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July 31, 2017

—Via Electronic Filing—

Mr. William Grant
Deputy Commissioner, Division of Energy Resources
Minnesota Department of Commerce
85 7th Place East, Suite 500
St. Paul, MN 55101-2198

RE: AVOIDED TRANSMISSION AND DISTRIBUTION COST STUDY FOR ELECTRIC
2017-2019 CONSERVATION IMPROVEMENT PROGRAM TRIENNIAL PLANS
DOCKET NO. E999/CIP-16-541 & CIP SPECIAL SERVICE LIST

Dear Deputy Commissioner Grant:

Northern States Power Company, doing business as Xcel Energy, on behalf of itself, Minnesota Power, Otter Tail Power Company, and the Mendota Group, LLC submits to the Minnesota Department of Commerce, Division of Energy Resources (Department) this Avoided Transmission and Distribution Cost Study in response to the Deputy Commissioner's May 23, 2016; September 12, 2016; and March 22, 2017 Decisions.

Please contact me at shawn.m.white@xcelenergy.com or 612-330-6096 if you have any questions regarding this filing.

Sincerely,

/s/

SHAWN WHITE
MANAGER, DSM REGULATORY STRATEGY AND PLANNING

Enclosures

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Minnesota Transmission and Distribution Avoided Cost Study

Xcel Energy, Minnesota Power, Otter Tail Power
Company with The Mendota Group, LLC/Energy &
Environmental Economics (Third Party Evaluator)

July 31, 2017

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Executive Summary

Estimating transmission and distribution (T&D) costs avoided by energy efficiency is a challenge for all utilities. Unlike generation avoided costs, which can use proxy generators (for capacity) and system forecast marginal energy costs (for energy), T&D costs have no easy proxy. In addition, transmission and distribution systems are very diverse, and heavily impacted by local factors, such as area load growth, the existing load carrying capacity in each area, and project backlog.

The Minnesota Department of Commerce in a September 2016 decision ordered that utilities, with assistance and input from a third-party evaluator and a technical advisory committee, recalculate their estimates of transmission and distribution costs avoided by energy efficiency. Upon completion, the utilities are to submit a final report that includes the utilities' updated T&D avoided costs and a standardized methodology for estimating such costs.

This report provides these revised estimates of transmission and distribution costs avoided by energy efficiency investments for Xcel Energy, Minnesota Power and Otter Tail Power Company (the IOUs) and a proposed standardized methodology for estimating such costs. The eight-month process that led to this report included a substantive dialogue between the IOUs, the third-party evaluator, Department of Commerce staff, and the technical advisory committee. The IOUs performed in-depth modeling and examined what current systems (software, metering, monitoring, etc.) were capable of providing to develop these estimates. The resulting approaches to estimating avoided T&D costs differ somewhat between utilities, in part, because the data available to utilities varies based on the system information required to successfully operate each utility.

This report recommends that utilities use the Continuous Valuation approach to estimate their avoided T&D costs and that the Department of Commerce adopt the values proposed by each utility for the 2018-2019 portion of the current Triennial Conservation Improvement Program (CIP). The following pages provide background, description of the two proposed methodologies, utility write-ups regarding their estimates of avoided costs using the two proposed methodologies, utility pro / con assessments of the methodologies, and the Third-Party Evaluator's assessment of utility estimates and recommended methodology.

A. Background

As part of their review of Minnesota electric investor owned utilities' (IOU) 2017 - 2019 Conservation Improvement Program Triennial Plans, Minnesota Department of Commerce, Division of Energy Resources staff assessed the methodologies used to develop avoided costs and the associated avoided cost values incorporated into cost effectiveness (CE) evaluations. Staff defined avoided costs as follows, "Electric utility investment in demand-side management (DSM) can enable utilities to avoid or defer supply-side investments in peak capacity, energy, transmission, distribution, and even ancillary services."¹ This assessment resulted in the Deputy Commissioner's May 23, 2016 Decision approving utilities' 2017 avoided generating capacity, marginal energy costs and transmission and distribution (T&D) costs for use in IOU 2017-2019 evaluations of cost effectiveness. However, the Decision did "not accept (*for 2018-2019*) these utilities' avoided T&D costs until a study is completed to justify the reasonableness and accuracy of utilities' avoided T&D costs."²

On September 12, 2016, the Deputy Commissioner ordered that utilities:

- conduct the study using a system planning approach, and adapt as appropriate,
- hire a third-party evaluator to assist with the process,
- convene a Technical Advisory Committee (TAC) to ensure that there is independent review and a standardized process to conduct the study, and
- produce a final report that include utilities' updated T&D avoided costs and a standardized methodology for estimating such costs that can be used in future CIP Triennial cycles.³

The utilities subsequently issued a Request for Proposals and in late November hired The Mendota Group, LLC (Mendota Group) as the Third-Party Evaluator (TPE).⁴ The utilities filed a Scope of Work (SOW) for the T&D Study on December 7, 2016. Department Staff provided the TPE a list of members for the TAC and the first meeting of the TAC was held on December 15, 2016 (TAC members are listed in Appendix A). After reviewing the original SOW, Department Staff on December 22, 2016 submitted comments recommending the Deputy Commissioner extend the timeline so the utilities could revise the SOW and incorporate any feedback from the

¹"Proposal Filing – Avoided Electric Cost Assumptions for the 2017-2019 Conservation Improvement Program Triennial Plan (Docket Nos. CIP-16-115, CIP-16-116, CIP-16-117, CI-08-133)", Minnesota Department of Commerce, March 17, 2016, p. 1.

²"Decision," *In the Matter of Avoided Electric Cost Assumptions For 2017-2019 CIP Triennials (Docket Nos. CIP-16-115, CIP-16-116, CIP-16-117, CI-08-133)*, Minnesota Department of Commerce, May 23, 2016.

³"Decision," *In the Matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 CIP Triennial Plan (Docket No. E999/CIP-16-541)*, Minnesota Department of Commerce, September 12, 2016.

⁴The Third-Party Evaluator is The Mendota Group, LLC and its subcontractor, Energy and Environmental Economics, Inc. (E3).

TAC and other stakeholders.⁵ Also, on December 22, 2016, the Mendota Group filed comments providing more information on methodologies for calculating avoided T&D costs.⁶

The utilities, with assistance from the Third-Party Evaluator and feedback from stakeholders, drafted a revised SOW for the T&D study and filed it on March 1, 2017. The Deputy Commissioner approved the Scopes of Work on March 22, 2017.⁷

With this report, the utilities have fulfilled the requirements from the Deputy Commissioner's September 12, 2016 Decision. The process and its findings described by this report satisfy the first three elements itemized above and the report itself fulfills the last item.

⁵ "Comments," *In the Matter of Avoided Transmission and Distribution Cost Study for 2017-2019 Electric Conservation Improvement Program Triennial Plans (Docket No. E999/CIP-16/541)*, Staff of the Minnesota Department of Commerce, December 22, 2016.

⁶ "Comments from the Third-Party Evaluator," *In the Matter of Avoided Transmission and Distribution Cost Study for 2017-2019 Electric Conservation Improvement Program Triennial Plans (Docket No. E999/CIP-16/541)*, The Mendota Group, LLC and Energy and Environmental Economics, Inc., December 22, 2016.

⁷ "Scope of Work," *In the Matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 CIP Triennial Plan (Docket No. E999/CIP-16-541)*, Northern States Power d/b/a Xcel Energy, Minnesota Power, Otter Tail Power Company, and the Mendota Group, March 1, 2017. "Decision," *In the Matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 CIP Triennial Plans (Docket No. E999/CIP-16-541)*, Minnesota Department of Commerce, March 22, 2017.

B. Description of Methodologies

As directed by the Deputy Commissioner in his September 12, 2016 Decision, the utilities used the System Planning Method for determining T&D Avoided Costs. This methodology is defined in the U.S. Environmental Protection Agency's (EPA) report: *Assessing the Multiple Benefits of Clean Energy*. The report describes the system planning method:

The system planning approach uses projected costs and projected load growth for specific T&D projects based on the results from a system planning study – a rigorous engineering study of the electric system to identify site-specific system upgrade needs. Other data requirements include site-specific investment and load data. This approach assesses the difference between the present value of original T&D investment projects and the present value of deferred T&D projects.⁸

The TPE, in its December 22 Comments, explained that there were two ways of applying the System Planning Method, namely the Discrete and the Continuous Valuation with Statistical Peak Coincident Allocation Factor (PCAF) approaches.⁹ The Peak Capacity Allocation Factor can be applied to either the Discrete or the Continuous Valuation approach. Therefore, PCAF is explained separately below. During the course of the study, though, PCAFs were usually associated with the Continuous Valuation approach as this was the TPE's preferred method as stated in its Comments.

Discrete Approach

As described above in the EPA's system planning approach definition, the Discrete approach looks at T&D investments with and without the energy efficiency (EE) impacts on the T&D system. The differences in those costs are totaled and divided by the amount of the EE impacts. A more detailed explanation of this approach is provided in Appendix B and applications of this approach are provided by the utilities in their sections of the report (except for Otter Tail, which is currently unable to utilize this approach).

Continuous Valuation Approach

The Continuous Valuation approach estimates the marginal cost of avoided T&D based on the utility's forecasted system plan for load growth-driven capital projects. The methodological basis for the marginal cost is that a reduction in area net peak load (area usage net of "in-front-of-the-meter" in-area generation or storage) could defer growth-related capacity projects. This deferral would result in a financial benefit to utility ratepayers. The benefit would arise because the deferral of a project reduces the net present value of a project (due to discounting), albeit with some loss of value due to cost escalation for the project when it is finally installed. The net effect is commonly referred to as the "deferral benefit."

To convert the deferral benefit into the form commonly used for marginal costs, one first divides the deferral benefit by the kW associated with the deferral. For example, if the deferral benefit is based on a one-year deferral, one would divide the dollar value of the year's deferral by the load

⁸ "Assessing the Multiple Benefits of Clean Energy." Pages 75-76. Environmental Protection Agency. Sep. 2011.

⁹ Continuous Valuation with Statistical PCAF is the method used in California. See "Avoided Costs 2016 Interim Update," Energy and Environmental Economics, Inc., August 1, 2016.

growth deferred for one year to get the \$/kW deferral benefit. One then multiplies this \$/kW value by a levelization factor (based on the planning horizon) to convert it to a \$/kW-yr. value that is the standard form for marginal cost studies. A more detailed explanation of this approach is provided in Appendix B.

Statistical Peak Capacity Allocation Factor (PCAF)

Different from marginal energy or generating capacity costs, costs for transmission and distribution systems are very location-specific. Load growth, new construction, business expansions, and other factors affect the distribution and transmission system differently throughout the area the system serves. As such, energy efficiency can have different impacts on the system depending on where it is applied. Energy efficiency projects on circuits with extra capacity may have no current T&D benefit while EE projects on circuits at or near capacity may help defer projects that are planned in the near future, thus providing near immediate cost savings.

To simulate the locational and timing effects that energy efficiency can have on the transmission and distribution system, it is possible to develop factors that allocate avoided T&D costs (calculated by Discrete or Continuous Valuation approach) to relevant peak periods. These factors are the peak capacity allocation factors (PCAFs). Ideally, one would develop PCAFs to correlate with the way the distribution or transmission system peaks by time of day and area. When applied to individual measures in a utility's portfolio, this would, in turn, help guide energy efficiency investments to the areas of the system where they produce the greatest benefit.¹⁰ However, this level of detail is both difficult to calculate by area and more difficult to implement since, generally, energy efficiency programs are not focused on specific locations within the system.

Therefore, calculating PCAFs relies upon simplifying assumptions. Rather than use location-specific distribution system peaks, one can use overall system peaks. But, different from the system peaks used for generating capacity avoided costs, PCAFs use a collection of “near peak” system hours to simulate the diversity of distribution system peaks.¹¹ A common convention is to use the hours associated with one standard deviation from the overall system peak (based on 8,760 hourly peaks) as the representation of these near peaks. Once calculated, these peak capacity allocation factors can be applied to the \$/kW-yr marginal cost to convert the marginal cost into an 8,760-hourly stream of \$/kW-hr marginal costs, or the allocation factors can be multiplied with hourly load reduction shapes (e.g. lighting shape) to calculate the “coincident” peak reduction of the load reduction shape.¹² These PCAFs can then be applied to individual energy efficiency measures based on a measure's load shape.

¹⁰ Or, if not actually guiding investments, at least resulting in more accurate estimates of transmission and distribution costs avoided if utilities capture information regarding the location of the implemented energy efficiency.

¹¹ Energy efficiency measures are typically assigned “coincidence factors” that represent the probability that the measure is saving energy at the time of system peak. The customer's demand savings produced by the measure (e.g. 0.2 kW) is multiplied by the coincidence factor (e.g. 0.45) and the avoided generating capacity cost (e.g. \$80/kW-year) to determine the measure's annual generating capacity costs saved for a given year of operation (in this case, $0.2 * 0.45 * 80 = \$7.20$).

¹² See the further discussion in Appendix D regarding measure load shapes and PCAFs.

In the following sections, the Minnesota investor-owned utilities describe their calculations of avoided T&D costs using the Discrete and Continuous Valuation approaches and their applications of PCAFs to measure load shapes. The IOUs also provide their views of the pros and cons of each approach and their recommended approach. The Third-Party Evaluator's section describes the role the TPE played, provides comments on each utility's estimates and explanations for differences between utilities, and explains the TPE's recommendation.

C. Xcel Energy

Distribution Avoided Costs

As described in the March 1, 2017 Scope of Work, Northern States Power – Minnesota (NSPM) performs an annual assessment to establish performance and modeling requirements to allow its distribution system to operate reliably under normal system configuration and probable contingencies. The assessment includes system intact and contingency analysis over the near-term (1-5 years) planning horizon, as well as selected area longer range (10-20 years) studies, and identifies corrective action projects or plans to mitigate performance outside NSPM's reliability criteria.

For assessing their effect on the distribution system, the energy efficiency impacts were allocated to each distribution substation and feeder load proportionally based on percentage of system load share, and a subsequent summer peak analysis was performed and analyzed to determine if projects could be deferred. A deferral value, expressed as \$/kW, was calculated based on the Xcel Energy corporate weighted average cost of capital (WACC) using planning level costs and the deferral period.

Modeling and Assumptions

Xcel Energy took into account a multitude of assumptions when calculating distribution avoided costs, including:

- The years of the study span from 2019-2023;
- The energy efficiency goal over that period varies from 68-102MW for an average of 92MW annual reduction each year for five years;
- Overall corporate growth rate without EE is adjusted per each division based on feeder data from the Itron Distribution Asset Analysis (DAA) system;
- Feeder demand adjustments based upon the percentage of NSPM total system demand served;
- The potential to defer substation (bank) capacity and feeder capacity projects were studied, up to two years beyond study period;
- No 'avoided' costs;
- No 'reduced' costs;
- Only deferred costs were taken into account in the study;
- Value of project deferral is based upon WACC savings and inflation;
- Only n-0 overloads were modeled (mitigation of n-1 conditions is not mandated and usually based upon available funding);
- EE impacts have the same load shape as each feeder; and
- Evenly spaced load reduction at distribution load transformers based on EE percentage reduction.

Xcel Energy also took into account a number of assumptions when calculating a revenue requirement multiplier to levelize the costs of a T&D asset, including:

- An asset value of \$10 million;
- Asset life of 40 years since these assets typically have a 40-year life;
- Property taxes of 2 percent per year;

- Incremental operation and maintenance of 1.5 percent based on accumulated reserve balance per year (as assets depreciate, more and more incremental maintenance costs are incurred to keep it in service);
- Income Tax Depreciation Life/Rate of 15 years Modified Accelerated Cost Recovery System (MACRS); and
- WACC is 7.09 percent which results in an after-tax discount rate of 6.16 percent.

Xcel Energy also took into account a number of assumptions to levelize the results. The estimates of marginal costs in the Discrete approach represent the avoided costs over a 5-yr period 2017-2021 from the effect of future DSM over that period. Throughout that period the kW impact of future DSM accumulates from 92 MW in 2017 to 460 MW in 2021. In the cost-effectiveness assessment of DSM programs a stream of \$/kW for each year across the lifetime of DSM measures is applied. To determine this \$/kW-yr value, the average annual deferred costs must be divided by the average annual MW reduction from future DSM, or 276 MW.

For the Continuous Valuation approach, the marginal costs can be converted to annual \$/kW-yr marginal costs by annualizing Xcel’s marginal cost estimates using a five-year levelization factor. Five years is used to match the forward-looking planning horizon used by Xcel in their deferral analysis.

Distribution Avoided Costs Results

Discrete Approach

Table 1 provides the results utilizing the Discrete approach:

Table 1 - Distribution Avoided Costs (Discrete Approach)

| Distribution Cost Center | Total Deferred Costs (over 5 years) | Annual Deferred Costs |
|--------------------------|--|-----------------------|
| Bank | \$2,623,469 | \$524,694 |
| Feeder | \$3,375,132 | \$675,026 |
| Total | \$5,998,601 | \$1,199,720 |

| | |
|---------------|--------------------------------|
| \$4.35 | per KW-year (276 MW Avg.) |
| 1.61 | Revenue Requirement Multiplier |
| \$7.00 | per KW-year |

Continuous Valuation Approach

Table 2 provides the results utilizing the Continuous Valuation approach:

Table 2 - Distribution Avoided Costs (Continuous Valuation Approach)

| Total Cost Center | Cost/kW |
|--------------------------|----------------|
| Bank | \$8.12 |
| Feeder | \$8.96 |
| Total | \$17.08 |

| | |
|----------------|--------------------------------|
| \$17.08 | per KW |
| 1.61 | Revenue Requirement Multiplier |
| \$27.49 | per KW |
| 23.77% | Levelization Factor |
| \$6.54 | per kW-year |

Transmission Avoided Costs

As described in the March 1, 2017 Scope of Work, NSPM performs an annual assessment on the transmission system which aligns with NERC Transmission Planning Standard TPL-001-4 to establish performance and modeling requirements for the system to operate reliably under a variety of conditions and probable contingencies.¹³ The assessment includes power flow contingency analysis over the near-term (1-5 years) and long-term (6-10 years) planning horizons and identifies corrective action projects or plans to mitigate performance outside NSPM’s reliability criteria.

NSPM also proposes transmission projects to comply with public policy requirements and customer interconnection requests. Public policy and customer interconnection requests generally do not result in load driven capacity increase projects and therefore are not expected to be affected by DSM load reduction.

For assessing transmission impacts, the energy efficiency impacts were allocated to each transmission bus load proportionally based on percentage of system load share and a subsequent summer peak contingency analysis was performed, deferral value was calculated based on the Xcel Energy corporate cost of capital and the deferral period.

In assessing DSM’s impact on transmission costs, NSPM used the Siemens PTI PSSE software program to perform the analysis. PSSE provides electric transmission system power flow contingency analysis.

Modeling and Assumptions

Xcel Energy took into account a multitude of assumptions when calculating transmission avoided costs, including:

¹³ Transmission System Planning Performance Requirements, North American Electric Reliability Corporation, January 1, 2015. <http://www.nerc.com>.

- Years of the study cover 2019-2023;
- EE goal varies 68-102MW for an average 92MW annual reduction each year for 5 years;
- Study covered the entire NSPM transmission system;
- Feeder demand adjustments based upon percentage of NSPM total system demand served;
- The potential to defer substation (bank) capacity and feeder capacity projects were studied;
- No ‘avoided costs’;
- No ‘reduced costs’;
- Only ‘deferred’ costs, the transmission system will grow, however load reduction may delay (or defer) mitigations;
- Value of project deferral is based upon WACC savings and inflation;
- n-0, n-1 on entire system, and n-1-1 on system >100kV overloads were modeled;
- EE impacts have the same load shape as each feeder; and
- Evenly spaced load reduction at transmission load busses based on EE percentage reduction.

Xcel Energy assumed potential for variation exists when calculating transmission and distribution avoided costs, including:

- The proposed 68-102MW of load reduction is approximately 0.9-1.4 percent of NSPM total load and can be considered ‘noise’ (e.g. variations of summer weather can typically affect peak loading anywhere from 1 to 7 percent);
- Load reduction based upon EE may have already been anticipated by planners and reflected by their future load estimates (this would double count load reduction);
- In many instances, a 1 percent reduction in loading would not impact the decision to mitigate; and
- In all instances, a 1 percent reduction in loading would not be enough to suspend or postpone a project once it has started (e.g. substation projects would not be stopped since long lead time items have been purchased, workers mobilized on-site, outages scheduled, etc. Also, the financing savings from any delay is offset by increased permitting costs, increased project complexity costs and costs to accommodate additional growth).

Transmission Avoided Costs Results

Discrete Approach

Table 3 illustrates the transmission avoided costs utilizing the Discrete approach:

Table 3 - Transmission Avoided Costs (Discrete Approach)

| Transmission Cost Center | Total Deferred Costs (over 5 years) | Annual Deferred Costs |
|---------------------------------|--|------------------------------|
| Transmission Cost Centers | \$1,896,262 | \$389,667 |
| Bank | \$322,889 | \$64,578 |
| Feeder | \$0 | \$0 |
| Total | \$2,219,150 | \$454,245 |

| | |
|---------------|--------------------------------|
| \$1.65 | per KW-year (276 MW Avg.) |
| 1.61 | Revenue Requirement Multiplier |
| \$2.65 | per KW-year |

Continuous Valuation Approach

Table 4 illustrates the transmission avoided costs utilizing the Continuous Valuation approach:

Table 4 - Transmission Avoided Costs (Continuous Valuation Approach)

| Transmission Cost Center | Annual Deferred Costs |
|---------------------------------|------------------------------|
| Transmission Cost Centers | \$3.34 |
| Total | \$3.34 |

| | |
|---------------|--------------------------------|
| \$3.34 | per KW |
| 1.61 | Revenue Requirement Multiplier |
| \$5.37 | per KW |
| 23.77% | Levelization Factor |
| \$1.32 | per kW-year |

Summary of T&D Results

Table 5 summarizes the T&D avoided cost results for Xcel Energy and by each methodology for 2017, while Table 6 shows the results through 2038, the time period covering all impacts of DSM measures installed in the current 2017-2019 Triennial period. These future values use a 2.36% escalation factor applied to the 2017 values.

Table 5 - Combined T&D Avoided Costs (2018)

| Discrete Approach | | | Continuous Valuation Approach | | |
|--------------------------|--------|--------|--------------------------------------|--------|--------|
| Distribution | \$7.16 | /kW-yr | Distribution | \$6.69 | /kW-yr |
| Transmission | \$2.71 | /kW-yr | Transmission | \$1.35 | /kW-yr |
| Total | \$9.88 | /kW-yr | Total | \$8.04 | /kW-yr |

Table 6 - Future Combined T&D Avoided Costs (\$/kW-year)

| Year | As Originally Approved in Docket No. 16-115 | Discrete Approach | Continuous Valuation Approach |
|-------------|--|--------------------------|--------------------------------------|
| 2018 | \$37.08 | \$9.88 | \$8.04 |
| 2019 | \$37.96 | \$10.11 | \$8.23 |
| 2020 | \$38.85 | \$10.35 | \$8.43 |
| 2021 | \$39.77 | \$10.59 | \$8.63 |
| 2022 | \$40.71 | \$10.84 | \$8.83 |
| 2023 | \$41.67 | \$11.10 | \$9.04 |
| 2024 | \$42.65 | \$11.36 | \$9.25 |
| 2025 | \$43.66 | \$11.63 | \$9.47 |
| 2026 | \$44.69 | \$11.90 | \$9.69 |
| 2027 | \$45.74 | \$12.18 | \$9.92 |
| 2028 | \$46.82 | \$12.47 | \$10.16 |
| 2029 | \$47.93 | \$12.76 | \$10.40 |
| 2030 | \$49.06 | \$13.07 | \$10.64 |
| 2031 | \$50.22 | \$13.37 | \$10.89 |
| 2032 | \$51.40 | \$13.69 | \$11.15 |
| 2033 | \$52.62 | \$14.01 | \$11.41 |
| 2034 | \$53.86 | \$14.34 | \$11.68 |
| 2035 | \$55.13 | \$14.68 | \$11.96 |
| 2036 | \$56.43 | \$15.03 | \$12.24 |
| 2037 | \$57.76 | \$15.38 | \$12.53 |
| 2038 | \$59.12 | \$15.75 | \$12.82 |

Statistical Peak Capacity Allocation Factor (PCAF) Results

Table 7 shows the details in the PCAF factor calculation for the individual DSM measure load shapes used in Xcel Energy’s most recent CIP Triennial Plan, specifically the impact at “near peak” system hours and the impact at the system peak hour. These impacts combine to produce the PCAF factor.

Table 7 – Calculation of Statistical PCAF for Load Shapes

| Load Shape | Impact at Near-Peak System Hours | Impact at Peak System Hour | PCAF |
|------------------------------------|---|-----------------------------------|-------------|
| Business Custom Cooling | 0.170 | 0.197 | 0.863 |
| Business Compressed Air Efficiency | 2.310 | 2.605 | 0.887 |
| Business Custom Compressed Air | 0.120 | 0.152 | 0.789 |
| Business Custom | 0.082 | 0.063 | 1.305 |
| Business Energy Management | 0.412 | 0.309 | 1.332 |

| Load Shape | Impact at Near-Peak System Hours | Impact at Peak System Hour | PCAF |
|-------------------------------------|----------------------------------|----------------------------|-------|
| Systems | | | |
| Business Lighting | 0.708 | 0.738 | 0.959 |
| Business Lighting - Large Customers | 0.837 | 0.880 | 0.951 |
| Business Lighting - Off-Peak | 0.436 | 0.241 | 1.807 |
| Business Motors - VFD | 0.570 | 0.623 | 0.915 |
| Business Motors | 0.380 | 0.430 | 0.884 |
| Business Recommissioning | 0.412 | 0.309 | 1.332 |
| System Load | 0.570 | 0.623 | 0.915 |
| Residential A/C Direct Load Control | 0.130 | 0.171 | 0.763 |
| Residential Energy Star Homes | 0.194 | 0.269 | 0.720 |
| Residential Home Efficiency | 1.771 | 2.088 | 0.848 |
| Residential Room A/C | 1.505 | 1.830 | 0.822 |
| Residential Freezer | 0.126 | 0.128 | 0.985 |
| Residential Lighting | 0.062 | 0.046 | 1.354 |
| Residential Primary Refrigerator | 0.132 | 0.130 | 1.016 |

Table 8 illustrates the PCAF factors for the individual DSM measure load shapes applied to the two methods – Discrete and Continuous Valuation:

Table 8 - Combined T&D Avoided Costs with Statistical PCAF

| Load Shape | PCAF | Discrete Approach | | Continuous Valuation | |
|-------------------------------------|-------|-------------------|-------------------|----------------------|-------------------|
| | | T&D \$/kW-yr | Adjusted \$/kW-yr | T&D \$/kW-yr | Adjusted \$/kW-yr |
| Business Custom Cooling | 0.863 | \$9.65 | \$8.33 | \$7.81 | \$6.74 |
| Business Compressed Air Efficiency | 0.887 | \$9.65 | \$8.55 | \$7.81 | \$6.93 |
| Business Custom Compressed Air | 0.789 | \$9.65 | \$7.61 | \$7.81 | \$6.17 |
| Business Custom | 1.305 | \$9.65 | \$12.60 | \$7.81 | \$10.20 |
| Business Energy Management Systems | 1.332 | \$9.65 | \$12.86 | \$7.81 | \$10.41 |
| Business Lighting | 0.959 | \$9.65 | \$9.25 | \$7.81 | \$7.50 |
| Business Lighting - Large Customers | 0.951 | \$9.65 | \$9.18 | \$7.81 | \$7.43 |
| Business Lighting - Off-Peak | 1.807 | \$9.65 | \$17.44 | \$7.81 | \$14.12 |
| Business Motors - VFD | 0.915 | \$9.65 | \$8.83 | \$7.81 | \$7.15 |
| Business Motors | 0.884 | \$9.65 | \$8.53 | \$7.81 | \$6.91 |
| Business Recommissioning | 1.332 | \$9.65 | \$12.86 | \$7.81 | \$10.41 |
| System Load | 0.915 | \$9.65 | \$8.83 | \$7.81 | \$7.15 |
| Residential A/C Direct Load Control | 0.763 | \$9.65 | \$7.36 | \$7.81 | \$5.96 |
| Residential Energy Star Homes | 0.720 | \$9.65 | \$6.95 | \$7.81 | \$5.63 |
| Residential Home Efficiency | 0.848 | \$9.65 | \$8.18 | \$7.81 | \$6.63 |

| Load Shape | PCAF | Discrete Approach | | Continuous Valuation | |
|----------------------------------|-------|-------------------|----------------------|----------------------|----------------------|
| | | T&D \$/kW-yr | Adjusted \$/kW-yr | T&D \$/kW-yr | Adjusted \$/kW-yr |
| Residential Room A/C | 0.822 | \$9.65 | \$7.93 | \$7.81 | \$6.43 |
| Residential Freezer | 0.985 | \$9.65 | \$9.50 | \$7.81 | \$7.69 |
| Residential Lighting | 1.354 | \$9.65 | \$13.07 | \$7.81 | \$10.58 |
| Residential Primary Refrigerator | 1.016 | \$9.65 | \$9.80 | \$7.81 | \$7.94 |

Methodology Pros and Cons

Pros/Cons of the Discrete Approach

Pros

- More consistent with system planning;
- Simple to implement with portfolios/DSMore.

Cons

- Avoided or deferred costs may be truncated (in other words, method not accounting for avoided costs that may result from cumulative impacts of EE on the system).

Pros/Cons of the Continuous Valuation Approach (without PCAFs)

Pros

- Avoids truncation of deferred costs.

Cons

- Not consistent with system planning.

Pros/Cons of the PCAF Approach

Pros

- Approach recognizes value of Transmission and Distribution Avoidance at hours other than generation system peak;
- Simple method to capture effect;
- Can be implemented by Xcel Energy in spreadsheets containing cost-benefit analyses.

Cons

- Method has not been proven to accurately capture avoidance at hours other than generation system peak;
- Results by some measures may be so exaggerated that constant value applied across all measures may be more accurate.

Recommendation

Xcel Energy believes that both the Discrete and Continuous Valuation Approaches are reasonable to determine the avoided T&D benefits resulting from DSM achievements in its 2017-2019 CIP Triennial Plan period. The Company would support implementation of either method.

The Company does not believe that the PCAF approach provides additional accuracy in the assessment of avoided T&D benefits for individual DSM measures. The Company does agree that the impacts may differ by measure given differences in impacts at “near peak” system hours, but the formula utilized in the PCAF approach has not been proven to more accurately measure the effect. To validate the PCAF approach, system planning for each individual measure could be completed and compared to the results by measure from the PCAF method. This would provide a more rigorous estimate of the impact by individual measure and may prove that the PCAF method provides a more accurate estimate of the impact by measure. This analysis has not been accomplished in this study and would be administratively burdensome to conduct. Also, the PCAF values for both Xcel and Otter Tail Power load shapes include a significant amount of variance which would greatly affect the cost-effectiveness of individual DSM measures and may produce significant shifts in the DSM measures included in each company’s DSM portfolio. Xcel Energy does not believe that the PCAF approach has been validated and is not proven enough to inform significant shifts in the DSM portfolio. Given these results, the Company does not recommend using the PCAF approach.

D. Minnesota Power

Distribution Avoided Costs

Minnesota Power's planning group is currently in the process of implementing a new modeling and analysis software package to aid in distribution planning functions. At this stage of the implementation process, the models are not refined to a point at which efficient analysis can be performed on significant portions of the distribution system. Because of this, Minnesota Power has indicated from the beginning of this process that in order to determine distribution cost values using the Discrete approach, the Siemens PTI PSSE models would need to be leveraged and that only the firm capacity at the distribution interfaces in the model would be examined for overloads.

Minnesota Power maintains a five-year capital construction budget that is refined on an annual basis. In this five-year plan, there are currently eight capacity-related projects with planning level estimates that were evaluated for the Continuous Valuation approach.

Modeling and Assumptions

As stated above, Minnesota Power did not perform its analysis within the distribution models. Minnesota Power considered the following assumptions when calculating the distribution avoided costs:

- The capital projects considered were in the 2017-2021 timeframe;
- Only capacity projects were included, although it should be noted that some of the projects were a mix of age-related and capacity-related;
- Load growth assumed to be 0.4%, consistent with EFRP;
- Revenue requirements assumed an asset life of 40 years, tax depreciation rate of 20 years, WACC of 8.18%, and property tax rate of 3.00%;
- Inflation rate of 2.5%; and
- Annual O&M expense of approximately 3%.

Distribution Avoided Costs Results

Discrete Approach

There were no distribution projects identified using the Discrete approach as Minnesota Power maintained firm capacity at all of the distribution interfaces in the PSSE models. No distribution power transformers were loaded above their top rating.

Continuous Valuation with Statistical PCAF Approach

Eight distribution projects were put into the Continuous Valuation spreadsheet provided by the Third-Party Evaluator. Minnesota Power's internal financial analysts determined specific revenue requirement costs on a per-project basis and those values were used to determine a revenue requirement multiplier by dividing by the estimated project cost. Minnesota Power does not have a consistent internal methodology to estimate operations and maintenance (O&M) expenses on a per-project basis for distribution; however, as suggested by the TPE, an annual O&M expense of roughly 3% was assumed in the Continuous Valuation analysis.

Table 9 provides the distribution avoided cost results utilizing the Continuous Valuation approach:

Table 9 - Distribution Avoided Costs (Continuous Valuation Approach)

| Year | Distribution Avoided Cost (\$/kW-yr) |
|-------------|---|
| 2018 | \$4.05 |
| 2019 | \$4.15 |
| 2020 | \$4.26 |
| 2021 | \$4.36 |
| 2022 | \$4.47 |
| 2023 | \$4.58 |
| 2024 | \$4.70 |
| 2025 | \$4.82 |
| 2026 | \$4.94 |
| 2027 | \$5.06 |
| 2028 | \$5.19 |
| 2029 | \$5.32 |
| 2030 | \$5.45 |
| 2031 | \$5.59 |
| 2032 | \$5.73 |
| 2033 | \$5.87 |
| 2034 | \$6.02 |
| 2035 | \$6.17 |
| 2036 | \$6.32 |
| 2037 | \$6.48 |
| 2038 | \$6.64 |

Transmission Avoided Costs

Modeling and Assumptions

Minnesota Power proposed to perform the transmission analysis using MTEP16¹⁴ models with 2021 winter and summer peak load cases. Internally, it made the most sense to use the MTEP16 models, as the base case results were already available from the MISO process and the only additional work to be performed would be to remove the energy efficiency assumptions and run the models with the incremental loads.

Minnesota Power’s load forecasting department provided a load forecast with the EE assumptions removed, which otherwise matched the assumptions made for the load forecast that was provided for the MTEP16 models. The only modification made to the models and load cases

¹⁴ MTEP is MISO’s Transmission Expansion Planning effort. See <https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP16.aspx>.

that differed from the base case MTEP16 model was the application of the incremental load associated with removing the energy efficiency assumptions from the load forecast. There was an additional 43MW allocated in the 2021 summer case and 50MW in the 2021 winter case. This incremental load was scaled across Minnesota Power's entire scalable load in the models, except for Superior Water Light & Power's buses as they are not included in Minnesota Power's EE eligible load. There are some scalable buses that include both municipal and/or wholesale load in addition to Minnesota Power's load which will slightly skew the allocation as municipal and wholesale load is not part of the EE assumptions.

Minnesota Power also used the same contingency file that was used during the MTEP16 process, excluding P3, P6, and extreme event contingencies. P3 contingencies include the loss of a generator unit followed by a single contingency, and corrective action plans are not required. P6 contingencies are multiple contingencies (overlapping singles) for which corrective action plans are not required. Extreme event contingencies are specific to each utility and are outside the scope of this study. For more background information on contingency definitions, please refer to standard NERC TPL-001-4 Transmission System Planning Performance Requirements.¹⁵

Minnesota Power considered the following assumptions when calculating transmission avoided costs:

- A five-year-out peak model (MTEP 2021) was used;
- The energy efficiency goal was consistent with the 2017-2019 approved CIP triennial filing;
- The increased load assumptions from EE was allocated proportionally across all Minnesota Power scalable load buses (consistent with the customers who are eligible for energy efficiency);
- Study covered entire Minnesota Power transmission system, including the distribution interfaces (280 buses, 241 branches);
- N-0 and N-1 on entire system, same contingency file used in the MISO MTEP process, filtering out P3, P6, and extreme event contingencies; and
- Corrective action projects would only be identified for violations approaching the emergency limit, not merely exceeding the normal rating (Rate A).

Transmission Avoided Costs Results

Discrete Approach

After running contingency analysis on the winter and summer cases, no thermal or voltage violations were found in which Minnesota Power would proactively mitigate compared to the base case results. Increased flows on lines were seen due to the increased load, but the relatively small increase in load did not cause any transmission line to increase enough to warrant a corrective action plan.

There were a few lines that showed up only in the increased non-EE load case above their normal ratings. These lines included Forbes to ETCO (18L), Nashwauk to Blackberry (62L), and Laskin to Forbes (38L). While these lines became loaded past their normal ratings, they had

¹⁵ Transmission System Planning Performance Requirements, North American Electric Reliability Corporation, January 1, 2015. <http://www.nerc.com>.

substantial margin in their emergency ratings and a corrective action plan would not be put in place to mitigate the overloads. Therefore, under the Discrete approach, avoided transmission costs are \$0.

Continuous Valuation with Statistical PCAF Approach

After a discussion with the TPE about the Discrete approach results, it was initially determined that some of the projects identified in the Discrete approach should be analyzed with the Continuous Valuation approach despite not needing a corrective action plan to mitigate the small increases over the normal limit. It was ultimately determined that the sheer amount of load increase needed on the lines to get them from slightly above the normal rating to the point of needing a corrective action plan was more than energy efficiency reductions could realistically impact in the planning horizon. Additionally, the transmission lines in question mostly serve industrial load pockets on the Iron Range that, due to requested and approved exemption from the Company’s CIP program, are not eligible to participate in Minnesota Power’s energy efficiency programs. It was, therefore, decided that these projects could not realistically be evaluated using the Continuous Valuation approach. It is simply not realistic to assume that load reductions due to energy efficiency assumptions could defer investments on the transmission lines in question within the planning horizon, particularly when the loading on the lines is tied to industrial customers. Thus, estimates of transmission avoided costs using the Continuous Valuation approach also resulted in a zero value.

Summary of T&D Results

Table 10 provides the summary T&D avoided cost results as originally filed in Minnesota Power’s 2017-2019 CIP Triennial filing and utilizing the Continuous Valuation approach.

Table 10 - Summary of Transmission & Distribution Avoided Costs (\$/kW-year)

| Year | As Originally Approved in Docket No. 16-117 | Continuous Valuation Approach |
|-------------|--|--------------------------------------|
| 2018 | \$11.38 | \$4.05 |
| 2019 | \$11.72 | \$4.15 |
| 2020 | \$12.07 | \$4.26 |
| 2021 | \$12.43 | \$4.36 |
| 2022 | \$12.81 | \$4.47 |
| 2023 | \$13.18 | \$4.58 |
| 2024 | \$13.59 | \$4.70 |
| 2025 | \$13.99 | \$4.82 |
| 2026 | \$14.41 | \$4.94 |
| 2027 | \$14.84 | \$5.06 |
| 2028 | \$15.29 | \$5.19 |
| 2029 | \$15.75 | \$5.32 |

| Year | As Originally Approved in Docket No. 16-117 | Continuous Valuation Approach |
|------|---|-------------------------------|
| 2030 | \$16.22 | \$5.45 |
| 2031 | \$16.71 | \$5.59 |
| 2032 | \$17.21 | \$5.73 |
| 2033 | \$17.72 | \$5.87 |
| 2034 | \$18.25 | \$6.02 |
| 2035 | \$18.80 | \$6.17 |
| 2036 | \$19.36 | \$6.32 |
| 2037 | \$19.93 | \$6.48 |
| 2038 | \$20.53 | \$6.64 |

Statistical Peak Capacity Allocation Factor (PCAF) Results

Table 11 shows the details in the PCAF factor calculation for the individual DSM measure load shapes used in Minnesota Power's CIP portfolio.

Table 11 - PCAF Applied to Minnesota Power CIP Portfolio

| Load Shape | MP Winter Peak (kW) | Ratio of PCAF to System (kW) | PCAF (kW) | Annual T&D (\$/KW) | T&D Value (\$) | T&D Value (\$/KW) |
|------------------------------|---------------------|------------------------------|-----------|--------------------|----------------|-------------------|
| Res Refrigeration | 7.16 | 1.05 | 7.52 | \$ 4.05 | \$ 30.45 | \$ 4.25 |
| Res Closed Loop GSHP | 374.62 | 0.87 | 326.78 | \$ 4.05 | \$ 1,323.07 | \$ 3.53 |
| Res Air Conditioning | 0.00 | 0.00 | 0.00 | \$ 4.05 | \$ 0.00 | \$ - |
| Res ASHP mini split ductless | 425.17 | 0.87 | 370.87 | \$ 4.05 | \$ 1,501.56 | \$ 3.53 |
| Res ASHP Std split | 31.74 | 0.87 | 27.68 | \$ 4.05 | \$ 112.08 | \$ 3.53 |
| Res Tstat w/ Electric Heat | 34.34 | 0.87 | 29.96 | \$ 4.05 | \$ 121.30 | \$ 3.53 |
| Res Indoor Lighting | 8.49 | 0.89 | 7.53 | \$ 4.05 | \$ 30.47 | \$ 3.59 |
| Res Exterior Lighting | 3.19 | 0.56 | 1.78 | \$ 4.05 | \$ 7.22 | \$ 2.26 |
| Res Water Heating (DWHR) | 0.66 | 1.15 | 0.76 | \$ 4.05 | \$ 3.08 | \$ 4.66 |
| Res Water Heating (HP Pilot) | 4.63 | 1.15 | 5.31 | \$ 4.05 | \$ 21.48 | \$ 4.64 |
| C&I Air Compressor | 464.08 | 0.99 | 458.42 | \$ 4.05 | \$ 1,856.02 | \$ 4.00 |
| C&I HVAC | 750.26 | 0.99 | 744.73 | \$ 4.05 | \$ 3,015.21 | \$ 4.02 |
| C&I Lighting | 5,031.91 | 0.71 | 3,556.48 | \$ 4.05 | \$ 14,399.28 | \$ 2.86 |
| C&I Motors and Drives | 341.43 | 2.30 | 784.85 | \$ 4.05 | \$ 3,177.64 | \$ 9.31 |
| C&I Process | 556.89 | 0.79 | 440.67 | \$ 4.05 | \$ 1,784.18 | \$ 3.20 |
| C&I Refrigeration | 265.19 | 1.00 | 265.01 | \$ 4.05 | \$ 1,072.96 | \$ 4.05 |

Methodology Pros and Cons

Pros/Cons of the Discrete Approach

Pros

- More consistent with traditional planning approach and the reality of how Minnesota Power implements T&D projects.
- The method is straightforward and Minnesota Power is currently capable of implementing the approach for transmission projects with little additional effort.

Cons

- At the time of the study, Minnesota Power's distribution models were not refined enough for efficient analysis to be performed on significant portions of the distribution system using the Discrete approach.
- Avoided or deferred costs may be truncated. For Minnesota Power, the Discrete approach resulted in \$0 values for both transmission and distribution.

Pros/Cons of the Continuous Valuation Approach (without PCAFs)

Pros

- This method is more or less a refinement of the method Minnesota Power has historically used. As such, the method is relatively straightforward and Minnesota Power is currently capable of implementing this approach with little additional effort.
- It is consistent with the manner in which Minnesota Power considers generation supply resources for the purpose of DSM evaluation where the intent is to understand what may be useful in deferring resources. This method, therefore, better enables the Company to assess *potential* for impacts on avoided T&D costs.

Cons

- This method does not necessarily reflect how T&D and resource planners consider DSM. However, some misalignment between the two types of processes is to be expected given that their intended purposes are not necessarily the same.

Pros/Cons of the PCAF Approach

Pros

- Since costs are being allocated to many near peak hours rather than a single peak, the simplified PCAF method *may* theoretically increase the likelihood of capturing benefits to the T&D system during hours outside of the generation system peak.

Cons

- While the approach theoretically increases the likelihood (but does not guarantee) that avoided costs are being applied to hours more relevant to the transmission/distribution system, it may also be spreading costs across hours where no real benefit would actually be realized through energy efficiency.
- Given the simplified application of the method (necessary to address current data limitations) for this study, the PCAF approach does not address the locational diversity of

T&D costs, which is where the real value of using a more granular method of avoided T&D value allocation is derived.

- For Minnesota Power, on a portfolio basis, the resulting aggregate T&D avoided cost estimates from this PCAF allocation method do not differ significantly from allocating to a single peak hour. While some values differ at the measure and sector level, there is uncertainty as to how realistic the results are, especially in terms of how well they reflect the reality of impacts to the system.
- The approach does not reflect the realities of how Minnesota Power currently conducts system planning.
- The benefit/cost evaluation software in use (DSMore) cannot currently handle the application of PCAFs as proposed in this study. Updates to the software could be made to add the necessary functionality, but would require utility investment and time for programming and testing. Further, there may be more realistic paths to pursue in the future should parties agree increased accuracy of avoided T&D impacts and alignment with system planning processes are priorities. It cannot feasibly be determined how well the results from the proposed simplified PCAF approach reflect actual impacts on the system. In all likelihood, the benefits (if any) achieved from the approach would be so minimal that they would not outweigh the costs associated with implementing the method.
- For Minnesota Power, EE does not frequently offer the possibility of deferring transmission projects, in large part due to the size and location of projects (which often serve large CIP exempt customers). This is reflected in the Company's extremely low T&D avoided cost values, which currently make up less than 3% of total avoided costs (The results of this study indicate this percentage would be even lower if one of the proposed methods is implemented.). As such, the additional cost and effort of implementing this approach are even less justifiable for Minnesota Power.

Recommendation

Minnesota Power supports the implementation of the Continuous Valuation approach, without the use of PCAFs. Regarding PCAFs, in general Minnesota Power agrees there may be benefits to allocating T&D avoided costs to more than a single system peak hour, especially for utilities in a capacity deficit situation. However, as described in the "Description of Methodology" section by the Third-Party Evaluator, costs for transmission and distribution systems are very location-specific and the benefits of this type of approach stem from allocating avoided T&D costs to better account for the diversity of distribution and transmission system peaks. Ideally, this means cost allocation needs to reflect the timing and, more importantly, *locations* of T&D peaks/constraints. Since achieving this is not currently feasible due to data limitations, the proposed PCAF methodology used in this study, which simplifies this approach, attempts to capture some the value from EE during hours where parts of the T&D systems might be peaking outside of the single generation system peak.

While Minnesota Power agrees that allocating costs to relevant peak periods on the T&D system could result in more accurate EE program evaluation estimates and other program planning benefits, the Company is not convinced that this simplified allocation methodology better estimates the impacts of EE on transmission and distribution system costs. Minnesota Power's study indicates that there is minimal difference in benefit/cost results from allocating T&D

benefits to multiple hours as opposed to allocating to the single peak hour. The simplified method may increase the likelihood of capturing benefits to the T&D system during hours outside of the generation system peak (since costs are being allocated to many near peak hours), but it does not account for any locational impacts, which is where the true value of such an approach is derived. Furthermore, the approach does not reflect the reality of how Minnesota Power conducts T&D system planning. The benefits (if any) of the simplified PCAF approach likely do not warrant the additional time and dollar costs associated with implementing such an approach.

E. Otter Tail Power

Otter Tail determined during the process that it was unable to use the Discrete approach to estimate avoided T&D costs because it requires additional modeling of the transmission system both with and without energy efficiency. The modeling of the transmission system takes into consideration Otter Tail's distribution loading and would also be relied upon to calculate the distribution avoided costs. Otter Tail performs a ten-year transmission system assessment triennially. Its most recent study was performed in 2014 and does not have a model incorporating energy efficiency. Otter Tail performs a ten-year transmission planning study every three years with the last study completed in 2014. The results of the next study will not be available until 2018. Therefore, Otter Tail only used the Continuous Valuation approach to estimate avoided costs.

Distribution Avoided Costs

Modeling and Assumptions

Otter Tail performs an annual assessment on the distribution system to establish performance and system needs to operate reliably under normal system configuration and contingencies. The assessment includes system intact and contingency analysis over one to five years to ensure capacity exceeds demand throughout the current year and into the foreseeable future. Capacity requirement decisions are evaluated at the substation level and, periodically, on the feeder level. Otter Tail's distribution engineering group monitors capacity needs and performs analysis using DNV-GL Synergi software. Twice a year, substation loading is compared with substation capacity. This exercise is a significant part of the yearly capital budget planning process.

To assess energy efficiency impacts on the distribution system, Otter Tail identified distribution projects in its five-year capital budget that were required for capacity or voltage excursion caused by load. The impact of energy efficiency is allocated to each of the identified projects based on a ratio of the substation load to the system load. Otter Tail considered the following assumptions when calculating the distribution avoided costs:

- The years of the study span from 2017-2021;
- The energy efficiency goal was known for 2017 through 2019 and estimated for 2020 and 2021. Each year's goal was used for the estimated year of the project;
- The study covered entire Otter Tail's distribution system (498 substations, 735 feeders) based on capital project submissions;
- The projects were selected based on capacity additions or voltage violations caused by load;
- The annual growth rate was determined by review of substation load growth and approximated;
- The escalation was assumed to be three percent;
- Value of project deferral is based upon weighted average cost of capital savings and inflation;
- Assume EE impacts have the same load shape of each feeder; and,
- Only Minnesota projects were selected in the samples.

Distribution Avoided Costs Results

Continuous Valuation Approach

Table 12 provides the distribution avoided cost results utilizing the continuous valuation approach:

Table 12 - Distribution Avoided Costs (Continuous Valuation Approach)

| Year | Distribution Avoided Cost (\$/kW-yr) |
|-------------|---|
| 2018 | \$4.63 |
| 2019 | \$4.77 |
| 2020 | \$4.91 |
| 2021 | \$5.06 |
| 2022 | \$5.21 |
| 2023 | \$5.37 |
| 2024 | \$5.53 |
| 2025 | \$5.70 |
| 2026 | \$5.87 |
| 2027 | \$6.04 |
| 2028 | \$6.23 |
| 2029 | \$6.41 |
| 2030 | \$6.60 |
| 2031 | \$6.80 |
| 2032 | \$7.01 |
| 2033 | \$7.22 |
| 2034 | \$7.43 |
| 2035 | \$7.66 |
| 2036 | \$7.89 |
| 2037 | \$8.12 |
| 2038 | \$8.37 |
| 2039 | \$8.62 |
| 2040 | \$8.88 |
| 2041 | \$9.14 |
| 2042 | \$9.42 |
| 2043 | \$9.70 |

Transmission Avoided Costs

Modeling and Assumptions

Otter Tail performs an assessment of its transmission system triennially utilizing the Siemens PTI PSSE software program. Models are built in-house to populate a Ten-Year Development Plan to ensure Otter Tail's transmission system operates effectively and reliably under a variety

of conditions and probable contingencies. Otter Tail completed the latest version of the Plan in 2014 and currently utilizes it to identify and rank transmission projects to assist in meeting compliance requirements and local reliability planning criteria. The assessment includes power flow contingency analysis for the ten-year planning horizon and identifies projects and plans to mitigate performance outside Otter Tail's reliability criteria. The assessment provides capacity related projects with their associated costs and need dates. Results from the PSSE software provide information on the additional capacity gains from each project.

Otter Tail considered the following assumptions when calculating transmission avoided costs from conservation efforts:

- Years of the study cover 2014-2023 with an annual growth rate of one percent;
- Study covered the entire Otter Tail transmission system; and,
- n-0 and n-1 system configurations were modeled.

For evaluating the impacts of conservation on the transmission system, Otter Tail chose transmission projects within Minnesota with load growth being the primary driver for a project. Energy efficiency could potentially delay the in-service date of the project, which qualifies it as a valid energy efficiency project to be included in the estimates. Projects not included were driven by a need other than load growth such as a request for looped service or an age and condition issue.

Transmission Avoided Costs Results

Continuous Valuation Approach

Table 13 provides the transmission avoided cost results utilizing the Continuous Valuation approach:

Table 13 - Transmission Avoided Costs (Continuous Valuation Approach)

| Year | Transmission Avoided Cost (\$/kW-yr) |
|-------------|---|
| 2018 | \$5.92 |
| 2019 | \$6.10 |
| 2020 | \$6.28 |
| 2021 | \$6.47 |
| 2022 | \$6.67 |
| 2023 | \$6.87 |
| 2024 | \$7.07 |
| 2025 | \$7.28 |
| 2026 | \$7.50 |
| 2027 | \$7.73 |
| 2028 | \$7.96 |
| 2029 | \$8.20 |
| 2030 | \$8.44 |
| 2031 | \$8.70 |

| Year | Transmission Avoided Cost (\$/kW- yr) |
|-------------|--|
| 2032 | \$8.96 |
| 2033 | \$9.23 |
| 2034 | \$9.50 |
| 2035 | \$9.79 |
| 2036 | \$10.08 |
| 2037 | \$10.38 |
| 2038 | \$10.70 |
| 2039 | \$11.02 |
| 2040 | \$11.35 |
| 2041 | \$11.69 |
| 2042 | \$12.04 |
| 2043 | \$12.40 |

Summary of T&D Results

Table 14 provides the summary T&D avoided cost results as originally filed in Otter Tail’s 2017-2019 CIP Triennial filing and utilizing the Continuous Valuation approach.

Table 14 - Summary of Transmission & Distribution Avoided Costs

| Year | As Originally Approved in Docket No. 16-116 | Continuous Valuation Approach (\$/kW-yr) |
|-------------|--|---|
| 2018 | \$71.63 | \$10.55 |
| 2019 | \$72.46 | \$10.87 |
| 2020 | \$71.98 | \$11.20 |
| 2021 | \$71.71 | \$11.53 |
| 2022 | \$70.86 | \$11.88 |
| 2023 | \$70.02 | \$12.24 |
| 2024 | \$69.21 | \$12.60 |
| 2025 | \$68.43 | \$12.98 |
| 2026 | \$67.64 | \$13.37 |
| 2027 | \$66.87 | \$13.77 |
| 2028 | \$66.11 | \$14.18 |
| 2029 | \$65.35 | \$14.61 |
| 2030 | \$64.60 | \$15.05 |
| 2031 | \$64.73 | \$15.50 |
| 2032 | \$64.87 | \$15.97 |
| 2033 | \$65.01 | \$16.44 |
| 2034 | \$65.15 | \$16.94 |
| 2035 | \$65.30 | \$17.44 |
| 2036 | \$65.45 | \$17.97 |
| 2037 | \$65.61 | \$18.51 |
| 2038 | \$65.77 | \$19.06 |
| 2039 | \$65.93 | \$19.63 |
| 2040 | \$66.11 | \$20.22 |
| 2041 | \$66.28 | \$20.83 |
| 2042 | \$67.28 | \$21.45 |
| 2043 | \$68.28 | \$22.10 |

T&D Avoided Costs Using Continuous Valuation with Statistical PCAF

Table 15 illustrates the 2018 T&D avoided costs with the PCAFs applied to avoided costs from the Continuous Valuation approach.

Table 15 - 2018 T&D Avoided Costs Using Continuous Valuation with Statistical PCAF

| (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---------------|---------------------|----------------|----------------------------------|-----------------------------------|-------------------------------------|-----------------------------|
| Sector | Load Shape* | PCAF kW | Load at System Peak (kW) | Ratio of PCAF to System kW | Continuous Valuation (\$/kW) | Avoided T&D Cost |
| Residential | Cooling | 0.0031 | 0.0004 | 7.7850 | \$10.55 | \$82.13 |
| Residential | Heating | 0.3909 | 0.4735 | 0.8256 | \$10.55 | \$8.71 |
| Residential | Heating/Cooling | 0.3940 | 0.4739 | 0.8314 | \$10.55 | \$8.77 |
| Residential | Lighting | 0.8043 | 0.9168 | 0.8773 | \$10.55 | \$9.26 |
| Residential | Refrigeration | 0.7730 | 0.7422 | 1.0414 | \$10.55 | \$10.99 |
| Residential | WaterHeating | 0.7743 | 0.9637 | 0.8034 | \$10.55 | \$8.48 |
| Residential | Behavioral Programs | | Measure load shape not available | | | |
| Residential | Engine Block Timer | | Measure load shape not available | | | |
| Commercial | Cooling | 0.0363 | 0.0252 | 1.4431 | \$10.55 | \$15.22 |
| Commercial | Heating | 0.2568 | 0.3555 | 0.7223 | \$10.55 | \$7.62 |
| Commercial | Heating/Cooling | 0.2931 | 0.3807 | 0.7700 | \$10.55 | \$8.12 |
| Commercial | LightingInternal | 0.7391 | 0.8081 | 0.9146 | \$10.55 | \$9.65 |
| Commercial | LightingExternal | 0.2156 | 0.0507 | 4.2525 | \$10.55 | \$44.86 |
| Commercial | Refrigeration | 0.7642 | 0.7658 | 0.9979 | \$10.55 | \$10.53 |
| Commercial | Cooking | | Measure load shape not available | | | |
| Commercial | Ventilation | 0.7644 | 0.7658 | 0.9982 | \$10.55 | \$10.53 |
| Commercial | WaterHeating | 0.6455 | 0.6818 | 0.9467 | \$10.55 | \$9.99 |
| Industrial | MachineDrives | 0.8816 | 0.9675 | 0.9112 | \$10.55 | \$9.61 |
| Industrial | HVAC | 0.8428 | 0.9596 | 0.8783 | \$10.55 | \$9.27 |
| Industrial | ProcessHeating | 0.8756 | 0.9705 | 0.9022 | \$10.55 | \$9.52 |

*Measure load shapes pulled from the Electric Power Research Institute (EPRI) Load Shape Library 4.0.

Methodology Pros and Cons

Pros/Cons of the Continuous Valuation Approach

- Otter Tail believes the Continuous Valuation approach to be a straightforward method which calculates a reasonable avoided T&D Cost.

Pros/Cons of Statistical Peak Capacity Allocation Factors

Otter Tail calculated its Peak Capacity Allocation Factors (PCAFs) using its hourly system-wide data. For Otter Tail, the system peak occurs in the winter.

Pros

- Theoretically, using the PCAFs may capture more of the T&D benefits at hours other than generation system peak.

Cons

- While the PCAF method has some theoretical merit, real world application proves difficult. Many energy efficiency projects are very specific custom projects with specific measure load shapes (Compressed Air projects, Custom Grant projects, and Recommissioning projects, etc.), or measure load shapes do not exist for the measure (engine block timers, home energy reports, water heater load control, no loss drains,

commercial kitchen equipment, etc.). Using measure load shapes that may be similar detracts from the purpose of using PCAFs. A utility may collect data to create the measure load shape, but this increases the costs to a program or project and may make the program or project not cost-effective.

- Data availability differs between the utilities, how the PCAFs are calculated will introduce inconsistency among the utilities. This deviates from the original purpose of the T&D Cost Study to create consistency in how the T&D avoided cost is calculated.
- The September 12, 2016 Order stated, “Each utility would have a single value that can be utilized system wide.” The PCAF methodology creates a different avoided T&D cost for each measure as illustrated in Table 14.
- Otter Tail uses DSMore for calculating all program cost-effectiveness. DSMore would have to be updated by its developer, Integral Analytics, to handle the use of PCAFs. This would be a significant cost to Minnesota utilities depending on when such an update occurs. It also would require utilities to purchase Integral Analytics LoadSEER tool to achieve accurate results adding more program costs while providing minimal benefit.

Recommendation

Otter Tail does not oppose using the Continuous Valuation approach as proposed by the TPE. However, it does oppose applying the PCAFs. While the theory behind the PCAFs is intended to provide a more accurate measure of the benefits an efficiency measure has on the T&D system if the correct assumptions are made, the real-life application has not been thoroughly vetted. In addition, the data needed to more accurately calculate and apply the PCAFS are currently not available.

Using specific measure load shape data would also be a new endeavor for Otter Tail. Historically, Otter Tail has used customer load shapes to apply measure energy savings through the DSMore software modeling tool. While Otter Tail believes the method of using customer load shapes to model the energy efficiency benefits with DSMore may not be perfect, it provides a reasonably accurate method to calculating the benefits of an energy efficiency measure as it still targets certain hours for coincident peak reduction: the greatest driver of customer benefits. In addition, Otter Tail’s method of using customer load shapes for modeling does take in to account coincident demand factors established by the Department’s TRM.

F. Third-Party Evaluator

The Third-Party Evaluator's objectives in this process were to:

- clarify application of the system planning method to calculations of avoided transmission and distribution costs,
- assist utilities in estimating these costs, manage Technical Advisory Committee participation in the process, and
- assist with development of the final report.

Department Staff also requested that the Third-Party Evaluator include its recommended approach in the final report.

The two primary methods of estimating avoided T&D costs discussed in this report, the Discrete and Continuous Valuation approaches, are variants of the system planning approach. Both approaches calculate the marginal cost of T&D based on the present value cost savings provided by load reductions that allow deferral of planned T&D investments.

The approaches differ in that the Discrete approach starts with a forecast of load reductions from energy efficiency, and calculates the deferral benefit (if any) from that load reduction. The deferral benefit is determined using integer years (no partial year deferrals). If, for example, the amount of load reduction required in Year 2 of the T&D plan to defer an investment is 2,000 kW and the amount of load reduction anticipated from EE is only 1,000 kW, the T&D marginal cost in that year would be \$0.

The Continuous Valuation approach relies on a marginal cost method of valuing T&D costs avoided by energy efficiency investments. Rather than starting with an EE forecast, the approach assumes that the load growth driven T&D capital projects are deferred by one year, and uses the load growth forecast for the project area to calculate the \$/kW-year marginal cost of T&D capacity. In this way, the continuous valuation approach is independent of an EE forecast. In addition, different from the Discrete approach, the CV approach assumes that EE could defer *increments* of T&D capacity as opposed to requiring that it defer the investment by an entire year or more.

In this sense, the CV approach is very similar to the way Minnesota utilities use a proxy generator (e.g. a natural gas-fired combustion turbine) to calculate avoided capacity costs. Rather than require that EE programs be of sufficient magnitude in any given year to defer construction of the combustion turbine, utilities assume that energy efficiency that reduces system peak load (kW) receives a generating capacity deferral benefit commensurate with the \$/kW-year avoided capacity cost. In other words, it is assumed that even a very small increment of savings if delivered on peak will defer an increment of generating capacity.

Comments on Utility Avoided Cost Estimates

The Third-Party Evaluator has actively engaged with the IOUs in developing their estimates and generally believes that the utilities' estimates as presented in this report are reasonable. The TPE has provided guidance on calculation methods that the utilities have incorporated into the report.

The following sections relay comments specific to each utility and recommendations for ways to improve the methodology used.

Xcel Energy

Xcel has provided marginal cost estimates using both the Discrete and CV approaches. The Xcel Discrete approach departs from traditional marginal cost methods by evaluating the impact of an increasing amount of EE reduction each year (the traditional approach is to quantify the impact of a fixed amount of load change). The use of an increasing amount of EE complicates the determination of marginal costs, and required numerous discussions between Xcel and the TPE to arrive at a reasonable representation of the marginal cost of T&D capacity for Xcel. It is worth noting that the final Xcel Discrete approach makes corrections to these past practices, which is the reason for the large change in the marginal costs compared to Xcel's prior results.

Xcel's calculation of CV marginal costs is consistent with the methodology provided by the TPE, and we find those results to be reasonable as well. Because of the more transparent nature of the CV method, we recommend that approach for all of the Minnesota utilities. However, it is expected, and comforting, that the marginal cost results under both the Discrete and CV approach are comparable.

In the future, we recommend that Xcel also take a closer look at capacity-driven projects that it deems ineligible for deferral. Currently, the company's model allows no potential deferral benefit and, therefore, a zero marginal cost for projects that are forecast to have peak loads above their rated carrying capacity prior to the start of the EE program. While this conforms to the logic that such projects would need to be built before EE reductions could relieve any problem, we are concerned that the vast majority of the capacity projects forecast by Xcel are needed prior to the start of the EE reduction period.

For example, of the feeder projects, 92 projects are "needed" in 2018, followed by about 12 additional projects each year after that. The EE reductions begin in 2019, so the feeder portion of Xcel's distribution marginal costs (both Discrete and CV) are based on the roughly 12 projects per year. If some of the 90 projects identified for 2018 would not actually be constructed in 2018, and have small enough deficiencies that they could be further deferred by EE, then such projects should be included in distribution marginal cost estimates.

Minnesota Power

Minnesota Power calculated distribution marginal costs using the Discrete approach by analyzing the firm capacity at the 115kV interfaces in the PSSE transmission models. The avoided costs that came out of that methodology were zero. Minnesota Power recognized that this was a simplistic method to estimating distribution avoided costs with the Discrete approach; however, because of current modeling limitations with the company's distribution models, a more granular analysis could not be performed. Minnesota Power did not calculate distribution marginal costs using the Discrete approach because of current modeling limitations. Minnesota Power was able to estimate marginal costs using the CV approach, and the inputs and results appear reasonable. The estimated marginal costs for each of the eight identified projects are large, but as they represent only three percent of the Minnesota Power system, the weighted average system avoided cost is small. This highlights the potential future opportunity for increasing the value of EE or other demand management options through localized targeting.

For transmission, Minnesota Power did not identify any projects that could be affected by the forecast amounts of EE. There are, therefore, no Discrete approach avoided costs. While the CV approach does not require the use of an EE forecast for estimating marginal costs, Minnesota Power determined that EE would not offer the possibility of deferring any of the projects. This is not an unexpected result for transmission projects, and in the Minnesota Power case, the transmission lines in question predominantly serve industrial customers that are ineligible from participating in Minnesota Power EE programs. We deem the Minnesota Power approach reasonable for the estimation of avoided costs for EE, but caution that there may be non-zero marginal transmission capacity costs for other resource options.

Otter Tail Power

Because of limitations in their planning models and processes, Otter Tail was unable to estimate marginal costs using the Discrete approach. Their calculation of CV approach avoided costs appear appropriate for each project. As with Minnesota Power, the Otter Tail areas with potentially deferrable capacity projects represent a small fraction of the total Otter Tail service territory (11 percent for transmission projects, and 12.4 percent for distribution projects). Therefore, while the marginal cost for a project area could be over \$100 per kW-year, the average marginal cost across the entire service territory is in single digits. We find the Otter Tail calculations and results to be reasonable.

Explaining Differences Between Utility Estimates

We find all the utility marginal cost estimates to be comparable, and the differences to be expected given the cost drivers discussed below. After correcting the Xcel Energy values to \$/kW-yr, their estimates of distribution avoided costs are comparable to Minnesota Power's and Otter Tail Power Company's. It should be noted that variations in T&D marginal costs are to be expected when looking across utilities. Indeed, variations in marginal cost are generally very large across geographic areas within a utility.

The primary drivers of T&D marginal costs include the following factors:

- Equipment inflation rates;
- Utility discount rates;
- Equipment and labor costs;
- Equipment types;
- Engineering design and planning standards;
- Area load growth;
- Existing load carrying capacity headroom in each area; and
- Project backlog.

Of these drivers, the last three have the largest impact on marginal cost variation. Obviously, if there is no growth, there is no need for capacity projects, and no marginal cost for that area. Conversely, high growth will require more capacity projects, but the marginal cost of those projects, on a \$/kW-yr basis, will not necessarily be high because high growth equals a high kW denominator used to calculate the \$/kW-yr marginal cost. In other words, the deferral value (numerator) would be high because of the large projects, but the amount of kW needed to defer the projects (denominator) would also be high because of the high growth. Therefore, the value

of each kW of reduction would not necessarily be that large. Indeed, the highest marginal cost cases tend to be in those areas with slow growth and no remaining load carrying capability in the area.

The amount of existing load carrying capability in an area can also depress marginal costs. The excess capability (capability above peak loading) can allow an area to absorb load growth without the need for a new capacity project. This results in zero marginal cost for those areas, which also drives down the system average T&D capacity value.

Finally, it is worth noting that project backlog can also depress capacity values. This can be counterintuitive because the utilities will be doing capacity work. However, that work is likely not deferrable because the backlog work is already past the “need date” and deferral would require immediate load reduction that compensates for both load growth, and the existing load exceedance amounts. It is common for utilities to exclude such projects from their marginal cost calculations, as has Xcel Energy in its case.

TPE Recommendations

From the beginning of this process, the TPE has articulated its preference for estimating avoided T&D based on the Continuous Valuation approach. As shared with utilities and other members of the TAC and filed in Docket E999/CIP-16-541, the TPE believes that the combination of the Continuous Valuation approach with Statistical PCAFs enables utilities to potentially develop avoided T&D estimates that better reflect the impact energy efficiency program activities are having on their transmission and distribution systems. As discussed within this report, however, the application of the Statistical PCAF method to utilities’ current method of estimating cost effectiveness has proven problematic (see additional discussion in Appendix D).

The Statistical Peak Capacity Allocation Factor provides a way of assigning annualized transmission and distribution costs to a broader set of time periods than simply the time at which the overall system is peaking. The PCAF method, thereby, attempts to address the timing issue associated with the desire to align savings associated with energy efficiency investments with the time of the year (and day) at which the transmission and distribution system is peaking. This estimating process can be achieved by applying these time-varied values to energy efficiency measure load shapes. The PCAF approach as used during this study does not, though, address the locational issue associated with the desire to align energy efficiency investments with places on the utility’s grid where EE can provide the most value. This is due to the fact that Minnesota IOUs do not currently incorporate into planning or implementation information regarding where within their service territories energy efficiency measures are being installed. Frankly, few utilities in the country are currently able to achieve this objective, but many are starting the process.

Although the TPE determined that it would be possible to modify DSMore to accommodate PCAFs and for utilities to, in turn, modify the way they incorporate avoided T&D values into their CE evaluations, the IOUs do not currently support these changes. In addition, the study process revealed that utility energy efficiency measure load shapes, with limited exception, have not been recently updated. Accurate load shapes are an important component of successfully applying temporally and locationally-differentiated estimates of avoided transmission and distribution costs to utility cost effectiveness evaluations. Unfortunately, studies to update

measure load shapes can be expensive and time consuming. Currently, utilities rely more on technical assumptions in the Technical Reference Manual (TRM) than measure load shapes to estimate measure and program cost effectiveness.

Given current system limitations, the cost of potential system upgrades, and constraints on utility staffing resources available to adopt the TPE's preferred approach (CV with Statistical PCAF), the TPE recommends that utilities adopt estimates developed using the Continuous Valuation approach without PCAF and update these values with each triennial. Unless an IOU determines that it is able to apply PCAFs and supports their implementation, PCAFs would not be implemented at this time due to locational data, EE evaluation tool, and end use shape limitations.

Although Xcel Energy has stated that the CV method does not match the system planning process as well as does the Discrete approach, the basis for the CV approach is the utility planning process. The CV approach takes a more theoretical approach to determining the value of load reductions than the Discrete approach, but the CV results are shown to be comparable to those of Discrete approach, and the CV approach has been shown to be more uniformly calculable.

The TPE recommends that the Department consider investigating for future triennials the potential for utilities to:

- update measure load shapes to more accurately reflect timing of measure savings and to align with TRM technical assumptions;
- incorporate mechanisms into CIPs to enable tracking of locations where energy efficiency measures are installed and factor these elements into CIP Triennial planning;
- apply to CV estimates use of measured Distribution and Transmission system peaking information, and
- utilize updated load shape, locational tracking information, and T&D system peaking information in future cost effectiveness evaluations.

Investigation of each alternative should include consideration of whether the costs to implement outweigh the benefits the changes could provide.

The TPE also recommends, to the extent it is not currently happening, that the Department seek to integrate CIP planning with ongoing Minnesota PUC Grid Modernization efforts (Docket No. E999/CI-15-566). Xcel Energy's current geo-targeting pilot project can help inform efforts to integrate EE into distribution planning.

G. Conclusion

This report represents the outcome of the process to develop estimates of transmission and distribution costs avoided by energy efficiency and establish a standardized methodology for revising these values for future triennials. Although the utilities did not support applying Peak Capacity Allocation Factors to their avoided cost estimates, the concept should not be completely abandoned as it (or a similar approach) could help inform ways that utilities can adapt their cost effectiveness models to account for energy efficiency's locational and timing benefits to the grid. The exercise of considering why and how a utility would develop allocators for transmission and distribution avoided costs was a useful part of the current process.

As presented in Appendix C, the utility estimates of avoided T&D costs based on Continuous Valuation method are the values proposed for the 2018-2019 portion of the current Triennial and the CV method is the standardized method that it is suggested utilities adopt for future triennials. The Third-Party Evaluator and the Technical Advisory Committee believe that these estimates are technically and methodologically sound and provide the utilities with reasonable values with which to estimate measure and program cost effectiveness.

As the role energy efficiency may play in transmission and distribution planning continues to evolve, so too may the way utilities develop estimates of T&D costs avoided by EE. However, for the time being, the values and methodology proposed in this report will serve the utilities and the state well in assessing the value of energy efficiency. Energy efficiency is a valuable resource for meeting customer energy needs and evaluating EE cost effectiveness plays an important role in determining the appropriate quantities, types and timing of such investments.

Appendix A – Technical Advisory Committee Members

| Name | Organization |
|-----------------------------|------------------------------------|
| Carl Nelson | Center for Energy and Environment |
| Kavita Maini | KM Energy Consulting |
| Julia Friedman [†] | Midwest Energy Efficiency Alliance |
| Tina Koecher | Minnesota Power |
| Christopher Davis | MN Department of Commerce |
| Adam Zoet | MN Department of Commerce |
| Cezar Panait | MN Public Utilities Commission |
| Jason Grenier | Otter Tail Power Company |
| Shawn White | Xcel Energy |
| Christopher Barthol | Xcel Energy |
| <i>Marty Kushler*</i> | ACEEE |
| <i>Rao Konidena*</i> | MISO |

* These individuals were invited but unable to participate.

[†] Julia Friedman was later replaced by Nikhil Vijaykar from MEEA.

Appendix B – Detailed Descriptions of Discrete and Continuous Valuation Approaches

Third-Party Evaluator¹⁶

Continuous Valuation with Statistical PCAF

Under the Continuous Valuation with Statistical PCAF method, the marginal cost of T&D is based on the utility's forecasted system plan for load growth driven capital projects. The methodological basis for the marginal cost is that a reduction in area net peak load (area usage net of “in-front-of-the-meter” in-area generation or storage) could defer growth-related capacity projects, and this deferral results in a financial benefit to utility ratepayers. The benefit arises because the deferral of a project reduces the net present value of a project (due to discounting), albeit with some loss of value due to cost escalation for the project when it is finally installed. The net effect is commonly referred to as the “deferral benefit.”

To convert the deferral benefit into the form commonly used for marginal costs, one first divides the deferral benefit by the kW associated with the deferral. For example, if the deferral benefit is based on a one year deferral, one would divide by one year of load growth to get the \$/kW deferral benefit. One then multiplies this \$/kW value by a levelization factor to convert it to a \$/kW-yr value that is the standard form for marginal cost studies.

As a final step, hourly allocation factors are calculated to identify and value the peak hours of importance for the project area. These peak capacity allocation factors (PCAF) can be applied to the \$/kW-yr marginal cost to convert the marginal cost into an 8760 hourly stream of \$/kW-hr marginal costs, or the allocation factors can be multiplied with hourly load reduction shapes (e.g.: lighting shape) to calculate the “coincident” peak reduction of the load reduction shape. The detailed steps and formulae for the Continuous Valuation with Statistical PCAF method are provided below:

1. Gather information on growth-driven projects. Growth-driven projects are those T&D investments that are occurring because of load growth on the system (as opposed to projects related to implementing new technologies, those to accommodate new customers [e.g. new housing subdivision], projects to accommodate non-native load or supply, etc.). Information should include:
 - Project Cost in \$000 (ProjectCost, \$000)
 - Project installation year (InstallYr)
 - Year basis for the cost estimate (YrBasis)
 - Corporate after-tax discount rate (disc, %/yr)
 - Revenue Requirements multiplier that is the present value of the revenue requirements associated with the project, divided by the Project Cost. A typical value is 1.4 and

¹⁶ This information is verbatim from the comments submitted by the Third-Party Evaluator on December 22, 2016 in Docket E999/CIP-16-541.

reflects additional costs to customers such as corporate taxes, return on and of investment, property taxes, fees, general plant, and administrative costs. (RevReqMult)

- Annual escalation rate for the project cost. (esc, %/yr)
- Annual O&M in \$000 that could be avoided by project deferral (AnnO&M, \$000/yr)
- Length of the T&D planning horizon in years. (Horizon, yrs)
- Annual load growth or capacity deficiency in the installation year for the project area in MW/yr. The project area is the geographic area that electrically feeds to the constrained point of the system that requires the capacity addition. The project area is typically a subset of the utility service territory for distribution projects, but can encompass the entire utility service territory for large transmission projects. (GrowthMW, MW/yr)
- Hourly loads aggregated to the project area. (Load[h])
- Analysis year, that is the first year for which marginal costs will be calculated. (FirstYr)
- Distribution loss factors by Voltage. Losses are from the meter to the constrained equipment level. This can be a simple differentiation between distribution and transmission-level losses. (DLoss)

2. Calculate the present value of the full cost of all growth-driven projects, j, in the project area over the planning horizon. The reason for present valuing the costs is to make costs comparable notwithstanding the year in which the project is implemented. (FullCost, \$000)

$$FullCost = \sum_{\text{projects in the area}}^{\text{planning horizon}} \left[ProjectCost[j] * RevReqMult * \frac{(1 + esc)^{(InstallYr[j]-Yrbasis[j])}}{(1 + disc)^{(InstallYr[j]-FirstYr)}} \right]$$

Where

$$FirstYr = \text{First year of the marginal cost estimates}$$

3. Calculate the capital value of deferring the project by one year. The reason for calculating the one-year deferral is to establish the financing cost savings derived from pushing a project out one year. The use of one year enables one to establish the marginal cost (\$/kW-year) to use in EE avoided cost calculations. (DefValCap, \$000)

$$DefValCap = FullCost * \left[1 - \left(\frac{1 + esc}{1 + disc} \right)^{\Delta t} \right]$$

Where $\Delta t = 1$

4. Calculate the total present value of deferring one year, by adding in the O&M savings. Again, the present valuing is done to make comparable multiple projects that come in different years. (DefValTot, \$000)

$$DefValTot = DefValCap + AnnO\&M * \frac{(1 + esc)^{(InstallYr-Yrbasis)}}{(1 + disc)^{(InstallYr-FirstYr)}}$$

5. Calculate the marginal cost in \$/kW (ValperkW, \$/kW)

$$\text{ValperkW} = \text{DefValTot} / \text{GrowthMW}$$

6. Calculate a levelization factor for the marginal cost to convert it to a \$/kW-yr value.
(LvlFctr, %)

The calculation using Excel formulas:

$$\text{LvlFctr} = \text{PMT}((1-(1+\text{disc})/(\text{Horizon})), \text{Horizon}, -1, 0, 1)$$

7. Calculate the marginal cost in FirstYr, by multiplying by the levelization factor, and extend out 20 years (reason for 20 years is to capture projected costs over a long-term horizon – is point 2 in Staff’s July 1, 2016 comments – see above) by inflating by the escalation factor.
(MC[yr], \$/kW-yr)

$$\text{MC}[\text{yr}] = \text{ValperkW} * \text{LvlFctr} * (1+\text{esc})^{(\text{yr}-\text{FirstYr})}$$

Steps 1 through 7 above complete steps 1 through 2 outlined in the Staff recommendation. Some example calculation are provided below. As can be seen from the example, the resulting marginal costs are consistent across years --- hence the ‘Continuous Valuation’ label assigned to this method. This method does a considerable amount of smoothing of the lumpiness of T&D project costs, so it is appropriate to use for representative T&D marginal cost value, but the results are not representative of actual cost savings one would expect to attain in any particular year.

We believe these types of marginal costs are appropriate for informing system-wide EE efforts, but would not be the avoided costs one would want to use for a targeted EE program that aims to defer a specific T&D investment with specific EE or other DERs. For that type of analysis, a rolling timeframe approach or a discrete approach would be more appropriate.

Figure 1: Sample marginal cost calculations (continuous valuation)

| | | | | |
|--|-----------------|-------------------------|-----------------|----------------|
| Discount rate | 7% | <i>disc</i> | | |
| Escalation | 3% | <i>esc</i> | | |
| Revenue Requirement Multiplier | 1.40 | <i>RevReqMultiplier</i> | | |
| Yr basis for cost estimates | 2015 | <i>YrBasis</i> | | |
| Planning Horizon (yrs) | 10 | <i>Horizon</i> | | |
| First year of marginal costs | 2017 | <i>FirstYr</i> | | |
| Inputs | | | | |
| | Project 1 | Project 2 | Project 3 | |
| Cost (\$000) | \$10,000 | \$15,000 | \$5,000 | |
| Installation year for the project (InstallYr) | 2019 | 2020 | 2018 | |
| Annual O&M (\$000/yr) (AnnO&M) | 10 | 20 | 5 | |
| Annual Growth (MW) (GrowthMW) | 5 | 10 | 2 | |
| EE Allocation (%) | 20% | 45% | 35% | |
| Calculations | | | | |
| Fully Loaded Capital Cost (\$000) (FullCost) | \$13,762.88 | \$19,872.57 | \$7,148.68 | |
| PW Capital Deferral Value for 1 Yr (\$000) (DefValCap) | \$514.50 | \$742.90 | \$267.24 | |
| PW Total Deferral Value for 1 Yr (\$000) (DefValTot) | \$524.33 | \$761.83 | \$272.35 | |
| PW Value (\$/kW) (ValperkW) | \$104.87 | \$76.18 | \$136.17 | |
| Real Discount Rate | 3.88% | 3.88% | 3.88% | |
| Levelization Factor (LvlFctr) | 11.80% | 11.80% | 11.80% | |
| Annual Marginal Costs (\$/kW-yr) (MC[yr]) | | | | System |
| | Project 1 | Project 2 | Project 3 | Wtd Avg |
| 2017 | \$12.37 | \$8.99 | \$16.07 | \$12.14 |
| 2018 | \$12.74 | \$9.26 | \$16.55 | \$12.51 |
| 2019 | \$13.13 | \$9.54 | \$17.05 | \$12.88 |
| 2020 | \$13.52 | \$9.82 | \$17.56 | \$13.27 |
| 2021 | \$13.93 | \$10.12 | \$18.08 | \$13.67 |
| 2022 | \$14.34 | \$10.42 | \$18.63 | \$14.08 |
| 2023 | \$14.77 | \$10.73 | \$19.19 | \$14.50 |
| 2024 | \$15.22 | \$11.06 | \$19.76 | \$14.94 |
| 2025 | \$15.67 | \$11.39 | \$20.35 | \$15.38 |
| 2026 | \$16.14 | \$11.73 | \$20.96 | \$15.84 |
| 2027 | \$16.63 | \$12.08 | \$21.59 | \$16.32 |
| 2028 | \$17.13 | \$12.44 | \$22.24 | \$16.81 |
| 2029 | \$17.64 | \$12.82 | \$22.91 | \$17.31 |
| 2030 | \$18.17 | \$13.20 | \$23.60 | \$17.83 |
| 2031 | \$18.72 | \$13.60 | \$24.30 | \$18.37 |
| 2032 | \$19.28 | \$14.00 | \$25.03 | \$18.92 |
| 2033 | \$19.86 | \$14.42 | \$25.78 | \$19.49 |
| 2034 | \$20.45 | \$14.86 | \$26.56 | \$20.07 |
| 2035 | \$21.07 | \$15.30 | \$27.35 | \$20.67 |
| 2036 | \$21.70 | \$15.76 | \$28.17 | \$21.29 |
| 2037 | \$22.35 | \$16.24 | \$29.02 | \$21.93 |
| 2038 | \$23.02 | \$16.72 | \$29.89 | \$22.59 |

The next step in the Staff recommendation (Step 3) is to allocate the T&D marginal costs to peak hours of the year. This is done so that the coincidence of EE with the T&D peaks can be incorporated into the EE valuation. The EE valuation formula is as shown below:

$$EEValue[m] = \sum_{h=1}^{8760} [EEShape[m, h] * PCAF[h] * MC[y]]$$

Where

EEShape[m,h] = The EE reductions for measure m, in hour h.

PCAF[h] = The Peak Capacity Allocation Factors that allocate the T&D marginal cost to hours of the year

Also note that the EEValue formula can be re-expressed in a way that highlights the fact the PCAFs need not be applied to the marginal cost to decompose it into hourly values, but could instead be applied to the hourly EE shapes to develop weighted average peak reductions. In this

form, the PCAFs are basically used to develop coincident peak reductions, where the coincident peaks are weighted averages over the entire T&D peak period.

$$EEValue[m] = MC[y] * \sum_{h=1}^{8760} [EEShape[m,h] * PCAF[h]]$$

Below is a recommended formula for calculating the peak capacity allocation factors (PCAFs). The PCAFs can be developed at the area level using area load data, or at the system level using system load data. The decision would be driven by the availability of data, and the expected variation between area and system peaks.

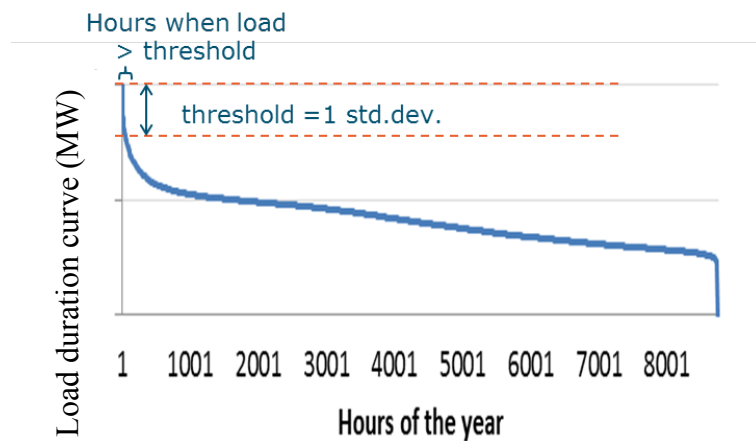
PCAF = Peak capacity allocation factor to assign relative weights to each hour in the peak period. The sum of the PCAFs for any year sum to 1.0.

$$PCAF[p, yr, h] = \frac{Max(0, Load[p, yr, h] - Thresh[p])}{\sum_{hr=1}^{8760} Max(0, Load[p, yr, h] - Thresh[p])}$$

Load[p, yr, h] = Hourly load or need in the project area (p), in the year (yr), for each hour (h).

Thresh[p] = Threshold for defining the peak hours for the project area. All hours with load above Thresh would be considered peak hours. For simplicity, we recommend that the threshold be set at one standard deviation below the single hour peak as shows in Figure 2. Using one standard deviation has the advantage of including relatively few hours in the peak period if an area has a peaky load duration curve, and a large number of hours in the peak period if the area has a flatter load duration curve where the peak could occur over a wide range of hours.

Figure 2: PCAF Hours
The peak period is only those hours with load above the threshold.



Note that this PCAF approach assumes that the EE reductions are not large enough to change the hours in the peak period. If the EE were expected to alter the peak period substantially, then an average of the PCAF weights prior to EE, and the PCAF weights after EE should be used. The final step (Step 4) in developing the marginal costs is to gross them up for losses to the customer meter. While in the process whether the gross-up occurs nor not is not critical, care should be taken to label all information to indicate if the values are adjusted for losses or not.

Alternate Marginal Cost Approaches

Rolling Approach

Under the rolling approach, the marginal costs are calculated using a forward looking planning period window. The approach uses the Present Worth (PW) method, as does the continuous method, but recalculates the PW results for every year as the planning period window rolls forward. In the first year, the results of the Rolling Approach and the Continuous Approach are the same. However, the rolling approach rises more rapidly as it approaches the year of the project --- 2020 in the example shown in Figure 3; and then the rolling approach drops off in the year after the project, since there are no future investments in the dataset to be deferred in the area. The calculations for the example, as well as an area that has two projects are shown in Figure 4.

Figure 3: Comparison of Continuous and Rolling Marginal Costs (Project 2)

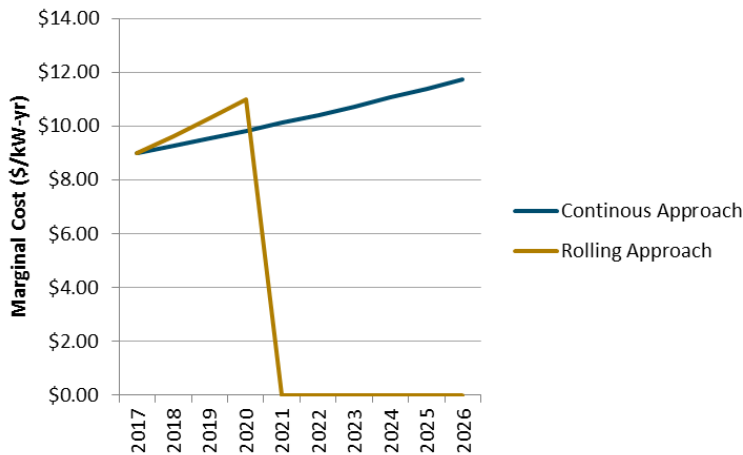


Figure 4: Example Calculations for Rolling Method of Marginal Cost Estimation

| Rolling Approach - Example 1 | | | | | | | | | | | | | | | | | | |
|--------------------------------|---------------|--------------------------------|--------------------|----------------------------|---------------------|------------------------------------|-------------------------|-----------------------------|---------------------------|--------------------|--------------------------------|--------------------|----------------------------|---------------------|------------------------------------|-------------------------|-----------------------------|---------------------------|
| Discount rate | | 7% <i>disc</i> | | | | | | | | | | | | | | | | |
| Escalation | | 3% <i>esc</i> | | | | | | | | | | | | | | | | |
| Revenue Requirement Multiplier | | 1.40 <i>RevReqMultiplier</i> | | | | | | | | | | | | | | | | |
| Yr basis for cost estimates | | 2015 <i>YrBasis</i> | | | | | | | | | | | | | | | | |
| Planning Horizon (yrs) | | 10 <i>Horizon</i> | | | | | | | | | | | | | | | | |
| Real Discount Rate | | 3.88% | | | | | | | | | | | | | | | | |
| Levelization Factor | | 11.80% | | | | | | | | | | | | | | | | |
| Project 2 | | | | | | | | | | Project 4 | | | | | | | | |
| Annual O&M (\$000/yr) | | 20 | | | | | | | | Annual Growth (MW) | | 10 | | | | | | |
| | | Proj 1 | | 12 | | | | | | Annual Growth (MW) | | 10 | | | | | | |
| | | Proj 2 | | 8 | | | | | | | | | | | | | | |
| Year | Input (\$000) | Fully Loaded Capital Nominal\$ | Annual O&M (\$000) | Rolling Capital PV (\$000) | Rolling O&M (\$000) | PW Value for 1 yr deferral (\$000) | PW Value per kW (\$/kW) | PW Capital Value (\$/kW-yr) | PW total value (\$/kW-yr) | Input (\$000) | Fully Loaded Capital Nominal\$ | Annual O&M (\$000) | Rolling Capital PV (\$000) | Rolling O&M (\$000) | PW Value for 1 yr deferral (\$000) | PW Value per kW (\$/kW) | PW Capital Value (\$/kW-yr) | PW total value (\$/kW-yr) |
| 2017 | - | - | - | 19,873 | 19 | 743 | 74.29 | \$8.77 | \$8.99 | - | - | - | 18,936 | 18 | 708 | 70.79 | \$8.35 | \$8.56 |
| 2018 | - | - | - | 21,264 | 20 | 795 | 79.49 | \$9.38 | \$9.62 | - | - | - | 20,262 | 19 | 757 | 75.74 | \$8.94 | \$9.16 |
| 2019 | - | - | - | 22,752 | 22 | 851 | 85.05 | \$10.04 | \$10.29 | - | - | - | 21,680 | 20 | 810 | 81.05 | \$9.56 | \$9.80 |
| 2020 | 15,000 | 24,345 | 23 | 24,345 | 23 | 910 | 91.01 | \$10.74 | \$11.01 | 10,000 | 16,230 | 13.9 | 23,198 | 22 | 867 | 86.72 | \$10.23 | \$10.49 |
| 2021 | - | - | - | - | - | - | - | \$0.00 | \$0.00 | - | - | - | 7,456 | 9 | 279 | 27.87 | \$3.29 | \$3.39 |
| 2022 | - | - | - | - | - | - | - | \$0.00 | \$0.00 | - | - | - | 7,977 | 9 | 298 | 29.82 | \$3.52 | \$3.63 |
| 2023 | - | - | - | - | - | - | - | \$0.00 | \$0.00 | - | - | - | 8,536 | 10 | 319 | 31.91 | \$3.77 | \$3.88 |
| 2024 | - | - | - | - | - | - | - | \$0.00 | \$0.00 | 5,000 | 9,133 | 10.4 | 9,133 | 10 | 341 | 34.14 | \$4.03 | \$4.15 |
| 2025 | - | - | - | - | - | - | - | \$0.00 | \$0.00 | - | - | - | - | - | - | - | \$0.00 | \$0.00 |
| 2026 | - | - | - | - | - | - | - | \$0.00 | \$0.00 | - | - | - | - | - | - | - | \$0.00 | \$0.00 |

All values continue to be zero after 2026 because there are no new investments in the dataset

The shortcoming of the rolling approach is that it is not necessarily compatible with the estimation of marginal costs over many years. Because the rolling approach moves the planning horizon forward each year, it will underestimate marginal costs if load-growth driven investments that may be needed in the future are not included in the dataset. In other words, while the Rolling Approach example in Figure 3 drops to zero after 2020, it would rise again once the rolling planning horizon encompassed the next required investment --- if that investment could be known.

One way to address the rolling approach shortcoming is to assume repetition of the investment in the future as a proxy for future load-growth relative investments. This could reflect a future investment in the same area, or a similar investment in a different geographic area. An example of this proxy repetition is illustrated in the following figure and table.

Recall that under the Continuous Approach, one calculates the capital value of deferring the project by one year (DefValCap, \$000) as follows:

$$DefValCap = FullCost * \left[1 - \left(\frac{1 + esc}{1 + disc} \right)^{\Delta t} \right]$$

Where $\Delta t = 1$

Under the Discrete Approach, one would not assume a year of deferral ($\Delta t = 1$). Instead one would forecast the amount of EE load reduction for the area and divide the reduction by the amount of reduction needed to defer the project. If Δt were to be less than 1.0, a value of zero would be used (Δt would be truncated to an integer). In that case DefValCap = 0, and the marginal cost would equal zero. An example follows:

| | |
|--|----------|
| Predicted EE load reduction in Area X | 200 kW |
| Amount of load reduction required to defer the project by 1 year | 2,000 kW |

Therefore, Δt in this instance is approximately 1/10 of a year or a little over 1 month. In this instance, the area EE would receive a value of 0.

Put another way, avoided costs are highest just prior to the construction of a capacity expansion project. However, once the project is built, it would likely be many years before another project is required in the area, and the new annual avoided cost for the area would be almost zero. Using the method described above captures area and annual cost differences.¹⁷

¹⁷ “Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs,” p. 96.

Appendix C – Comparison of IOU 2017-2019 Program Avoided Costs with Study Proposed¹⁸

| Year | Avoided Transmission and Distribution Costs | | | | | | | | | | | | | | | | | | | |
|------|---|---------|--------|----------------------|---------|--------|---------|-------------------------|--------|--------|----------------------|--------|--------|---------|-------------------|-----|-------|----------------------|---------|---------|
| | Xcel Energy | | | | | | | Minnesota Power | | | | | | | Other Trail Power | | | | | |
| | Discrete | | | Continuous Valuation | | | | Discrete | | | Continuous Valuation | | | | Discrete | | | Continuous Valuation | | |
| | 2017-2019 ¹⁹ | D | T | TOTAL | D | T | TOTAL | 2017-2019 ¹⁹ | D | T | TOTAL | D | T | TOTAL | D | T | TOTAL | D | T | TOTAL |
| 2018 | \$37.08 | \$7.16 | \$2.71 | \$9.88 | \$6.69 | \$1.35 | \$8.04 | \$11.38 | \$0.00 | \$0.00 | \$4.05 | \$0.00 | \$4.05 | \$71.63 | N/A | N/A | N/A | \$4.63 | \$5.92 | \$10.55 |
| 2019 | \$37.96 | \$7.33 | \$2.78 | \$10.11 | \$6.85 | \$1.38 | \$8.23 | \$11.72 | \$0.00 | \$0.00 | \$4.15 | \$0.00 | \$4.15 | \$72.46 | N/A | N/A | N/A | \$4.77 | \$6.10 | \$10.87 |
| 2020 | \$38.85 | \$7.51 | \$2.84 | \$10.35 | \$7.01 | \$1.41 | \$8.43 | \$12.07 | \$0.00 | \$0.00 | \$4.26 | \$0.00 | \$4.26 | \$71.98 | N/A | N/A | N/A | \$4.91 | \$6.28 | \$11.19 |
| 2021 | \$39.77 | \$7.68 | \$2.91 | \$10.59 | \$7.18 | \$1.45 | \$8.63 | \$12.43 | \$0.00 | \$0.00 | \$4.36 | \$0.00 | \$4.36 | \$71.71 | N/A | N/A | N/A | \$5.06 | \$6.47 | \$11.53 |
| 2022 | \$40.71 | \$7.86 | \$2.98 | \$10.84 | \$7.35 | \$1.48 | \$8.83 | \$12.81 | \$0.00 | \$0.00 | \$4.47 | \$0.00 | \$4.47 | \$70.86 | N/A | N/A | N/A | \$5.21 | \$6.67 | \$11.88 |
| 2023 | \$41.67 | \$8.05 | \$3.05 | \$11.10 | \$7.52 | \$1.52 | \$9.04 | \$13.18 | \$0.00 | \$0.00 | \$4.58 | \$0.00 | \$4.58 | \$70.02 | N/A | N/A | N/A | \$5.37 | \$6.87 | \$12.24 |
| 2024 | \$42.65 | \$8.24 | \$3.12 | \$11.36 | \$7.70 | \$1.55 | \$9.25 | \$13.59 | \$0.00 | \$0.00 | \$4.70 | \$0.00 | \$4.70 | \$69.21 | N/A | N/A | N/A | \$5.53 | \$7.07 | \$12.60 |
| 2025 | \$43.66 | \$8.43 | \$3.19 | \$11.63 | \$7.88 | \$1.59 | \$9.47 | \$13.99 | \$0.00 | \$0.00 | \$4.82 | \$0.00 | \$4.82 | \$68.43 | N/A | N/A | N/A | \$5.70 | \$7.28 | \$12.98 |
| 2026 | \$44.69 | \$8.63 | \$3.27 | \$11.90 | \$8.07 | \$1.63 | \$9.69 | \$14.41 | \$0.00 | \$0.00 | \$4.94 | \$0.00 | \$4.94 | \$67.64 | N/A | N/A | N/A | \$5.87 | \$7.50 | \$13.37 |
| 2027 | \$45.74 | \$8.84 | \$3.35 | \$12.18 | \$8.26 | \$1.66 | \$9.92 | \$14.84 | \$0.00 | \$0.00 | \$5.06 | \$0.00 | \$5.06 | \$66.87 | N/A | N/A | N/A | \$6.04 | \$7.73 | \$13.77 |
| 2028 | \$46.82 | \$9.05 | \$3.42 | \$12.47 | \$8.45 | \$1.70 | \$10.16 | \$15.29 | \$0.00 | \$0.00 | \$5.19 | \$0.00 | \$5.19 | \$66.11 | N/A | N/A | N/A | \$6.23 | \$7.96 | \$14.19 |
| 2029 | \$47.93 | \$9.26 | \$3.51 | \$12.76 | \$8.65 | \$1.74 | \$10.40 | \$15.75 | \$0.00 | \$0.00 | \$5.32 | \$0.00 | \$5.32 | \$65.35 | N/A | N/A | N/A | \$6.41 | \$8.20 | \$14.61 |
| 2030 | \$49.06 | \$9.48 | \$3.59 | \$13.07 | \$8.86 | \$1.78 | \$10.64 | \$16.22 | \$0.00 | \$0.00 | \$5.45 | \$0.00 | \$5.45 | \$64.60 | N/A | N/A | N/A | \$6.60 | \$8.44 | \$15.04 |
| 2031 | \$50.22 | \$9.70 | \$3.67 | \$13.37 | \$9.07 | \$1.83 | \$10.89 | \$16.71 | \$0.00 | \$0.00 | \$5.59 | \$0.00 | \$5.59 | \$64.73 | N/A | N/A | N/A | \$6.80 | \$8.70 | \$15.50 |
| 2032 | \$51.40 | \$9.93 | \$3.76 | \$13.69 | \$9.28 | \$1.87 | \$11.15 | \$17.21 | \$0.00 | \$0.00 | \$5.73 | \$0.00 | \$5.73 | \$64.87 | N/A | N/A | N/A | \$7.01 | \$8.96 | \$15.97 |
| 2033 | \$52.62 | \$10.16 | \$3.85 | \$14.01 | \$9.50 | \$1.91 | \$11.41 | \$17.72 | \$0.00 | \$0.00 | \$5.87 | \$0.00 | \$5.87 | \$65.01 | N/A | N/A | N/A | \$7.22 | \$9.23 | \$16.45 |
| 2034 | \$53.86 | \$10.40 | \$3.94 | \$14.34 | \$9.72 | \$1.96 | \$11.68 | \$18.25 | \$0.00 | \$0.00 | \$6.02 | \$0.00 | \$6.02 | \$65.15 | N/A | N/A | N/A | \$7.43 | \$9.50 | \$16.93 |
| 2035 | \$55.13 | \$10.65 | \$4.03 | \$14.68 | \$9.95 | \$2.01 | \$11.96 | \$18.80 | \$0.00 | \$0.00 | \$6.17 | \$0.00 | \$6.17 | \$65.30 | N/A | N/A | N/A | \$7.66 | \$9.79 | \$17.45 |
| 2036 | \$56.43 | \$10.90 | \$4.13 | \$15.03 | \$10.19 | \$2.05 | \$12.24 | \$19.36 | \$0.00 | \$0.00 | \$6.32 | \$0.00 | \$6.32 | \$65.45 | N/A | N/A | N/A | \$7.89 | \$10.08 | \$17.97 |
| 2037 | \$57.76 | \$11.16 | \$4.22 | \$15.38 | \$10.43 | \$2.10 | \$12.53 | \$19.93 | \$0.00 | \$0.00 | \$6.48 | \$0.00 | \$6.48 | \$65.61 | N/A | N/A | N/A | \$8.12 | \$10.38 | \$18.50 |
| 2038 | \$59.12 | \$11.42 | \$4.32 | \$15.75 | \$10.67 | \$2.15 | \$12.82 | \$20.53 | \$0.00 | \$0.00 | \$6.64 | \$0.00 | \$6.64 | \$65.77 | N/A | N/A | N/A | \$8.37 | \$10.70 | \$19.07 |

¹⁸ 2017-2019 values are from “Proposal Filing – Avoided Electric Cost Assumptions for the 2017-2019 Conservation Improvement Program Triennial Plan (Docket Nos. CIP-16-115, CIP-16-116, CIP-16-117, CI-08-133)”, Attachment A.

Appendix D – Discussion on Cost Effectiveness Calculations

During the course of developing estimates of electricity transmission and distribution costs avoided by energy efficiency, discussions naturally turned to how these values are used and thus, the operational aspects of how cost effectiveness is calculated. Questions focused on the capabilities of the software used to calculate CE, ways that utilities use the software, and in general, the data utilities use to calculate cost effectiveness. Clarifying these issues is helpful to understanding the role that avoided T&D estimates play in evaluating energy efficiency programs and the various ways that avoided T&D estimates can be calculated.

Why Do Utilities Model EE Cost Effectiveness?

Utilities model energy efficiency program cost effectiveness as a way to compare the cost of “demand-side” resources (e.g. energy efficiency) to supply-side resources (e.g. power plants, T&D infrastructure). In states like Minnesota, this process is undertaken through integrated resource plans (IRPs), where utilities can compare the costs and characteristics of energy efficiency directly against supply-side resources to determine optimal levels of investment in each type of resource (depending on how each resource affects customer costs; Minnesota assesses based on Net Present Value of Revenue Requirements).^{19,20} However, in part due to timing (IRP processes do not necessarily align with energy efficiency program approval processes) and due to other idiosyncrasies of IRP modeling, CE evaluations and IRPs are used to inform each other’s process, and are traditionally done separately. Utilities, therefore, use software designed to estimate cost effectiveness based on a set of fixed assumptions that are designed to mirror the IRP process. In Minnesota, the investor-owned utilities use Integral Analytics, Inc.’s DSMore software to model cost effectiveness.

The fixed assumptions that utilities incorporate into their cost effectiveness models include avoided generating (G) capacity, marginal energy (E), transmission (T), and distribution (D) costs.²¹ These avoided costs constitute the “benefits” that are measured against the “costs” associated with individual energy efficiency measures.²² Cost effectiveness is generally expressed as a benefit-cost ratio, with the net present value of the stream of benefits from energy efficiency programs forming the numerator and the net present value of the stream of costs from EE programs forming the denominator. These costs are considered ‘avoided’ because energy efficiency programs drive customers to use less energy and, thereby, reduce the amount of generating, transmission and distribution system capacity utilities have to build or buy and the energy utilities have to generate or purchase. Avoided generation, transmission, and distribution costs are expressed in terms of \$/kW because generation, transmission, and distribution

¹⁹ IRPs are not used to calculate transmission and distribution costs. Therefore, estimates of T&D investments avoided by EE are done separately.

²⁰ Many states do not have IRPs and use CE evaluations without any connection to resource planning.

²¹ There are a host of other assumptions incorporated into the cost effectiveness calculations, such as utility discount rates, customer retail rates, and corporate escalation (inflation) rates.

²² It is important to note that this document uses the conventional term “avoided costs”, although this is not necessarily accurate as this term implies that the utility is eliminating investments. EE and other DERs will more typically “defer” or “delay” supply-side investments rather than avoid them. Although DERs can certainly eliminate some investments, it is more likely to defer, delay or change the character (change from one type of generating unit to another) of the investment.

infrastructure is constructed in kilowatt²³ increments. Marginal energy costs are measured in \$/kWh because energy is priced volumetrically over a specified period of time (the convention is the number of kilowatts over one hour or kilowatt-hour [kWh]).

Estimates of avoided generating capacity costs are based on the current all-in cost to construct the type of generator that EE programs are most likely to displace, such as a gas-fired combustion turbine (CT) or a gas-fired combined cycle (CC) unit (termed “proxy unit”). Proxy unit cost information often comes from the utility’s IRP. The choice between which generating unit to use is based on the utility’s and regulator’s determination of whether energy efficiency programs are more likely to avoid a CT or a CC.²⁴

This leads back to the effort to develop estimates of avoided transmission and distribution costs, which are usually expressed in \$/kW or \$/kW-year (the \$/kW can be apportioned to years to enable cost effectiveness calculations that use a stream of annual benefits and costs). It should be noted that capacity costs can be expressed in terms of \$/kWh by assigning the costs to hours of the year. This is, in effect, what happens in cost effectiveness evaluations in that DSMore apportions the \$/kW costs for generation, transmission & distribution to hours of the year that energy efficiency programs reduce energy use (more on this topic in the discussion on load shapes). However, for ease of conveying the values, utilities express generation, transmission, and distribution capacity costs as \$/kW or \$/kW-year (\$/kW is a single value while \$/kW-year changes annually).

Cost Effectiveness Evaluations and Load Shapes

DSMore and other cost effectiveness modeling software packages take inputs related to individual energy efficiency measures (e.g. 12-watt LED lamp that replaces a 60-watt incandescent light bulb), including the measure’s energy savings for a year, its kW savings, its effective useful life, its coincidence with the utility’s system peak (probability that the measure will be operating when the utility is experiencing its maximum load), and its costs. Simplified, a program with only one measure would incorporate the number of expected units of the measure (1,000 12-watt LED lamps in year 1) and the measure’s benefit-cost ratio would be determined by adding together avoided capacity and energy costs [**capacity** - calculating the number of units multiplied by the measure’s kW savings, coincidence factor and avoided capacity costs (generation, transmission & distribution) and **energy** – number of units multiplied by measure’s annual kWh savings and the avoided energy costs]. Measure and any program costs apportioned by measure make up the denominator.

²³ One kilowatt (kW) equals 1,000 watts (W), or the amount of energy produced or utilized at a fixed moment in time.

²⁴ Note that this is where one of the differences between the IRP and EE cost effectiveness evaluations occurs. This is because, in the dynamic modeling of the IRP, EE programs may not actually displace (eliminate) a generating unit. It is more likely that EE will delay the unit’s construction one or more years or change the type and size of the unit in the forecast. In the CE evaluation, it is assumed that energy efficiency programs can displace investments in G, T & D in very small increments and need not truly eliminate or even delay construction plans.

Example:

$$\text{Benefit Cost Ratio} = \frac{(\text{Avoided Energy Costs} + \text{Avoided Capacity Costs})}{(\text{Measure Costs} + \text{Program Costs})}$$

Where:

$$\text{Avoided Energy Costs} = \# \text{ of Measure units} * \frac{\text{Annual kWh Savings}}{\text{Measure}} * \frac{\text{Avoided Energy Cost}}{\text{kWh}}$$

And,

$$\text{Avoided Capacity Costs} = \# \text{ of Units} * \frac{\text{kW Savings}}{\text{Measure}} * \frac{\text{Avoided Capacity Cost}}{\text{kWh}}$$

However, this is a simplified version. In assessing cost effectiveness, most CE models distribute measure savings based on measure load shapes by customer type. These are also called “end-use load shapes”. Load shapes define how measure energy savings (EE measure energy consumption compared with baseline measure energy consumption) are spread over a typical year. “The load shape is important because energy savings are more valuable when they avoid higher priced energy and also help avoid the construction of new distribution, transmission and generation infrastructure.”²⁵ Therefore, a measure that uses a load shape that correlates with the utility’s system peak (for example, business lighting) would be more valuable because it is helping to reduce system peak. Studies to develop load shapes are generally quite expensive as they rely upon detailed customer surveys and other information. Therefore, load shape data may not be frequently updated. Minnesota’s IOUs differ in terms of the load shape information each possess and how they use this information.

As an example, Xcel Energy uses 25 different load shapes in its cost effectiveness modeling. Xcel Energy assigns this collection of load shapes to the approximately 460 electric measures in its portfolio, applying the shape most applicable to the measure and customer type. Minnesota Power uses approximately 20 load shapes for their 80 different measures. Otter Tail Power uses customer class load shapes for its analyses.

Although these load shapes may include data based on estimates of energy use for every hour of an average year, they are typically simplified into “day types”. As an example, Xcel Energy uses 48 different day types, for weekdays (low, mid, and high demand = 3 weekday values), weekends (1), and for each month of the year (12). Since these values are for each of the 24 hours in a day, one measure load shape in the Xcel example has 1,152 (48*24) data points. Each of these 1,152 values allocates the measure energy savings to day type.

²⁵ “Better Buildings Energy Efficiency Cost-Effectiveness Tool (v2.0), Frequently Asked Questions,” Better Buildings, U.S. Department of Energy, Prepared by: Energy and Environmental Economics (E3) and Lawrence Berkeley National Laboratory, March 2017, p. 5.

Load shapes and associated day types are applied to avoided costs to calculate measure (and program) benefits. For marginal energy, these hourly load shape values are multiplied by the \$/kWh marginal energy avoided cost values to derive the avoided energy costs. For generating capacity, these hourly load shape values may or may not be used to calculate avoided generating capacity benefits. This occurs, because as a simplifying assumption, DSMore multiplies the \$/kW-year avoided generating cost value against the measure's coincident peak kW value ("generator kW savings"). This assumption is based on the notion that energy efficiency measures provide "capacity" value only to the extent they can reduce system peak. This assumption is generally acceptable for generating capacity because utilities build (or buy) capacity to ensure they can meet customer demand and, to the extent energy efficiency can reduce these peaks, it can help defer build or buy.

Statistical Peak Capacity Allocation Factor

However, for T&D capacity, the "system" is considerably more diverse and is, instead, built to meet local area load that can peak at times different from the system peak. Thus, if possible, it is best to understand how these areas peak in order to calculate how energy efficiency measures can reduce the need for T&D capacity. This is the reason for calculating statistical peak allocation capacity factors (PCAFs). Ideally, the PCAFs would be calculated for each local T&D area within a utility's system, to reflect the unique peak timing for each area. In this manner, a utility would examine the "area peaks" within its T&D system to see if they differed substantially from overall system peaks. If they differed substantially from system peaks, this peaking "pattern" would be used to allocate \$/kW-year avoided T&D values to hours of the year. These hours of the year to which the avoided T&D costs are allocated would, in turn, receive value in cost effectiveness evaluations based on whether a particular measure's load shape indicated that it was saving energy at that time.

However, absent that level of disaggregation, the PCAF methodology can still be useful in representing the need for peak capacity as it occurs over multiple hours in a year, rather than just a single system peak hour. Even if the T&D system does not peak differently from the system (or this information is not available), it can make sense to derive a more varied set of near peak hours based on the assumption that the system built to transmit and distribute electricity has more diverse locational peaks intra system than the system built to generate electricity. Thus, PCAFs can be developed based on a variety of methods. The method E3 proposed for the current study was to take one standard deviation of overall system peaks (which, depending on the utility, might vary from tens of hours to hundreds of hours), and use these values for PCAFs.

Such a probabilistic view of the need for capacity can provide a better reflection of the variation in area peak loads than the single system peak hour approach.

Looking Forward -- PCAF and DSMore

Although PCAFs are not currently utilized, their incorporation into DSMore would be a straightforward process. DSMore would use system load information and require the user to specify a PCAF threshold level to calculate PCAFs. DSMore would then calculate the hourly PCAFs and distribute them to daytypes or retain in the hourly form as needed, and the PCAFs could be used to calculate the T&D benefits for EE.

Under this methodology, the PCAF would be limited to system loads. While this is what is currently being done in Minnesota due to limited data, one would ideally use disaggregated data that reflects local distribution usage profiles, not just the system profile.

In summary, modifying DSMore to account for PCAFs or a similar method may be a reasonable approach for future CIP Triennials.

CERTIFICATE OF SERVICE

I, Carl Cronin, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota; or

xx by electronic filing.

Docket No.: E999/CIP-16-541 & CIP Special Service List

Dated this 31st day of July 2017.

/s/

Carl Cronin
Regulatory Administrator

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|------------|-----------|--------------------------------------|---|---|--------------------|-------------------|--------------------------|
| Gary | Connett | gconnett@grenergy.com | Great River Energy | 12300 Elm Creek Blvd N Maple Grove, MN 553694718 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| George | Crocker | gwilic@hawo.org | North American Water Office | PO Box 174 Lake Elmo, MN 55042 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Carl | Cronin | Regulatory.records@xcelenergy.com | Xcel Energy | 414 Nicollet Mall FL 7 Minneapolis, MN 554011993 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Jill | Curran | jcurran@mnchamber.com | Minnesota Waste Wise | 400 Robert Street North Suite 1500 St. Paul, Minnesota 55101 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Leigh | Currie | lcurrie@mncenter.org | Minnesota Center for Environmental Advocacy | 26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Stacy | Dahl | sdahl@minnkota.com | Minnkota Power Cooperative, Inc. | 1822 Mill Road PO Box 13200 Grand Forks, ND 58208-3200 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Ian | Dobson | Residential.Utilities@ag.state.mn.us | Office of the Attorney General-RUD | 1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130 | Electronic Service | Yes | OFF_SL_16-541_CIP-16-541 |
| Ian | Dobson | ian.dobson@ag.state.mn.us | Office of the Attorney General-RUD | Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Steve | Downer | sdowner@mmua.org | MMUA | 3025 Harbor Ln N Ste 400 Plymouth, MN 554475142 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|-----------|------------------------------|--|--|--------------------|-------------------|--------------------------|
| Charles | Drayton | charles.drayton@enbridge.com | Enbridge Energy Company, Inc. | 7701 France Ave S Ste 600 Edina, MN 55435 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Jim | Erchul | jerchul@dbnhs.org | Daytons Bluff Neighborhood Housing Sv. | 823 E 7th St St. Paul, MN 55106 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Greg | Ernst | gaerst@q.com | G. A. Ernst & Associates, Inc. | 2377 Union Lake Tri Northfield, MN 55057 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Emma | Fazio | emma.fazio@stoel.com | Stoel Rives LLP | 33 South Sixth Street Suite 4200 Minneapolis, MN 55402 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Melissa S | Feine | melissa.feine@semcac.org | SEMCAC | PO Box 549 204 S Elm St Rushford, MN 55971 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Sharon | Ferguson | sharon.ferguson@state.mn.us | Department of Commerce | 85 7th Place E Ste 280 Saint Paul, MN 55102 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Edward | Garvey | garvey@aol.com | Residence | 32 Lawton St Saint Paul, MN 55102 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Angela E. | Gordon | angela.e.gordon@lmco.com | Lockheed Martin | 1000 Clark Ave. St. Louis, MO 63102 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Pat | Green | N/A | N Energy Dev | City Hall 401 E 21st St Hibbing, MN 55746 | Paper Service | No | OFF_SL_16-541_CIP-16-541 |
| Jason | Grenier | jgrenier@otpc.com | Otter Tail Power Company | 215 South Cascade Street Fergus Falls, MN 56537 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|-----------|------------------------------------|--|---|--------------------|-------------------|--------------------------|
| Stephan | Gunn | sgunn@appliedenergygroup.com | Applied Energy Group | 1941 Pike Ln De Pere, WI 54115 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Jeffrey | Haase | jhaase@grenergy.com | Great River Energy | 12300 Elm Creek Blvd Maple Grove, MN 55369 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Tony | Hainault | anthony.hainault@co.hennepin.mn.us | Hennepin County DES | 701 4th Ave S Ste 700 Minneapolis, MN 55415-1842 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Patty | Hanson | phanson@rpu.org | Rochester Public Utilities | 4000 E River Rd NE Rochester, MN 55906 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Norm | Harold | N/A | NKS Consulting | 5591 E 180th St Prior Lake, MN 55372 | Paper Service | No | OFF_SL_16-541_CIP-16-541 |
| Jared | Hendricks | hendricks@owatonnautilities.com | Owatonna Public Utilities | PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Karolanne | Hoffman | kmh@dairynet.com | Dairyland Power Cooperative | PO Box 817 La Crosse, WI 54602-0817 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Jim | Horan | Jim@MREA.org | Minnesota Rural Electric Association | 11640 73rd Ave N Maple Grove, MN 55369 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Brian | Hori | Brian@ethree.com | Energy and Environmental Economics, Inc. | 101 Montgomery St FL 16 San Francisco, CA 94104 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Lori | Hoyum | lhoyum@mnpower.com | Minnesota Power | 30 West Superior Street Duluth, MN 55802 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|-----------|---------------------------------|---------------------------------------|--|--------------------|-------------------|--------------------------|
| Anne | Hunt | anne.hunt@ci.stpaul.mn.us | City of St. Paul | 390 City Hall 15 West Kellogg Boulevard Saint Paul, MN 55102 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Dave | Johnson | dave.johnson@aeoa.org | Arrowhead Economic Opportunity Agency | 702 3rd Ave S Virginia, MN 55792 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Joel W. | Kanvik | joel.kanvik@enbridge.com | Enbridge Energy LLC | 4628 Mike Colalillo Dr Duluth, MN 55807 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Deborah | Knoll | dknoll@mpower.com | Minnesota Power | 30 W Superior St Duluth, MN 55802 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Tina | Koecher | tkoecher@minnpower.com | Minnesota Power | 30 W Superior St Duluth, MN 558022093 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Kelly | Lady | kelly@austinutilities.com | Austin Utilities | 400 4th St NE Austin, MN 55912 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Joel | Larson | jjarson@minnkota.com | Minnkota Power Cooperative, Inc. | 1822 Mill Road Grand Forks, ND 58203 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Martin | Lepak | Martin.Lepak@aeoa.org | Arrowhead Economic Opportunity | 702 S 3rd Ave Virginia, MN 55792 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Nick | Mark | nick.mark@centerpointenergy.com | CenterPoint Energy | 800 LaSalle Ave Minneapolis, MN 55402 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Pam | Marshall | pam@energycents.org | Energy CENTS Coalition | 823 7th St E St. Paul, MN 55106 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|------------|--------------------------------|-------------------------------------|--|--------------------|-------------------|--------------------------|
| Samuel | Mason | smason@beltramielctric.com | Beltrami Electric Cooperative, Inc. | 4111 Technology Dr. NW PO Box 488 Bemidji, MN 56619-0488 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Scott | McClure | scotmcclure@alliantenergy.com | Interstate Power And Light Company | 4902 N Blitmore Ln PO Box 77007 Madison, WI 537071007 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| John | McWilliams | jimm@dairynet.com | Dairyland Power Cooperative | 3200 East Ave SPO Box 817 La Crosse, WI 54601-7227 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Brian | Meloy | brian.meloy@stinson.com | Stinson, Leonard, Street LLP | 150 S 5th St Ste 2300 Minneapolis, MN 55402 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Herbert | Minke | hminke@allete.com | Minnesota Power | 30 W Superior St Duluth, MN 55802 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| David | Moeller | dmoeller@allete.com | Minnesota Power | 30 W Superior St Duluth, MN 558022093 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Andrew | Moratzka | andrew.moratzka@stoel.com | Stoel Rives LLP | 33 South Sixth St Ste 4200 Minneapolis, MN 55402 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Gary | Myers | garym@hpuc.com | Hibbing Public Utilities | PO Box 249 Hibbing, MN 55746 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Susan K | Nathan | snathan@appliedenergygroup.com | Applied Energy Group | 2215 NE 107th Ter Kansas City, MO 64155-8513 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Carl | Nelson | cnelson@mncee.org | Center for Energy and Environment | 212 3rd Ave N Ste 560 Minneapolis, MN 55401 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|-----------|--|--|--|--------------------|-------------------|--------------------------|
| Samantha | Norris | samanthanorris@alliantenergy.com | Interstate Power and Light Company | 200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Audrey | Partridge | audrey.pear@centerpointenergy.com | CenterPoint Energy | 505 Nicollet Mall Minneapolis, Minnesota 55402 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| James | Phillippo | jophillippo@minnesotaenergyresources.com | Minnesota Energy Resources Corporation | PO Box 19001 Green Bay, WI 54307-9001 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Lisa | Pickard | lpickard@mnnkota.com | Minnkota Power Cooperative | 1822 Mill Rd PO Box 13200 Grand Forks, ND 582083200 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Bill | Poppert | info@technologycos.com | Technology North | 2433 Highway Ave St Paul, MN 55119 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Scott | Reimer | reimer@federatedrea.coop | Federated Rural Electric Assoc. | 77100 US Highway 71 PO Box 69 Jackson, MN 56143 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Dave | Reinke | dreinke@dakotaelectric.com | Dakota Electric Association | 4300 220th St W Farmington, MN 55024-9583 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Richard | Savelkoul | rsavelkoul@martinsquires.com | Martin & Squires, P.A. | 332 Minnesota Street Ste W2750 St Paul, MN 55101 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Bruce | Saylor | bruce@connexusenergy.com | Connexus Energy | 14601 Ramsey Boulevard Ransey, MN 55303 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|-------------|-----------------|------------------------------------|----------------------------------|---|--------------------|-------------------|--------------------------|
| Christopher | Schoenherr | cp.schoenherr@smmpa.org | SMMPA | 500 First Ave SW Rochester, MN 55902-3303 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Cindy | Schweitzer Rott | cindy.schweitzer@clearsolution.com | CLEARResult's | S12637A Merrill Rd. Spring Green, WI 53588 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Ken | Smith | ken.smith@districtenergy.com | District Energy St. Paul Inc. | 76 W Kellogg Blvd St. Paul, MN 55102 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Anna | Sommer | anna@sommerenergy.com | Sommer Energy LLC | PO Box 766 Grand Canyon, AZ 86023 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Jeffrey | Springer | jef@dairynet.com | Dairyland Power Cooperative | 3200 East Avenue South La Crosse, WI 54601 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Grey | Staples | gstaples@mendotagroup.com | The Mendota Group LLC | 1830 Fargo Lane Mendota Heights, MN 55118 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Richard | Szydlowski | rszydlowski@mncee.org | Center for Energy & Environment | 212 3rd Ave N Ste 560 Minneapolis, MN 55401-1459 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Steve | Tomac | stomac@bepcc.com | Basin Electric Power Cooperative | 1717 E Interstate Ave Bismarck, ND 58501 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Michael | Volker | mvolker@eastriver.coop | East River Electric Power Coop | 211 S. Harth Ave Madison, SD 57042 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Sharon N. | Walsh | swalsh@shakoeeutilities.com | Shakopee Public Utilities | 255 Sarazin St Shakopee, MN 55379 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|-----------|-------------------------------|---------------------------------------|---|--------------------|-------------------|--------------------------|
| Robert | Walsh | bwalsh@mnvalleyrec.com | Minnesota Valley Coop Light and Power | PO Box 248 501 S 1st St Montevideo, MN 56265 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Cam | Winton | cwinton@mnchamber.com | Minnesota Chamber of Commerce | 400 Robert Street North Suite 1500 St Paul, Minnesota 55101 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Robyn | Woeste | robynwoeste@alliantenergy.com | Interstate Power and Light Company | 200 First St SE Cedar Rapids, IA 52401 | Electronic Service | No | OFF_SL_16-541_CIP-16-541 |
| Daniel P | Wolf | dan.wolf@state.mn.us | Public Utilities Commission | 121 7th Place East Suite 350 St Paul, MN 551012147 | Electronic Service | Yes | OFF_SL_16-541_CIP-16-541 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|-----------|-----------------------------------|------------------------------------|--|--------------------|-------------------|---------------------------------|
| Julia | Anderson | Julia.Anderson@ag.state.mn.us | Office of the Attorney General-DOC | 1800 BRM Tower 445 Minnesota St St Paul, MN 551012134 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Tom | Balster | tombalster@alliantenergy.com | Interstate Power & Light Company | PO Box 351 200 1st St SE Cedar Rapids, IA 524060351 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Lisa | Beckner | lbeckner@mnpower.com | Minnesota Power | 30 W Superior St Duluth, MN 55802 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| William | Black | wblack@mmua.org | MMUA | Suite 400 3025 Harbor Lane North Plymouth, MN 554475142 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Christina | Brusven | cbrusven@fredlaw.com | Fredrikson Byron | 200 S 6th St Ste 4000 Minneapolis, MN 554021425 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Charlie | Buck | charlie.buck@oracle.com | Oracle | 760 Market St FL 4 San Francisco, CA 94102 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Ray | Choquette | rchoquette@agp.com | Ag Processing Inc. | 12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Gary | Connett | gconnett@grenergy.com | Great River Energy | 12300 Elm Creek Blvd N Maple Grove, MN 553694718 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| George | Crocker | gwilic@nawo.org | North American Water Office | PO Box 174 Lake Elmo, MN 55042 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Carl | Cronin | Regulatory.records@xcelenergy.com | Xcel Energy | 414 Nicollet Mall FL 7 Minneapolis, MN 554011993 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|-----------|-------------------------------------|--|---|--------------------|-------------------|------------------------------------|
| Jill | Curran | jcurran@mnchamber.com | Minnesota Waste Wise | 400 Robert Street North Suite 1500 St Paul, Minnesota 55101 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Leigh | Currie | lcurrie@mncenter.org | Minnesota Center for Environmental Advocacy | 26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Ian | Dobson | Residential.Uilities@ag.state.mn.us | Office of the Attorney General-RUD | 1400 BRM Tower 445 Minnesota St St Paul, MN 551012130 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Steve | Downer | sdowner@mmua.org | MMUA | 3025 Harbor Ln N Ste 400 Plymouth, MN 554475142 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Charles | Drayton | charles.drayton@enbridge.com | Enbridge Energy Company, Inc. | 7701 France Ave S Ste 600 Edina, MN 55435 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Jim | Erchul | jerchul@dbnhs.org | Daytons Bluff Neighborhood Housing Sv. | 823 E 7th St St. Paul, MN 55106 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Greg | Ernst | gaernst@q.com | G. A. Ernst & Associates, Inc. | 2377 Union Lake Trl Northfield, MN 55057 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Emma | Fazio | emma.fazio@stoel.com | Stoel Rives LLP | 33 South Sixth Street Suite 4200 Minneapolis, MN 55402 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Melissa S | Feine | melissa.feine@semcac.org | SEMCAC | PO Box 549 204 S Elm St Rushford, MN 55971 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|-----------|------------------------------------|-----------------------------|---|--------------------|-------------------|---------------------------------|
| Sharon | Ferguson | sharon.ferguson@state.mn.us | Department of Commerce | 85 7th Place E Ste 280 Saint Paul, MN 551012198 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Angela E. | Gordon | angela.e.gordon@lmco.com | Lockheed Martin | 1000 Clark Ave. St Louis, MO 63102 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Pat | Green | N/A | N Energy Dev | City Hall 401 E 21st St Hibbing, MN 55746 | Paper Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Jason | Grenier | jgrenier@otpc.com | Otter Tail Power Company | 215 South Cascade Street Fergus Falls, MN 56537 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Stephan | Gunn | sgunn@appliedenergyp.com | Applied Energy Group | 1941 Pike Ln De Pere, WI 54115 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Tony | Hainault | anthony.hainault@co.hennepin.mn.us | Hennepin County DES | 701 4th Ave S Ste 700 Minneapolis, MN 55415-1842 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Patty | Hanson | phanson@rpu.org | Rochester Public Utilities | 4000 E River Rd NE Rochester, MN 55906 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Norm | Harold | N/A | NKS Consulting | 5591 E 180th St Prior Lake, MN 55372 | Paper Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Jared | Hendricks | hendricksj@owatonnautilities.com | Owatonna Public Utilities | PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Karolanne | Hoffman | knh@dairynet.com | Dairyland Power Cooperative | PO Box 817 La Crosse, WI 54602-0817 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|-----------|------------------------------------|---------------------------------------|--|--------------------|-------------------|---------------------------------|
| Jim | Horan | Jim@MREA.org | Minnesota Rural Electric Association | 11640 73rd Ave N Maple Grove, MN 55369 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Anne | Hunt | anne.hunt@ci.stpaul.mn.us | City of St. Paul | 390 City Hall 15 West Kellogg Boulevard Saint Paul, MN 55102 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Dave | Johnson | dave.johnson@aeoa.org | Arrowhead Economic Opportunity Agency | 702 3rd Ave S Virginia, MN 55792 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Joel W. | Kanvik | joel.kanvik@enbridge.com | Enbridge Energy LLC | 4628 Mike Colalillo Dr Duluth, MN 55807 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Deborah | Knoll | dknoll@mpower.com | Minnesota Power | 30 W Superior St Duluth, MN 55802 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Tina | Koecher | tkoecher@mnpower.com | Minnesota Power | 30 W Superior St Duluth, MN 558022093 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Kelly | Lady | kelly@austinutilities.com | Austin Utilities | 400 4th St NE Austin, MN 55912 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Erica | Larson | erica.larson@centerpointenergy.com | CenterPoint Energy | 505 Nicollet Avenue P.O. Box 59038 Minneapolis, Minnesota 55459-0038 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Martin | Lepak | Martin.Lepak@aeoa.org | Arrowhead Economic Opportunity | 702 S 3rd Ave Virginia, MN 55792 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Nick | Mark | nick.mark@centerpointenergy.com | CenterPoint Energy | 800 LaSalle Ave Minneapolis, MN 55402 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|------------|--------------------------------|------------------------------------|---|--------------------|-------------------|------------------------------------|
| Pam | Marshall | pam@energycents.org | Energy CENTS Coalition | 823 7th St E St Paul, MN 55106 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Scott | McClure | scotmclure@alliantenergy.com | Interstate Power And Light Company | 4902 N Blitmore Ln PO Box 77007 Madison, WI 537071007 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| John | McWilliams | jimm@dairynet.com | Dairyland Power Cooperative | 3200 East Ave SPO Box 817 La Crosse, WI 54601-7227 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Brian | Meloy | brian.meloy@stinson.com | Stinson, Leonard, Street LLP | 150 S 5th St Ste 2300 Minneapolis, MN 55402 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| David | Moeller | dmoeller@alliate.com | Minnesota Power | 30 W Superior St Duluth, MN 558022093 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Andrew | Moratzka | andrew.moratzka@stbel.com | Stoel Rives LLP | 33 South Sixth St Ste 4200 Minneapolis, MN 55402 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Gary | Myers | garym@hpuc.com | Hibbing Public Utilities | PO Box 249 Hibbing, MN 55746 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Susan K | Nathan | snathan@appliedenergygroup.com | Applied Energy Group | 2215 NE 107th Ter Kansas City, MO 64155-8513 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Carl | Nelson | cnelson@mncee.org | Center for Energy and Environment | 212 3rd Ave N Ste 560 Minneapolis, MN 55401 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|-------------|-----------------|-------------------------------------|------------------------------------|--|--------------------|-------------------|---------------------------------|
| Samantha | Norris | samanthanorris@alliantenergy.com | Interstate Power and Light Company | 200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Matt | Okeefe | Matt.okeefe@oracle.com | Oracle | 760 Market St FL 4 San Francisco, CA 94102 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Audrey | Partridge | audrey.pear@centerpointenergy.com | CenterPoint Energy | 505 Nicollet Mall Minneapolis, Minnesota 55402 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Lisa | Pickard | lpickard@minnkota.com | Minnkota Power Cooperative | 1822 Mill Rd PO Box 13200 Grand Forks, ND 582083200 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Bill | Poppert | info@technologycos.com | Technology North | 2433 Highwood Ave St Paul, MN 55119 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Dave | Reinke | drinke@dakotaelectric.com | Dakota Electric Association | 4300 220th St W Farmington, MN 55024-9583 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Christopher | Schoenherr | cp.schoenherr@smmpa.org | SMMPA | 500 First Ave SW Rochester, MN 55902-3303 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Cindy | Schweitzer Rott | cindy.schweitzer@clearsolutions.com | CLEARResult's | S12637A Merrillae Rd. Spring Green, WI 53588 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Ken | Smith | ken.smith@districtenergy.com | District Energy St. Paul Inc. | 76 W Kellogg Blvd St Paul, MN 55102 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |
| Anna | Sommer | anna@sommerenergy.com | Sommer Energy LLC | PO Box 766 Grand Canyon, AZ 86023 | Electronic Service | No | SPL_SL_CIP SPECIAL SERVICE LIST |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|------------|------------|-------------------------------|---------------------------------------|--|--------------------|-------------------|------------------------------------|
| Richard | Szydlowski | rszydlowski@nmcee.org | Center for Energy & Environment | 212 3rd Ave N Ste 560 Minneapolis, MN 55401-1459 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Steve | Tomac | stomac@bepc.com | Basin Electric Power Cooperative | 1717 E Interstate Ave Bismarck, ND 58501 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Michael | Volker | mvolker@eastriver.coop | East River Electric Power Coop | 211 S. Harth Ave Madison, SD 57042 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Sharon N. | Walsh | swalsh@shakopeeutilities.com | Shakopee Public Utilities | 255 Sarazin St Shakopee, MN 55379 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Robyn | Woeste | robynwoeste@alliantenergy.com | Interstate Power and Light Company | 200 First St SE Cedar Rapids, IA 52401 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |
| Daniel P | Wolf | dan.wolf@state.mn.us | Public Utilities Commission | 121 7th Place East Suite 350 St Paul, MN 551012147 | Electronic Service | No | SPL_SL_CIP_SPECIAL SERVICE LIST |