily available data listed in Section 5.3 within fifteen (15) Business Days of receipt of a completed request form and payment. The Pre-Application Report produced by the Area EPS Operator is non-binding, does not confer any rights, and does not preclude the Interconnection Customer from any interconnection process steps including submission of the Interconnection Application.

5.2. Information Provided

Using the information provided in the Pre-Application Report Request form, the Area EPS Operator will identify the substation/area bus, bank or circuit likely to serve the proposed PCC. This selection by the Area EPS Operator does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional Pre-Application Reports if information about multiple PCC is requested.

The Pre-Application Report will only include existing data. A request for a Pre-Application Report does not obligate the Area EPS Operator to conduct a study or other analysis of the proposed DER in the event that data is not readily available. The Area EPS Operator will provide the Interconnection Customer with the data that is available. The confidentiality provisions in Section 12.1 **Error! Reference source not found.**apply to Pre-Application Reports.

5.3. Pre-Application Report Components

The Pre-Application Report shall include following pieces of information provided the data currently exists and is readily available.

- Total capacity (in megawatts (MW)) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Common Coupling.

- Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Common Coupling.

- Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Common Coupling.

- Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Common Coupling (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

- Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

- Nominal distribution circuit voltage at the proposed Point of Common Coupling.

- Approximate circuit distance between the proposed Point of Common Coupling and the substation.

- Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load and absolute minimum load, when available.

- Whether the Point of Common Coupling is located behind a line voltage regulator.
- Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.

- Number of phases available on the Area EPS medium voltage system at the proposed Point of Common Coupling. If a single phase, distance from the three-phase circuit.

- Limiting conductor ratings from the proposed Point of Common Coupling to the distribution substation.

- Whether the Point of Common Coupling is located on a spot network, grid network, or radial supply.

- Based on the proposed Point of Common Coupling, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks

6 Capacity of the Distributed Energy Resources

6.1. Existing DER System Expansion

If the Interconnection Application is for an increase in capacity to an existing DER system, the Interconnection Application shall be evaluated on the basis on the total new alternating current (AC) capacity of the DER. The maximum capacity for the DER shall be the aggregate maximum Nameplate Rating unless the conditions in Section 6.3 are met.

6.2. New DER Systems

An Interconnection Application for a DER that includes a single or multiple energy production devices, (i.e. solar and storage), at a site for which the Interconnection Customer seeks a simple Point of Coupling, shall be evaluated on the basis of the aggregated maximum Nameplate Rating unless the conditions in Section 6.3 are met.

6.3. Limited Capacity

A DER system may include devices, (i.e. control systems, power relays or other similar device settings), that can limit the maximum capacity at which the DER system can generate into the Area EPS Operator's distribution system. For DER system that include capacity limited devices, the Interconnection Customer must obtain the Area EPS

Operator's agreement to consider the DER system with the Nameplate Rating as the limited capacity. The Area EPS Operator's agreement shall not be unreasonable withheld provided proper documentation is provided showing the effective limit active power output will not adversely affect the safety and reliability of the Area EPS Operator's distribution system. If the Area EPS Operator does not agree, the Interconnection Application must be withdrawn or revised to specify the maximum capacity that the DER system is capable of injecting into the Area EPS Operator's distribution system without such limitations. Nothing in this section shall prevent the Area EPS Operator from considering a higher output, (i.e. aggregate Nameplate Rating), if the limitations do not provide adequate assurance, when evaluating the system impacts.

7 Modification to Interconnection Applications

7.1. Procedures

At any time after the Interconnection Application is deemed complete, the Interconnection Customer or the Area EPS Operator may identify modifications to the proposed DER system that may improve costs and benefits (including reliability) of the proposed DER system and the ability for the Area EPS Operator to accommodate the proposed DER system. The Interconnection Customer shall submit to the Area EPS Operator in writing all proposed modifications to any information provided in the Interconnection Application. The Area EPS Operator cannot unilaterally modify the Interconnection Application.

Additional information regarding modifications to interconnection applications is found in each process track document.

8 Interconnection Agreements

8.1. Timelines

After the Interconnection Application has been approved by the Area EPS Operator, the Area EPS Operator shall provide the Interconnection Customer with an executable Interconnection Agreement within five (5) Business Days. The Interconnection Customer shall have thirty (30) Business Days to sign and return the Interconnection Agreement to the Area EPS Operator. The Area EPS Operator shall sign the Interconnection Agreement within five (5) business days after receiving the signed Interconnection Agreement from the Interconnection Customer.

If the Interconnection Customer fails to return a signed Interconnection Agreement to the Area EPS Operator within thirty (30) Business Days and fails to request an extension as explained in Section 10, the Interconnection Application will be deemed withdrawn.

8.2. Types of Agreements

There are two main types of Interconnection Agreements that may be executed with an approved Interconnection Application. In general, Interconnection Customers with a proposed DER system that qualifies for the Simplified Process track will sign the Area EPS Operator's Uniform Contract for Cogeneration and Small Power Production Facilities (Uniform Contract). Proposed DER systems less than 100 kW that are under the Fast Track process may also sign the Uniform Contract. All other sized DER system will sign the Interconnection Agreement. Area EPS Operators who do not purchase the excess generation of the proposed DER system will also require the Interconnection Agreement executed for any size of DER system.

Table 8.1. Interconnection Agreements

Process Track		Interconnection Agreement
Simplified		Uniform Contract
Fast Track	Qualifies for Net Energy Billing	Uniform Contract
	Less than 100 kW & Area EPS Agrees to Purchase Excess Generation	Uniform Contract
	All Other DER systems	Interconnection Agreement
Study		Interconnection Agreement

Interconnection Customers may choose to sign the Interconnection Agreement in lieu of the Uniform Contact. A separate power purchase agreement will also need to be executed if the Uniform Contract is not utilized. Interconnection of the proposed DER system will not occur until a signed Uniform Contract or the Interconnection Agreement is returned to the Area EPS Operator no later than five (5) days prior to schedule testing and inspection.

9 Interconnection

9.1. Metering

Any metering requirements necessitated by the use of the DER system shall be installed at the Interconnection Customer's expense. The metering requirement costs will be included in the final invoice of interconnection costs to the Interconnection Customer. The Interconnection Customer is also responsible for metering replacement costs not covered in the Interconnection Customer's general customer charge. The Area EPS Operator may charge Interconnection Customers an ongoing metering-related charge for an estimate of ongoing metering-related costs specifically demonstrated.

9.2. Inspection, Testing and Commissioning

The Interconnection Customer shall arrange for the inspection and testing of the DER system and the Customer's Interconnection Facilities prior to interconnection pursuant to Minnesota Interconnection Technical Requirements. Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards of Minnesota's Technical Requirements and Section 15.

The Interconnection Customer shall notify the Area EPS Operator of testing and inspection no fewer than five (5) Business Days in advance, or as may be agreed to by the Parties. Depending on the process track, either a Certificate of Completion or a testing procedure shall be submitted to the Area EPS Operator prior to the testing and inspection date. The Area EPS Operator shall send qualified personnel to the DER site to inspect the interconnection and witness the testing. Testing and inspection shall occur on a Business Day at a mutually agreed upon time and date. The Area EPS Operator may waive the right to witness the testing.

9.3. Interconnection Costs

The Interconnection Customer shall pay for the actual cost of the Interconnection Facilities and Distribution Upgrades along with the Area EPS Operator's cost to commission the proposed DER system. An estimate of the interconnection costs shall be stated in the Uniform Contract or Interconnection Agreement.

9.4. Non-Warrantee

Area EPS Operator does not give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, operated, installed or maintained by the Interconnection Customer, including without limitation the DER and any structures, equipment, wires, appliances or devices not owned, operated or maintained by the Area EPS Operator. The Area EPS Operator does not guarantee uninterrupted power supply to the DER and will operate the distribution system with the same reliability standards for the entire customer base.

9.5. Technical Requirements

The Area EPS Operator shall use Reasonable Efforts to provide the Interconnection Customer the Minnesota Technical Requirements by providing the document with the notice of approval of the interconnection application or by providing a website link to the document. Additionally, the Area EPS Operator shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. Unless notified by the Area EPS Operator, the Interconnection Customer only needs to be in compliance of the current version of the Minnesota Technical Requirements at the time of interconnection.

9.6. Authorization for Parallel Operations

The Interconnection Customer shall not operate its DER system in parallel with the Area EPS Operator's distribution system without prior written authorization from the Area EPS Operator. The Area EPS Operator shall provide such authorization within three (3) Business Days from when the Area EPS Operator receives notification that the Interconnection Customer has complied with all applicable parallel operations requirements; the completion of a successful testing and inspection of the DER system and all payments for issued bills related to the interconnection process that are past due have been paid in full. Such authorization shall not be unreasonably withheld, conditioned or delayed.

10 Extension of Timelines

10.1. Reasonable Efforts

The Area EPS Operator shall make Reasonable Efforts to meet all time frames provided in these procedures. If the Area EPS Operator cannot meet a deadline provided herein, it must notify the Interconnection Customer in writing within three (3) Business Days after the deadline to explain the reason for the failure to meet the deadline and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

10.2. Extensions

For applicable time frames described in these procedures, the Interconnection Customer may request, in writing, one extension equivalent to half of the time originally allotted (e.g., ten (10) Business Days for a twenty (20) Business Days original time frame) which the Area EPS Operator may not unreasonably refuse. No further extensions for the applicable time frame shall be granted absent a Force Majeure Event or other similarly extraordinary circumstance.

11 Disputes

11.1. Procedures

The Parties agree in a good faith effort to attempt to resolve all disputes arising out of the interconnection process and associated study and Interconnection Agreements. The Parties agree to follow the established dispute resolution policy adopted by the Area EPS Operator.

12 Clauses

12.1. Confidentiality

Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures, design, operating specifications, and metering data provided by the Interconnection Customer may be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such. If requested by either Party, the other Party shall provide in writing the basis for asserting that the information warrants confidential treatment. Parties providing a Governmental Authority trade secret, privileged or otherwise not public or nonpublic data under Minnesota Government Data Practices Act, Minnesota Statute Chapter 13, shall identify such data consistent with the Commission's September 1, 1999 Revised Procedures for Handling Trade Secret and Privileged Data available online at: https://mn.gov/puc/puc-documents/#4.

Confidential Information does not include information previously in the public domain with proper authorization, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be publicly divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements that could not otherwise be fulfilled by not making the information public.

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

Critical infrastructure information or information that is deemed or otherwise designated by a Party as Critical Energy/Electric Infrastructure Information (CEII) pursuant to FERC regulation, 18 C.F.R. §388.133, as may be amended from time to time, may be subject to further protections for disclosure as required by FERC or FERC regulations or orders and the disclosing Party's CEII policies. Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

Confidential Information does not include information previously in the public domain with proper authorization, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be publicly divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements that could not otherwise be fulfilled by not making the information public.

Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages and may seek other remedies available at law or in equity for breach of this provision.

12.2. Non-Warranty

The Area EPS Operator does not give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, operated, installed or maintained by the Interconnection Customer, including without limitation the DER and any structures, equipment, wires, appliances or devices not owned, operated or maintained by the Area EPS Operator.

12.3. Indemnification

Each Party is protected from liability incurred to third parties as a result of carrying out the provisions of this interconnection process and subsequent interconnection agreements. The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

This indemnification obligation shall apply notwithstanding any negligent or intentional acts, errors or omissions of the indemnified Party, but the indemnifying Party's liability to indemnify the indemnified Party shall be reduced in proportion to the percentage by which the indemnified Party's negligent or intentional acts, errors or omissions caused the damages.

Neither Party shall be indemnified for its damages resulting from its sole negligence, intentional acts or willful misconduct. These indemnity provisions shall not be construed to relieve any insurer of its obligation to pay claims consistent with the provisions of a valid insurance policy.

If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

12.4. Limitation of Liability

Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for an indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under in Section 12.3.

13 Glossary

Affected System – Another Area EPS Operator's System, Transmission Owner's Transmission System, or Transmission System connected generation which may be affected by the proposed interconnection.

Applicant Agent – A person designated in writing by the Interconnection Customer to represent or provide information to the Area EPS on the Interconnection Customer's behalf throughout the interconnection process.

Area EPS – The electric power distribution system connected at the Point of Common Coupling.

Area EPS Operator – An entity that owns, controls, or operates the electric power distribution systems that are used for the provision of electric service in Minnesota. For this Interconnection Process the Area EPS Operator is Shakopee Public Utilities Commission.

Business Day – Monday through Friday, excluding Holidays as defined by Minn. Stat. §645.44, Subdivision 5. Any communication to have been sent or received after 4:30 p.m. Central Prevailing Time or on a Saturday, Sunday or holiday shall be considered to have been sent on the next Business Day.

Certified Equipment – Certified equipment is equipment that has been tested by a national recognized lab meeting a specific standard. For DER systems, UL 1741 listing is a common form of DER inverter certification. Additional information is seen in Section 15 and Section 14.

Confidential Information – Any confidential and/or proprietary information provided by one Party to the other Party and is clearly marked or otherwise designated "Confidential." All procedures, design, operating specifications, and metering data provided by the Interconnection Customer may be deemed Confidential Information. See Section 12.1 for further information.

Distributed Energy Resource (DER) – A source of electric power that is not directly connected to a bulk power system or central station service. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER. For the purpose of the Interconnection Process and interconnection agreements, the DER includes the Customer's Interconnection Facilities but shall not include the Area EPS Operator's Interconnection Facilities.

Distribution System – The Area EPS facilities which are not part of the Local EPS, Transmission System or any generation system.

Distribution Upgrades – The additions, modifications, and upgrades to the Distribution System at or beyond the Point of Common Coupling to facilitate interconnection of the DER and render the distribution service necessary to effect the Interconnection Customer's connection to the Distribution System. Distribution Upgrades do not include Interconnection Facilities.

Electric Power System (EPS) – The facilities that deliver electric power to a load.

Fast Track Process – The procedure as described in the Interconnection Process - Fast Track Process for evaluating an Interconnection Application for a DER that meets the eligibility requirements of Section 3.4.

Force Majeure Event – An act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, an order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or another cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and act which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Area EPS Operator, or any Affiliate thereof. The governing authority of the municipal utility is the authority governing interconnection requirements unless otherwise provided for in the Minnesota Technical Requirements.

Interconnection Agreement – The terms and conditions between the Area EPS Operator and Interconnection Customer (Parties). See Section 8 for when the Uniform Contract or Interconnection Agreement applies.

Interconnection Application – The Interconnection Customer's request to interconnect a new or modified, as described in Section 4, DER. See Simplified Application Form and Interconnection Application Form.

Interconnection Customer – The person or entity, including the Area EPS Operator, whom will be the owner of the DER that proposes to interconnect a DER(s) with the Area EPS Operator's Distribution System. The Interconnection Customer is responsible for ensuring the DER(s) is designed, operated and maintained in compliance with the Minnesota Technical Requirements.

Interconnection Facilities – The Area EPS Operator's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the DER and the Point of Common Coupling, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the DER to the Area EPS Operator's System. Some examples of Customer Interconnection Facilities include: supplemental DER devices, inverters, and associated wiring and cables up to the Point of DER Connection. Some examples of Area EPS Operator Interconnection Facilities include sole use facilities; such as, line extensions, controls, relays, switches, breakers, transformers and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Process – The Area EPS Operator's interconnection standards in this document.

Material Modification – A modification to machine data, equipment configuration or to the interconnection site of the DER at any time after receiving notification by the Area EPS Operator of a complete Interconnection Application that has a material impact on the cost, timing, or design of any Interconnection Facilities or Upgrades, or a material impact on the cost, timing or design of any Interconnection Application with a later Queue Position or the safety or reliability of the Area EPS.[6]

MN Technical Requirements – The term including all of the DER technical interconnection requirement documents for the state of Minnesota; including Attachment 2 Distributed Generation Interconnection Requirements established in the Commission's September 28, 2004 Order in E-999/CI-01-1023) until superseded and upon Commission approval of updated Minnesota DER Technical Interconnection and Interoperability Requirements in E-999/CI-16-521 (anticipated July 2019.)

Nameplate Rating – nominal voltage (V), current (A), maximum active power (kWac), apparent power (kVA), and reactive power (kVar) at which a DER is capable of sustained operation. For a Local EPS with multiple DER units, the aggregate nameplate rating is equal to the sum of all

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[6] A Material Modification shall include, but may not be limited to, a modification from the approved Interconnection Application that: (1) changes the physical location of the point of common coupling; such that it is likely to have an impact on technical review; (2) increases the nameplate rating or output characteristics of the Distributed Energy Resource; (3) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (4) changes transformer connection(s) or grounding; and/or (5) changes to a certified inverter with different specifications or different inverter control settings or configuration. A Material Modification shall not include a modification from the approved Interconnection Application that: (1) changes the ownership of a Distributed Energy Resource; (2) changes the address of the Distributed Energy Resource, so long as the physical point of common coupling remains the same; (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; and/or (4) increases the DC/AC ratio but does not increase the maximum AC output capability of the Distributed Energy Resource in a way that is likely to have an impact on technical review.

DERs nameplate rating in the Local EPS. For purposes of the Attachment V in the Interconnection Agreement, the DER system's capacity may, with the Area EPS's agreement, be limited thought use of control systems, power relays or similar device settings or adjustments as identified in IEEE 1547. The nameplate ratings referenced in the Interconnection Process are alternating current nameplate DER ratings at the Point of DER Coupling.

Network Upgrades – Additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the DER interconnects with the Area EPS Operator's System to accommodate the interconnection with the DER to the Area EPS Operator's System. Network Upgrades do not include Distribution Upgrades.

Operating Requirements – Any operating and technical requirements that may be applicable due to the Transmission Provider's technical requirements or Minnesota Technical Requirements, including those set forth in the Interconnection Agreement.

Party or Parties – The Area EPS Operator and the Interconnection Customer.

Point of Common Coupling (PCC) – The point where the Interconnection Facilities connect with the Area EPS Operator's Distribution System. See figure 1. Equivalent, in most cases, to "service point" as specified by the Area EPS Operator and described in the National Electrical Code and the National Electrical Safety Code.

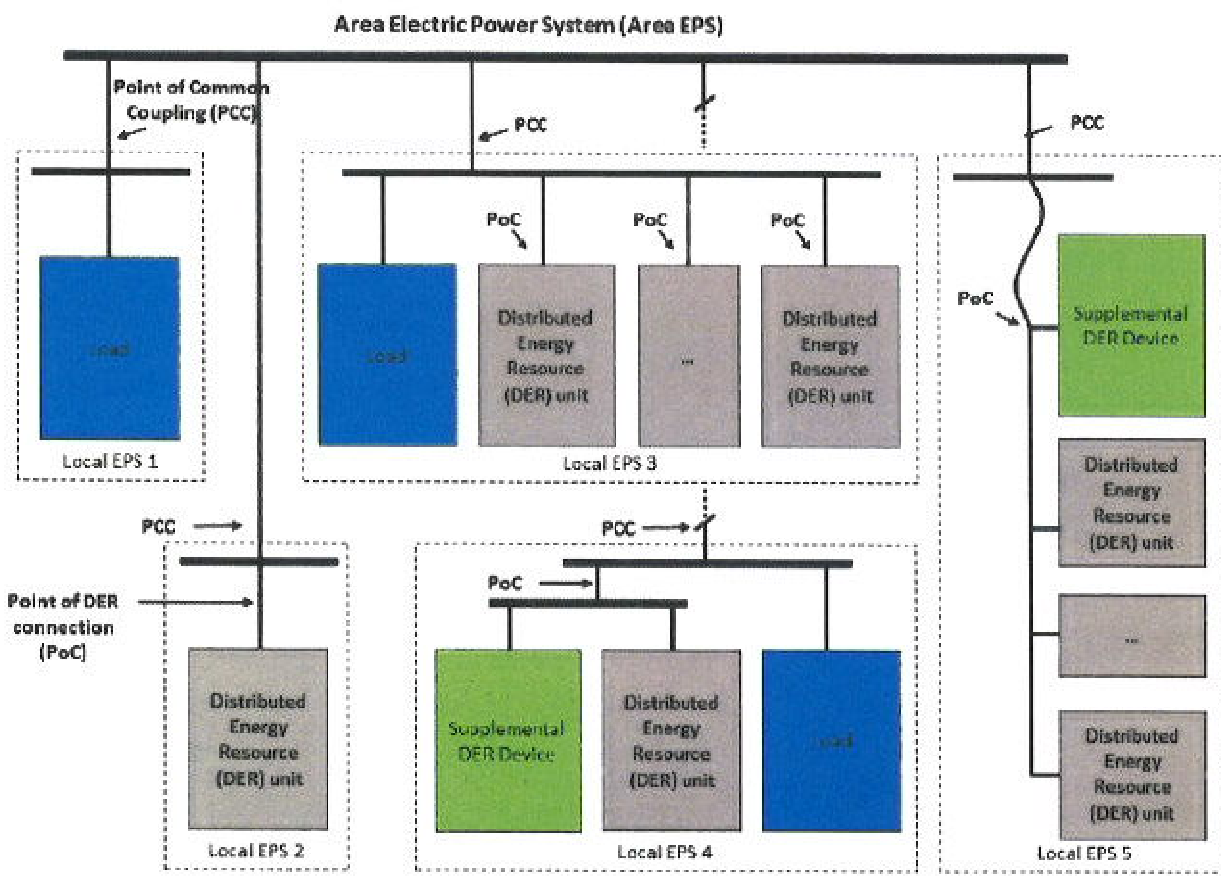

Figure 1: Point of Common Coupling and Point of DER Connection

(Source: IEEE 1547)

Point of DER Connection (PoC) – When identified as the Reference Point of Applicability, the point where an individual DER is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS (e.g. terminals of the inverter when no supplemental DER device is required.) For DER unit(s) that are not self-sufficient to meet the requirements without a supplemental DER device(s), the Point of DER Connection is the point where the requirements of this standard are met by DER in conjunction with a supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

Queue Position – The order of a valid Interconnection Application, relative to all other pending valid Interconnection Applications, that is established based upon the date- and time- of receipt of the complete Interconnection Application as described in Section 4.7.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under these procedures, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Reference Point of Applicability – The location, either the Point of Common Coupling or the Point of DER Connection, where the interconnection and interoperability performance requirements specified in IEEE 1547 apply. With mutual agreement, the Area EPS Operator and Customer may determine a point between the Point of Common Coupling and Point of DER Connection. See Minnesota Technical Requirements for more information.

Simplified Process – The procedure for evaluating an Interconnection Application for a certified inverter-based DER no larger than 20 kW that uses the screens described in the Interconnection Process – Simplified Process document. The Simplified Process includes simplified procedures.

Study Process – The procedure for evaluating an Interconnection Application that includes the scoping meeting, system impact study, and facilities study.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System relevant to the Interconnection.

Transmission Provider – The entity (or its designated agent) that owns, leases, controls, or operates transmission facilities used for the transmission of electricity. The term Transmission Provider includes the Transmission Owner when the Transmission Owner is separate from the Transmission Provider. The Transmission Provider may include the Independent System Operator or Regional Transmission Operator.

Transmission System – The facilities owned, leased, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service. See the

Commission's July 26, 2000 Order Adopting Boundary Guidelines for Distinguishing Transmission from Generation and Distribution Assets in Docket No. E-999/CI-99-1261.

Uniform Contract – the Area EPS Operator's Agreement for Cogeneration and Small Power Production Facilities (Uniform Contract) that may be applied to all qualifying new and existing interconnections between the Area EPS Operator and an DER system having capacity less than 40 kilowatts.

Upgrades – The required additions and modifications to the Area EPS Operator's Transmission or Distribution System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

14 Certification of DER Equipment

Distributed Energy Resource (DER) equipment proposed for use in an interconnection system shall be considered certified for interconnected operation if the following criteria is met:

1) It has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in the Overview Process,

2) It has been labeled and is publicly listed by such NRTL at the time of the interconnection application and,

3) Such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

The Interconnection Customer must verify that the assembly and use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for a DER Design Evaluation or an on-site commissioning test by the parties to the interconnection as provided for in the Minnesota Technical Requirements.

If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further type-test review, testing or additional equipment on the customer side of the Point of Common Coupling shall be required to be considered certified for the purposes of this interconnection procedure; however, nothing herein shall preclude the need for a DER Design Evaluation or an on-site commissioning test by the parties to the interconnection as provided for in the Minnesota Technical Requirements.

An equipment package does not include equipment provided by the Area EPS.

15 Certification Codes and Standards

The existing Minnesota Technical Requirements and the following standards shall be used in conjunction with the Interconnection Process. The process has started to update the Technical Requirements to meet IEEE 1547-2018. Once that process is completed, the updated DER Technical Interconnection and Interoperability Requirements will supersede this section.

When the stated version of the following standards is superseded by an approved revision then that revision shall apply:

IEEE 1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547a-2014 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1

IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547.1a-2015 (Amendment to IEEE Std 1547.1-2005) IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems – Amendment 1

UL 1741 Inverters, Converters, Controllers, and Interconnection System Equipment for Use in Distributed Energy Resources (2010)

NFPA 70 (2017), National Electrical Code

IEEE Std C37.90.1 (2012) (Revision of IEEE Std C37.90.1-2002), IEEE Standard for Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems Associated with Electric Power Apparatus

IEEE Std C37.90.2 (2004) (Revision of IEEE Std C37.90.2-1995), IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-20021989 (Revision of C37.108-19892002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2014 (Revision of IEEE Std C57.12.44-2005), IEEE Standard Requirements for Secondary Network Protectors

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

IEEE Std C62.41.2-2002_Cor 1-2012 (Corrigendum to IEEE Std C62.41.2-2002) – IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits Corrigendum 1: Deletion of Table A.2 and Associated Text

IEEE Std C62.45-2002 (Revision of IEEE Std C62.45-1992) – IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and less) AC Power Circuits

ANSI C84.1-(2016) Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Standards Dictionary Online, [Online]

NEMA MG 1-2016, Motors and Generators

IEEE Std 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

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RESOLUTION #1245

A RESOLUTION APPROVING SHAKOPEE PUBLIC UTILITIES COMMISSION'S COGENERATION AND SMALL POWER PRODUCTION TARIFF

WHEREAS, the Rules Governing the Interconnection of Cogeneration and Small Power Production Facilities with Shakopee Public Utilities Commission and Minnesota Statutes Section 216B.164 require the utility to annually adopt a Cogeneration and Small Power Production Tariff.

WHEREAS, Schedule 1 shall contain the calculation of the average retail utility rates to be updated annually.

WHEREAS, Schedule 2 shall contain all standard contracts to be used with qualifying facilities, containing applicable terms and conditions.

WHEREAS, Schedule 3 shall contain the utility's adopted interconnection process, safety standards, technical requirements for distributed energy resource systems, required operating procedures for interconnected operations, and the functions to be performed by any control and protective apparatus.

WHEREAS, Schedule 4 shall contain the estimated average incremental energy costs by seasonal, peak and off-peak periods for the utility's power supplier from which energy purchases are first avoided. Schedule 4 shall also contain the net annual avoided capacity costs, if any, stated per kilowatt-hour and averaged over the on-peak hours and over all hours for the utility's power supplier from which capacity purchases are first avoided. Both the average incremental energy costs and net annual avoided capacity costs shall be increased by a factor equal to 50 percent of the utility and the utility's power supplier's overall line losses due to distribution, transmission and transformation of electric energy.

WHERAS, these filings shall be maintained at the Shakopee Public Utilities Commission offices and shall be made available for public inspection during normal business hours.

THEREFORE, BE IT RESOLVED that the Shakopee Public Utilities Commission approves the following Cogeneration and Small Power Production Tariff for transactions following the date of adoption stated below.

Adopted in the regular session of the Shakopee Public Utilities Commission, this 15th day of April, 2019.

____

Commission President: Terrance Joos

SCHEDULE 1 – AVERAGE RETAIL UTILITY ENERGY RATES

Average Retail Utility Energy Rate: Available to any Qualifying Facility of less than 40 kW capacity that does not select either Roll Over Credits, Simultaneous Purchase and Sale Billing or Time of Day rates.

Utility shall bill Qualifying Facilities for any excess of energy supplied by Utility above energy supplied by the Qualifying Facility during each billing period according to Utility's applicable rate schedule. Utility shall pay the customer for the energy generated by the Qualifying Facility that exceeds that supplied by Utility during a billing period at the "average retail utility energy rate." "Average retail utility energy rate" means, for any class of utility customer, the quotient of the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales. Data from the most recent 12-month period available shall be used in the computation.

"Average retail utility energy rates" are as follows:

	2018
RESIDENTIAL	
TOTAL REVENUES	$ 17,891,566.43
LESS UNDERGROUND RELOCATION FEES	$ 110,636.06
LESS FIXED REVENUES (CUSTOMER CHARGE)	$ 1,643,595.00
NET REVENUES	$ 16,137,335.37
TOTAL KWH SALES	$ 139,277,526.00
AVERAGE RETAIL ENERGY RATE	**$ 0.1159**
COMMERCIAL	
TOTAL REVENUES	$ 1,648,656.86
LESS WATER DIVISION ELECTRIC FOR PUMPING	$ 265,755.03
LESS FIXED REVENUES (CUSTOMER CHARGE)	$ 182,966.00
NET REVENUES	$ 1,199,935.83
TOTAL KWH SALES	$ 10,453,260.00
AVERAGE RETAIL ENERGY RATE	**$ 0.1148**
INDUSTRIAL	
TOTAL REVENUES	$ 29,766,176.60
LESS FIXED REVENUES (CUSTOMER CHARGE)	$ 462,998.00
LESS DEMAND CHARGES	$ 6,837,050.72
NET REVENUES	$ 22,466,127.88
TOTAL KWH SALES	$ 303,338,391.00
AVERAGE RETAIL ENERGY RATE	**$ 0.0741**

UNIFORM CONTRACT FOR COGENERATION AND SMALL POWER PRODUCTION FACILITIES

THIS CONTRACT is entered into ___________________, ___, by Shakopee Public Utilities Commission, a municipal utility under Minnesota law, (hereafter called "Utility") and ____ (hereafter called "QF").

RECITALS

The QF has installed electric generating facilities, consisting of ___________________ _____________________________ (Description of facilities), rated at ____kilowatts AC of electricity, on property located at ____ ____.

The QF is a customer of the Utility located within the assigned electric service territory of the Utility.

The QF is prepared to generate electricity in parallel with the Utility.

The QF's electric generating facilities meet the requirements of the rules adopted by the Utility on Cogeneration and Small Power Production and any technical standards for interconnection the Utility has established that are authorized by those rules.

The Utility is obligated under federal and Minnesota law to interconnect with the QF and to purchase electricity offered for sale by the QF.

A contract between the QF and the Utility is required.

AGREEMENTS

The QF and the Utility agree:

1. The Utility will sell electricity to the QF under the rate schedule in force for the class of customer to which the QF belongs.
2. The Utility will buy electricity from the QF under the current rate schedule filed with the city council or city-appointed governing body of the utility. The QF elects the rate schedule category hereinafter indicated:

____ a. Average retail utility energy rate.

- QF capacity must be less than 40 kW.

____ b. Simultaneous purchase and sale billing rate.

- QF capacity must be less than 40 kW.

____ c. Roll-over credits.

- QF capacity must be less than 40 kW.

____ d. Time-of-day purchase rates.

- QF capacity must be 40 kW or more and less than or equal to 100 kW.

A copy of the presently approved rate schedule is attached to this contract.

3. The rates for sales and purchases of electricity may change over the time this contract is in force, due to actions of the Utility or the State of Minnesota, and the QF and the Utility agree that sales and purchases will be made under the rates in effect each month during the time this contract is in force.

4. The Utility will compute the charges and payments for purchases and sales for each billing period. Any net credit to the QF, other than kilowatt-hour credits under clause 2(c), will be made under one of the following options as chosen by the QF.

____ a. Credit to the QF's account with the Utility.
____ b. Paid by check or electronic payment service to the QF within fifteen (15) days of the billing date.

5. Renewable energy credits associated with generation from the facility are owned by:

____.

6. The QF must operate its electric generating facilities within any rules, regulations, and policies adopted by the Utility not prohibited by the rules governing Cogeneration and Small Power Production on the Utility's system which provide reasonable technical connection and operating specifications for the QF and are consistent with the Minnesota Public Utilities Commission's rules on Cogeneration and Small Power Production, as required under Minnesota Statutes §216B.164, subdivision 9.

7. The QF will not enter into an arrangement whereby electricity from the generating facilities will be sold to an end user in violation of the Utility's exclusive right to provide electric service in its service area under Minnesota Statutes, §216B.37-44.

8. The QF will operate its electric generating facilities so that they conform to the national, state, and local electric and safety codes, and will be responsible for the costs of conformance.

9. The QF is responsible for the actual, reasonable costs of interconnection which are estimated to be $__________. The QF will pay the Utility in this way:

____

____.

10. The QF will give the Utility reasonable access to its property and electric generating facilities if the configuration of those facilities does not permit disconnection or testing from the Utility 's side of the interconnection. If the Utility enters the QF's property, the Utility will remain responsible for its personnel.

11. The Utility may stop providing electricity to the QF during a system emergency. The Utility will not discriminate against the QF when it stops providing electricity or when it resumes providing electricity.

12. The Utility may stop purchasing electricity from the QF when necessary for the Utility to construct, install, maintain, repair, replace, remove, investigate, or inspect any equipment or facilities within its electric system. The Utility may stop purchasing electricity from the QF in the event the generating facilities listed in this contract are documented to be causing power quality, safety or reliability issues to the Utility's electric distribution system.

The Utility will notify the QF before it stops purchasing electricity in this way:

____

____.

13. The QF will keep in force general liability insurance against personal or property damage due to the installation, interconnection, and operation of its electric generating facilities. The amount of insurance coverage will be $ ___________. (The amount must be consistent with the distributed generation tariff adopted by the Utility pursuant to Minnesota Statutes §216B.1611, subdivision 3, clause 2.)

14. The QF and the Utility agree to attempt to resolve all disputes arising hereunder promptly and in a good faith manner.

15. The city council or city-appointed body governing the Utility has authority to consider and determine disputes, if any, that arise under this contract in accordance with procedures in the rules it adopts implementing Minnesota Statute §216B.164, pursuant to §216B.164, subdivision 9.

16. This contract becomes effective as soon as it is signed by the QF and the Utility. This contract will remain in force until either the QF or the Utility gives written notice to the other that the contract is canceled. This contract will be canceled thirty (30) days after notice is given. If the listed electric generating facilities are not interconnected to the Utility's distribution system within twelve months of the contract being signed by the QF and the Utility, the contract terminates. The QF and the Utility may delay termination by mutual agreement.

17. Neither the QF nor the Utility will be considered in default as to any obligation if the QF or the Utility is prevented from fulfilling the obligation due to an act of God, labor disturbance, act of public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, an order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or other cause beyond the QF's or Utility's control. However, the QF or Utility whose performance under this contract is hindered by such an event shall make all reasonable efforts to perform its obligations.

18. This contract can only be amended or modified by mutual agreement in writing signed by the QF and the Utility.

19. The QF must notify the Utility prior to any change in the electric generating facilities' capacity size or generating technology according to the interconnection process adopted by the Utility.

20. Termination of this contract is allowed (i) by the QF at any time without restriction; (ii) by Mutual Agreement between the Utility and the QF; (iii) upon abandonment or removal of electric generating facilities by the QF; (iv) by the Utility if the electric generating facilities are continuously non-operational for any twelve (12) consecutive month period; (v) by the Utility if the QF fails to comply with applicable interconnection design requirements or fails to remedy a violation of the interconnection process; or (vi) by the Utility upon breach of this contract by the QF unless cured with notice of cure received by the Utility prior to termination.

21. In the event this contract is terminated, the Utility shall have the rights to disconnect its facilities or direct the QF to disconnect its generating facilities.

22. This contract shall continue in effect after termination to the extent necessary to allow either the Utility or the QF to fulfill rights or obligations that arose under the contract.

23. Transfer of ownership of the generating facilities shall require the new owners and the Utility to execute a new contract. Upon the execution of a new contract with the new owners this contract shall be terminated.

24. The QF and the Utility shall at all times indemnify, defend, and save each other harmless from any and all damages, losses, claims, including claims and actions relating to injury or death of any person or damage to property, costs and expenses, reasonable attorneys' fees and court costs, arising out of or resulting from the QF's or the Utility's performance of its obligations under this contract, except to the extent that such damages, losses or claims were caused by the negligence or intentional acts of the QF or the Utility.

25. The Utility and the QF will each be responsible for its own acts or omissions and the results thereof to the extent authorized by law and shall not be responsible for the acts or omissions of any others and the results thereof.

26. The QF's and the Utility's liability to each other for failure to perform its obligations under this contract shall be limited to the amount of direct damage actually occurred. In no event, shall the QF or the Utility be liable to each other for any punitive, incidental, indirect, special, or consequential damages of any kind whatsoever, including for loss of business opportunity or profits, regardless of whether such damages were foreseen.

27. The Utility does not give any warranty, expressed or implied, to the adequacy, safety, or other characteristics of the QF's interconnected system.

28. This contract contains all the agreements made between the QF and the Utility. The QF and Utility are not responsible other than those stated in this contract.

THE QF AND THE UTILITY HAVE READ THIS CONTRACT AND AGREE TO BE BOUND BY ITS TERMS. AS EVIDENCE OF THEIR AGREEMENT, THEY HAVE EACH SIGNED THIS CONTRACT BELOW ON THE DATE LISTED BY SIGNER.

QF

By: ______________________________

Printed Name: ______________________

DATE: ___________________________

UTILITY

By: ______________________________

Printed Name: ______________________

DATE: ___________________________

Contract Version: *February 2019*

SHAKOPEE PUBLIC UTILITIES

"Lighting the Way – Yesterday, Today and Beyond"

SHAKOPEE PUBLIC UTILITIES COMMISSION

DISTRIBUTED ENERGY RESOURCE INTERCONNECTION PROCESS

Table of Contents

Detroit Lakes Public Utility's 29.3 KW Select Solar Community Solar Garden Detroit Lakes, MN

INTERCONNECTION PROCESS

Process Overview

ABSTRACT

Interconnection Process for Distributed Energy Resources less than 10 megawatt (MW) interconnected to the Distribution System of a Municipal in the State of Minnesota.

Contents

Foreword

The State of Minnesota currently has interconnection process standards in effect to address the interconnection of distributed energy resources (DER) to the distribution grid. Under Minnesota Statute §216B.1611, cooperatives and municipals shall adopt an interconnection process that addresses the same issues as the interconnection process approved by the Minnesota Public Utilities Commission. The Municipal Minnesota Distributed Energy Resources Interconnection Process (Interconnection Process or M-MIP) applies to any DER no larger than 10-megawatt (MW) AC interconnecting to and operating in parallel with Shakopee Public Utilities Commission's distribution system in Minnesota. This interconnection process document is designed to be customer-centric when explaining the steps and details to interconnect DER systems to the distribution grid.

The interconnection process document is broken into five parts: Process Overview, Simplified Process, Fast Track Process, Study Process and Interconnection Agreement. For the majority of DER interconnection, only the Process Overview and the Simplified Process parts will apply. For larger and more complex DER interconnections, the Fast Track Process and the Study Process may apply.

In addition to the interconnection process documents, interconnection agreement(s) are to be executed prior to the DER system being interconnected to the distribution grid. For most DER interconnection, the Shakopee Public Utilities Commission Contract for Cogeneration and Small Power Production Facilities (Uniform Contract) will be used. For DER systems that do not fall under the terms of the Uniform Contract, the M-MIP Interconnection Agreement will apply.

The process to interconnect a DER system to the distribution grid starts with the submission of an Interconnection Application. Each track has different information that is requested in the application and the non-refundable interconnection application fees will vary. Both the electric utility and the interconnecting customer have timelines that are enforced to ensure a timely application review, contract execution and interconnection commissioning.

The key to a successful interconnection of a DER system is communication between all parties. Timely submission of the Interconnection Application prior to the purchase and installation of a DER system is strongly recommended. The Utility encourages customers to ask questions throughout the interconnection process. Interconnecting DER system to the distribution grid is not an effortless process, but it does not need to be a problematic process either.

1 Key Terminology

1.1. Distributed Energy Resource

Distributed Energy Resources, DER, was often referred to in past interconnection processes as Distributed Generation, DG, and on occasion also interchanged with the term Qualifying Facility, QF. This Interconnection Process uses the term DER to address all types of generation and energy resources that can be interconnected to the electric distribution system. DER technologies can include photovoltaic solar systems, wind turbines, storage batteries or diesel generators and are not limited to renewable types of technologies.

1.2. Point of Coupling/Connection

DER systems often reside behind the utility's revenue meter of a residence or business. The meter is normally the point of demarcation between the utility-owned equipment and the customer-owned equipment. The term Point of Common Coupling, PCC, is the demarcation location between the utility and the customer.

The Point of DER Connection, PoC, can be different from the PCC. The PoC is the location where a DER system(s) would interconnect to the electrical system normally owned by the customer. For example, the PoC for a rooftop photovoltaic solar system may the main electrical panel in a customer's home.

1.3. Capacity

Throughout the Interconnection Process will be references to capacity of the DER system. In most cases, the capacity listed is referring to the Nameplate Capacity of the DER system. All capacity reference will be in alternating current, AC.

There can be multiple DER systems with different PoCs that all have the same PCC submitted on a single interconnection application. The capacity for this type of interconnection would be the aggregate Nameplate Capacity of all DER systems at the individual PoCs. Additional examples of DER system arrangements can be seen in Section 13 under the definition of Point of Common Coupling.

2 Roles

2.1. Overview

During the interconnection process for a proposed DER system, there are multiple entities involved in the application, approval and commissioning processes. The main entities that are involved during the Interconnection Process for a proposed DER system are the Interconnection Customer, the Application Agent and the DER

Interconnection Coordinator. Official definitions of each entity are defined in the Glossary (Section 13). Additional details are explained in the subsections below.

2.2. DER Interconnection Coordinator

The utility is referred to as the Area Electric Power Supply Operator in this Interconnection Process. The Area EPS Operator shall designate a DER Interconnection Coordinator(s) to serve as a single point of contact from which general information on the application process may be obtained. The DER Interconnection Coordinator shall be available to provide coordination assistance with the Interconnection Customer but is not responsible to directly answer or resolve all of the issues involved in review and implementation of the interconnection process and standards.

The contact information of the DER Interconnection Coordinator will be posted on the Area EPS Operator's website when feasible.

2.3. Interconnection Customer

The owner of the proposed DER system and the entity requesting interconnection to the distribution system.

2.4. Application Agent

The Interconnection Customer may designate, on the Interconnection Application or in writing after the application has been submitted, an Application Agent to serve as a single point of contact to coordinate with the DER Interconnection Coordinator on their behalf. Designation of an Application Agent does not absolve the Interconnection Customer from signing application documents and the responsibilities outlined in the Interconnection Process or in interconnection agreements. DER vendors, project managers or electricians are common entities that the Interconnection Customer may designate to perform this role.

2.5. Engineering Roles

Either party may designate a specific person to be a single point of contact to provide technical expertise during the Interconnection Process for their organization. The person to supply engineering expertise may be a third party such as an engineering consultant or manufacturer's engineer.

3 Processes

3.1. Overview

The Interconnection Process applies to any DER no larger than 10 MW AC interconnecting to and operating in parallel with an Area EPS distribution system in

Minnesota. Interested parties with plans to interconnect DER systems larger than 10 MW AC to the distribution system should contact the Area EPS Operator for the specific interconnection process. Federal Energy Regulatory Commission's (FERC) interconnection process will supersede any interconnection process the Area EPS Operator has for DER system interconnections that fall under the jurisdiction of FERC.

The Interconnection Process for DER is broken into three different tracks; the Simplified Process, the Fast Track Process, and the Study Process. The general classification of each track is summarized in Table 3.1 below.

Table 3.1. Interconnection Process Tracks

Track	DER Technology	Size Limitations
Simplified Process	Certified Inverter only	20 kW AC
Fast Track Process	All types	5 MW AC
Study Process	All types	10 MW AC

If engineering screens are failed during the application process, a proposed DER interconnection may be moved into a different track. When a proposed DER interconnection is moved into a different track, additional information may be requested and additional fees may apply.

3.2. Importance of Process Timelines

It is very important to pay attention to timelines listed for each process track. The timelines exist for an orderly and efficient process to interconnect DER systems to the Distribution System. If a timeline is missed by an Interconnection Customer, without the Interconnection Customer requesting a Timeline Extension explained in Section 10, the Interconnection Application will be deem withdrawn by the Area EPS Operator.

The Area EPS Operator also need to abided to the timelines listed for each process track. The process for an Area EPS Operator to request Timeline Extensions is also addressed in Section 10.

Unless otherwise state, all time frames are measured in Business Days. For purpose of measuring these time intervals, the time shall be computed so as to exclude the first and include the last day of the prescribed duration of time. Any communication sent or received after 4:30 p.m. Central Prevailing Time or on a Saturday, Sunday or Holiday shall be considered to be sent on the next Business Day.

3.3. Simplified Process

An application to interconnect a certified[1], inverter-based DER system no larger than 20 kilowatts (kW) shall be evaluated under the Simplified Process. A common form of DER inverter certification is UL 1741. Proposed DER systems that require Area EPS system modifications to accommodate the interconnection do not qualify for the Simplified Process. A transformer change, fusing upgrades or line extensions are common examples of Area EPS system modification. Simplified Process eligibility does not imply or indicate the Interconnection Application will pass the initial review screens. Failure to pass the screens will route the Interconnection Application to the Fast Track Process.

3.4. Fast Track Process

An application to interconnect a DER shall be evaluated under the Fast Track Process if the eligibility requirements are not exceeded in Table 3.2 and the application does not qualify for the Simplified Process. Fast Track eligibility for DERs is determined based upon the generator type, the size of the generator, voltage of the line, and the location of and the type of line at the Point of Common Coupling, (PCC). All synchronous and induction machines must be no larger than 2 MW to be eligible for Fast Track Process consideration.

Table 3.2. Fast Track Eligibility for DER

Line Voltage	Fast Track Eligibility[2] Regardless of Location	Fast Track Eligibility for certified, inverter-based DER on a Mainline[3] and ≤ 2.5 Electrical Circuit Miles from Substation[4]
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 30 kV	≤ 2 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

In addition to the size threshold, the Interconnection Customer's proposed DER must meet the codes, standards and certification requirements found in Section 15 and Section 14.

[1] Additional information regarding certified equipment is found in Section 15 and Section 14.

[2] Synchronous and induction machine eligibility is limited to no more than 2 MW even when line voltage is greater than 15 kV.

[3] For purposes of this table, a Mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 266 kcmil, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[4] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report described in Section 5.

3.5. Study Process

An application to interconnect a DER that does not meet the Simplified Process or Fast Track Process eligibility requirements or does not pass the review as described in either process, shall be evaluated under the Study Process.

3.6. Process Assistance

Prior to submitting an Interconnection Application, the Interconnection Customer may ask the Area EPS Operator's DER Interconnection Coordinator which process track a proposed interconnection is subject to and additional details on each process track.

An Interconnection Customer can obtain, through an informal request, general information about the interconnection process and on Affected System(s) for a proposed interconnection at a specific location. Upon request, the existing electric system information provided to the Interconnection Customer should include relevant system study results, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Area EPS Operator's System. Information will be provided to the extent such provision does not violate the privacy policies of the Area EPS Operator, confidentiality provisions of prior agreements or critical infrastructure requirements. The Area EPS Operator shall comply with reasonable requests for such information.

4 Interconnection Application

4.1. Overview

Each process track has different information that needs to be provided to the Area EPS Operator. Table 4.1 indicates which application is to be completed in its entirety and submitted to the Area EPS Operator to start the interconnection process for the proposed DER system.

Table 4.1. Interconnection Application

Process Track	Application
Simplified	Simplified Interconnection Application
Fast Track	Standard Interconnection Application
Study	Standard Interconnection Application

The Area EPS Operator will provide all necessary Interconnection Applications, Interconnection Process documents and sample interconnection agreements on its website if possible. The Area EPS Operator will also accept Interconnection Applications submitted electronically either through a web portal or to an email address specified by the Area EPS Operator. The Area EPS Operator may allow the Interconnection Application to be submitted with an electronic signature.

4.2. Availability of Information

The Area EPS Operator will provide all necessary Interconnection Applications, Interconnection Process documents and sample interconnection agreements on its website if possible. If a website is not available, the applicable documents will be readily available at the Area EPS Operator's main office.

The Area EPS Operator will establish a public queue of active interconnection applications on its website once the Area EPS Operator has received at least 40 completed Interconnection Applications in a year. The public queue will be updated, at minimum, on a monthly basis.

4.3. Interconnection Application Process Fees

Each Interconnection Application submitted to the Area EPS Operator must include the appropriate interconnection application process fee prior to the Area EPS Operator reviewing the Interconnection Application. The required process fee for each process track is listed in Table 4.2.

Table 4.2. Interconnection Application Process Fee

Process Track		Process Fee
Simplified		$100
Fast Track	Certified[5] System	$100 + $1/kW
	Non-Certified System	$100 + $2/kW
Study		$1,000 + $2/kW down payment. Additional study fees may apply.

4.4. Application Review Timelines

The Interconnection Application shall be date- and time-stamped upon initial, and if necessary, resubmission receipt. The Area EPS Operator shall notify the Interconnection Customer if the Interconnection Application is deemed incomplete within ten (10) Business Days. This notification shall include a written list detailing all information that must be provided to complete the Interconnection Application. Depending on the process track the Interconnection Customer has between five (5) and ten (10) Business Days to provide the missing information unless additional time is

[5] Additional information regarding certified equipment is found in Section 15 and Section 14.

requested with valid reasons. Failure to submit the requested information within the stated timeline will result in the Interconnection Application being withdrawn.

An Interconnection Application will be deemed complete upon submission to the Area EPS Operator when all documents, fees and information required with the Interconnection Application adhering to Minnesota Technical Requirements is included. The time- and date- stamp of the completed Interconnection Application shall be accepted as the qualifying date for purposes of establishing a queue position as described in Section 4.7.

Depending on the process track the Area EPS Operator has either a total of twenty (20) Business Days or twenty-five (25) Business Days to complete the Interconnection Application review and submit notice back to the Interconnection Customer stating the proposed DER system may proceed with the interconnection process or the proposed DER system requires additional engineering studies. The period of time when waiting for the Interconnection Customer to provide missing information is not included in the Area EPS Operator's twenty (20) Business Days or twenty-five (25) Business Days review timeline.

4.5. Comparability

The Area EPS Operator shall receive, process and analyze all Interconnection Applications in a timely manner. The Area EPS Operator shall use the same Reasonable Efforts in processing and analyzing Interconnection Applications from all Interconnection Customers.

4.6. Changing Process Queues

During the review of the initially submitted Interconnection Application for the proposed DER system, the Area EPS Operator may determine the proposed DER system should be in a different process track. For proposed DER systems that are moved into a different process track after submittal of the initial application, the difference between the originally submitted processing fee and the current process track's processing fee will be assessed. In addition, the Area EPS Operator may request the Interconnection Customer to provide additional information regarding the proposed DER system.

4.7. Queue Position

The Area EPS Operator shall maintain a single, administrative queue and may manage the queue by geographical region. The queue position of each completed Interconnection Application is used to determine the engineering review. The queue position is also used to determine the cost responsibility for system upgrades necessary to accommodate the interconnection.

An Interconnection Application will retain its queue number even when it is moved into a different process track. An Interconnection Application can lose its queue position if the Interconnection Customer misses timelines in the applicable process track. The Interconnection Customer and Area EPS Operator have the opportunity to request timeline extensions which are explained in detail in Section 10.

4.8. Site Control

Documentation of site control must be submitted with the Interconnection Application. Site control may be demonstrated by any of the following:

- Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the DER system.
- An option to purchase or acquire a leasehold site for constructing the DER system.
- An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for constructing the DER system.

For DER in the Simplified Process, proof of site control may be demonstrated by the site owner's signature on the Simplified Interconnection Application.

5 Pre-Application Report

5.1. Pre-Application Report Requests

The Interconnection Customer may submit a Pre-Application Report Request, including a non-refundable fee of $300, for a Pre-Application Report on a proposed project at a specific site. The Interconnection Customer must fill out the Pre-Application Request form as completely as possible. The Area EPS Operator shall provide the readily available data listed in Section 5.3 within fifteen (15) Business Days of receipt of a completed request form and payment. The Pre-Application Report produced by the Area EPS Operator is non-binding, does not confer any rights, and does not preclude the Interconnection Customer from any interconnection process steps including submission of the Interconnection Application.

5.2. Information Provided

Using the information provided in the Pre-Application Report Request form, the Area EPS Operator will identify the substation/area bus, bank or circuit likely to serve the proposed PCC. This selection by the Area EPS Operator does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional Pre-Application Reports if information about multiple PCC is requested.

The Pre-Application Report will only include existing data. A request for a Pre-Application Report does not obligate the Area EPS Operator to conduct a study or other analysis of the proposed DER in the event that data is not readily available. The Area EPS Operator will provide the Interconnection Customer with the data that is available. The confidentiality provisions in Section 12.1 **Error! Reference source not found.**apply to Pre-Application Reports.

5.3. Pre-Application Report Components

The Pre-Application Report shall include following pieces of information provided the data currently exists and is readily available.

- Total capacity (in megawatts (MW)) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Common Coupling.

- Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Common Coupling.

- Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Common Coupling.

- Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Common Coupling (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

- Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

- Nominal distribution circuit voltage at the proposed Point of Common Coupling.

- Approximate circuit distance between the proposed Point of Common Coupling and the substation.

- Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load and absolute minimum load, when available.

- Whether the Point of Common Coupling is located behind a line voltage regulator.
- Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.

- Number of phases available on the Area EPS medium voltage system at the proposed Point of Common Coupling. If a single phase, distance from the three-phase circuit.

- Limiting conductor ratings from the proposed Point of Common Coupling to the distribution substation.

- Whether the Point of Common Coupling is located on a spot network, grid network, or radial supply.

- Based on the proposed Point of Common Coupling, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks

6 Capacity of the Distributed Energy Resources

6.1. Existing DER System Expansion

If the Interconnection Application is for an increase in capacity to an existing DER system, the Interconnection Application shall be evaluated on the basis on the total new alternating current (AC) capacity of the DER. The maximum capacity for the DER shall be the aggregate maximum Nameplate Rating unless the conditions in Section 6.3 are met.

6.2. New DER Systems

An Interconnection Application for a DER that includes a single or multiple energy production devices, (i.e. solar and storage), at a site for which the Interconnection Customer seeks a simple Point of Coupling, shall be evaluated on the basis of the aggregated maximum Nameplate Rating unless the conditions in Section 6.3 are met.

6.3. Limited Capacity

A DER system may include devices, (i.e. control systems, power relays or other similar device settings), that can limit the maximum capacity at which the DER system can generate into the Area EPS Operator's distribution system. For DER system that include capacity limited devices, the Interconnection Customer must obtain the Area EPS

Operator's agreement to consider the DER system with the Nameplate Rating as the limited capacity. The Area EPS Operator's agreement shall not be unreasonable withheld provided proper documentation is provided showing the effective limit active power output will not adversely affect the safety and reliability of the Area EPS Operator's distribution system. If the Area EPS Operator does not agree, the Interconnection Application must be withdrawn or revised to specify the maximum capacity that the DER system is capable of injecting into the Area EPS Operator's distribution system without such limitations. Nothing in this section shall prevent the Area EPS Operator from considering a higher output, (i.e. aggregate Nameplate Rating), if the limitations do not provide adequate assurance, when evaluating the system impacts.

7 Modification to Interconnection Applications

7.1. Procedures

At any time after the Interconnection Application is deemed complete, the Interconnection Customer or the Area EPS Operator may identify modifications to the proposed DER system that may improve costs and benefits (including reliability) of the proposed DER system and the ability for the Area EPS Operator to accommodate the proposed DER system. The Interconnection Customer shall submit to the Area EPS Operator in writing all proposed modifications to any information provided in the Interconnection Application. The Area EPS Operator cannot unilaterally modify the Interconnection Application.

Additional information regarding modifications to interconnection applications is found in each process track document.

8 Interconnection Agreements

8.1. Timelines

After the Interconnection Application has been approved by the Area EPS Operator, the Area EPS Operator shall provide the Interconnection Customer with an executable Interconnection Agreement within five (5) Business Days. The Interconnection Customer shall have thirty (30) Business Days to sign and return the Interconnection Agreement to the Area EPS Operator. The Area EPS Operator shall sign the Interconnection Agreement within five (5) business days after receiving the signed Interconnection Agreement from the Interconnection Customer.

If the Interconnection Customer fails to return a signed Interconnection Agreement to the Area EPS Operator within thirty (30) Business Days and fails to request an extension as explained in Section 10, the Interconnection Application will be deemed withdrawn.

8.2. Types of Agreements

There are two main types of Interconnection Agreements that may be executed with an approved Interconnection Application. In general, Interconnection Customers with a proposed DER system that qualifies for the Simplified Process track will sign the Area EPS Operator's Uniform Contract for Cogeneration and Small Power Production Facilities (Uniform Contract). Proposed DER systems less than 100 kW that are under the Fast Track process may also sign the Uniform Contract. All other sized DER system will sign the Interconnection Agreement. Area EPS Operators who do not purchase the excess generation of the proposed DER system will also require the Interconnection Agreement executed for any size of DER system.

Table 8.1. Interconnection Agreements

<table>
<tr><th colspan="2">Process Track</th><th>Interconnection Agreement</th></tr>
<tr><td colspan="2">Simplified</td><td>Uniform Contract</td></tr>
<tr><td rowspan="3">Fast Track</td><td>Qualifies for Net Energy Billing</td><td>Uniform Contract</td></tr>
<tr><td>Less than 100 kW & Area EPS Agrees to Purchase Excess Generation</td><td>Uniform Contract</td></tr>
<tr><td>All Other DER systems</td><td>Interconnection Agreement</td></tr>
<tr><td colspan="2">Study</td><td>Interconnection Agreement</td></tr>
</table>

Interconnection Customers may choose to sign the Interconnection Agreement in lieu of the Uniform Contact. A separate power purchase agreement will also need to be executed if the Uniform Contract is not utilized. Interconnection of the proposed DER system will not occur until a signed Uniform Contract or the Interconnection Agreement is returned to the Area EPS Operator no later than five (5) days prior to schedule testing and inspection.

9 Interconnection

9.1. Metering

Any metering requirements necessitated by the use of the DER system shall be installed at the Interconnection Customer's expense. The metering requirement costs will be included in the final invoice of interconnection costs to the Interconnection Customer. The Interconnection Customer is also responsible for metering replacement costs not covered in the Interconnection Customer's general customer charge. The Area EPS Operator may charge Interconnection Customers an ongoing metering-related charge for an estimate of ongoing metering-related costs specifically demonstrated.

9.2. Inspection, Testing and Commissioning

The Interconnection Customer shall arrange for the inspection and testing of the DER system and the Customer's Interconnection Facilities prior to interconnection pursuant to Minnesota Interconnection Technical Requirements. Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards of Minnesota's Technical Requirements and Section 15.

The Interconnection Customer shall notify the Area EPS Operator of testing and inspection no fewer than five (5) Business Days in advance, or as may be agreed to by the Parties. Depending on the process track, either a Certificate of Completion or a testing procedure shall be submitted to the Area EPS Operator prior to the testing and inspection date. The Area EPS Operator shall send qualified personnel to the DER site to inspect the interconnection and witness the testing. Testing and inspection shall occur on a Business Day at a mutually agreed upon time and date. The Area EPS Operator may waive the right to witness the testing.

9.3. Interconnection Costs

The Interconnection Customer shall pay for the actual cost of the Interconnection Facilities and Distribution Upgrades along with the Area EPS Operator's cost to commission the proposed DER system. An estimate of the interconnection costs shall be stated in the Uniform Contract or Interconnection Agreement.

9.4. Non-Warrantee

Area EPS Operator does not give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, operated, installed or maintained by the Interconnection Customer, including without limitation the DER and any structures, equipment, wires, appliances or devices not owned, operated or maintained by the Area EPS Operator. The Area EPS Operator does not guarantee uninterrupted power supply to the DER and will operate the distribution system with the same reliability standards for the entire customer base.

9.5. Technical Requirements

The Area EPS Operator shall use Reasonable Efforts to provide the Interconnection Customer the Minnesota Technical Requirements by providing the document with the notice of approval of the interconnection application or by providing a website link to the document. Additionally, the Area EPS Operator shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. Unless notified by the Area EPS Operator, the Interconnection Customer only needs to be in compliance of the current version of the Minnesota Technical Requirements at the time of interconnection.

9.6. Authorization for Parallel Operations

The Interconnection Customer shall not operate its DER system in parallel with the Area EPS Operator's distribution system without prior written authorization from the Area EPS Operator. The Area EPS Operator shall provide such authorization within three (3) Business Days from when the Area EPS Operator receives notification that the Interconnection Customer has complied with all applicable parallel operations requirements; the completion of a successful testing and inspection of the DER system and all payments for issued bills related to the interconnection process that are past due have been paid in full. Such authorization shall not be unreasonably withheld, conditioned or delayed.

10 Extension of Timelines

10.1. Reasonable Efforts

The Area EPS Operator shall make Reasonable Efforts to meet all time frames provided in these procedures. If the Area EPS Operator cannot meet a deadline provided herein, it must notify the Interconnection Customer in writing within three (3) Business Days after the deadline to explain the reason for the failure to meet the deadline and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

10.2. Extensions

For applicable time frames described in these procedures, the Interconnection Customer may request, in writing, one extension equivalent to half of the time originally allotted (e.g., ten (10) Business Days for a twenty (20) Business Days original time frame) which the Area EPS Operator may not unreasonably refuse. No further extensions for the applicable time frame shall be granted absent a Force Majeure Event or other similarly extraordinary circumstance.

11 Disputes

11.1. Procedures

The Parties agree in a good faith effort to attempt to resolve all disputes arising out of the interconnection process and associated study and Interconnection Agreements. The Parties agree to follow the established dispute resolution policy adopted by the Area EPS Operator.

12 Clauses

12.1. Confidentiality

Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures, design, operating specifications, and metering data provided by the Interconnection Customer may be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such. If requested by either Party, the other Party shall provide in writing the basis for asserting that the information warrants confidential treatment. Parties providing a Governmental Authority trade secret, privileged or otherwise not public or nonpublic data under Minnesota Government Data Practices Act, Minnesota Statute Chapter 13, shall identify such data consistent with the Commission's September 1, 1999 Revised Procedures for Handling Trade Secret and Privileged Data available online at: https://mn.gov/puc/puc-documents/#4.

Confidential Information does not include information previously in the public domain with proper authorization, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be publicly divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements that could not otherwise be fulfilled by not making the information public.

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

Critical infrastructure information or information that is deemed or otherwise designated by a Party as Critical Energy/Electric Infrastructure Information (CEII) pursuant to FERC regulation, 18 C.F.R. §388.133, as may be amended from time to time, may be subject to further protections for disclosure as required by FERC or FERC regulations or orders and the disclosing Party's CEII policies. Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

Confidential Information does not include information previously in the public domain with proper authorization, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be publicly divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements that could not otherwise be fulfilled by not making the information public.

Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages and may seek other remedies available at law or in equity for breach of this provision.

12.2. Non-Warranty

The Area EPS Operator does not give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, operated, installed or maintained by the Interconnection Customer, including without limitation the DER and any structures, equipment, wires, appliances or devices not owned, operated or maintained by the Area EPS Operator.

12.3. Indemnification

Each Party is protected from liability incurred to third parties as a result of carrying out the provisions of this interconnection process and subsequent interconnection agreements. The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

This indemnification obligation shall apply notwithstanding any negligent or intentional acts, errors or omissions of the indemnified Party, but the indemnifying Party's liability to indemnify the indemnified Party shall be reduced in proportion to the percentage by which the indemnified Party's negligent or intentional acts, errors or omissions caused the damages.

Neither Party shall be indemnified for its damages resulting from its sole negligence, intentional acts or willful misconduct. These indemnity provisions shall not be construed to relieve any insurer of its obligation to pay claims consistent with the provisions of a valid insurance policy.

If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

12.4. Limitation of Liability

Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for an indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under in Section 12.3.

13 Glossary

Affected System – Another Area EPS Operator's System, Transmission Owner's Transmission System, or Transmission System connected generation which may be affected by the proposed interconnection.

Applicant Agent – A person designated in writing by the Interconnection Customer to represent or provide information to the Area EPS on the Interconnection Customer's behalf throughout the interconnection process.

Area EPS – The electric power distribution system connected at the Point of Common Coupling.

Area EPS Operator – An entity that owns, controls, or operates the electric power distribution systems that are used for the provision of electric service in Minnesota. For this Interconnection Process the Area EPS Operator is Shakopee Public Utilities Commission.

Business Day – Monday through Friday, excluding Holidays as defined by Minn. Stat. §645.44, Subdivision 5. Any communication to have been sent or received after 4:30 p.m. Central Prevailing Time or on a Saturday, Sunday or holiday shall be considered to have been sent on the next Business Day.

Certified Equipment – Certified equipment is equipment that has been tested by a national recognized lab meeting a specific standard. For DER systems, UL 1741 listing is a common form of DER inverter certification. Additional information is seen in Section 15 and Section 14.

Confidential Information – Any confidential and/or proprietary information provided by one Party to the other Party and is clearly marked or otherwise designated "Confidential." All procedures, design, operating specifications, and metering data provided by the Interconnection Customer may be deemed Confidential Information. See Section 12.1 for further information.

Distributed Energy Resource (DER) – A source of electric power that is not directly connected to a bulk power system or central station service. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER. For the purpose of the Interconnection Process and interconnection agreements, the DER includes the Customer's Interconnection Facilities but shall not include the Area EPS Operator's Interconnection Facilities.

Distribution System – The Area EPS facilities which are not part of the Local EPS, Transmission System or any generation system.

Distribution Upgrades – The additions, modifications, and upgrades to the Distribution System at or beyond the Point of Common Coupling to facilitate interconnection of the DER and render the distribution service necessary to effect the Interconnection Customer's connection to the Distribution System. Distribution Upgrades do not include Interconnection Facilities.

Electric Power System (EPS) – The facilities that deliver electric power to a load.

Fast Track Process – The procedure as described in the Interconnection Process - Fast Track Process for evaluating an Interconnection Application for a DER that meets the eligibility requirements of Section 3.4.

Force Majeure Event – An act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, an order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or another cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and act which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Area EPS Operator, or any Affiliate thereof. The governing authority of the municipal utility is the authority governing interconnection requirements unless otherwise provided for in the Minnesota Technical Requirements.

Interconnection Agreement – The terms and conditions between the Area EPS Operator and Interconnection Customer (Parties). See Section 8 for when the Uniform Contract or Interconnection Agreement applies.

Interconnection Application – The Interconnection Customer's request to interconnect a new or modified, as described in Section 4, DER. See Simplified Application Form and Interconnection Application Form.

Interconnection Customer – The person or entity, including the Area EPS Operator, whom will be the owner of the DER that proposes to interconnect a DER(s) with the Area EPS Operator's Distribution System. The Interconnection Customer is responsible for ensuring the DER(s) is designed, operated and maintained in compliance with the Minnesota Technical Requirements.

Interconnection Facilities – The Area EPS Operator's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the DER and the Point of Common Coupling, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the DER to the Area EPS Operator's System. Some examples of Customer Interconnection Facilities include: supplemental DER devices, inverters, and associated wiring and cables up to the Point of DER Connection. Some examples of Area EPS Operator Interconnection Facilities include sole use facilities; such as, line extensions, controls, relays, switches, breakers, transformers and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Process – The Area EPS Operator's interconnection standards in this document.

Material Modification – A modification to machine data, equipment configuration or to the interconnection site of the DER at any time after receiving notification by the Area EPS Operator of a complete Interconnection Application that has a material impact on the cost, timing, or design of any Interconnection Facilities or Upgrades, or a material impact on the cost, timing or design of any Interconnection Application with a later Queue Position or the safety or reliability of the Area EPS.[6]

MN Technical Requirements – The term including all of the DER technical interconnection requirement documents for the state of Minnesota; including Attachment 2 Distributed Generation Interconnection Requirements established in the Commission's September 28, 2004 Order in E-999/CI-01-1023) until superseded and upon Commission approval of updated Minnesota DER Technical Interconnection and Interoperability Requirements in E-999/CI-16-521 (anticipated July 2019.)

Nameplate Rating – nominal voltage (V), current (A), maximum active power (kWac), apparent power (kVA), and reactive power (kVar) at which a DER is capable of sustained operation. For a Local EPS with multiple DER units, the aggregate nameplate rating is equal to the sum of all

[6] A Material Modification shall include, but may not be limited to, a modification from the approved Interconnection Application that: (1) changes the physical location of the point of common coupling; such that it is likely to have an impact on technical review; (2) increases the nameplate rating or output characteristics of the Distributed Energy Resource; (3) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (4) changes transformer connection(s) or grounding; and/or (5) changes to a certified inverter with different specifications or different inverter control settings or configuration. A Material Modification shall not include a modification from the approved Interconnection Application that: (1) changes the ownership of a Distributed Energy Resource; (2) changes the address of the Distributed Energy Resource, so long as the physical point of common coupling remains the same; (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; and/or (4) increases the DC/AC ratio but does not increase the maximum AC output capability of the Distributed Energy Resource in a way that is likely to have an impact on technical review.

DERs nameplate rating in the Local EPS. For purposes of the Attachment V in the Interconnection Agreement, the DER system's capacity may, with the Area EPS's agreement, be limited thought use of control systems, power relays or similar device settings or adjustments as identified in IEEE 1547. The nameplate ratings referenced in the Interconnection Process are alternating current nameplate DER ratings at the Point of DER Coupling.

Network Upgrades – Additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the DER interconnects with the Area EPS Operator's System to accommodate the interconnection with the DER to the Area EPS Operator's System. Network Upgrades do not include Distribution Upgrades.

Operating Requirements – Any operating and technical requirements that may be applicable due to the Transmission Provider's technical requirements or Minnesota Technical Requirements, including those set forth in the Interconnection Agreement.

Party or Parties – The Area EPS Operator and the Interconnection Customer.

Point of Common Coupling (PCC) – The point where the Interconnection Facilities connect with the Area EPS Operator's Distribution System. See figure 1. Equivalent, in most cases, to "service point" as specified by the Area EPS Operator and described in the National Electrical Code and the National Electrical Safety Code.

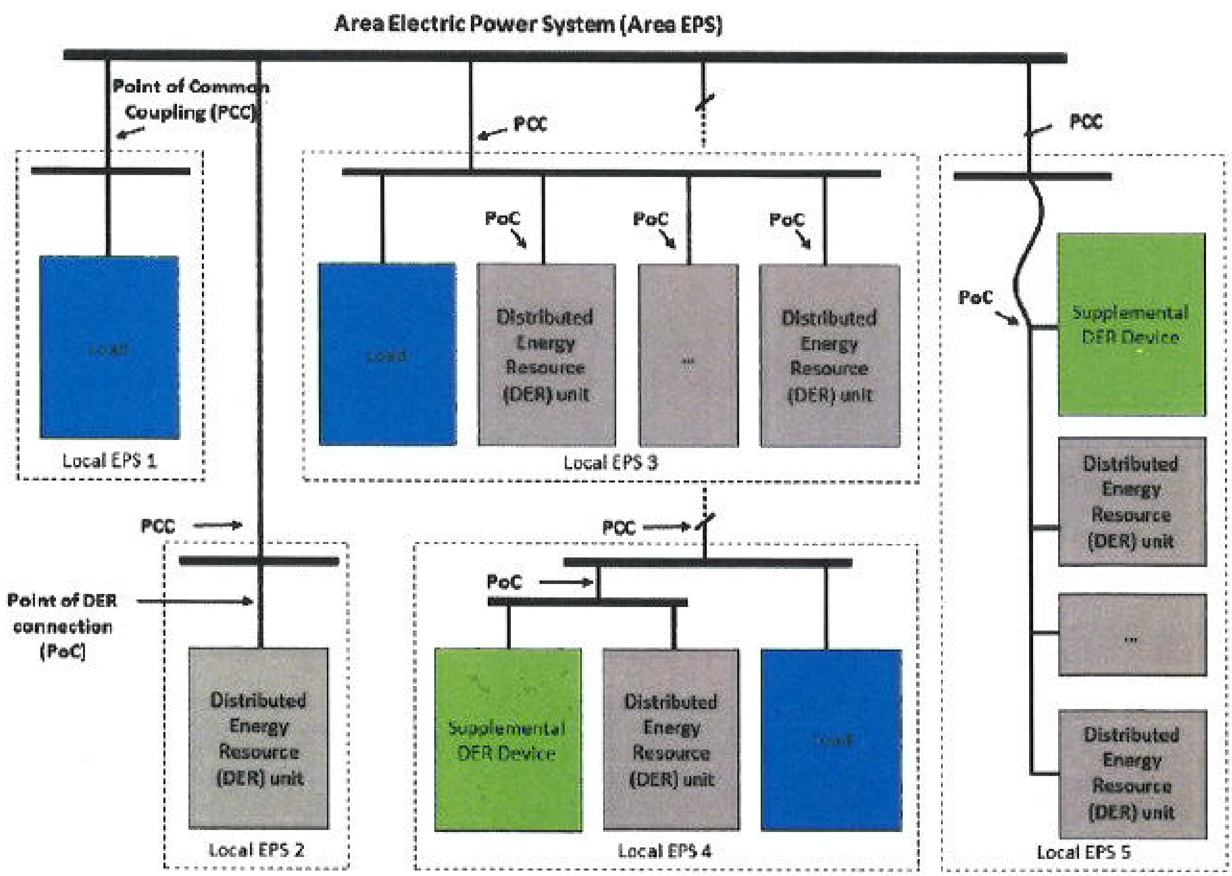

Figure 1: Point of Common Coupling and Point of DER Connection

(Source: IEEE 1547)

Point of DER Connection (PoC) – When identified as the Reference Point of Applicability, the point where an individual DER is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS (e.g. terminals of the inverter when no supplemental DER device is required.) For DER unit(s) that are not self-sufficient to meet the requirements without a supplemental DER device(s), the Point of DER Connection is the point where the requirements of this standard are met by DER in conjunction with a supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

Queue Position – The order of a valid Interconnection Application, relative to all other pending valid Interconnection Applications, that is established based upon the date- and time- of receipt of the complete Interconnection Application as described in Section 4.7.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under these procedures, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Reference Point of Applicability – The location, either the Point of Common Coupling or the Point of DER Connection, where the interconnection and interoperability performance requirements specified in IEEE 1547 apply. With mutual agreement, the Area EPS Operator and Customer may determine a point between the Point of Common Coupling and Point of DER Connection. See Minnesota Technical Requirements for more information.

Simplified Process – The procedure for evaluating an Interconnection Application for a certified inverter-based DER no larger than 20 kW that uses the screens described in the Interconnection Process – Simplified Process document. The Simplified Process includes simplified procedures.

Study Process – The procedure for evaluating an Interconnection Application that includes the scoping meeting, system impact study, and facilities study.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System relevant to the Interconnection.

Transmission Provider – The entity (or its designated agent) that owns, leases, controls, or operates transmission facilities used for the transmission of electricity. The term Transmission Provider includes the Transmission Owner when the Transmission Owner is separate from the Transmission Provider. The Transmission Provider may include the Independent System Operator or Regional Transmission Operator.

Transmission System – The facilities owned, leased, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service. See the

Commission's July 26, 2000 Order Adopting Boundary Guidelines for Distinguishing Transmission from Generation and Distribution Assets in Docket No. E-999/CI-99-1261.

Uniform Contract – the Area EPS Operator's Agreement for Cogeneration and Small Power Production Facilities (Uniform Contract) that may be applied to all qualifying new and existing interconnections between the Area EPS Operator and an DER system having capacity less than 40 kilowatts.

Upgrades – The required additions and modifications to the Area EPS Operator's Transmission or Distribution System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

14 Certification of DER Equipment

Distributed Energy Resource (DER) equipment proposed for use in an interconnection system shall be considered certified for interconnected operation if the following criteria is met:

1) It has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in the Overview Process,

2) It has been labeled and is publicly listed by such NRTL at the time of the interconnection application and,

3) Such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

The Interconnection Customer must verify that the assembly and use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for a DER Design Evaluation or an on-site commissioning test by the parties to the interconnection as provided for in the Minnesota Technical Requirements.

If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further type-test review, testing or additional equipment on the customer side of the Point of Common Coupling shall be required to be considered certified for the purposes of this interconnection procedure; however, nothing herein shall preclude the need for a DER Design Evaluation or an on-site commissioning test by the parties to the interconnection as provided for in the Minnesota Technical Requirements.

An equipment package does not include equipment provided by the Area EPS.

15 Certification Codes and Standards

The existing Minnesota Technical Requirements and the following standards shall be used in conjunction with the Interconnection Process. The process has started to update the Technical Requirements to meet IEEE 1547-2018. Once that process is completed, the updated DER Technical Interconnection and Interoperability Requirements will supersede this section.

When the stated version of the following standards is superseded by an approved revision then that revision shall apply:

IEEE 1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547a-2014 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1

IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547.1a-2015 (Amendment to IEEE Std 1547.1-2005) IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems – Amendment 1

UL 1741 Inverters, Converters, Controllers, and Interconnection System Equipment for Use in Distributed Energy Resources (2010)

NFPA 70 (2017), National Electrical Code

IEEE Std C37.90.1 (2012) (Revision of IEEE Std C37.90.1-2002), IEEE Standard for Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems Associated with Electric Power Apparatus

IEEE Std C37.90.2 (2004) (Revision of IEEE Std C37.90.2-1995), IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-20021989 (Revision of C37.108-19892002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2014 (Revision of IEEE Std C57.12.44-2005), IEEE Standard Requirements for Secondary Network Protectors

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

IEEE Std C62.41.2-2002_Cor 1-2012 (Corrigendum to IEEE Std C62.41.2-2002) – IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits Corrigendum 1: Deletion of Table A.2 and Associated Text

IEEE Std C62.45-2002 (Revision of IEEE Std C62.45-1992) – IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and less) AC Power Circuits

ANSI C84.1-(2016) Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Standards Dictionary Online, [Online]

NEMA MG 1-2016, Motors and Generators

IEEE Std 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

SCHEDULE 4 – UTILITY AVOIDED ENERGY, CAPACITY AND RENEWABLE ENERGY CREDIT RATES

Qualifying Facilities that qualify and select the Simultaneous Purchase and Sale or Time-of-Day rates for compensation from Utility for all generation shall be compensated by Utility as detailed in Parts N and O of the Utility's Rules Governing the Interconnection of Cogeneration and Small Power Productions Facilties. Compensation will be based on the rates as follows:

	Energy ($/kWh)	Capacity ($/kWh)	REC ($/kWh)
Summer Months (June-Sept)			
On Peak	$0.0329	$0.0000	$0.0000
Off Peak	$0.0215	$0.0000	$0.0000
All Hours	$0.0267	$0.0000	$0.0000
Winter Months (Oct-May)			
On Peak	$0.0312	$0.0000	$0.0000
Off Peak	$0.0233	$0.0000	$0.0000
All Hours	$0.0270	$0.0000	$0.0000
Annual (January-December)	$0.0269	$0.0000	$0.0000

11a

Shakopee Public Utilities

"Lighting the Way – Yesterday, Today and Beyond"

April 11, 2019

TO: John Crooks, Utilities Manager

FROM: Sharon Walsh, Director of Marketing and Customer Relations

SUBJECT: 2019 Tom Bovitz Scholarship Award Recipient

Overview

Each year SPU partners with MMUA to sponsor the Tom Bovitz Memorial Scholarship. The SPU scholarship is offered to high school seniors who have plans to attend a post-secondary educational institution and who are, or have legal guardians who are, customers of SPU. Students participate in an essay competition interpreting one or more aspects of the theme, "Municipal Utilities: Good For All of Us."

SPU awards a first place scholarship in the amount of $1000 and a second place scholarship in the amount of $500. The first place winner will have their essay submitted to the MMUA to compete at the state level. This winner will have the opportunity to earn an additional scholarship of $500, $1000, $1500 or $2000, depending on their placement in the state competition.

Commissioners review all submissions (absent entrant identity) and the submissions are ranked on content, grammar and overall quality. We are happy to announce the 2019 1st Place SPU Tom Bovitz Memorial Scholarship goes to Shelby Zander.

Action Requested

No action is required.

Post Office Box 470 • 255 Sarazin Street • Shakopee, Minnesota 55379-0470
(952) 445-1988 • Fax (952) 445-7767 • www.spucweb.com

11c

SHAKOPEE PUBLIC UTILITIES

"Lighting the Way – Yesterday, Today and Beyond"

April 11, 2019

TO: John Crooks

CC: Joe Adams
Sherri Anderson
Greg Drent
Lon Schemel
Sharon Walsh

FROM: Renee Schmid, Director of Finance and Administration

SUBJECT: Financial Results for March, 2019

The following Financial Statements are attached for your review and approval.

Month to Date & Year to Date Financial Results – March, 2019

- Combined Statement of Revenue & Expense and Net Assets – Electric, Water and Total Utility
- Electric Operating Revenue & Expense Detail
- Water Operating Revenue & Expense Detail

Key items to note:

Month to Date Results – March, 2019

- Total Utility Operating Revenues for the month of March totaled \$3.8 million and were unfavorable to budget by \$265k or 6.5%. Electric revenues were unfavorable to budget by \$246k or 6.5% driven by lower than plan power cost adjustment revenues and lower than plan energy sales in the residential and industrial revenue groups. Water revenues were also unfavorable to budget by \$19k or 6.6% due to lower than plan sales in all revenue groups.
- Total operating expenses were \$3.7 million and were unfavorable to budget by \$41k or 1.1%. Total purchased power in March was \$2.6 million and was \$133k or 5.4% higher than budget for the month. Total Operating Expense for electric including purchased power totaled \$3.3 million and was unfavorable to budget by \$77k or 2.4% due to higher than plan purchased power costs of \$133k and depreciation expense of \$3k, that were partially offset by lower than plan expenses due to timing in customer accounts of \$13k, administrative and general expenses of \$13k, and operation and maintenance expenses of \$33k. Total Operating Expense for Water totaled \$381k and was favorable to budget by \$36k or 8.5% due timing of expenditures in operation and maintenance of \$24k, administrative and general expenses of \$15k, depreciation of \$4k, and partially offset by higher than plan expense in customer accounts of \$8k. The month of March included three payroll periods causing some of the variances versus the monthly budget amounts which is straight lined.

- Total Utility Operating Income was $71k and was $306k unfavorable to budget due to lower than plan operating revenues of $265k and higher than plan operating expenses of $41k.
- Total Utility Non-Operating Revenue was $294k and was favorable to budget by $198k driven by higher than plan rental and miscellaneous income of $88k due to billing for water main plan review inspections, and higher than plan investment income of $110k.
- Capital Contributions for the month of March totaled $768k and were favorable to budget by $508k due to timing of collection of trunk water fees of $166k and water connection fees of $341k.
- Transfers to the City of Shakopee totaled $210k and were very slightly lower than budget for the month by 0.1%.
- Change in Net Position was $0.9 million and was favorable to budget by $0.4 million primarily due to higher than plan non-operating income of $0.2 million and higher than plan capital contributions of $0.5 million, that were partially offset by lower than plan operating income of $0.3 million.
- Electric usage billed to customers in March was 34,150,222 kWh, a decrease of 21.2% from February usage billed at 43,345,001 kWh.
- Water usage billed to customers in March was 82.0 million gallons, a decrease of 15.8% from February usage billed at 97.4 million gallons.

Year to Date Financial Results – March, 2019

- Total Utility Operating Revenue year to date March was $12.9 million and was favorable to budget by $0.7 million or 5.6%. Electric revenues totaled $12.1 million and were favorable to budget by $643k or 5.6% driven by higher than plan energy sales in all revenue groups and partially offset by lower than plan power cost adjustment revenue. Average cost per kWh purchased in first quarter 2019 was 7.1196 cents per kWh versus a planned cost per kWh of 7.0958 cents per kWh for first quarter 2019 which results in lower power cost adjustment revenue that was partially offset by higher energy sales volume. Water revenues totaled $0.9 million and were also favorable to budget by $40k or 4.8% driven by higher than plan sales volumes in the residential revenue group.
- Total Utility Operating Expenses year to date March were $11.2 million and were favorable to budget by $224k or 2.0% primarily due to timing of expenditures in energy conservation of $129k, administrative and general expense of $105k of which $99k is in outside services, operations and maintenance expense in electric and water of $54k due to timing, and depreciation expense of $3k, that were partially offset by higher than plan purchased power costs of $66k due to higher sales. Total Operating Expense for electric including purchased power was $10.0 million and was favorable to budget by $0.1 million or 1.4%. Total Operating Expense for Water was $1.2 million and was also favorable to budget by $0.1 million or 6.6%.
- Total Utility Operating Income was $1.7 million and was favorable to budget by $0.9 million driven by higher than planned operating revenues of $0.7 million and lower than plan operating expenses of $0.2 million.
- Total Utility Non-Operating Income was $719k and was favorable to budget by $394k due to higher than planned investment income of $268k, higher than plan rental and miscellaneous income of $97k due to timing, $26k net gain on the sale of electric vehicles and equipment, and lower than plan interest expense on customer deposits of $3k.

- YTD Capital Contributions were $1.2 million and are favorable to budget by $478k due to timing of collection of trunk water fees of $106k and timing of collection of water connection fees of $371k.
- Municipal contributions to the City of Shakopee totaled $630k year to date and are lower than plan by $2k or 0.2%. The actual estimated payment throughout the year is based on prior year results and will be trued up at the end of the year.
- YTD Change in Net Position is $3.1 million and is favorable to budget by $1.8 million reflecting higher than plan operating revenues, lower than operating expense, higher than plan non-operating revenues, and higher than plan capital contributions.

SHAKOPEE PUBLIC UTILITIES

YEAR TO DATE FINANCIAL RESULTS

MARCH 2019

SHAKOPEE PUBLIC UTILITIES
"Lighting the Way – Yesterday, Today and Beyond"

SHAKOPEE PUBLIC UTILITIES
COMBINED STATEMENT OF REVENUES, EXPENSES AND CHANGES IN FUND NET POSITION

	Year to Date Actual - March 2019			Year to Date Budget - March 2019			Electric YTD Actual v. Budget B/(W)		Water YTD Actual v. Budget B/(W)		Total Utility YTD Actual v. Budget B/(W)	
	Electric	Water	Total Utility	Electric	Water	Total Utility	$	%	$	%	$	%
OPERATING REVENUES	$ 12,079,058	891,089	12,970,148	11,435,782	850,648	12,286,430	643,277	5.6%	40,441	4.8%	683,717	5.6%
OPERATING EXPENSES						-						
Operation, Customer and Administrative	9,390,625	791,546	10,182,171	9,538,944	864,601	10,403,546	148,320	1.6%	73,055	8.4%	221,375	2.1%
Depreciation	618,213	410,741	1,028,954	607,954	423,281	1,031,235	(10,259)	-1.7%	12,540	3.0%	2,281	0.2%
Amortization of Plant Acquisition	-	-	-	-	-	-	-	0.0%	-	-	-	0.0%
Total Operating Expenses	10,008,837	1,202,287	11,211,125	10,146,899	1,287,882	11,434,781	138,061	1.4%	85,595	6.6%	223,656	2.0%
Operating Income	2,070,221	(311,198)	1,759,023	1,288,883	(437,234)	851,650	781,338	60.6%	126,036	28.8%	907,373	106.5%
NON-OPERATING REVENUE (EXPENSE)												
Rental and Miscellaneous	65,155	218,984	284,139	50,904	135,687	186,591	14,251	28.0%	83,297	61.4%	97,548	52.3%
Interdepartment Rent from Water	22,500	-	22,500	22,500		22,500	-	0.0%	-	-	-	0.0%
Investment Income	250,851	152,848	403,698	80,948	54,379	135,328	169,902	209.9%	98,468	181.1%	268,371	198.3%
Interest Expense	(16,175)	(515)	(16,690)	(18,981)	(485)	(19,467)	2,807	14.8%	(29)	-6.1%	2,777	14.3%
Amortization of Debt Issuance Costs and Loss on Refunding	-	-	-	-	-	-	-	#DIV/0!	-	0.0%	-	#DIV/0!
Gain/(Loss) on the Disposition of Property	25,777	-	25,777	-	-	-	25,777	0.0%	-	-	25,777	-
Total Non-Operating Revenue (Expense)	348,108	371,317	719,424	135,371	189,581	324,952	212,737	157.2%	181,736	95.9%	394,473	121.4%
Income Before Contributions and Transfers	2,418,329	60,119	2,478,447	1,424,254	(247,653)	1,176,602	994,075	69.8%	307,771	124.3%	1,301,846	110.6%
CAPITAL CONTRIBUTIONS	-	1,258,359	1,258,359	-	780,087	780,087	-	-	478,272	61.3%	478,272	61.3%
MUNICIPAL CONTRIBUTION	(356,715)	(272,969)	(629,684)	(361,617)	(269,645)	(631,261)	4,902	1.4%	(3,324)	-1.2%	1,577	0.2%
CHANGE IN NET POSITION	$ 2,061,614	1,045,508	3,107,122	1,062,637	262,790	1,325,427	998,976	94.0%	782,719	297.8%	1,781,695	134.4%

SHAKOPEE PUBLIC UTILITIES
ELECTRIC OPERATING REVENUE AND EXPENSE

		YTD Actual March 2019	YTD Budget March 2019	YTD Actual v. Budget Better/(Worse) $	%
OPERATING REVENUES					
Sales of Electricity					
Residential	$	4,348,199	4,106,940	241,259	5.9%
Commercial and Industrial		7,454,912	7,069,477	385,435	5.5%
Uncollectible accounts		-	-	-	#DIV/0!
Total Sales of Electricity		11,803,111	11,176,417	626,694	5.6%
Forfeited Discounts		78,519	64,495	14,025	21.7%
Free service to the City of Shakopee		21,374	21,005	369	1.8%
Conservation program		176,055	173,866	2,189	1.3%
Total Operating Revenues		12,079,058	11,435,782	643,277	5.6%
OPERATING EXPENSES					
Operations and Maintenance					
Purchased power		7,775,114	7,709,447	(65,667)	-0.9%
Distribution operation expenses		102,045	118,225	16,180	13.7%
Distribution system maintenance		156,110	184,152	28,042	15.2%
Maintenance of general plant		100,662	82,188	(18,474)	-22.5%
Total Operation and Maintenance		8,133,931	8,094,013	(39,919)	-0.5%
Customer Accounts					
Meter Reading		30,820	32,937	2,117	6.4%
Customer records and collection		141,132	131,325	(9,807)	-7.5%
Energy conservation		58,356	187,146	128,790	68.8%
Total Customer Accounts		230,308	351,409	121,101	34.5%
Administrative and General					
Administrative and general salaries		161,116	172,085	10,969	6.4%
Office supplies and expense		87,931	56,558	(31,373)	-55.5%
Outside services employed		50,136	110,967	60,832	54.8%
Insurance		35,514	44,889	9,375	20.9%
Employee Benefits		557,476	610,902	53,426	8.7%
Miscellaneous general		134,213	98,123	(36,090)	-36.8%
Total Administrative and General		1,026,385	1,093,523	67,138	6.1%
Total Operation, Customer, & Admin Expenses		9,390,625	9,538,944	148,320	1.6%
Depreciation		618,213	607,954	(10,259)	-1.7%
Amortization of plant acquisition		-	-	-	0.0%
Total Operating Expenses	$	10,008,837	10,146,899	138,061	1.4%
OPERATING INCOME	$	2,070,221	1,288,883	781,338	60.6%

SHAKOPEE PUBLIC UTILITIES
WATER OPERATING REVENUE AND EXPENSE

		YTD Actual March 2019	YTD Budget March 2019	YTD Actual v. Budget Better/(Worse) $	%
OPERATING REVENUES					
Sales of Water	$	885,097	844,934	40,163	4.8%
Forfeited Discounts		5,991	5,714	277	4.9%
Uncollectible accounts		1	-	1	#DIV/0!
Total Operating Revenues		891,089	850,648	40,441	4.8%
OPERATING EXPENSES					
Operations and Maintenance					
Pumping and distribution operation		108,918	131,705	22,787	17.3%
Pumping and distribution maintenance		94,820	119,811	24,991	20.9%
Power for pumping		76,344	78,004	1,660	2.1%
Maintenance of general plant		35,605	14,048	(21,558)	-153.5%
Total Operation and Maintenance		315,688	343,568	27,880	8.1%
Customer Accounts					
Meter Reading		17,272	17,352	80	0.5%
Customer records and collection		39,587	36,443	(3,144)	-8.6%
Energy conservation		-	-	-	-
Total Customer Accounts		56,859	53,795	(3,064)	-5.7%
Administrative and General					
Administrative and general salaries		104,972	113,717	8,745	7.7%
Office supplies and expense		30,900	17,298	(13,602)	-78.6%
Outside services employed		10,472	49,233	38,762	78.7%
Insurance		11,838	14,963	3,125	20.9%
Employee Benefits		189,015	217,518	28,503	13.1%
Miscellaneous general		71,802	54,509	(17,293)	-31.7%
Total Administrative and General		418,999	467,238	48,239	10.3%
Total Operation, Customer, & Admin Expenses		791,546	864,601	73,055	8.4%
Depreciation		410,741	423,281	12,540	3.0%
Amortization of plant acquisition		-	-	-	-
Total Operating Expenses	$	1,202,287	1,287,882	85,595	6.6%
OPERATING INCOME	$	(311,198)	(437,234)	126,036	28.8%

SHAKOPEE PUBLIC UTILITIES

MONTH TO DATE FINANCIAL RESULTS

MARCH 2019

SHAKOPEE PUBLIC UTILITIES
"Lighting the Way – Yesterday, Today and Beyond"

SHAKOPEE PUBLIC UTILITIES
COMBINED STATEMENT OF REVENUES, EXPENSES AND CHANGES IN FUND NET POSITION

	Month to Date Actual - March 2019			Month to Date Budget - March 2019			Electric MTD Actual v. Budget B/(W)		Water MTD Actual v. Budget B/(W)		Total Utility MTD Actual v. Budget B/(W)	
	Electric	Water	Total Utility	Electric	Water	Total Utility	$	%	$	%	$	%
OPERATING REVENUES	$ 3,517,791	269,647	3,787,437	3,763,466	288,610	4,052,077	(245,676)	-6.5%	(18,964)	-6.6%	(264,639)	-6.5%
OPERATING EXPENSES						-						
Operation, Customer and Administrative	3,128,722	244,008	3,372,729	3,055,520	275,375	3,330,895	(73,202)	-2.4%	31,368	11.4%	(41,834)	-1.3%
Depreciation	206,071	136,914	342,985	202,651	141,094	343,745	(3,420)	-1.7%	4,180	3.0%	760	0.2%
Amortization of Plant Acquisition	-	-	-	-	-	-	-	0.0%	-	-	-	0.0%
Total Operating Expenses	3,334,793	380,921	3,715,714	3,258,171	416,469	3,674,640	(76,622)	-2.4%	35,548	8.5%	(41,074)	-1.1%
Operating Income	182,998	(111,275)	71,723	505,295	(127,859)	377,437	(322,297)	-63.8%	16,584	13.0%	(305,713)	-81.0%
NON-OPERATING REVENUE (EXPENSE)												
Rental and Miscellaneous	30,420	106,596	137,016	16,968	32,428	49,396	13,452	79.3%	74,168	228.7%	87,620	177.4%
Interdepartment Rent from Water	7,500	-	7,500	7,500		7,500	-	0.0%	-	-	-	0.0%
Investment Income	118,639	36,155	154,794	26,983	18,126	45,109	91,656	339.7%	18,029	99.5%	109,685	243.2%
Interest Expense	(5,511)	(183)	(5,694)	(6,327)	(162)	(6,489)	816	12.9%	(21)	-12.8%	795	12.3%
Amortization of Debt Issuance Costs and Loss on Refunding	-	-	-	-	-	-	-	#DIV/0!	-	-	-	#DIV/0!
Gain/(Loss) on the Disposition of Property	-	-	-	-	-	-	-	-	-	-	-	0.0%
Total Non-Operating Revenue (Expense)	151,048	142,569	293,617	45,124	50,393	95,516	105,925	234.7%	92,176	182.9%	198,101	207.4%
Income Before Contributions and Transfers	334,046	31,294	365,340	550,419	(77,466)	472,953	(216,373)	-39.3%	108,760	140.4%	(107,613)	-22.8%
CAPITAL CONTRIBUTIONS	-	767,675	767,675	-	260,029	260,029	-	-	507,646	195.2%	507,646	195.2%
TRANSFER TO MUNICIPALITY	(119,125)	(91,000)	(210,125)	(120,539)	(89,882)	(210,420)	1,414	1.2%	(1,118)	-1.2%	296	0.1%
CHANGE IN NET POSITION	$ 214,922	707,969	922,891	429,880	92,681	522,561	(214,958)	-50.0%	615,288	663.9%	400,330	76.6%

SHAKOPEE PUBLIC UTILITIES
ELECTRIC OPERATING REVENUE AND EXPENSE

		MTD Actual March 2019	MTD Budget March 2019	MTD Actual v. Budget Better/(Worse) $	%
OPERATING REVENUES					
Sales of Electricity					
Residential	$	1,248,153	1,325,450	(77,297)	-5.8%
Commercial and Industrial		2,179,544	2,351,994	(172,450)	-7.3%
Uncollectible accounts		-	-	-	-
Total Sales of Electricity		3,427,698	3,677,444	(249,746)	-6.8%
Forfeited Discounts		31,886	21,498	10,388	48.3%
Free service to the City of Shakopee		7,125	7,002	123	1.8%
Conservation program		51,083	57,523	(6,440)	-11.2%
Total Operating Revenues		3,517,791	3,763,466	(245,676)	-6.5%
OPERATING EXPENSES					
Operations and Maintenance					
Purchased power		2,617,388	2,484,162	(133,226)	-5.4%
Distribution operation expenses		(1,243)	39,408	40,651	103.2%
Distribution system maintenance		55,040	61,384	6,344	10.3%
Maintenance of general plant		40,822	27,396	(13,426)	-49.0%
Total Operation and Maintenance		2,712,007	2,612,351	(99,657)	-3.8%
Customer Accounts					
Meter Reading		12,616	10,979	(1,637)	-14.9%
Customer records and collection		67,309	43,775	(23,534)	-53.8%
Energy conservation		23,668	62,382	38,715	62.1%
Total Customer Accounts		103,592	117,136	13,544	11.6%
Administrative and General					
Administrative and general salaries		63,975	57,362	(6,613)	-11.5%
Office supplies and expense		6,048	18,853	12,805	67.9%
Outside services employed		18,746	36,989	18,243	49.3%
Insurance		11,838	14,963	3,125	20.9%
Employee Benefits		160,885	165,159	4,274	2.6%
Miscellaneous general		51,631	32,708	(18,923)	-57.9%
Total Administrative and General		313,122	326,033	12,911	4.0%
Total Operation, Customer, & Admin Expenses		3,128,722	3,055,520	(73,202)	-2.4%
Depreciation		206,071	202,651	(3,420)	-1.7%
Amortization of plant acquisition		-	-	-	0.0%
Total Operating Expenses	$	3,334,793	3,258,171	(76,622)	-2.4%
OPERATING INCOME	$	182,998	505,295	(322,297)	-63.8%

SHAKOPEE PUBLIC UTILITIES
WATER OPERATING REVENUE AND EXPENSE

		MTD Actual March 2019	MTD Budget March 2019	MTD Actual v. Budget Better/(Worse) $	%
OPERATING REVENUES					
Sales of Water	$	267,284	286,706	(19,422)	-6.8%
Forfeited Discounts		2,363	1,905	458	24.0%
Uncollectible accounts		-	-	-	-
Total Operating Revenues		269,647	288,610	(18,964)	-6.6%
OPERATING EXPENSES					
Operations and Maintenance					
Pumping and distribution operation		16,602	43,902	27,300	62.2%
Pumping and distribution maintenance		40,765	39,937	(828)	-2.1%
Power for pumping		24,991	26,001	1,011	3.9%
Maintenance of general plant		8,065	4,683	(3,383)	-72.2%
Total Operation and Maintenance		90,423	114,523	24,099	21.0%
Customer Accounts					
Meter Reading		7,544	5,784	(1,760)	-30.4%
Customer records and collection		18,388	12,148	(6,240)	-51.4%
Energy conservation		-	-	-	-
Total Customer Accounts		25,932	17,932	(8,000)	-44.6%
Administrative and General					
Administrative and general salaries		41,429	37,906	(3,524)	-9.3%
Office supplies and expense		2,597	5,766	3,169	55.0%
Outside services employed		5,315	16,411	11,096	67.6%
Insurance		3,946	4,988	1,042	20.9%
Employee Benefits		57,289	59,681	2,392	4.0%
Miscellaneous general		17,077	18,170	1,093	6.0%
Total Administrative and General		127,652	142,921	15,269	10.7%
Total Operation, Customer, & Admin Expenses		244,008	275,375	31,368	11.4%
Depreciation		136,914	141,094	4,180	3.0%
Amortization of plant acquisition		-	-	-	-
Total Operating Expenses		380,921	416,469	35,548	8.5%
OPERATING INCOME	$	(111,275)	(127,859)	16,584	13.0%