STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF DEMAND SIDE MANAGEMENT (DSM) PLAN, INCLUDING ENERGY EFFICIENCY (EE) PROGRAMS, AND ASSOCIATED ACCOUNTING AND RATEMAKING TREATMENT, INCLUDING TIMELY RECOVERY THROUGH I&M'S DSM/EE PROGRAM COST RIDER OF ASSOCIATED COSTS, INCLUDING PROGRAM OPERATING COSTS, NET LOST REVENUE, AND FINANCIAL INCENTIVES.	) CAUSE NO. 45285

IURC
INTERVENOR'S-CAC
EXHIBIT NO. 5
10-15-20
DATE REPORTER

TESTIMONY OF BRIAN HORII IN OPPOSITION TO

SETTLMENT BETWEEN I&M AND OUCC

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA

SEPTEMBER 15, 2020

I. Introduction and Summary

Q. Please state your name and business address.

A. My name is Brian Horii. My business address is 44 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3"). Founded in 1989, E3 is an energy consulting firm with expertise in helping utilities, regulators, policy makers, developers, and investors make the best strategic decisions possible as they implement new public policies, respond to technological advances, and address customers' shifting expectations.

Q. Please describe your professional background and experience.

A. I received both a Bachelor of Science and Master of Science degree in Civil Engineering and Resource Planning from Stanford University. My full curricula vita is provided as Attachment BH-1. My prior work experience in this subject matter includes the following:

- Expert witness for the South Carolina Office of Regulatory Staff on avoided cost-based rates for solar PURPA and Net Energy Metering compensation;
- Developed the methodology for calculating avoided costs used by the California Public Utilities Commission for evaluation of Distributed Energy Resources ("DER") since 2004;
- Served as the third party evaluator for the Minnesota Department of Commerce investigation into capacity costs for Conservation Improvement Program Triennial Plans;
- Developed the methodology for calculating avoided costs used by the California Energy Commission for evaluation of building energy programs;

- Authored avoided cost studies for BC Hydro, Wisconsin Electric Power Company, and PSI Energy;
- Provided review of, and corrections to, PG&E avoided cost models used in their general electric rate case;
- Developed the integrated planning model used by Con Edison and Orange and Rockland Utilities to determine least cost DER supply plans for their network systems;
- Developed the hourly generation dispatch model used by El Paso Electric Company to evaluate the marginal cost impacts of their off-system sales and purchases;
- Produced publicly vetted tools used in California for the evaluation of energy efficiency programs, distributed generation, demand response, and storage programs;
- Analyzed the cost impacts of electricity generation market restructuring in Alaska, Canada, and China; and
- Developed the "Public Tool" used by California stakeholders to evaluate Net Energy Metering program revisions in California.

Q. Have you testified previously before the Indiana Utility Regulatory Commission ("Commission" or "IURC")?

A. No

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Citizens Action Coalition of Indiana ("CAC").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe methods used to calculate avoided costs for energy efficiency ("EE") and demand side programs in other jurisdictions that are relevant for the calculation of EE benefits and cost-benefit ratio for I&M. My testimony focuses on three avoided cost categories in particular: 1) system or generation capacity value, 2) distribution capacity value, and 3) carbon or greenhouse gas ("GHG") emissions value. For generation capacity avoided cost, I address the argument made by OUCC Witness John E Haselden that avoided capacity costs apply only in years for which there is a need for new capacity.[1] On distribution capacity avoided cost, I address the argument in the July 1, 2019 I&M Integrated Resource Planning ("IRP") Report that it is not possible to determine a global, aggregated distribution avoided cost.[2] Finally, for GHG emissions avoided costs, I address the argument that the effects of a forecasted carbon tax should be removed.[3]

Q. Please summarize your conclusions and recommendations.

A. My recommendations are based on my experience developing avoided costs in California pursuant to the California Standard Practice Manual and working on avoided costs and cost-effectiveness in several other states. In addition, I have reviewed avoided costs submitted by MidAmerican in Iowa and Xcel Energy in Minnesota. My recommendations are that: 1) it would be reasonable to include generation capacity avoided costs in all years, even those in which there is not an identified need for new capacity, 2) a distribution capacity avoided cost that is broadly applied to all EE should be calculated and included,

[1] OUCC Witness Haselden Direct Testimony, page 11.
[2] I&M 2018-2019 IRP, Section 4.6.3, page 95.
[3] OUCC Witness Haselden Settlement Testimony, page 5.

and 3) it is reasonable to include a carbon emissions avoided cost even absent a defined carbon tax or cap and trade regime.

Q. Please describe your experience developing avoided costs in California.

A. I, along with my fellow partner at E3 Ren Orans, developed the first area and time specific avoided costs adopted by the California Public Utilities Commission ("CPUC") in 2004. Since then, I have led or supported work to develop and implement updates and revisions to the Avoided Cost Calculator for the CPUC. The most recent update was adopted in July 2020 and includes avoided costs for generation capacity, transmission capacity, distribution capacity, energy, avoided ancillary services procurement, losses and GHG emissions. These avoided costs are used to evaluate the cost effectiveness of over $1 billion annually in EE and demand response ("DR") programs, distributed PV, distributed energy storage as well as several other distributed energy resource ("DER") programs.

Q. Does California assign a generation capacity value to all years regardless of whether there is a need for new generation capacity in the year?

A. Yes. The original adopted avoided cost methodology used the concept of a "Resource Balance Year" to determine when new capacity resources are needed. The resource balance year is when the load forecast with EE and DR removed exceeds the available generation capacity resources. Prior to the resource balance year, a short-run generation capacity value was used for avoided costs. At the resource balance year, the avoided cost calculation transitioned to a long-run generation capacity value.

In 2016, the CPUC[4] determined that the avoided costs should reflect a need for new capacity for all years (even prior to the resource balance year) to reflect that demand side resources are the preferred resource for meeting future energy needs.

Q. What is the rational for removing forecasted EE and DR from the load forecast to determine the resource balance year?

A. EE and DR delay the need for capacity and can push the resource balance year further into the future. In order to determine the value provided by new forecasted EE and DR, one must determine the marginal costs using a base case that does not have that EE and DR already reflected in the load forecast. To include the EE and DR in the base case would bias the marginal capacity cost estimate downward.

Q. What was the rational for the 2016 CPUC decision to administratively assume a need for new resources for the entire avoided cost forecast period?

A. The CPUC decision "set the resource balance year to zero", effectively directing that the avoided costs use a long-run capacity value for the entire forecast period. The rationale given is that in recurring integrated resource planning cycles, the need for new capacity can consistently be pushed several years into the future. The value that consistent procurement of EE and DR over time provide in avoiding new capacity build can thereby be undercounted. The CPUC argued that EE and DR should not be "penalized" because the utilities over-procured or had excess supply side resources.

[4] Decision 16-06-007, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K338/163338441.PDF

Q. Prior to 2016, how were the short-run capacity values used for years prior to the resource balance year determined in California?

A. Short-run capacity value was based on prices estimated or reported for the Resource Adequacy ("RA") market. The RA prices represent the market price for capacity procured by the utilities to meet generating capacity requirements. In years where there is ample generation capacity in excess of planning reserve margins, the RA prices are far below the annualized cost of a new combustion turbine.

As an example, in 2018, the CPUC reported a weighted average RA price of $2.87/kW-month ($34.44/kW-year) and that 85% of MWs procured were at or below $3.90/kW-month ($46.8/kW-year).[5]

Q. In addition to the rationales of reflecting market prices and the problem of generation need being constantly pushed out, are there other reasons to attribute generation capacity value to EE and DR even in years without a forecasted need for new capacity?

A. Yes. Stepping back, one needs to recognize that decisions to add capacity are based on a balance of the cost of the capacity additions versus the customer cost of an outage. Some jurisdictions may make this an explicit tradeoff through setting the planning reserve margin based on customer outage costs. Others may use a more engineering-based metric such as the 1 day in 10 year loss of load probability ("LOLP"), but even that kind of metric is based on some judgment of costs versus outages. Even if the 1-in-10 LOLP were adopted because it "just felt right," the underlying mental calculus for such a

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[5]https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018%20RA%20Report%20rev.pdf

decision would have to be balancing outage risk to plant cost. Just as one may weigh the cost of buying a new car versus the risk that one's 20 year old car may fail to start when needed, generation planning is also a matter of balancing costs and risks.

It is clear that reductions in customer demand reduce the risk and or extent of outages. To be sure, that risk reduction is very small when there is plenty of excess generation capacity (excess in terms of supply exceeding the planning reserve margin), but as that excess generation capacity shrinks, the risk reduction increases. While it is simple to treat generation avoided costs in a binary fashion, with zero marginal capacity value in years prior to the planned need date for new generation, such a treatment ignores the value to customers provided by load reduction.

It is true that there may not be any direct monetary capacity cost reduction for the utility from load reductions prior to the need date, but it is also true that there is an increase in customer welfare from the outage risk reduction. It therefore would be reasonable to include capacity value in years prior to the need date (albeit at a lower cost than the marginal cost in the year of need) in order to reflect the value provided to all utility customers from the load reducing resources.

Q. How were the long-run capacity valued determined in California?

A. Long-run capacity resources were calculated based on the cost-of-new-entry (CONE) for a combustion turbine. The CONE is the capacity payment necessary to fully recover the costs for a combustion turbine and provide sufficient revenue to encourage new investment. The CONE of a peaker resource like a combustion turbine is a metric commonly used by independent system operators, utilities and regulatory commissions to estimate capacity value. Some jurisdictions, such as California in 2020, are moving to using the CONE of energy storage as the proxy resource for new capacity, in place of a combustion turbine.

Q. Can you provide another example of determining avoided capacity costs based on the cost of new peaking capacity even in years without a forecasted need for new capacity?

A. Yes, Xcel Energy in Minnesota calculates avoided generation capacity cost based on the estimated $/kW-year cost of a brownfield natural gas combustion turbine.[6] The rational for Xcel's method is described by the company that it:

> bases all Avoided Capacity Costs on the costs of future plants rather than market capacity prices, regardless of the need for the construction of a new power plant in specific years. We believe this is a more accurate method of quantifying the value of avoided generation capacity. [7]

Q. Please summarize Xcel Energy's rational for using the estimated cost of a new combustion turbine for avoided generation capacity costs.

A. Xcel describes that 1) the time required to build new generation is significant, and all of the previous resource plans affecting the build plans each year must be considered, and 2) the cumulative impact of DSM achievements must be considered since the magnitude of incremental DSM achievements each year are significantly smaller than the capacity of individual power plants that are built.[8] Xcel also describes how the IRP process can continuously push out the need for new capacity, in part because of prior implementation of DSM. Xcel gives an example that in the 2010 and 2013 IRP it may be shown that DSM avoids the need for new capacity in 2017. But in the 2016 IRP, the need for new

[6] 20195-153032-01, p. 24 (Attachment BH-2).
[7] 20164-119663-01, p. 3 (Attachment BH-3).
[8] *Id*.

capacity will now longer exist due to the resources (including DSM) procured as a result of the 2010 and 2013 IRPs.

Q. Is the method of using either a short-run capacity cost based on market prices or the long-run cost of a new peaking capacity resource as the avoided cost for generation capacity consistent with 170 Ind. Admin. Code 4-7?

A. Yes, in 170 IAC 4-7-0.5, it provides the following definitions:

> (b) "Avoided cost" means the incremental or marginal cost to a utility of energy or capacity, or both, not incurred by a utility if an alternative supply-side resource or demand-side resource is included in the utility's IRP;
>
> (cc) "Preferred resource portfolio" means the utility's selected long term supply-side and demand-side resource mix that safely, reliably, efficiently, and cost-effectively meets the electric system demand, taking cost, risk, and uncertainty into consideration;
>
> (pp) "Supply-side resource" means a resource that provides a supply of electrical energy or capacity, or both, to a utility. A supply-side resource includes the following:
> (1) A utility-owned generation capacity addition.
> (2) A wholesale power purchase.
> (3) A refurbishment or upgrade of an existing utility-owned generation facility.
> (4) A cogeneration facility.
> (5) A renewable resource.
> (6) Distributed generation.

I would interpret a method based either on short-run capacity costs, as indicated by market prices, bilateral contracts or other sources, or long-run capacity costs based on a new peaking resource as being consistent with 170 IAC 4-7.

Q. Is the rationale provided by the CPUC and Xcel for using a long-run capacity value for the avoided cost of generation capacity consistent with prior IURC orders?

A. I am not familiar with the procedural history of I&M's prior cases on integrated resource planning or DSM plans. However, the Final Order in IURC Cause No. 43827 DSM 9

(Jan. 2, 2020) at page 9 states:

> I&M's calculation as previously approved is based on the avoided costs from the 2015 IRP and is consistent with previous tracker filings approved by this Commission. This methodology aligns the annual DSM savings with the respective year avoided capacity cost used to develop the three-year plan and better reflects the value of installing DSM measures over a period of time, rather than only the first year in which capacity is needed as reflected in the IRP.

In reviewing DSM programs for Duke Energy Indiana, the Commission's findings state:

> We note that adopting the OUCC's recommendations would create a disincentive for electric utilities to invest in EE in years when they have capacity surplus. Furthermore, it is neither practical nor prudent to implement EE programs only in years when the Petitioner has a capacity deficit. In addition, focusing solely on a utility's current capacity needs ignores the long-term nature of DSM efforts as reflected in the IRP, devalues EE efforts in years when there is capacity surplus, conflicts with the purpose of including EE programs in a long-term resource acquisition plan.

Final Order in IURC Cause No. 43955 DSM 7 (Feb. 26, 2020), p. 11.

The rationales given by the CPUC and Xcel Energy make similar arguments that a long-run capacity value based avoided generation capacity cost better reflects the value of installing DSM measures over time.

Q. In years for which there is not a forecasted need for new capacity, do you believe it is reasonable to include a value for avoided generation capacity?

A. Either a short- or long-run generation capacity value can be reasonable bases for avoided generation capacity costs in years without a need for new generation. A short-run value represents the actual monetary costs avoided by the utility and its ratepayers and reflects the value of adding incremental DSM to the existing resource mix. But it is not uncommon to adopt a long-run value on policy grounds, as in the example of the CPUC, or to reflect long-run value provided by DSM overtime that may be overlooked in periodic IRP planning cycles. It can be argued this is an appropriate method to value the totality of DSM that is procured over time.

Q. Transitioning to avoided distribution capacity, do you agree with the claim by I&M in its 2018-2019 Integrated Resource Planning Report that it is not possible to calculate a meaningful aggregated distribution avoided cost?

A. No. Section 4.6.3, p. 95, of the 2018-2019 I&M IRP claims:

> Because distribution system needs are so dependent upon location and factors beyond the Company's control, such as generation from others entities, local customer load changes, demand management, and local customer load diversity, it is nearly impossible to determine a global, aggregated distribution specific avoided cost that has real meaning or that is reliable for the Company to use in financial valuations other than on a very narrow, site specific, case-by-case basis.

It is true, that load growth related distribution investments are highly time and location specific. However, it is clearly possible to calculate distribution marginal capacity costs, as there are myriad examples of jurisdictions that do so.

Q. Does the Company have a valid concern that it cannot develop a "meaningful" global aggregated value?

A. No. To be sure, it would be ideal to estimate individual distribution marginal capacity costs for each small subsegment of the utility distribution system that has a capacity need in the near term. However, absent that ideal situation, I&M essentially asserts that it is more meaningful to assume that there is no distribution capacity value anywhere in the utility system, and never would be any value. Clearly, this is wrong.

Q. Why is it more appropriate to use a system average distribution capacity value than exclude distribution capacity completely?

A. By including a distribution marginal cost, one is recognizing that there is value to load reductions for the distribution system. In addition, for long lived resources like EE, the use of system average distribution costs are especially valid and meaningful as distribution costs tend to revert to the mean over time. For example, Area A may have a high distribution marginal cost in year 1, but after capacity investments are made in the area, the marginal cost drops to near zero for many years. Conversely, Area B may have no distribution capacity cost in year 1, but 10 years from now may have a high distribution marginal cost due to load growth eventually "using up" the surplus distribution capacity in the area that made it a zero cost area in year 1. By using a system average distribution marginal capacity cost, one is essentially smoothing out the ups and downs for individual areas, while recognizing that there is a fundamental distribution value for load reductions.

Q. If the Company were to wish to derive more precise time and location-specific estimates (as opposed to system average estimates) of distribution marginal capacity costs, would that be possible?

A. Yes. This is in fact done in California. My objective here is not to describe the approach in detail, but to show that such a calculation is feasible. The CPUC has implemented a Distribution Resource Plan proceeding that requires the utilities annually to submit a Grid Needs Assessment ("GNA") and Distribution Deferral Opportunity Report ("DDOR"). These reports identify all distribution investments on the utility system over the next five years, the grid need that is driving the investment (e.g. load growth, voltage, reliability), the $/kW-Yr. cost of the investment, and whether it is feasible to defer the investment with DSM. Load forecasts for each distribution feeder are also provided, with the amount of DSM included in the forecast specifically identified. With this data of planned load growth related distribution investments and load forecasts with and without DSM, a bottoms-up $/kW-yr. cost distribution investment required and avoided by DSM individually for each feeder can be calculated. The method is more fully described in the 2020 ACC Documentation.[9]

Q. Is it necessary to perform such a detailed, feeder by feeder analysis to calculate an avoided cost for distribution capacity?

A. No. The data for the kind of detailed analysis discussed above is not commonly available for an entire utility service territory in most jurisdictions. The California example does show that the highly time and location specific nature of distribution investment does not itself preclude calculating distribution avoided costs. That said, distribution avoided costs are more commonly calculated using far less data.

Q. Is there a single best or recommended approach for calculating distribution avoided costs for DSM?

A. No. There are several different methods commonly used by different utilities and jurisdictions. Xcel Energy Minnesota provides a useful benchmarking summary in a 2016

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[9] 2020 ACC Documentation v1c Final p. 48, available at https://ethreesf-my.sharepoint.com/personal/gabe_mantegna_ethree_com/_layouts/15/onedrive.aspx?originalPath=aHR0cHM6Ly9ldGhyZWVzZi1teS5zaGFyZXBvaW50LmNvbS86ZjovZy9wZXJzb25hbC9nYWJlX21hbnRlZ25hX2V0aHJlZV9jb20vRXVfckZXSXo3cjVLbDhyMENMY09idE1Cbk9TVkNmMVFLbElseEZKbDBuTTVUQT9ydGltZT1qcUliQk5wWjJFZw&id=%2Fpersonal%2Fgabe%5Fmantegna%5Fethree%5Fcom%2FDocuments%2FCPUC%20ACC%20Documents%2FVersion%20v1c%20%28FINAL%29%2F2020%20ACC%20Documentation%20v1c%20Final%2Epdf&parent=%2Fpersonal%2Fgabe%5Fmantegna%5Fethree%5Fcom%2FDocuments%2FCPUC%20ACC%20Documents%2FVersion%20v1c%20%28FINAL%29

filing for its 2017-2019 Conservation Improvement Program (CIP).[10] The study, "Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments" by the Mendota Group, concluded that there are a number of methodologies to calculate T&D avoided costs and that there is no single approach to estimating these costs. A copy of that report (filed by Xcel Colorado) is provided as Attachment BH-4. The study also provides example distribution avoided costs from at least 20 different utilities, countering the assertion that meaningful, aggregated distribution avoided costs cannot be calculated for DSM programs.

Q. Can you provide a more specific example of how distribution avoided costs are calculated for a utility in the Midwest?

A. Yes. A March 2019 proposed decision of the Minnesota Department of Commerce describes a "Discrete Approach" method adopted in "Deputy Commissioner's Decision: In the Matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 CIP Triennial Plans." Docket no. 16-541. Filed September 29, 2017. Xcel Energy, Minnesota Power and Otter Tail estimated avoided transmission and distribution costs using the Discrete Approach. I served as a Third Party Evaluator in that proceeding. The Discrete Approach follows the six general steps outlined below to estimate avoided T&D costs:

1. Start with a forecast of the load reductions each electric utility's Conservation Improvement Program ("CIP") would provide over the study period.

[10] Attachment BH-3, p. 6.

2. Calculate the present value of the costs (revenue requirement) of load-growth driven T&D investments needed in the future to provide a reliable system under normal operating conditions.
3. Allocate the projected load reductions due to projected CIP achievements to the T&D systems on a proportional basis based on percentage of system load share.
4. Calculate the present value of the costs of load-growth driven T&D investments that are needed in the future, after load reductions, to provide a reliable system under normal operating conditions.
5. Calculate the differences in the present value of costs (revenue requirement) before and after DSM investments (under the discrete method, there will be no difference if the projected CIP load reductions were not large enough to defer T&D investments).
6. Divide the difference in projected T&D deferred costs ($) by the average annual projected CIP load reductions (kW per year) to obtain a $/kW-yr estimate of T&D deferral benefit.

Q. Can you provide an example for another utility in the Midwest?

A. Yes. The approached used by Mid American in Iowa is described in the direct testimony of Jennifer Long (included as Attachment BH-5). Ms. Long explains at page 3 that Iowa administrative rules do not require use of avoided T&D costs, but that the rules allow parties to submit and explain alternative methods for calculating avoided capacity and energy avoided costs. Ms. Long proceeds to describe an approach using FERC Form 1 data, which includes historical utility capital and operating costs by category. Ms. Long describes that capital costs not dependent on load levels were removed from consideration. The costs are divided by the estimated capacity of the transmission and distribution system respectively to calculate a $/kW cost. The costs are spread across an assumed book life for transmission and distribution assets and multiplied by an economic recovery factor to calculate an annualize cost of $14.59/kW-Yr. for transmission and $31.93/kW-yr. for distribution.

Q. Do you recommend that I&M should use follow one of these examples to calculate distribution capacity costs?

A. These are examples to show that it would not be burdensome on I&M to calculate distribution capacity costs. However, the best method for I&M will depend on the Company's specific situation and available data. I do recommend implementing an approach for calculating a non-zero value for transmission and distribution avoided costs but cannot recommend a specific approach at this time.

Q. Do you believe it is necessary to remove the carbon tax from the avoided cost calculation used to determine shareholder incentives, as recommended by of Mr. Haselden?

A. No. I am not familiar with the shareholder incentive mechanism and can only comment on the reasonableness of including an avoided cost of carbon for cost-effectiveness evaluation. The absence of a carbon tax or cap and trade allowance price does not necessarily mean it is inappropriate to include a cost of carbon in avoided cost calculations.

Q. Is there a standard practice for including a cost of carbon as a benefit in the utility or total resource cost test?

A. No. Jurisdictions have taken different approaches with respect to including a cost of carbon or cost of emissions as a benefit in the TRC, UCT and RIM. It is a more common, though not universal practice to include a cost of carbon in the SCT. Some jurisdictions have also chosen to include a carbon, emissions or externality cost in the TRC, even in the absence of an actual carbon tax or cap and trade allowance price.

Q. Please describe how an avoided cost of carbon is calculated in California.

A. There are two components of the avoided cost of carbon used in California. California has a cap and trade allowance market with a floor and ceiling price. The California Energy Commission ("CEC") forecasts cap and trade allowance prices in the annual Integrated Energy Policy Report ("IEPR"). These forecasts are used as one category of carbon avoided costs. There is a second GHG adder category, based on the projected marginal cost to meet electric sector GHG emissions targets. The IRP proceeding develops a least-cost resource portfolio to meet long-term GHG reduction targets in the electric sector. This process produces a marginal cost of carbon abatement for the electric sector that is higher than the cap and trade allowance price. To meet GHG emission targets, utilities must procure renewable energy and energy storage that is more expensive than what the marginal generation resource would be absent a GHG emission target. The last and most expensive zero carbon generation resource needed to comply with the GHG emission target sets the marginal cost of carbon abatement. The cap and trade allowance avoided cost plus the GHG adder avoided cost in total equal the marginal cost of carbon abatement for the electric sector. This is an example in which electric sector specific policies to meet GHG emission targets produce an "implied" cost of carbon that is higher than the allowance price in the cap and trade market. California includes this avoided cost as a benefit in the utility, ratepayer, total resource and societal cost test.

Q. Can you provide other examples where an environmental or carbon cost is included in avoided costs for DSM absent a carbon tax or cap and trade allowance market?

A. Yes. Iowa IAC Chapter 35 includes an externality factor ("EF") which is a 10 percent factor applied to avoided energy and avoided capacity costs in each costing period to account for societal costs of supplying energy. The code also allows the utility to propose a different externality factor but it must document the factor's accuracy. The externality factor is included as a benefit in the total resource cost test, but not the ratepayer or utility cost test. Also, in December 2015, the Public Service Commission of Wisconsin adopted an avoided cost of carbon emissions for assessing the cost-effectiveness of energy efficiency and renewable resources.[11]

Q. Why would one choose to include a cost of carbon in the TRC, but not the UCT or RIM?

A. Some jurisdictions strictly interpret the UCT and RIM to include as benefits only those costs that are incurred as a monetary cost or cash payment by the utility and avoided by DSM.

[11] WPSC REF#: 279739 Docket 5-FE-100.

Q. Please summarize your conclusions.

A. My conclusions regarding avoided costs for DSM are:

1) It would be reasonable to include an avoided cost of capacity even in years for which there is not a forecasted need for new capacity;

2) It is both possible and reasonable to calculate a generally applicable avoided cost of transmission and distribution capacity even though distribution investments are highly location and time specific; and

3) It would be reasonable to calculate and include an avoided cost of carbon even in the absence of a carbon tax or cap and trade allowance market.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I, Brian Horii, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

______________________________ September 15, 2020

Brian Horii Date

ATTACHMENT BH-1

Brian Horii

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ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Senior Partner 1993 – Present

Mr. Horii is one of the founding partners of Energy and Environmental Economics, Inc. (E3). He is a lead in the practice areas of Resource Planning; Energy Efficiency and Demand Response; Cost of Service and Rate Design; and acts as a lead in quantitative methods for the firm. Mr. Horii also works in the Energy and Climate Policy, Distributed Energy Resources, and regulatory support practice areas. He has testified and prepared expert testimony for use in regulatory proceedings in California, South Carolina, Texas, Vermont, British Columbia, Quebec, and Ontario, Canada. He designed and implemented numerous computer models used in regulatory proceedings, litigation, utility planning, utility requests for resource additions, and utility operations. His clients include BC Hydro, California Energy Commission, California Public Utilities Commission, Consolidated Edison, El Paso Electric Company, Hawaiian Electric Company, Hydro Quebec, Minnesota Department of Commerce, NYSERDA, Orange and Rockland, PG&E, Sempra, Southern California Edison, and South Carolina Office of Regulatory Staff.

Cost of Service and Rate Design:

- Designed standard and innovative electric utility rate options for utilities in the U.S., Canada, and the Middle East
- Principal author of the *Full Value Tariff and Retail Rate Choices* report for NYSERDA and the New York Department of Public Staff as part of the New York REV proceeding
- Developed the rate design models used by BC Hydro and the BCUC for rate design proceedings from 2008 through 2016
- Principal author on marginal costing, ratemaking trends and rate forecasting for the California Energy Commission's investigation into the revision of building performance standards to effect improvements in resource consumption and investment decisions
- Consulted to the New York State Public Service Commission on appropriate marginal cost methodologies (including consideration of environmental and customer value of service) and appropriate cost tests
- Authored testimony for BC Hydro on Bulk Transmission Incremental Costs (1997); principal author of B.C. Hydro's System Incremental Cost Study 1994 Update (With Regional Results Appendix)
- Performed detailed market segmentation study for Ontario Hydro under both embedded and marginal costs
- Testified for the South Carolina Office of Regulatory Staff on SCANA, Duke Energy Progress and Duke Energy Carolinas marginal costs and Net Energy Metering rates
- Taught courses on customer profitability analysis for the Electric Power Research Institute
- Other work has addressed marginal cost-based revenue allocation and rate design; estimating area and time specific marginal costs; incorporating customer outage costs into planning; and designing a comprehensive billing and information management system for a major energy services provider operating in California

Resource Planning:

- Authored the Locational Net Benefits Analysis (LNBA) tool used by California IOUs to evaluate the total system and local benefit of distributed energy resources by detailed distribution subareas
- Created the software used by BC Hydro to evaluate individual bids and portfolios tendered in calls for supplying power to Vancouver Island, demand response from large customers, and new clean power generation
- Designed the hourly generation dispatch and spinning reserve model used by El Paso Electric to simulate plant operations and determine value-sharing payments
- Evaluated the sale value of hydroelectric assets in the Western U.S.
- Simulated bilateral trading decisions in an open access market; analyzed market segments for micro generation options under unbundled rate scenarios; forecasted stranded asset risk and recovery for North American utilities; and created unbundled rate forecasts
- Reviewed and revised local area load forecasting methods for PG&E, Puget Sound Energy, and Orange and Rockland Utilities

Energy Efficiency, Demand Response, and Distributed Resources:

- Author of the "E3 Calculator" tool used as the basis for all energy efficiency programs evaluations in California since 2006
- Independent evaluator for the development of locational avoided costs by the Minnesota electric utilities
- Consulted on the development of the NEM 2.0 Calculator for the CPUC Energy Division that was used by stakeholders in the proceeding as the common analytical framework for party positions; also authored the model's sections on revenue allocation that forecast customer class rate changes over time, subject to changes in class service costs
- Co-author of the avoided cost methodology adopted by the California CPUC for use in distributed energy resource programs since 2005
- Principal consultant for the California Energy Commission's Title 24 building standards to reflect the time and area specific value of energy usage reductions and customer-sited photovoltaics and storage
- Principal investigator for the 1992 EPRI report *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District*, one of the first reports to focus on demand-side alternatives to traditional wires expansion projects
- Provided testimony to the CPUC on the demand response cost effectiveness framework on behalf of a thermal energy storage corporation

Transmission Planning and Pricing:

- Designed a hydroelectric water management and renewable integration model used to evaluate the need for transmission expansion in California's Central Valley
- Developed the quantitative modeling of net benefits to the California grid of SDG&E's Sunrise Powerlink project in support of the CAISO's testimonies in that proceeding
- Testified on behalf of the Vermont Department of Public Service on the need for transmission capacity expansion by VELCO
- Determined the impact of net vs. gross billing for transmission services on transmission congestion in Ontario and the revenue impact for Ontario Power Generation

- Authored numerous Local Integrated Resource Planning studies for North American utilities that examine the cost effectiveness of distributed resource alternatives to traditional transmission and distribution expansions and upgrades
- Developed the cost basis for BC Hydro’s wholesale transmission tariffs
- Provided support for numerous utility regulatory filings, including testimony writing and other litigation services

Energy and Climate Policy:

- Author of the E3 “GHG Calculator” tool used by the CPUC and California Energy Commission for evaluating electricity sector greenhouse gas emissions and trade-offs
- Primary architect of long-term planning models evaluating the cost and efficiency of carbon reduction strategies and technologies
- Testified before the British Columbia Public Utilities Commission on electric market restructuring

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Project Manager, Supervisor of Electric Rates 1987-1993

- Managed and provided technical support to PG&E's investigation into the Distributed Utilities (DU) concept; projects included an assessment of the potential for DU devices at PG&E, an analysis of the loading patterns on PG&E's 3000 feeders, and formulation of the modeling issues surrounding the integration of Generation, Transmission, and Distribution planning models
- As PG&E's expert witness on revenue allocation and rate design before the California Public Utilities Commission (CPUC), was instrumental in getting PG&E's area-specific loads and costs adopted by the CPUC and extending their application to cost effectiveness analyses of DSM programs
- Created interactive negotiation analysis programs and forecasted electric rate trends for short-term planning

INDEPENDENT CONSULTING San Francisco, CA
Consultant 1989-1993

- Helped develop methodology for evaluating the cost-effectiveness of decentralized generation systems for relieving local distribution constraints; created a model for determining the least-cost expansion of local transmission and distribution facilities integrated with area-specific DSM incentive programs
- Co-authored *The Delta Report* for PG&E and EPRI, which examined the targeting of DSM measures to defer the expansion of local distribution facilities

Education

Stanford University Palo Alto, CA
M.S., Civil Engineering and Environmental Planning 1987

Stanford University — Palo Alto, CA
B.S., Civil Engineering — 1986

Citizenship

United States

Refereed Papers

1. *Woo, C.K., I. Horowitz, B. Horii, R. Orans, and J. Zarnikau (2012) "Blowing in the wind: Vanishing payoffs of a tolling agreement for natural-gas-fired generation of electricity in Texas," The Energy Journal, 33:1, 207-229.*
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7. *Woo, C.K., I. Horowitz, A. Olson, B. Horii and C. Baskette (2006) "Efficient Frontiers for Electricity Procurement by an LDC with Multiple Purchase Options," OMEGA, 34:1, 70-80.*
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9. *Woo, C. K., B. Horii and I. Horowitz (2002) "The Hopkinson Tariff Alternative to TOU Rates in the Israel Electric Corporation," Managerial and Decision Economics, 23:9-19.*
10. *Heffner, G., C.K. Woo, B. Horii and D. Lloyd-Zannetti (1998) "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," IEEE Transactions on Power Systems, PE-493-PWRS-012-1997, 13:2, 560-567.*
11. *Chow, R.F., Horii, B., Orans, R. et. al. (1995), Local Integrated Resource Planning of a Large Load Supply System, Canadian Electrical Association.*
12. *Woo, C.K., R. Orans, B. Horii and P. Chow (1995) "Pareto-Superior Time-of-Use Rate Option for Industrial Firms," Economics Letters, 49, 267-272.*
13. *Pupp, R., C.K.Woo, R. Orans, B. Horii, and G. Heffner (1995), "Load Research and Integrated Local T&D Planning," Energy - The International Journal, 20:2, 89-94.*

14. *Woo, C.K., D. Lloyd-Zannetti, R. Orans, B. Horii and G. Heffner (1995) "Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation," The Energy Journal, 16:2, 111-130.*
15. *Woo, C.K., R. Orans, B. Horii, R. Pupp and G. Heffner (1994), "Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," Energy - The International Journal, 19:12, 1213-1218.*
16. *Woo, C.K., B. Hobbs, Orans, R. Pupp and B. Horii (1994), "Emission Costs, Customer Bypass and Efficient Pricing of Electricity," Energy Journal, 15:3, 43-54.*
17. *Orans, R., C.K. Woo and B. Horii (1994), "Targeting Demand Side Management for Electricity Transmission and Distribution Benefits," Managerial and Decision Economics, 15, 169-175.*

Research Reports and Filed Testimony

1. *Horii B., (2019) Direct Testimony and Exhibit of Brian Horii on Behalf of the South Carolina Office or Regulatory Staff Docket No. 1995-1192-E In re: Proceeding for Approval or the Public Utility Regulatory Policies Act of 1978 (PURPA) Avoided Cost Rates for Electric Companies.* (case is currently suspended)
2. *Horii B., (2019) Surrebuttal Testimony of Brian Horii on Behalf of the South Carolina Office or Regulatory Staff Docket No. 2019-2-E In re: Annual Review of Base Rates and Fuel Costs For South Carolina Electric & Gas Company.*
3. *Horii B., (2019) Direct Testimony and Exhibit of Brian Horii on Behalf of the South Carolina Office or Regulatory Staff Docket No. 2019-2-E In re: Annual Review of Base Rates and Fuel Costs For South Carolina Electric & Gas Company.*
4. *Horii B., N Ryan, E. Cutter, O, Garnett, (2018) Testimony of Brian Horii on Forecast Increased EV Adoptions in Quebec due to DC Fast Charging Infrastructure Expansion.*
5. *Horii B., (2018) Direct Testimony and Exhibit of Brian Horii on Behalf of the South Carolina Office or Regulatory Staff Docket No. 2018-2-E In re: Annual Review of Base Rates and Fuel Costs For South Carolina Electric & Gas Company.*
6. *Ming Z., S. Price, Horii B., (2017) Avoided Costs 2017 Interim Update* for the California PUC.
7. *Horii B., (2017) Direct Testimony and Exhibit of Brian Horii on Behalf of the South Carolina Office or Regulatory Staff Docket No. 2017-2-E In re: Annual Review of Base Rates and Fuel Costs For South Carolina Electric & Gas Company.*
8. *Horii, B., (2016) Locational Net Benefit Analysis Modeling Framework* on behalf of the California IOUs for submission to the California PUC.
9. *Horii B., S. Price, E. Cutter, Z. Ming, K. Chawla, (2016) Avoided Costs 2016 Interim Update* for the California PUC.
10. *Horii B., C.K. Woo, E. Kollman and M. Chait (2009) Smart Meter Implementation Business Case, Rate-related Capacity Conservation Estimates - Technical Appendices submitted to B.C. Hydro.*
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12. *Horii, B., R. Orans, A. Olsen, S. Price and J Hirsch (2006) Report on 2006 Update to Avoided Costs and E3 Calculator, Prepared for the California Public Utilities Commission.*
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14. *Horii, B., R. Orans, and E. Cutter (2005) HELCO Residential Rate Design Investigation, Report prepared for Hawaiian Electric and Light Company.*
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19. *Price, S., B. Horii (2001) Chelsea and E. 13th Street / East River Evaluation, Local integrated resource planning study prepared for Consolidated Edison Company of New York.*
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33. *Horii, B., Orans, R., Woo, C.K., (1995) Area- and Time- Specific Marginal Cost Study, Report submitted to B.C. Hydro.*
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39. *Horii, B., (1991) Pacific Gas and Electric Company 1991 Electricity Cost Adjustment Clause Application (Revenue Allocation and Rate Design), Submitted to the California Public Utilities Commission.*

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1. *Heffner, G., C.K. Woo, B. Horii and D. Lloyd-Zannetti (1998) "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," IEEE Transactions on Power Systems, PE-493-PWRS-012-1997, 13:2, 560-567.*
2. *Horii, B., (1995), "Final Results for the NMPC Area Costing and Distributed Resource Study," Proceedings Distributed Resources 1995: EPRI's First Annual Distributed Resources Conference, Electric Research Power Institute, August 29-31, 1995, Kansas City, Missouri*
3. *Orans, R., C.K. Woo, B. Horii and R. Pupp, (1994), "Estimation and Applications of Area- and Time-Specific Marginal Capacity Costs," Proceedings: 1994 Innovative Electricity Pricing, (February 9-11, Tampa, Florida) Electric Research Power Institute, Report TR-103629, 306-315.*
4. *Heffner, G., R. Orans, C.K. Woo, B. Horii and R. Pupp (1993), "Estimating Area Load and DSM Impact by Customer Class and End-Use," Western Load Research Association Conference, September 22-24, San Diego, California; and Electric Power Research Institute CEED Conference, October 27-29, St. Louis, Missouri.*

E3: Brian Horii Resume

ATTACHMENT BH-2

COMMERCE DEPARTMENT

DECISION

BEFORE THE DEPUTY COMMISSIONER OF THE MINNESOTA DEPARTMENT OF COMMERCE

JOSEPH SULLIVAN, DEPUTY COMMISSIONER

Decision
CIP Electric Utilities - Cost-Effectiveness Review

Issue Date: May 20, 2019
Docket No. E999/CIP-18-783

I. PROCEDURAL HISTORY

On January 3, 2019, and February 7, 2019, Staff of the Minnesota Department of Commerce, Division of Energy Resources (Staff) submitted Information Requests to Minnesota Power (MP), Otter Tail Power (OTP), and Xcel Energy (Xcel) for information about the avoided electric cost assumptions that they intend to use in their 2020-2022 Conservation Improvement Program (CIP) Triennial Plan filings.

During mid-January and February 2019, MP, Xcel, and OTP, provided responses to Staff's Information Requests.

On March 20, 2019, Staff filed a Proposed Decision concerning the Electric Cost-Effectiveness Review for the 2020-2022 CIP Triennium.

On March 22 and March 28, 2019, the American Council for an Energy-Efficient Economy (ACEEE), Center for Energy and Environment (CEE), the Citizens Utility Board (CUB), and Fresh Energy filed letters requesting that the Department extend the cost-effectiveness review process to more broadly discuss issues.

On April 1, 2019, the Deputy Commissioner modified the sequencing of the comment period and Decision timelines for the Inputs to BENCOST for the Natural Gas IOU's 2020-2022 CIP Triennium and the CIP Electric Utilities' 2020-2022 Cost-Effectiveness Review to afford stakeholders the opportunity to file comments after a related Decision was issued to extend the 2017-2019 CIP Triennials through 2020.

On April 11, 2019, the Deputy Commissioner issued a Decision extending the 2017-2019 CIP Triennial Plans through calendar year 2020.[1]

On April 19, 2019, written comments were submitted by the ACEEE, CEE, Fresh Energy, MP, OTP, and Xcel.

On May 6, 2019, reply comments were submitted by CenterPoint Energy (CPE) and Xcel.

[1] *Deputy Commissioner's Decision - In the matter of Extending the 2017-2019 CIP Triennial Plans Through 2020.* April 11, 2019. Docket Nos. E,G002/CIP-16-115, E017/CIP-16-116, E015/CIP-16-117, G022/CIP-16-118, G008/CIP-16-119, G011/CIP-16-120, G004/CIP-16-121.

Table of Contents

II. BACKGROUND

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. The savings resulting from these DSM investments are known as avoided costs.

From January through May 2019, my Staff analyzed the three electric investor-owned utilities' (IOU) avoided cost methodologies and estimates that were to be used for the 2020-2022 CIP Triennial Plans. On March 20, 2019, Staff issued a Proposed Decision recommending that the Deputy Commissioner approve the electric utilities' 2020-2022 avoided costs.

Following the issuance of Staff's Proposed Decision, the Deputy Commissioner issued a separate but related Decision on April 11 that extended the 2017-2019 CIP Triennial Plans through calendar year 2020.[2] As described in more detail herein, this means that this current avoided electric cost Decision now effectively applies to the 2021-2023 CIP Triennium.

Thus, in order to realign the timing for which Triennial Plan years the cost-effectiveness assumptions apply to, the Deputy Commissioner provides the following clarifications:

- **2020 CIP Extension Plans (Electric IOUs submit on July 1, 2019):** The electric IOU's 2020 CIP Extension Plans shall use 2019 avoided costs, escalated to 2020 with approved escalation rates.
- **2021-2023 CIP Triennial Plans (Electric IOUs submit on June 1, 2020):** The electric IOU's 2021-2023 CIP Triennial Plans shall use the approved assumptions and methodologies outlined in this current Decision.

This Decision summarizes MP, OTP, and Xcel's electric avoided cost methodologies and estimates, and is structured into three main sections, as follows:

1. A summary of written comments by interested parties filed on eDockets as part of the cost-effectiveness review process, highlighting themes and areas of agreement and disagreement between the stakeholder groups.
2. The Deputy Commissioner's findings and determinations based on a review of Staff's analysis and written stakeholder comments.
3. The Deputy Commissioner's Final Decision, presenting the order points that conclude this current cost-effectiveness review process.

III. COMMENTS BY INTERESTED PARTIES

The Deputy Commissioner carefully considers comments and reply comments submitted by interested parties concerning CIP matters. As part of Staff's March 20, 2019 Proposed Decision concerning the CIP Electric Utilities 2020-2022 Cost-Effectiveness Review, Staff requested that MP, Xcel, and OTP submit written comments addressing the following areas:

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[2] *Deputy Commissioner's Decision - In the matter of Extending the 2017-2019 CIP Triennial Plans Through 2020.* April 11, 2019. Docket Nos. E,G002/CIP-16-115, E017/CIP-16-116, E015/CIP-16-117, G022/CIP-16-118, G008/CIP-16-119, G011/CIP-16-120, G004/CIP-16-121.

- The key factors contributed to the significant decrease in the three utilities' avoided capacity and marginal energy costs, when comparing the utilities' previously approved avoided costs with the proposed 2020-2022 CIP avoided costs.
- How MP and OTP could make their avoided marginal energy cost assumptions more transparent going forward (e.g. similar to Xcel Energy's proposal to compute its avoided marginal energy costs using an Excel spreadsheet-based model).

A. Factors Contributing to Decreased Avoided Costs

As part of their April 19 and May 6 comments and reply comments, Xcel, MP, and OTP responded to Staff's request to describe the key factors that led to the significant decreases in their avoided marginal energy and capacity costs, which are outlined in Table 1. For more details about these factors, please see the three electric IOUs' written comments found in Appendix A of this document.

Table 1. Key Factors Contributing to Decreased Electric Avoided Costs (2017-2019 Vs. 2020-2022)

Minnesota Power	Otter Tail	Xcel
Avoided Capacity Costs • ↓ Demand outlook for MISO-North • ↓ Costs of new gas generation (used as a proxy for the cost of capacity long-term) • Previous MISONorth demand outlook greater than current outlook (capacity price for MISO North is not at the cost of replacement capacity until 2024) Avoided Marginal Energy Costs • Market forecast prices ↓11% • Natural gas prices ↓20% • Fuel prices ↓ • New wind resources ↑	Avoided Capacity Costs • ↓ 40% in capital costs for upcoming natural gas combustion turbine project Avoided Marginal Energy Costs • Wind energy prices ↓ 33% • Natural gas price forecast from Wood Mackenzie ↓ • Market energy price forecast from Wood Mackenzie ↓	Avoided Capacity Costs • Different generation options (e.g. using brownfield CTs now compared to greenfield CTs previously) • ↓ growth in demand Avoided Marginal Energy Costs • Changes in the generation mix (e.g. more efficient and cost-effective generation) • Natural gas generation now estimated to serve more future customer load • ↓ 23% in power generation commodity costs (\$4.27/MCF previous BENCOST; \$3.25/MCF current BENCOST)

B. Ideas for Increased Transparency of Avoided Marginal Energy Costs

Additionally, as part of their April 19 and May 6 comments and reply comments, OTP and MP provided ideas for how they could make their avoided marginal energy cost assumptions more transparent going forward:

1. *Minnesota Power*
    - Transparency of the method and software used for calculating the hourly marginal energy costs series:
        - The spreadsheets and descriptions previously submitted regarding the calculations of avoided energy costs provide detail for the majority of the process and calculations.
        - MP is willing to provide the hourly data resulting from this process if necessary to increase transparency.

    - MP is willing to participate in further discussions with the interested parties to talk through the process and identify if there are other items that could be provided to help clarify and add transparency to the process.

- Transparency of the method and software used to apply the hourly marginal energy cost series to hourly energy savings data for individual DSM measures:
    - MP believes this part of the process is a fairly straightforward calculation and would not be very beneficial to pull this function out of DSMore.
    - Transitioning the application of avoided costs out of DSMore would require a significant amount of time and resources, thoroughly vet the new tool, and maintain and update the tool appropriately over time.
    - MP does not currently have the resources necessary for this level of work as the team relies on DSMore and the Integral Analytics experts to complete these tasks and ensure the accuracy of all functions performed within the software.

2. *Otter Tail Power*
    - To evaluate CIP measure/program cost-effectiveness, OTP uses a modeling software called, Demand Side Management Option Risk Evaluator (DSMore), which is developed by Integral Analytics Inc. (IA).
    - Traditionally, OTP sends marginal energy cost information to IA and the developer models price files the software uses to calculate the avoided marginal energy costs based on the load shape selected.
    - When OTP evaluates energy efficiency measures, DSMore accesses the price information files and computes the marginal energy benefits in the background. The user does not see all the hourly avoided energy information due to the volume of data but instead receives the overall energy benefits.
    - OTP recently requested IA to provide the marginal energy cost data at the hourly level. IA was happy to include this information to OTP and indicated this as no issue going forward.
    - OTP has included Attachment 2 and 3 with its filed comments.
        - Attachment 2 includes marginal energy prices from IA that are currently being used in OTP's 2017-2019 CIP triennial.
        - Attachment 3 includes hourly marginal energy prices expected to be used in evaluation measures and programs for 2020-2022. OTP utilizes scenario 1 for calculating its avoided marginal energy costs, which is the cost-based scenario. Scenarios 2-21 are market-based scenarios not utilized by the Company.
    - Per the Department's request, OTP believes it has now provided transparent marginal energy pricing.
    - OTP prefers not to use Xcel's evaluation workbook as it is very complex, with many worksheets, which could potentially introduce errors.

C. Requests to Extend Cost-effectiveness Timeline

On March 22 and March 28, 2019, ACEEE, CEE, CUB, and Fresh Energy filed letters requesting that the Department extend the electric and gas CIP cost-effectiveness review process to more broadly discuss ways to revise the cost-effectiveness methodologies that would apply to the 2021-2023 CIP Triennial Plans (given the Department's April 11, 2019 Decision to extend the 2017-2019 CIP Triennial Plans through 2020).

Other stakeholders, either as part of their April 19 comments or May 6 reply comments, stated their positions on extending the gas and electric cost-effectiveness process versus approving the cost-effectiveness assumptions now for the 2021-2023 CIP Triennial Plans.

Table 2 summaries the stakeholder feedback about extending the cost-effectiveness review process versus approving the electric and gas assumptions now. A majority of advocacy organizations supported extending the process, and a majority of the IOUs supported approving the assumptions now or were neutral about extending the process.

Table 2. Stakeholder Feedback on Extending Cost-Effectiveness Processes Vs. Approving Now

	Gas Utilities			Electric Utilities		Combined	Other Organizations				
	CPE	GP	MERC	MP	OTP	Xcel	CEE	Fresh Energy	CUB	ACEEE	Total
Approve Now				X	X						2
Extend Process						X	X	X	X	X	5
Neutral or No Answer	X	X	X								3

D. Using the Societal Discount Rate in the Utility Cost Test[3]

On February 4, 2019, Staff issued a related cost-effectiveness Proposed Decision on the Gas Inputs to BENCOST. As part of the written comment period on the Gas BENCOST Proposed Decision, Staff specifically requested that both the gas *and electric IOUs* submit comments related to the two primary discount rates used in cost-effectiveness testing, as follows:

- Whether or not the Department should make “Input 12 - Utility Discount Rate” equal to “Input 13 - Societal Discount Rate,” meaning both discount rates would equal 3.02%. If no change is made, then the Societal Discount Rate would equal 3.02% and the Utility Discount Rate would equal approximately 7.0%.[4]

- Using historical 2017-2019 CIP data, Staff requested that the electric and gas IOUs provide a comparison of their Utility Cost Test results using their weighted average cost of capital (WACC) compared to a 3.02% Societal Discount Rate (SDR).

On February 19, 2019, CEE, CPE, Fresh Energy, Great Plains Natural Gas (Great Plains), Minnesota Energy Resources Corporation (MERC), MP, OTP, and Xcel, submitted written comments on Staff’s BENCOST Proposed Decision.

On March 1, 2019, CEE, and CPE submitted reply comments.

This section provides a summary of the written stakeholder feedback received during the February 19 and March 1 comment periods, highlighting themes and areas of agreement and disagreement between the stakeholder groups. For more details about the individual stakeholder comments, please see Appendix A.

[3] Comments submitted in the Natural Gas BENCOST Proceeding can be found in Docket No. 18-782.
[4] Based on an average of the Utility Discount Rates reported in the investor-owned utilities’ 2017 CIP Status Reports.

The following section summarizes stakeholder feedback regarding whether or not the Department should consider making “Input 12 - Utility Discount Rate” equal to “Input 13 - Societal Discount Rate,” meaning both discount rates would equal 3.02%.

Table 3. Support/Non-Support for Making the Utility Discount Rate Equal to the Societal Discount Rate

Electric Utilities		Gas Utilities			Combined	Other Organizations	
Minnesota Power	**Otter Tail**	**MN Energy Resources**	**Great Plains**	**CenterPoint**	**Xcel**	**CEE**	**Fresh Energy**
Do not support. Could create inconsistencies between evaluation and valuation of energy efficiency through CIP and IRPs.	**Undecided.** Larger discussion needed to discuss if Societal Discount Rate should be used for IRP purposes.	**Undecided.** Consideration of changes should occur within the context utility financial incentive calculation.	**Support.** No issues identified.	**Do not support.** Same metrics should apply to long-term infrastructure investments and energy efficiency. Should use same discount rate as utility ratemaking proceedings (i.e., WACC).	**Support.** Sends a clear signal to utilities to value long-term energy impacts more than short-term impacts.	**Support.** Will make cost-effectiveness results more comparable and ensure utilities receive consistent signals about long-term value of energy savings.	**Support.** Will better reflect the long-natured policy intent of CIP and the low-risk profile of energy efficiency investments.

As summarized in Table 3, the written comments submitted by interested parties were split in their support or non-support of make the utility discount rate equal to the societal discount rate.

Figure 1. Electric Utility Net Benefits, SDR Compared to WACC, Historical 2017-2019 Assumptions

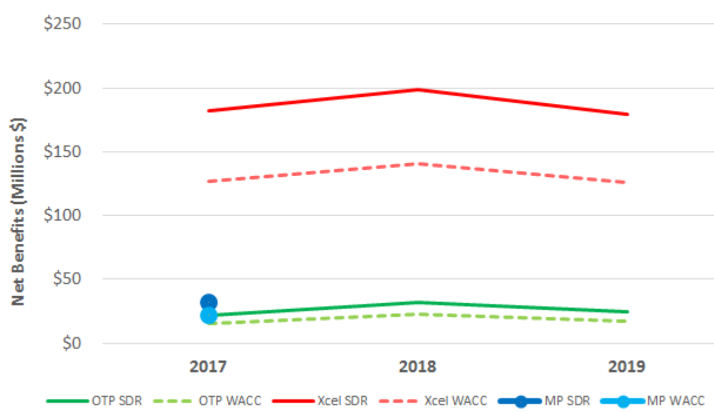
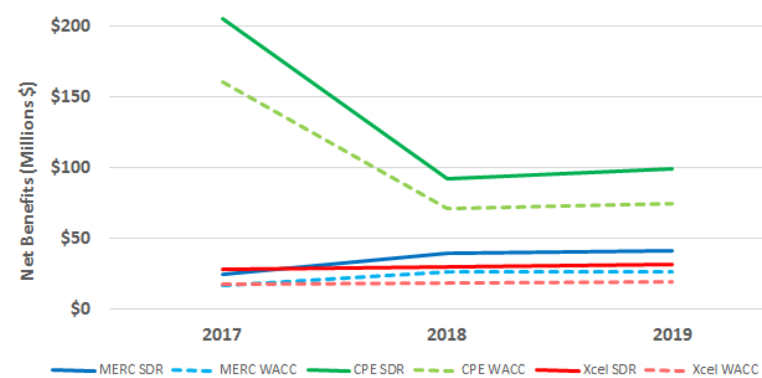


Figure 2. Gas Utility Net Benefits, SDR Compared to WACC, Historical 2017-2019 Assumptions



As summarized in Figures 1 and 2, using historical 2017-2019 CIP data, the gas and electric IOUs provided a comparison of their Utility Cost Test results using their WACC compared to the SDR. For the electric IOUs, using the SDR in the Utility Cost Test would increase their total net benefits by about 40-45%. For the gas IOUs, using the SDR would increase total net benefits by 50-60% for MERC and Xcel; and around 30% for CPE.

Figure 3. Xcel Electric Net Benefits Comparison, Old (2017-2019) Vs Updated (2020-2022) Avoided Costs

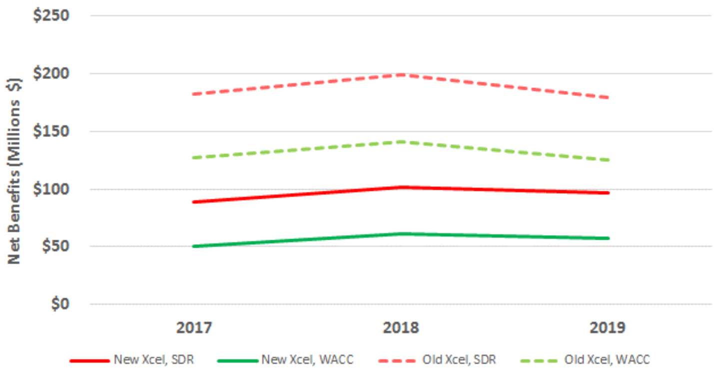
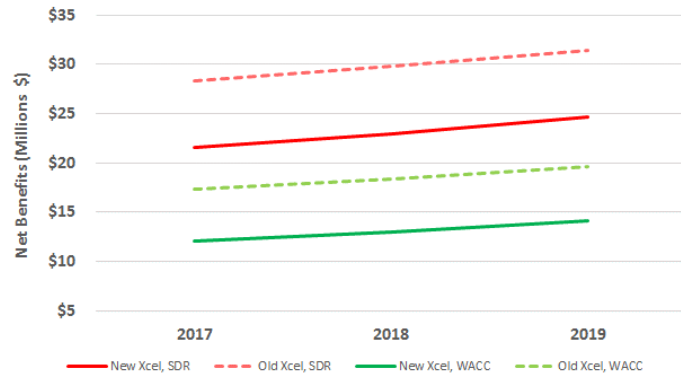


Figure 4. Xcel Gas Net Benefits Comparison, Old (2017-2019) Vs Updated (2020-2022) Avoided Costs



Xcel also provided its estimated net benefits using the preliminary 2020-2022 electric system avoided costs and the Gas BENCOST Inputs in comparison to Xcel's estimated net benefits when using the previously approved 2017-2019 avoided costs (see Figures 3 and 4). On the electric side, using the preliminary 2020-2022 electric avoided costs would reduce Xcel's net benefits by 46-51% when comparing the two SDR scenarios and by 55-60% comparing the two WACC scenarios. On the gas side, using the preliminary 2020-2022 Gas BENCOST Inputs would reduce Xcel's net benefits by 21-24% when comparing the two SDR scenarios and by 27-30% comparing the two WACC scenarios.

However, one caveat is that Xcel's net benefit figures in Figures 3 and 4 are based on its 2017-2019 CIP Triennial Plan goals – and not actuals. Because Xcel has historically exceeded its goals, Xcel's actual net benefits would be somewhat higher across the 2017-2019 and 2020-2022 avoided cost scenarios.

IV. FINDINGS AND DETERMINATIONS

This section presents the Deputy Commissioner's findings and determinations based on a review of my Staff's analysis and the written stakeholder comments submitted as part of this proceeding.

A. Avoided Electric Cost Methodologies and Values

Below is a summary of the core methodology details that each utility used to calculate their avoided capacity, marginal energy, and transmission and distribution (T&D) avoided costs, along with a comparison of the electric IOUs' 2017-2019 avoided cost values versus their 2020-2022 estimates.

1. *Avoided Marginal Energy Costs*[5]

The three IOUs use hourly marginal energy cost assumptions, but use different methods for calculating them. For example, there are differences in the modeling software used: MP uses an RTSim production cost model, OTP uses output from its DSMore capacity expansion model, and Xcel intends to convert from using DSMore to a spreadsheet-based model.

Xcel also thinks the impacts on planned dispatch and planned generation assets that are attributable to electric CIP programs should be accounted for in its upcoming CIP Triennial Plan assumptions. Xcel believes the preliminary modeling runs of DSM scenarios in the Company's upcoming 2020-2034 IRP (due July 2019) can be used to determine the effect on future generation build. In Xcel's May 6 reply comments, the Company notes that the "proposed 2020-2022 CIP avoided costs" refers to avoided cost values provided in January 2019 for the time period 2020-2035. Xcel states that it filed those preliminary values as indicators of its intended modeling methodology; however, results from updated modeling runs and the concurrent IRP process were not yet available at that time.

As part of their March 20, 2019 Proposed Decision, Staff noted the following about the electric IOU's avoided marginal energy cost values:

- *Xcel:* Xcel provided its avoided marginal energy cost estimates from 2020-2035, but treated the values as Trade Secret. Compared to Xcel's approved 2017-2019 avoided marginal energy costs, the 2020-2022 estimates represent a decrease of about 30-40% across the fifteen year time period.

- *Minnesota Power:* On February 15, 2019, Minnesota Power provided its avoided marginal energy cost estimates from 2019-2035, but treated the values as Trade Secret. Compared to MP's approved 2017-2019 CIP avoided marginal energy costs, the 2020-2022 estimates represent a decrease of about 30-40% across the sixteen year time period.

- *Otter Tail:* Otter Tail provided its avoided marginal energy cost estimates from 2017-2035, but treated the values as Trade Secret. Compared to OTP's approved 2017-2019 avoided marginal energy costs, the 2020-2022 estimates represent a decrease of about 35-50% over the eighteen year time period.

Deputy Commissioner's Determinations: In their March 20, 2019 Electric Cost-Effectiveness Review Proposed Decision, Staff recommended that the Deputy Commissioner approve the electric IOU's avoided electric cost assumptions based on a review of Xcel, MP, and OTP's avoided electric cost methodologies. The Deputy Commissioner has reviewed Staff's findings and approves Xcel, MP, and OTP's avoided marginal energy assumptions for the 2021-2023 CIP Triennials.

However, the Deputy Commissioner directs Staff to continue cost-effectiveness discussions with stakeholders through January 2020, and will allow for consideration of modifications to cost-effectiveness assumptions where justified, including potentially updating avoided marginal energy and capacity electric costs only if the Department finds the updates are reasonably justified *and* if

[5] The impacts of DSM include a reduction in the electric generation energy required to serve customers each hour in a year. To calculate the value of this impact, analysts estimate the hourly cost of electric generation energy that is avoided. This reduction is referred to as avoided marginal energy costs.

the avoided cost values have changed by more than 10% between the issuance of this Decision and September 2019.

2. *Avoided Capacity Costs*[6]

All three electric IOUs use similar methods of estimating avoided capacity costs, relying primarily on the combustion turbine (CT) cost assumptions from their recent IRPs for long-term assumptions, and existing purchases and forecasts of market capacity prices for the short term.

Additionally, as part of their March 20, 2019 Proposed Decision, Staff noted the following about the electric IOU's avoided capacity cost values:

- *Xcel:* Xcel provided its avoided capacity cost estimates from 2020-2035, but treated the values as Trade Secret. Compared to Xcel's approved 2017-2019 avoided capacity costs, the 2020-2022 estimates represent a decrease of about 30% across the fifteen year time period.

- *Minnesota Power:* On February 15, 2019, MP provided its avoided capacity cost estimates from 2019-2035, but treated the values as Trade Secret. Compared MP's approved 2017-2019 CIP avoided capacity costs, the 2020-2022 estimates represent a decrease of about 35% across the sixteen year time period.

- *Otter Tail:* OTP provided its avoided capacity cost estimates from 2020-2035, but treated the values as Trade Secret. Compared to OTP's approved 2017-2019 CIP avoided capacity costs, the 2020-2022 estimates represent a decrease of about 40% across the fifteen year time period.

Deputy Commissioner's Determinations: In their March 20, 2019 Electric Cost-Effectiveness Review Proposed Decision, Staff recommended that the Deputy Commissioner approve the electric utilities' avoided electric cost assumptions based on a review of Xcel, MP, and OTP's avoided electric cost methodologies. The Deputy Commissioner has reviewed Staff's findings and approves Xcel, MP, and OTP's avoided capacity assumptions for the 2021-2023 CIP Triennials.

However, the Deputy Commissioner directs Staff to continue cost-effectiveness discussions with stakeholders through January 2020, and will allow for consideration of modifications to cost-effectiveness assumptions where justified, including potentially updating avoided marginal energy and capacity electric costs only if the Department finds the updates are reasonably justified *and* if the avoided cost values have changed by more than 10% between the issuance of this Decision and September 2019.

[6] The impacts of DSM include a reduction in the electric generation capacity required to serve customers. To calculate the value of this impact, analysts derive an estimate of avoided electric generation capacity. This estimate is referred to as Avoided Capacity Costs.

3. Avoided T&D Costs[7]

On September 29, 2017, the Deputy Commission issued a Decision approving the Discrete Approach methodology as the standardized methodology for estimating electric utility avoided T&D costs as part of CIP Triennial Plan cycles. The Discrete Approach follows the six general steps outlined below to estimate avoided T&D costs[8]:

1. Start with a forecast of the load reductions each electric IOU's CIP would provide over the study period.
2. Calculate the present value of the costs (revenue requirement) of load-growth driven T&D investments that are needed in the future to provide a reliable system under normal operating conditions.
3. Allocate the projected load reductions due to projected CIP achievements to the transmission and distribution systems on a proportional basis based on percentage of system load share.
4. Calculate the present value of the costs of load-growth driven T&D investments that are needed in the future, after load reductions, to provide a reliable system under normal operating conditions.
5. Calculate the differences in the present value of costs (revenue requirement) before and after DSM investments (under the discrete method, there will be no difference if the projected CIP load reductions were not large enough to defer T&D investments).
6. Divide the difference in projected T&D deferred costs ($) by the average annual projected CIP load reductions (kW per year) to obtain a $/kW-yr estimate of T&D deferral benefit.

Xcel and MP already estimated their avoided T&D cost values using the Discrete Approach from the September 29, 2017 Decision in the CIP-16-541 docket. In their March 20, 2019 Proposed Decision, Staff did not believe there have been significant change in system conditions to justify performing new analysis of the avoided T&D costs, and Staff recommended that the Deputy Commissioner approve Xcel and MP's avoided T&D cost values from the study performed in the CIP-16-541 docket using the Discrete Approach.

On February 1, 2019 (docket number CIP-16-541), OTP submitted its avoided T&D cost estimates from 2019-2040, using the Department's approved Discrete Approach methodology. On February 7, 2019 (docket number 18-783), Staff submitted an Information Request to OTP, and requested that the Company clearly outline how its calculations follow the Discrete Approach methodology's six steps for estimating avoided T&D costs. On February 19, 2019, OTP responded to Staff's Information Request and provided a spreadsheet showing how the Company followed each of the Discrete Method's six steps for estimating its avoided T&D costs. Staff found that OTP appropriately followed the Discrete Approach

[7] The impacts of DSM include a reduction in the capacity on electric transmission and distribution (T&D) systems required to serve customers. To calculate the value of this impact, analysts estimate the cost of electric transmission and distribution capacity that is avoided. This estimate is referred to as avoided T&D costs.

[8] "Deputy Commissioner's Decision: In the Matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 CIP Triennial Plans." Docket no. 16-541. Filed September 29, 2017.

methodology's steps, and recommended that the Deputy Commissioner approve OTP's avoided T&D costs.

Table 4 provides a comparison of the three utilities' avoided T&D costs, comparing the previously approved 2017-2019 CIP Triennial values to the 2021-2023 CIP Triennial values that were estimated using the approved Discrete Approach methodology.

Table 4. Avoided T&D Costs ($/kW-Yr), 2017-2019 Triennial Values Vs. 2021-2023 Triennial Values

	Otter Tail			Minnesota Power			Xcel		
Year	2017-2019	2021-2023	% Change	2017-2019	2021-2023	% Change	2017-2019	2021-2023	% Change
2020	$71.98	$16.92	-76.49%	$12.07	$0.00	-100.00%	$38.85	$10.35	-73.36%
2021	$71.71	$17.43	-75.69%	$12.43	$0.00	-100.00%	$39.77	$10.59	-73.37%
2022	$70.86	$17.95	-74.67%	$12.81	$0.00	-100.00%	$40.71	$10.84	-73.37%
2023	$70.02	$18.49	-73.59%	$13.18	$0.00	-100.00%	$41.67	$11.10	-73.36%
2024	$69.21	$19.05	-72.48%	$13.59	$0.00	-100.00%	$42.65	$11.36	-73.36%
2025	$68.43	$19.62	-71.33%	$13.99	$0.00	-100.00%	$43.66	$11.63	-73.36%
2026	$67.64	$20.21	-70.12%	$14.41	$0.00	-100.00%	$44.69	$11.90	-73.37%
2027	$66.87	$20.81	-68.88%	$14.84	$0.00	-100.00%	$45.74	$12.18	-73.37%
2028	$66.11	$21.44	-67.57%	$15.29	$0.00	-100.00%	$46.82	$12.47	-73.37%
2029	$65.35	$22.08	-66.21%	$15.75	$0.00	-100.00%	$47.93	$12.76	-73.38%
2030	$64.60	$22.74	-64.80%	$16.22	$0.00	-100.00%	$49.06	$13.07	-73.36%
2031	$64.73	$23.43	-63.80%	$16.71	$0.00	-100.00%	$50.22	$13.37	-73.38%
2032	$64.87	$24.13	-62.80%	$17.21	$0.00	-100.00%	$51.40	$13.69	-73.37%
2033	$65.01	$24.85	-61.78%	$17.72	$0.00	-100.00%	$52.62	$14.01	-73.38%
2034	$65.15	$25.60	-60.71%	$18.25	$0.00	-100.00%	$53.86	$14.34	-73.38%
2035	$65.30	$26.37	-59.62%	$18.80	$0.00	-100.00%	$55.13	$14.68	-73.37%

Deputy Commissioner's Determinations: The Deputy Commissioner agrees with Staff's recommendation and approves Xcel, MP, and OTP's Discrete Approach avoided T&D costs for the 2021-2023 CIP Triennials.

B. Using the Societal Discount Rate in the Utility Cost Test

Deputy Commissioner's Determinations

Based on a review of Staff's analysis, stakeholder comments, and a sensitivity analysis examining the impacts on utility net benefits and program cost-effectiveness of using the societal discount rate (rather than the WACC) in the Utility Cost Test, the Deputy Commissioner does not approve changes to cost-effectiveness discount rates at this time.

However, the Deputy Commissioner understands the significant issues raised as part of stakeholders' written comments. Therefore, the Deputy Commissioner believes that there should be further examination and discussion of this issue in the context of the upcoming electric IRP filings - and as part of the continued cost-effectiveness conversations with CIP stakeholders through January 2020 - as there are good arguments both for and against using a lower discount rate, including:

- Making the change could be more consistent with Minnesota's longer-term policy objectives and regulatory time preference that maximizes the net benefits to customers rather than utility shareholders.
- Making the change could distort the valuation of energy efficiency as a utility resource. If the goal of CIP is to treat energy efficiency as a resource, then the same metrics should apply to long-term infrastructure investments and energy efficiency.

C. Cost-Effectiveness Timeline

Deputy Commissioner's Determinations

The Deputy Commissioner appreciates Staff's analysis and the information that all of the stakeholders provided as part of the process electric cost-effectiveness methodologies.

The Deputy Commissioner will not put a complete hold on the cost-effectiveness process as requested by some stakeholders. The Deputy Commissioner finds that Staff have completed a thorough review of the electric cost-effectiveness methodologies through the current proceeding, and concludes that the methodologies are reasonable for determining the cost-effectiveness of CIP programs.

On April 11, 2019, the Deputy Commissioner issued a Final Decision extending the 2017-2019 CIP Triennial Plans through calendar year 2020.[9] This decision to extend the 2017-2019 Triennial Plans through 2020 was approved after my Staff had already issued their Proposed Decision on the electric cost-effectiveness review, which would have applied to 2020-2022 Triennial Plans. Consequently, in order to realign the timing for which Triennial Plan years the required cost-effectiveness inputs apply to, the Deputy Commissioner makes the following determinations:

- **2020 CIP Extension Plans (Electric IOUs submit on July 1, 2019):** The electric IOU's 2020 CIP Extension Plans shall use 2019 avoided costs, escalated to 2020 with approved escalation rates.
- **2021-2023 CIP Triennial Plans (Electric IOUs submit on June 1, 2020):** The electric IOU's 2021-2023 CIP Triennial Plans shall use the approved assumptions and methodologies outlined in this current Decision.

However, the Deputy Commissioner also understands that there are longer-term issues that could be addressed to continue to improve the accuracy, standardization, and transparency of CIP's cost-effectiveness tests. Therefore, between June 1, 2019 and January 1, 2020, the Deputy Commissioner directs Staff to coordinate with the utilities and other stakeholders to determine whether additional changes are warranted to the gas and electric cost-effectiveness values and methodologies. Specifically, below are the list of issues that the Department commits to discussing further as part of an integrated cost-effectiveness process to continue examining the 2021-2023 gas and electric cost-effectiveness values and methodologies:

- Cost-effectiveness test discount rates.
- Updating avoided marginal energy and capacity electric costs only if the Department finds the updates are reasonably justified *and* if the avoided cost values have changed by more than 10% between the issuance of this Decision and September 2019.

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[9] *Deputy Commissioner's Decision - In the matter of Extending the 2017-2019 CIP Triennial Plans Through 2020.* April 5, 2019. Docket Nos. E,G002/CIP-16-115, E017/CIP-16-116, E015/CIP-16-117, G022/CIP-16-118, G008/CIP-16-119, G011/CIP-16-120, G004/CIP-16-121

- Ways to improve the transparency of electric avoided capacity costs and electric avoided marginal energy costs.
- Recommendations from stakeholders regarding additional long-term cost-effectiveness issues to explore as part of the 2024-2026 CIP Triennials.

By November 2019, the Deputy Commissioner directs Staff to issue updated Proposed Decisions for the gas and electric cost-effectiveness processes that will highlight any new proposed changes to the 2021-2023 cost-effectiveness values and methodologies for the Deputy Commissioner's consideration and that will provide a summary of findings from the continued stakeholder discussions.

The Deputy Commissioner recognizes that this approach entails some continued uncertainty around the finalized cost-effectiveness assumptions, and will require utility and staff resources to implement what might have been focused in other areas. However, the Deputy Commissioner believes that this is the best approach because it represents: 1) a compromise solution that balances stakeholder preferences for continued discussions versus completely finalizing the process now; 2) it provides some certainty around core approved cost-effectiveness values; and 3) it provides extra time to discuss a set of complex cost-effectiveness issues prior to the 2021-2023 CIP Triennial filings.

D. Other Issues

1. Clarification About CIP Incentive Mechanism

As part of Xcel's April 19 comments, Xcel requested that the Department provide clarification on how avoided costs and methods for determining cost-effectiveness for the 2021-2023 CIP Triennials will interact with future PUC filings on the CIP Incentive Mechanism.

Deputy Commissioner's Determinations:

As part of the Department's evaluation report on CIP and the Shared Savings DSM Financial Incentive Plan that is due on July 1, 2019, the Department intends to request that the Commission approve for the 2020 CIP year the same Shared Savings DSM financial incentive mechanism parameters that were approved for 2019.[10] Thus, the Net Benefits cap for 2020, would remain at 10 percent and the Percent of CIP Expenditures cap would remain at 30 percent and the utilities would use the avoided costs already approved for CIP years 2017-2019. This continuity is intended to help give the utilities some certainty in the near-term about the financial incentive.

For the 2021-2023 CIP Triennials, larger discussions will need to take place to determine the impacts of the updated avoided costs and cost-effectiveness methods and whether modifications to the Shared Savings DSM financial incentive mechanism parameters are warranted.

2. Discount Rates Used in Natural Gas BENCOST and Purpose of Utility Discount Rate

As part of CPE's May 6 reply comments, CPE provided the following comments:

- CPE requested guidance about whether Department Staff's recommendation regarding discount rates included the electric *Proposed Decision* is also intended to also apply to the natural gas cost-effectiveness proceeding.

[10] See the Commission's August 15, 2016 *ORDER ADOPTING MODIFICATIONS TO SHARED SAVINGS DEMAND-SIDE MANAGEMENT FINANCIAL INCENTIVE PLAN* in Docket No. E,G999/CI-08-133.

- With respect to the discount rate analysis provided in the electric *Proposed Decision*, CPE disagrees with Staff's interpretation that Utility Cost Test as a test intended to, "measure the opportunity cost of the investment." CPE requests that the Department clarify whether it views the purpose of the Utility Cost Test discount rate as quantifying avoided costs and benefits or opportunity costs.

<u>Deputy Commissioner's Determinations:</u>
The Deputy Commissioner clarifies that Staff's recommendation about discount rates included in the electric avoided cost Proposed Decision also applies to the 2021-2023 BENCOST Decision. Based on a review of Staff's analysis, stakeholder comments, and a sensitivity analysis examining the impacts on utility net benefits and program cost-effectiveness of using the societal discount rate (rather than the WACC) in the Utility Cost Test, the Deputy Commissioner does not approve changes to cost-effectiveness discount rates at this time. However, the Deputy Commissioner understands the significant issues raised as part of stakeholders' written comments. Therefore, the Deputy Commissioner believes that there should be further examination and discussion of this issue in the context of the upcoming electric IRP filings - and as part of the continued cost-effectiveness conversations with CIP stakeholders through January 2020.

The Deputy Commissioner agrees with CPE's distinction between opportunity costs and avoided costs. The Department views the definition of the Utility Cost Test discount rate as it defined in the 2021-2023 BENCOST Decision: "The discount rate used in the Utility Cost Test to value, in current dollars, the future stream of internal benefits and costs (excluding benefits resulting from avoided environmental damage) resulting from a utility conservation investment."

3. *Potential Inconsistency in the Discount Rate Used for the Electric Societal Cost Test*

In Xcel's May 6 reply comments, Xcel stated that it believes the language in the electric cost-effectiveness Proposed Decision leaves an unresolved inconsistency between the choice of discount rate for the gas and electric Societal Cost Tests, and requested that the Department provide additional clarification to ensure a common understanding of future plans for the Societal Cost Test methodology.

Xcel received clarifying questions about the following statement from multiple CIP stakeholders:

> *The Recommendation also eliminates the use of a Societal Discount Rate in any Electric DSM cost-effectiveness testing, which conflicts with the current process for Gas DSM, which does use a Societal Discount Rate for the Societal Cost Test.*

For context, Xcel made the comment above in response to the CIP Electric Utilities' 2020-2022 Cost-Effectiveness Review, Proposed Decision, specifically the following sentence on page 6:

> *Additionally, as discussed in more detail below, Staff do not recommend the Deputy Commissioner approve changes to the discount rates used in cost-effectiveness testing at this time.*

The Societal Discount Rate has been used for the Societal Cost Test in the Department's gas BENCOST models, for its electric DSM portfolio Xcel uses its approved WACC as the discount rate for the Societal Cost Test. From Xcel's perspective, the sentence above from the Proposed Decision indicates that no changes to the established discount rates for any of the electric DSM cost-effectiveness tests are recommended by the Department. Since the Societal Cost Test is part of the slate of current electric cost-effectiveness tests, the Company interprets this statement to apply to the Societal Cost Test and the WACC to continue as its discount rate.

The intent of Xcel's comment on this matter is to point out that the language in the Proposed Decision leaves an unresolved inconsistency between the choice of discount rate for the gas and electric Societal Cost Tests. We request that the Department provide additional clarification to ensure a common understanding of future plans for the Societal Cost Test methodology.

<u>Deputy Commissioner's Determinations:</u>
The Deputy Commissioner clarifies that Staff's recommendation was more narrowly related to not approving a change that would allow the utilities to use the societal discount rate (rather than the WACC) in the Utility Cost Test.

The Deputy Commissioner appreciates Xcel pointing out the inconsistency in the Societal Cost Test discount rate that the Company applies to its gas CIP versus its electric CIP evaluations. The Deputy Commissioner directs Staff to continue cost-effectiveness discussions with stakeholders through January 2020, and will allow for consideration of modifications to cost-effectiveness assumptions where justified, including the discount rates used in the cost-effectiveness tests.

V. DECISION

Based on a review of the electric avoided cost cost-effectiveness proceeding, the Deputy Commissioner approves the electric IOU's avoided cost assumptions for the 2021-2023 CIP Triennium with the following specific determinations:

1. On April 11, 2019, the Deputy Commissioner issued a Decision extending the 2017-2019 CIP Triennial Plans through calendar year 2020.[11] This decision to extend the 2017-2019 Triennial Plans through 2020 was approved after my Staff had already issued their Proposed Decision on the electric cost-effectiveness review, which would have applied to 2020-2022 Triennial Plans. Consequently, in order to realign the timing for which Triennial Plan years the cost-effectiveness assumptions apply to, the Deputy Commissioner makes the following determinations:
    a. **2020 CIP Extension Plans (Electric IOUs submit on July 1, 2019):** The electric IOU's 2020 CIP Extension Plans shall use 2019 avoided costs, escalated to 2020 with approved escalation rates.
    b. **2021-2023 CIP Triennial Plans (Electric IOUs submit on June 1, 2020):** The electric IOU's 2021-2023 CIP Triennial Plans shall use the approved assumptions and methodologies outlined in this current Decision.

2. The Deputy Commissioner directs Staff to continue cost-effectiveness discussions with stakeholders through January 2020, and will allow for consideration of modifications to the 2021-2023 cost-effectiveness assumptions where justified. The Deputy Commissioner approves the following scope for the continued discussions:

[11] *Deputy Commissioner's Decision - In the matter of Extending the 2017-2019 CIP Triennial Plans Through 2020.* April 5, 2019. Docket Nos. E,G002/CIP-16-115, E017/CIP-16-116, E015/CIP-16-117, G022/CIP-16-118, G008/CIP-16-119, G011/CIP-16-120, G004/CIP-16-121

   a. Between June 1, 2019 and January 1, 2020, Staff will coordinate with the IOUs and other stakeholders to determine whether additional changes are warranted to the 2021-2023 gas and electric cost-effectiveness values and methodologies.
   b. Below are the list of issues that the Department commits to discussing further as part of an integrated cost-effectiveness process to continue examining the 2021-2023 gas and electric cost-effectiveness values and methodologies:
      i. Cost-effectiveness test discount rates.
      ii. Updating avoided marginal energy and capacity electric costs only if the Department finds the updates are reasonably justified *and* if the avoided cost values have changed by more than 10% between the issuance of this Decision and September 2019.
      iii. Ways to improve the transparency of electric avoided capacity costs and electric avoided marginal energy costs.
      iv. Recommendations from stakeholders regarding additional long-term cost-effectiveness issues to explore as part of the 2024-2026 CIP Triennials.

3. By November 2019, Staff will issue updated Proposed Decisions for the gas and electric cost-effectiveness processes that will highlight any new proposed changes to the 2021-2023 cost-effectiveness values and methodologies for the Deputy Commissioner's consideration and that will provide a summary of findings from the continued stakeholder discussions.

BY ORDER OF THE DEPUTY COMMISSIONER

Joseph Sullivan
Deputy Commissioner,
Minnesota Department of Commerce,
Division of Energy Resources

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VI. APPENDIX A – WRITTEN COMMENTS

A. Electric Avoided Cost Comments (April 19, 2019)[12]

American Council for an Energy-Efficient Economy

Summary of Recommendations

- Recommends that the Department establish a new schedule for a more robust process to re-examine avoided costs and the cost-effectiveness issues, using the process described in the National Standard Practice Manual (NSPM).

Avoided Capacity Costs

- Given that the electric utilities use a gas combustion turbine as the proxy for avoided capacity costs, it is unclear how those costs could decline by 30-40% in the 2020-2022 period compared to the avoided capacity costs from the 2017-2019 period.

Cost-Effectiveness Test Discount Rates

- Concerned that Minnesota may be out-of-step with the most recent thinking regarding the role and underlying assumptions of the utility cost test.

- The NSPM advises that "regulators and other decision-makers should be circumspect about using the utility WACC as the discount rate for the UCT. The utility WACC represents the perspective of utility investors, which is fundamentally different from the customer or regulatory perspectives."

- If the Department is concerned that using a societal discount rate rather than the WACC would lead to unacceptably high utility performance incentives, then steps should be taken to modify the incentive mechanism itself.

Center for Energy and Environment

Summary of Recommendations

- *Minnesota's CIP Cost-Effectiveness Review Process*
    - Pause the current CIP cost-effectiveness process and work with stakeholders to expand the work plan for the CIP Cost-Effectiveness Review process for the 2021–2023 CIP Triennial.

    - Expand the CIP Cost-Effectiveness Review for the 2021–2023 CIP triennium to include consideration of the recommendations of the Synapse Report, in addition to the topics being evaluated in the current cost-effectiveness review process.

    - Complete the CIP Cost-Effectiveness Review for the 2021-2023 CIP Triennial by January 2020.

[12] Comments submitted on April 19, 2019 in docket no. CIP-18-783

- *Avoided Capacity Costs*
    - Consider using a more transparent data source to estimate avoided generation capacity costs.
    - Consider using data provided in the MISO annual calculation of the CONE for Minnesota's Local Regional Zone (Zone 1).
    - Review and discuss this recommendation through the proposed CIP Cost-Effectiveness Review process for the 2021–2023 CIP Triennial.
- *Avoided Marginal Energy Costs*
    - Work with utilities and stakeholders to determine how the value of energy efficiency to shape future generation assets can be determined and included in avoided marginal energy costs for all electric utilities.
    - Work with utilities and stakeholders to revisit, and possibly redefine, the concept of "marginal resources" to accommodate the changing electric supply and better align with Minnesota's policy goals of reducing costs to customers and achieving aggressive economy-wide carbon reductions.
    - Include discussion of the two recommendations above in the proposed CIP Cost-Effectiveness Review process for the 2021–2023 CIP Triennial.
- *The Discount Rate Applied to the Utility Cost Test*
    - Adopt the definition and purpose of the utility cost test as provided by National Standard Practice Manual:
        - The purpose of the utility cost test is to indicate whether the benefits of an energy efficiency resource will exceed its costs from the perspective of the utility system. The utility cost test includes all costs and benefits that affect the operation of the utility system and the provision of electric and gas services to customers.
    - Adopt the societal discount rate as the discount rate applied to the Utility Cost Test.
    - Provide guidance to utilities that the WACC should no longer apply as a discount rate to any of Minnesota's cost-effectiveness tests.

Fresh Energy

Summary of Recommendations

- Extend the 2020-2022 CIP cost-effectiveness work plan to reflect the 2020 Triennial extensions, and more broadly consider Minnesota's CIP cost-effectiveness framework and update process and recommendations from the National Standard Practice Manual and Synapse's White Paper with stakeholders.
- Consider ways to more transparently calculate utilities' avoided costs.
- Adopt the societal discount rate as the discount rate applied to the Utility Cost Test for Minnesota's CIP.

Electric IOUs Avoided Costs

- Critical that the evaluation of avoided costs be consistent, rigorous, and transparent.
- Concerning that the electric utilities' avoided costs have decreased by the percentages summarized in the Department's Electric Cost-effectiveness Proposed Decision compared to 2017-2019.
- Unclear with the information currently available whether the utilities' avoided cost values are different because of real, objective variations in utilities' operations or because of the methodologies themselves.

Transparency

- Fresh Energy hopes that in future filings, the electric IOUs and the Department consider using more transparent data sources and methodologies to estimate their avoided costs to allow for more robust analysis and discussion. In the 2020-2022 cost-effectiveness review dockets, all three electric IOU's avoided capacity and energy costs are marked as trade secret
- We agree with Staff that estimating utilities' avoided marginal energy costs in an Excel spreadsheet could make the process more transparent, and hope the Department will consider additional ways to make Minnesota electric utilities' avoided cost assumptions more transparent going forward.

Discount Rates

- Recommend that Minnesota no longer use a utility's WACC as the discount rate for the Utility Cost Test, and that the Department adopt the societal discount rate as the discount rate for the Utility Cost Test.
- If the Department has concerns over a disconnect between utility CIP filings and IRP filings, Fresh Energy recommend further examination and stakeholder discussion of this issue before issuing a final Decision in this docket.

Revise the 2020-2022 Cost-Effectiveness Review timeline

- In light of the Department's Decision extending the 2017-2019 CIP triennials by one year, Fresh Energy urges the Department to consider extending the current timeline that was laid out in the 2020-2022 cost-effectiveness review work plan in order to more closely work with stakeholders and review the practices and methodologies that apply to Minnesota's CIP cost-effectiveness framework.

Minnesota Power

Summary of Issues and Recommendations

- MP agrees with Staff's analysis and findings reviewing the electric IOUs' avoided capacity, marginal energy, and T&D cost methodologies.
- MP does not support extending the cost-effectiveness review process. While the 2020 Triennial extension decision could afford more time to look at avoided costs and other evaluation inputs before the new Triennial deadline, MP would like to emphasize that the same internal resources needed for a more in-depth cost-effectiveness review will likely be needed to address potential changes (legislative or otherwise) affecting the 2021-2023 Triennials.
- MP agrees with the Staff's recommendation to continue using the WACC in the Utility Cost Test, consistent with how the Company evaluates energy efficiency in Resource Planning
- MP outlined the key factors that contributed to its decreased avoided costs

- MP provided ideas for increasing the transparency of its avoided marginal energy cost assumptions.

Avoided Cost Update Process

- As part of each Triennial filing process, MP updates key assumptions used in the avoided capacity and marginal energy costs, including:
  - Fuel costs
  - Customer demand
  - Market price outlooks for energy and capacity
  - Power supply resources
- MP typically aligns these assumptions with the latest IRP. However, because the last IRP was submitted in 2015, the Company updated these assumptions.
- Since the 2017 – 2019 CIP Triennial filing, MP has made significant changes to the planned power supply, including the addition (and regulatory approval) of the EnergyFoward Resource Package, that includes 262 MW Nemadji Trail Energy Center ("NTEC") combined cycle project, 250 MW Nobles 2 wind project, and 10 MW Blanchard solar project. The addition of these new energy resources are expected to drive down marginal energy costs in Minnesota Power's power supply.
- There has also been a declining trend in several market outlooks that have a direct impact on the avoided cost calculation. MP utilizes third party vendors to maintain independent forecasts for these market outlooks.

Key Factors Contributing to Decrease in Avoided Marginal Energy Costs

- Market Prices: The latest IHS Markit forecast decreased by 11 percent when compared to the forecast used in the 2017 – 2019 CIP Triennial. The primary reasons for this decrease in prices since the 2017 – 2019 CIP Triennial Filing are a decrease in the outlook for natural gas prices as well as the evolution of the resource mix to more renewables.
- Natural Gas Prices: The latest IHS Markit forecast dropped 20 percent from the forecast used in the 2017 – 2019.
- Fuel Prices: **TRADE SECRET**
- Resources: The 2020 – 2022 CIP Triennial filing included the Nobles 2 250 MW wind project in October 2020. In addition, a combined cycle unit was slated to start in 2023 in the 2017 – 2019 CIP filing. For the 2020 – 2022 CIP filing, the combined cycle unit referenced, NTEC, now begins operation 2025.

Key Factors Contributing to Decrease in Avoided Capacity Costs

- The lower IHS Markit forecast for capacity prices used in the 2020 - 2022 CIP filing is driven by many factors, but the primary ones are a lower demand outlook for MISO-North and declining costs of new gas generation, which is used as a proxy for the cost of capacity long-term.
- The capacity price forecast used in the 2017 – 2019 CIP Triennial filing assumed a MISONorth demand outlook that was higher than the current outlook. This higher demand outlook led MISO-North to need new capacity sooner to maintain their targeted reliability requirements. The earlier need for capacity is reflected in the capacity prices in the 2017 – 2019 CIP filing, as they are at the cost of replacement capacity by 2020. Whereas, in the 2020 - 2022 CIP Triennial filing the capacity price for MISO North is not at the cost of replacement capacity until 2024.

Ideas for Increased Transparency in Avoided Marginal Energy Cost Assumptions

- Transparency of the method and software used for calculating the hourly marginal energy costs series:
    - The spreadsheets and descriptions previously submitted regarding the calculations of avoided energy costs provide detail for the majority of the process and calculations.
    - Willing to provide the hourly data resulting from this process if necessary to increase transparency.
    - Willing to participate in further discussions with the interested parties to talk through the process and identify if there are other items that could be provided to help clarify and add transparency to the process.
- Transparency of the method and software used to apply the hourly marginal energy cost series to hourly energy savings data for individual DSM measures:
    - Believes this part of the process is a fairly straightforward calculation and does not feel there are significant benefits to pulling this function out of DSMore.
    - Transitioning the application of avoided costs out of DSMore would require a significant amount of time and resources, thoroughly vet the new tool, and maintain and update the tool appropriately over time.
    - MP does not currently have the resources necessary for this level of work as the team relies on DSMore and the Integral Analytics experts to complete these tasks and ensure the accuracy of all functions performed within the software.

Cost-effectiveness Timeline Extension Proposal

- While the 2020 Triennial extension decision could afford more time to look at avoided costs and other evaluation inputs before the new Triennial deadline, MP would like to emphasize that the same internal resources needed for a more in-depth cost-effectiveness review will likely be needed to address potential changes (legislative or otherwise) affecting the 2021-2023 Triennials.

Otter Tail Power

Summary of Issues and Recommendations

- OTP does not support extending the cost-effectiveness review process. OTP believes the Department should approve avoided costs and cost-effectiveness metrics as soon as it is reasonably possible. Locking down these inputs allows the utilities to accurately plan programs.
- OTP supports Staff’s proposed decision to make no changes to the cost-effectiveness discount rates at this time and to have further discussion in the upcoming electric IRP filings.
- OTP outlined the key factors that contributed to its decreased avoided costs.
- OTP provided ideas for increasing the transparency of its avoided marginal energy cost assumptions.

Key Factors Contributing to the Decrease in Avoided Marginal Energy Costs

- OTP calculates its avoided marginal energy costs in DSMore using two sets of data: 1) the annual cost-based price projections used in the IRP process, and 2) the hourly prices data from Otter Tail’s MISO price hub.
- DSMore leverages MISO actual energy cost history and escalates the hourly level energy costs in proportion with the annual cost escalators provided by the IRP system lambda annual costs.

- The decrease in Otter Tail's avoided energy costs is driven by several different factors as follows:
    1. wind energy prices declined by 33 percent between Otter Tail's two previously approved IRPs,
    2. natural gas price forecast from Wood Mackenzie declined in the Company's latest approved IRP, and
    3. the market energy price forecast from Wood Mackenzie declined in the latest approved IRP.

Key Factors Contributing to the Decrease in Avoided Capacity Costs

- OTP bases its avoided capacity cost estimates on existing capacity purchases for the year 2020. For the years 2021-2041, the avoided capacity prices are based upon the levelized fixed charge rate for a 248 MW simple cycle natural gas CT, as identified in Otter Tail's approved 2016 IRP.
- The main driver for the decrease in OTP's avoided generation capacity costs stems from the decrease in capital costs for OTP's upcoming natural gas combustion turbine (CT) project. These costs decreased 40 percent between the two latest approved IRPs used for OTP's 2017-2019 CIP Triennial plan and Otter Tail's 2020-2022 planned CIP Triennial filing.

Key Factors Contributing to the Decrease in Avoided Transmission and Distribution Costs

- Per the Deputy Commissioner's Decision on September 29, 2017, in docket number CIP-16-541, OTP has adopted the Discrete Approach methodology for modeling its avoided T&D costs. Moving to this new methodology has significantly reduced Otter Tail's T&D avoided costs.

Ideas for Increased Transparency in Avoided Marginal Energy Cost Assumptions

- To evaluate CIP measure/program cost-effectiveness, OTP uses a modeling software called, Demand Side Management Option Risk Evaluator (DSMore) which is developed by Integral Analytics Inc. (IA).
- Traditionally, OTP sends marginal energy cost information to IA and the developer models price files the software uses to calculate the avoided marginal energy costs based on the load shape selected.
- When Otter Tail evaluates energy efficiency measures, DSMore accesses the price information files and computes the marginal energy benefits in the background. The user does not see all the hourly avoided energy information due to the volume of data but instead receives the overall energy benefits.
- OTP recently requested IA to provide the marginal energy cost data at the hourly level. IA was happy to include this information to OTP and indicated this is no issue going forward.
- OTP has included Attachment 2 and 3 with this filing. Attachment 2 includes marginal energy prices from IA that OTP is currently using in OTP's 2017-2019 CIP triennial. Attachment 3 includes hourly marginal energy prices that OTP expects to use in evaluation measures and programs for 2020-2022. OTP utilizes scenario 1 for calculating its avoided marginal energy costs, which is the cost-based scenario. Scenarios 2-21 are market-based scenarios not utilized by the Company.
- Per the Department's request, OTP has now provided transparent marginal energy pricing. OTP requests the Department to approve OTP's methodology and use of its marginal energy pricing within DSMore. OTP trusts the DSMore software that has been around for many years and has been vetted by many users.

- OTP prefers not to use Xcel's evaluation workbook as it is very complex, with many worksheets, which could potentially introduce errors.

Utility Discount Rates

- OTP supports Staff's proposed decision to make no changes to the discount rates at this time and to have further discussion in the upcoming electric IRP filings.
- OTP also appreciates Staff desire to use the same metrics when evaluating energy efficiency investments compared to how utility IRPs are evaluated.

Cost-effectiveness Timeline Extension Proposal

- OTP believes the Department should approve avoided costs and cost-effectiveness metrics as soon as it is reasonably possible. Locking down these inputs allows the utilities to accurately plan programs.
- The longer the discount rates are disputed the less time utilities will have for appropriate planning. OTP believes the discussion on the appropriate discount rate should first be had in the utility IRP process and then applied to CIP if appropriate.
- There are many upcoming stakeholder groups/filings the utilities and stakeholders will be engaged in: the CIP financial incentive docket, fuel switching stakeholder group, EUI discussions, ECO legislation changes, along with others likely. OTP is concerned with the heavy upcoming work load it will be very challenging for CIP stakeholders to engage in any additional deep analysis of discount rates.

Xcel Energy

Summary of Recommendations

- Revise the timeline for a Decision in this Docket to January 2020.
- Allow for revisions to the recommendations presented in the Staff Proposed Decision.
- Request that Staff provide clarification on how avoided costs and methods for determining cost-effectiveness for the 2021-2023 will interact with future PUC filings on the CIP Incentive Mechanism.

Cost-effectiveness Review Timeline

- The 2020 Extension makes any Decision in this Docket applicable only to the 2021-2023 CIP Triennial Plan, expected to be filed June 1, 2020. To ensure that the most accurate electric avoided cost values are applied in the 2021-2023 CIP Triennial Plan, revising the timeline to a January 2020 date for a Decision will provide more current and accurate cost assumptions with a reasonable amount of time to incorporate the assumptions in the 2021-2023 Triennial Plan filing.
- Important questions that have been raised by stakeholders that require further discussion and clarification, including the discount rate to be used and which costs and benefits should be included.
- Xcel is due to file its IRP in July 2019. Details, assumptions and modeling results from this filing will inform the values and methods to determine electric avoided costs in the Company's 2021-2023 CIP Triennial Plan. Allowing for a Decision after the filing of Xcel's IRP will allow for more accurate electric avoided costs.
- There is ongoing, proposed legislation that could have a significant impact on the 2021-2023 CIP Triennial Plan period. If passed, the legislation could require significant changes in both the

electric avoided costs and the methods to determine cost-effectiveness. Revising the timeline for a Decision to January 2020 would allow more time to gain policy certainty and/or make any necessary changes in methodology.

Cost-Effectiveness Discount Rates

- Staff's March 20, 2019 Electric Cost-effectiveness Proposed Decision states that "Staff do not recommend the Deputy Commissioner approve changes to the discount rates used in cost-effectiveness testing at this time." This recommendation would eliminate the use of a Societal Discount Rate in any Electric DSM cost-effectiveness testing, which conflicts with the current process for Gas DSM, which does use a Societal Discount Rate for the Societal Cost Test. Due to this inconsistency, Xcel suggests that this recommendation be subject to revision as well, that since the policy objectives are the same for both electric and gas, the choice of discount rate for the two fuels should match.

Comment on Proposed Decision and CIP Incentive Mechanism

- Comments submitted in this Docket show significant changes to the net benefits used in the current CIP Incentive Mechanism. Xcel requests that a summary of these results and the impact to the CIP Incentive Mechanism be included in the Decision to inform any upcoming PUC CIP Incentive Mechanism dockets.

B. Electric Avoided Cost Reply Comments (May 6, 2019)

CenterPoint Energy

Summary of Issues and Recommendations

- CPE supports use of the Minnesota Public Utilities Commission's approved WACC as the appropriate discount rate for the Utility Cost Test.
- CenterPoint Energy takes no position on whether the stakeholder process should continue through 2019.
- Requests guidance about whether Department Staff's recommendation regarding discount rates included the electric *Proposed Decision*, is also intended to also apply to the natural gas proceeding.
- Disagrees with Staff's interpretation that UCT as a test intended to, "measure the opportunity cost of the investment." CPE requests that the Department clarify whether it views the purpose of the Utility Cost Test discount rate as quantifying avoided costs and benefits or opportunity costs.

Cost-effectiveness Timeline Extension

- On April 19, 2019, *Comments* filed by various parties supported and opposed continuation of the stakeholder process for discussing BENCOST inputs for the 2021-2023 Triennial. CenterPoint Energy takes no position on whether the stakeholder process should continue through 2019.
- Some Commenters have mentioned specific points from Updating the Energy Efficiency Cost-Effectiveness Framework in Minnesota ("Synapse Report") that they recommend be a part of continued stakeholder discussion in 2019. The Company does not take a position at this time on the many recommendations made in the Synapse Report.

Issues for Clarification

- CPE seeks clarification on whether Staff intended to make a recommendation on the discount rate to be used in the gas BENCOST Utility Cost Test. In the Department's filing on March 20, 2019, Department Staff did not make a recommendation regarding changes to the discount rates used in the Utility Cost Test in the natural gas docket. The Company respectfully requests guidance from the Department about whether Department Staff's recommendation regarding discount rates included the electric *Proposed Decision*, Docket No. E-999/CIP-18-783, was intended to also apply to the natural gas proceeding, Docket No. G-999/CIP-18-782.
- With respect to the discount rate analysis provided in the electric *Proposed Decision*, CenterPoint Energy believes that Department Staff's description of the UCT as a test intended to, "measure the opportunity cost of the investment" is not accurate. The Department's previous BENCOST Decisions have stated that the UCT discount rate is used to value the future stream of benefits and costs resulting from an energy efficiency investment. Avoided costs (i.e., a benefit of energy efficiency) are not the same as opportunity costs. Opportunity costs are costs associated with foregone benefits from an alternative investment decision that could have been made instead of the investment chosen, whereas avoided costs and benefits focus only on the consequences of a given investment. As an example, when a gas utility invests in efficient water heater rebates for its customers, the utility avoids the costs of purchasing some quantity of natural gas. However, a potential opportunity cost for the utility may be that they do not have the resources (capital and employee time) to invest in designing and implementing an building energy use benchmarking tool for commercial customers. Avoiding natural gas purchases is a consequence of efficient water heaters, whereas building a tool is an alternative use of available resources, which could itself generate benefits and avoid future costs. In summary, avoided costs help select the lowest cost energy resource, while opportunity costs help select the preferred use of available capital. The Company respectfully requests that the Department clarify whether it views the purpose of the Utility Cost Test discount rate as quantifying avoided costs and benefits or opportunity costs.

Xcel Energy

Summary of Issues and Recommendations

- Xcel outlined the key factors that contributed to its decreased avoided costs.
    - Avoided Marginal Energy Costs: changes in the generation mix serving the Company and declines in the costs of key commodities used for power generation, such as natural gas.
    - Avoided Capacity Costs: The value is the estimated cost per kW-year of a new brownfield natural gas combustion turbine (CT). The approved 2017-2019 capacity values, in contrast, are not only a different generation type – greenfield CTs with higher land acquisition and different infrastructure connection costs – but were modeled as part of the previous Integrated Resource Plan update in 2015 when the predicted capacity shortages were larger and occurred at a different point in time. During the past five years, changes in the available generation options, such as brownfield CTs and lower growth in demand, have contributed to changes in the type of generation capacity selected for future needs. This difference in capacity types and sizes selected ultimately results in lower avoided capacity costs.
- Xcel believes the language in the Electric Cost-effectiveness Proposed Decision leaves an unresolved inconsistency between the choice of discount rate for the gas and electric Societal Cost Tests, and requests that the Department provide additional clarification to ensure a common understanding of future plans for the Societal Cost Test methodology.

Electric Avoided Cost Factors

- Xcel notes that the "proposed 2020-2022 CIP avoided costs" refers to avoided cost values provided in January 2019 for the time period 2020-2035. The Company filed those preliminary values as indicators of its intended modeling methodology; however, results from updated modeling runs and the concurrent integrated resource planning process were not yet available at that time.
- While key factors can be provided about why these preliminary values are smaller than the approved values for the 2017-2019 CIP Triennial Plan, final results may differ after updates from the Company's upcoming Integrated Resource Plan are incorporated.

Key Factors Contributing to the Decrease in Avoided Marginal Energy

- The main drivers of lower energy costs are changes in the generation mix serving the Company and declines in the costs of key commodities used for power generation, such as natural gas.
- The generation mix planned to serve the Company during the 2020-2035 time period is different now than it was when analyses for the 2017-2019 CIP Triennial Plan values were completed in 2015. Newer, more efficient and cost-effective generation is serving the Company and natural gas generation is now estimated to serve future customer load to a larger degree than was predicted in 2015.
- This change in generation type serving the Company means that this value stream depends more heavily on natural gas commodity costs. Besides examples cited by other respondents on this docket, one of the most direct examples of this is the drop in natural gas price assumptions used in the BENCOST model.
- The approved BENCOST model for 2017-2019 CIP Triennial Plan period uses a commodity cost of \$4.27/MCF as of 2016.4 However, the proposed natural gas commodity cost for the BENCOST model is now \$3.25/MCF for the index year 2019. This represents a drop of more than 23 percent in commodity costs. The lower commodity cost leads to a decrease in the operating costs of natural gas generation in the Company's marginal energy production cost model used for the marginal energy cost component in CIP. Updated analyses related to the Company's integrated resource planning process were not available at the time of the Company's response to information requests in January 2019; as the Company has indicated in past comments, this information is necessary in order to complete and update marginal energy values for the 2021-2023 CIP Triennial Plan.

Key Factors Contributing to the Decrease in Avoided Capacity Costs

- The Company assumes that avoided capacity costs are savings from the avoidance of newly constructed generation capacity necessary to serve additional demand at its system peak. In resource planning processes, new capacity resources of different sizes and types are selected to meet capacity shortages that are predicted to occur during a given time period. The estimated cost of building a selected new capacity resource at a particular time is estimated and its levelized cost is then represented by an economic carrying charge over the planning horizon.
- Changes in the timing or size of a Company's predicted capacity shortage can affect the type and size of generation resources considered, which impacts the cost. Additionally, technological advances and the policy landscape can also impact the size and type of generation capacity considered, which also impacts the cost.
- As specified in the Company's January 14, 2019 response to information requests, the value is the estimated cost per kW-year of a new brownfield natural gas combustion turbine (CT). This is

the generation option expected to serve additional demand at system peak in the Company's upcoming 2020-2034 Minnesota Integrated Resource Plan.

- The approved 2017-2019 capacity values, in contrast, are not only a different generation type – greenfield CTs with higher land acquisition and different infrastructure connection costs – but were modeled as part of the previous Integrated Resource Plan update in 2015 when the predicted capacity shortages were larger and occurred at a different point in time. During the past five years, changes in the available generation options, such as brownfield CTs and lower growth in demand, have contributed to changes in the type of generation capacity selected for future needs. This difference in capacity types and sizes selected ultimately results in lower avoided capacity costs.

<u>Societal Discount Rate Clarification</u>
The Company received clarifying questions about the following statement from multiple CIP stakeholders:

> *The Recommendation also eliminates the use of a Societal Discount Rate in any Electric DSM cost-effectiveness testing, which conflicts with the current process for Gas DSM, which does use a Societal Discount Rate for the Societal Cost Test.*

For context, the Company made the comment above in response to the CIP Electric Utilities' 2020-2022 Cost-Effectiveness Review, Proposed Decision, specifically the following sentence on page 6:

> *Additionally, as discussed in more detail below, Staff do not recommend the Deputy Commissioner approve changes to the discount rates used in cost-effectiveness testing at this time.*

While the Societal Discount Rate has been used for the Societal Cost Test in the Department's gas DSM BENCOST models, for its electric DSM portfolio the Company uses its approved Weighted Average Cost of Capital ("WACC") as the discount rate for the Societal Cost Test. From the perspective of the Company, the sentence above from the Proposed Decision indicates that no changes to the established discount rates for any of the electric DSM cost-effectiveness tests are recommended by the Department. Since the Societal Cost Test is part of the slate of current electric cost-effectiveness tests, the Company interprets this statement to apply to the Societal Cost Test and the WACC to continue as its discount rate. This same statement on page 6 appears in part on page 9 as well, but again no mention of specific or different implications for the Societal Cost Test is evident.

The Company is not opposed to a decision to change the discount rate used for the Societal Cost Test for electric DSM programs. In fact, the Company advocates for consistent discount rates in the following ways:

- The same discount rate should be used for the same type of cost-effectiveness test in both gas and electric DSM portfolios. For example, if the Societal Discount Rate is used for the Societal Cost Test in the gas DSM portfolio, the Societal Discount Rate should also be used for the Societal Cost Test in the electric DSM portfolio. Since the policy objectives are the same for both electric and gas DSM programs, the choice of discount rate for the two fuels should match.

- Within a single fuel, the same discount rate should be applied for both the Utility Cost Test and the Societal Cost Test. For example, if the Societal Discount Rate is used for the Societal Cost

Test in the electric DSM portfolio, the Societal Discount Rate should also be used for the Utility Cost Test in the electric DSM portfolio. As outlined by the Company and by other entities, the Societal Cost Test and the Utility Cost Test are both used in DSM planning and reporting processes. Using the same discount rate ensures consistency; it aligns the signals each of these tests for utility DSM planning and cost-effectiveness purposes.

The intent of the Company's comment on this matter is to point out that the language in the Proposed Decision leaves an unresolved inconsistency between the choice of discount rate for the gas and electric Societal Cost Tests. We request that the Department provide additional clarification to ensure a common understanding of future plans for the Societal Cost Test methodology.

C. Letters (March 22 and March 28, 2019)[13]

Summary of Issues

- CEE, ACEEE, CUB, and Fresh Energy submitted letters requesting that the Department extend the CIP cost-effectiveness review process, and establish a new timeline that would apply to a 2021-2023 CIP Triennial Plans (in light of the Department's April 11, 2019 Decision to extend the 2017-2019 CIP Triennial Plans through 2020).
- These four organizations seemed primarily concerned with Staff's recommendation in the March 20, 2019 Electric Cost-Effectiveness Proposed Decision (CIP-18-783) that the Deputy Commissioner not to approve changes allowing the societal discount rate, rather than the weighted average cost of capital (WACC), to be used in the Utility Cost Test at this time.

D. Cost-effectiveness Discount Rates (February 19 and March 1, 2019)

Center for Energy and Environment (2/19 Comments and 3/01 Reply Comments)

Main Recommendations

- Utility's weighted average cost of capital ("WACC") should no longer be used as the discount rate for the utility cost test (UCT) for CIP, because it is out of alignment with Minnesota's long-term public policy preference and objectives for energy efficiency as the preferred energy resource for the state, and is not reflective of the investment risk or investment term of energy efficiency investments made by utilities through Minnesota's CIP. The WACC unduly emphasizes short-term costs and benefits, while undervaluing the benefits of energy efficiency over the longer term.
- As recommended in the *Synapse Report,* CEE agrees that the Department should adopt the societal discount rate (or the utilities' approved short-term cost of debt) for use in the UCT in order to reflect the long-term perspective underlying CIP policy, as well as the low-risk nature of CIP investments. The societal discount rate places a high value on the long-term benefits of energy efficiency. Aligning the time-preference of Minnesota's cost-effectiveness tests will make the results of those tests more comparable and also ensure that utilities receive consistent signals about the long-term value of energy savings.

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[13] Letters Submitted on March 22, 2019 and March 28, 2019 in Docket nos. G999/CIP-18-782 and E999/CIP-18-783

Discount Rates and Implications for CIP

- The discount rate chosen for the UCT for Minnesota CIP for the 2020-2022 triennium will have significant implications for the types of measures and programs that utilities include and pursue in their CIP Triennial Plans, as well as the overall energy savings levels that utilities will strive to achieve.

- A discount rate is an important component of any cost-effectiveness analysis. The discount rate for an investment is meant to reflect the following:
    - The value of costs and benefits today compared to the value of costs and benefits in the future
    - The level of risk or certainty associated with the investment

- The UCT and societal cost test are the two most important cost-effectiveness tests for evaluating CIP measures and programs:
    - The societal cost test is used as the primary screening test for CIP.
    - The UCT is used in determining whether an efficiency investment is the least-cost resource to the utility system as well as the utility financial incentive.

Discount Rates and Minnesota's Policy Objectives

- Deciding what discount rate to apply to a given cost-effectiveness analysis is not a hard science, but rather a policy decision. A high discount rate places more value on short-term benefits and can also reflect a high degree of risk or uncertainty in the investment, while a low discount rate places more value on long-term benefits and can also reflect a low-risk investment.
- The policy objectives that underlie CIP as outlined in statute — strengthening our economy and creating economic opportunity, reducing energy costs for Minnesota businesses and residents, and protecting and improving the environment — are long-term, forward-looking objectives. The importance of energy efficiency is reflected in Minnesota statute, which states that "cost-effective energy savings are preferred over all other energy resources," and that "cost-effective energy savings should be procured systematically and aggressively to reduce utility costs for businesses and residents, improve the competitiveness and profitability of businesses, create more energy-related jobs, reduce the economic burden of fuel imports, and reduce pollution and emissions that cause climate change."
- Similarly, energy efficiency is a long-term, cumulative resource — many energy efficiency improvements have useful lifetimes of 20 years, contributing energy savings each year over the lifetime of the measure. The contribution that energy efficiency provides in meeting Minnesota's policy objectives should not be discounted over time in a way that diminishes the long-term value of energy efficiency.
- Through stakeholder interviews for the *Synapse Report*, Minnesota stakeholders acknowledged the low-risk and quick cost recovery of Minnesota's CIP. The *Synapse Report* notes a key response regarding discount rates from stakeholder interviews: "A low-risk discount rate may be most appropriate for energy efficiency resources. Utilities' efficiency investments are recovered almost instantaneously and are reconciled annually, resulting in little risk relative to power plant investments."

March 1 - Reply Comments
Below Center for Energy and Environment responds to specific issues noted by parties in their February 19 comments, including the following:

1. Issue: Energy efficiency should use the same discount rate applied to other long-term utility investments.
    a. CEE Reply: This fails to account for the fact that energy efficiency investments made through CIP are not long-term infrastructure investments and are not subject to the cost of capital like other supply-side investments. Minnesota utilities do not rely on investor capital to finance investments in energy efficiency through CIP. Utility investments in energy efficiency in Minnesota's CIP are recovered through a rate rider based on tracker accounting. Utilities recover CIP investments almost immediately and typically recover the cost of energy efficiency investments in full over a 12-month period.

2. Issue: The utility cost test should use the WACC as the discount rate to be consistent with methodologies for evaluating energy efficiency in the integrated resource planning process.
    b. CEE Reply: Agree that it may be appropriate to align the way these two processes value energy efficiency. However, it is inappropriate to discount the value of energy efficiency at the WACC, whether through the state's CIP, the integrated resource planning process, or any other regulatory process used to evaluate the benefits of energy efficiency.

3. Issue: Consider how changes to the utility cost test might affect the CIP utility financial incentives.
    a. CEE Reply: It is important to recognize that the current CIP utility financial incentive is not approved for the 2020–2022 CIP triennium, which is the period for which any changes to the utility cost test resulting from this docket would take place. Therefore, the Department and parties should not be constrained by implications of the positions and decisions made in this docket on the 2017–2019 CIP utility financial incentive mechanism.

CenterPoint Energy (2/19 Comments and 3/01 Reply Comments)
Main Recommendations

- CenterPoint Energy does not support using the societal discount rate for the UCT given the practical implications and the lack of theoretical justification for the change.
- The purpose of the UCT is not to maximize benefits, either to utility customers or utility shareholders, but to identify the least-cost energy resource by comparing investments in energy efficiency to other utility investments. The assertion that using the after-tax weighted average cost of capital (WACC) in the UCT somehow causes the test to maximize benefit to utility shareholders (while the use of the societal discount rate would cause it to maximize benefits to customers) is unfounded. The UCT represents this perspective and measures the benefits to a utility (and its current ratepayers) of avoiding various long-term infrastructure investments (as well as avoided commodity purchases) against the cost of delivering energy efficiency programs. The UCT is also called the revenue requirements test because it assesses the value of avoiding long-term investments, the costs of which would need to be recovered from ratepayers along with the cost of capital used to fund them.
- The societal discount rate would instead distort the valuation of energy efficiency as a resource. If the goal of CIP is to treat energy efficiency as a resource, then the same metrics (e.g., discount

rate) should apply to long-term infrastructure investments and energy efficiency. The cost should be calculated in the same manner whether the purpose is to calculate the revenue needed to pay for utility investments or to calculate the benefit to customers resulting from avoiding those investments. Accordingly, the UCT should use the same discount rate as is used in utility ratemaking proceedings (i.e., the WACC).

Discount Rate Implications for Utility CIP Performance Incentives

- It is also necessary to consider the potential effects of altering the UCT on the utility financial incentive calculation. Under current policy, the financial incentive is calculated based on the net benefits of the utility's CIP using the UCT. The UCT is the cost-benefit test most within the utility's control because major cost inputs (e.g., program rebates) are controllable through program design.
- Given the UCT's central role in calculating the shareholder incentive, policy decisions regarding the UCT should be made with an understanding of the practical impacts on the financial incentive mechanism. Using the societal discount rate in the UCT, without making any change to the financial incentive mechanism, would significantly increase utility financial incentives as compared to using the utility discount rate.

Correction to BENCOST Environmental Damage Factor Input

- CenterPoint Energy believes that the $1.84 per dekatherm (Dth) gas environmental damage factor (Input 9) should be revised to reflect environmental damages in 2019 dollars. The description of Input 9 states that the factor was "multiplied by an annual escalation rate of 2.3 percent". However, the $1.84 appears to represent environmental damages from PM2.5, NOx, and SO2 in 2014 dollars per ton and CO2 in 2015 dollars per ton. Because the BENCOST model expects inputs in dollars that correspond to the base year (2019), the Company suggests that the Department convert the environmental damages to 2019 dollars using the 2.3% escalation rate. The resulting gas environmental damage factor would be close to $2.03 per Dth if the escalation rate is applied to the factors selected by the department.
- CenterPoint Energy also recommends using Dth instead of thousand cubic feet (MCF) for BENCOST inputs related to natural gas.

March 1 – Reply Comments

Below CenterPoint Energy responds to specific issues noted by parties in their February 19 comments, including the following:

1. Issue: The purpose of the UCT is to evaluate whether the benefits of an energy efficiency resource will exceed its costs based on the perspective of the utility system.
    a. CenterPoint Reply: Agree with this purpose, and also agree that the UCT discount rate is meant to reflect the costs and benefits, in present value, of an energy efficiency investment to the utility system.

2. Issue: Using the societal discount rate in the UCT is more appropriate because energy efficiency is a low risk investment.
    a. CenterPoint Reply: Disagree with this argument. The purpose of the UCT in cost-benefits testing is not to maximize benefits, either to utility customers or utility shareholders, but to identify the least-cost energy resource by comparing investments in energy efficiency to other utility investments.

3. Issue: Energy efficiency investments are not long-term infrastructure investments and costs are recovered quickly.
    a. CenterPoint Reply: This ignores that benefits of energy efficiency investments to the utility system from the avoidance of long-term infrastructure investments are valued using the WACC. The UCT is used to compare the revenue needed to pay for utility investments with the cost of avoiding those investments. To make a valid comparison, the costs associated with different energy resources must be calculated in the same manner, and because the utility's revenue requirements for investment are calculated using the WACC, the value of avoiding that investment must also use the WACC.

4. Issue: The short-term cost of debt may be an appropriate discount rate.
    a. CenterPoint Reply: The rate used to calculate carrying charges in the CIP Tracker is not related to determining the least-cost energy resource for the utility system.

5. Issue: Should use a societal discount rate to align cost-effectiveness testing with state policy goals related to encouraging long-lived energy savings and maximizing net benefits to customers and society.
    a. CenterPoint Reply: CenterPoint Energy is open to discussing changes to cost-effectiveness tests (and other CIP processes) that further these goals by more accurately capturing the benefits of CIP, but the Company does not support modifications to the UCT that cause the test to misstate the actual benefits of CIP to utility systems.

Fresh Energy (2/19 Comments)

<u>Main Recommendations</u>

- The Department should make the Utility Discount Rate equal to the Societal Discount Rate in CIP cost-effectiveness tests. If the Societal Discount Rate is not chosen, a lower Utility Discount Rate should be adopted than a utility's weighted average cost of capital (WACC).

- We believe this change would better reflect the long-natured policy intent of CIP and the low-risk profile of utilities' energy efficiency investments. Making this change would also send a strong signal to utilities that Minnesota values the long-term impacts and benefits associated with energy efficiency resources.
- A discount rate based off a utility's WACC is not reflective of Minnesota's energy efficiency public policy goals nor the risk associated with energy efficiency investments made by utilities through CIP.

<u>Discount Rates and Minnesota's Policy Objectives</u>

- The choice of discount rates are important policy decisions when conducting energy efficiency cost-effectiveness testing, as costs are typically incurred in early years while benefits are experienced over many years.
- Minnesota's set of existing policy goals affirms that energy efficiency is the state's most valuable energy resource and that utilities should aggressively pursue cost-effective energy efficiency over all other energy resources. These policy goals also place an emphasis on the societal benefits of energy efficiency, which is consistent with Minnesota's decision to use the Societal Cost Test as the primary test in determining energy efficiency cost-effectiveness. This emphasis on societal impacts suggests that regulators place a higher priority on long-term impacts and the

time preference of society, instead of a perspective focused on utility impacts and investors alone. Consequently, the societal discount rate should be relatively low.

- Discount rates based off a utility's WACC do not support the objectives of Minnesota's energy efficiency policies. The WACC represents the utility's cost for its capital, which in practice represents the minimum return that the utility must earn on an asset to satisfy its investors, owners, and other providers of capital. These differences in objectives – identifying cost-effective resources to best serve customers while achieving applicable policy goals versus achieving the minimum return needed to satisfy utility owners and investors – represent a key difference and consideration when choosing a discount rate. For these reasons, we believe the WACC is out of alignment with Minnesota's long-term public policy objectives.
- A societal discount rate better reflects and is more consistent with Minnesota's energy efficiency policy objectives because it places a higher value on the long-term benefits and time preference that maximizes the net benefits to customers and society, rather than utility or utility shareholders. The goal of the cost-effectiveness analyses, including the UCT, should not be to maximize investor value but to maximize the net benefits to customers and to society. Therefore, the discount rate should be consistent with the time preference that regulators consider to achieve those policy goals.

Discount Rate Choice and Risk

- Discount rates are important because they are commonly used to compare these future streams of costs and benefits in a consistent way and aid in determining an investment's relative cost-effectiveness by reflecting the time preference (i.e. whether benefits/costs today are considered more or less valuable than benefits/costs in the future) and the estimated risk of an investment. A high discount rate places more value on short-term benefits and can also reflect a higher risk factor over the life of the investment, whereas a low discount rate places more value on long-term benefits and reflects a lower risk factor.
- Energy efficiency resources offer much different costs and benefits compared to supply-side resources in terms of financial, project, and portfolio risk, and that using a discount rate based off a utility's WACC does not properly reflect energy efficiency's low-risk to a utility.
- Generally, there are three types of risks related to investments in utility system resource planning:
    1. Financial risk refers to the risk associated with funding an investment. The funding source used to make an investment determines the "cost of capital" for that investment. Different sources of capital have different levels of risk associated with them.
    2. Project risk refers to the risks associated with planning, constructing and operating a particular project or resource. In utility planning, supply-side resources face project risk from many factors, such as siting constraints, fuel price volatility, construction costs uncertainty, current and future environmental regulations. Demand-side resources experience different project risks, such as customer adoption rates, technology performance, and contractor performance.
    3. Portfolio risk refers to the risk experienced by an investor from the total portfolio of investments, projects, or resources. Different combinations of investments, projects or resources will result in different levels of overall risk for the investor. One common practice for reducing portfolio risk is to diversify investments.

Synapse Report Recommendations

- Synapse recommends in the report that Minnesota not use a utility's weighted average cost of capital (WACC) as a discount rate in CIP cost-effectiveness tests. They assert that while the WACC is typically seen as being the utility's cost of capital, using a utility's WACC as a discount rate in CIP cost-effectiveness testing is generally inconsistent with Minnesota energy efficiency public policies as it improperly favors the time preference and value of the utility and utility investors instead of customers and regulators. Additionally, Synapse contends using the WACC as a discount rate is not reflective of a utility's investment risk compared to supply-side resources.
- Instead, Synapse recommends Minnesota use a societal discount rate in all CIP cost-effectiveness tests. They assert the societal discount rate is more appropriate and consistent with Minnesota CIP policies because it requires consideration of societal impacts and that generally Minnesota favors a regulatory perspective with policies that place high priority on long-term impacts. They also claim that using a societal discount rate in cost-effectiveness tests offers the advantage of allowing for more direct comparison of results across the different tests, and is more consistent with the recommendations of the NSPM.

Great Plains Natural Gas (2/19 Comments)

- Great Plains has no issue with Staff's proposal to set the Utility Discount Rate equal to the Societal Discount Rate.

Minnesota Energy Resources Corporation (2/19 Comments)

Main Recommendations

- Regarding whether the Department should make the utility discount rate equal societal discount rate, MERC advocates that this change would not be appropriate on its own. Consideration of changes to the UCT should occur within the context of how those changes will be reflected in the utility financial incentive calculation.
- All other things being equal, a lower discount rate implies a lower financial risk to the utility. This merits further discussion, particularly with respect to how a change in the discount rate for energy efficiency investments would interact with other types of utility investments, and whether it truly reflects the utility's perspective in benefit-cost analysis.

Minnesota Power (2/19 Comments)

Main Recommendations

- The purpose of the utility test is to reflect the value of energy efficiency to the utility (with the understanding that this value would indirectly benefit customers). Changing the discount rate used in the utility test would result in the test no longer serving its intended purpose.
- Could inadvertently create inconsistencies between evaluation of energy efficiency through CIP and through resource planning and this change could distort the valuation of energy efficiency.
- There are multiple tests for evaluating CIP in order to capture all the benefits (and costs) from various different perspectives. The Societal, Participant, and Ratepayer tests are more appropriate for capturing the net benefits to customers.

Otter Tail Power (2/19 Comments)

Main Recommendation

- Before changing the Utility Test in CIP to use the lower societal discount rate, a larger discussion should take place as to whether the societal discount rate should be used for integrated resource planning (IRP) purposes to maintain consistency for utility planning purposes.
- Otter Tail believes that to fairly evaluate demand-side resources like CIP compared to supply-side resources the same discount rate should be used for consistency.
- The utilities' IRP process selects the least-cost options for energy generation, and the utilities use the WACC for resource evaluation. The Department, the Minnesota Public Utilities Commission (MPUC), and other stakeholders have accepted using the WACC as a discount rate to evaluate supply-side resources.

Xcel Energy (2/19 Comments)

Main Recommendation

- The Department should make "Input 12 – Utility Discount Rate" equal to "Input 13 – Societal Discount Rate." This would effectively apply the Societal Discount Rate to all utility system benefits and avoided fuel benefits, which would place more value on long-term effects, making long-life DSM measures more cost effective. This change would send a clear signal to utilities to value long-term energy impacts more than short-term impacts.

Discount Rates and Implications for CIP

- This change would increase the benefits in the Societal and the Utility Cost tests in the BENCOST model. The Societal Test is the test used to determine which individual DSM measures or programs are cost-effective and the UCT is primarily used to determine the net benefits applied in the incentive mechanism. The Company believes that it makes sense to apply this signal of valuing long-life DSM measures in both cases. In planning for the 2020-2022 CIP Triennial Plan filing, the Company does not intend to implement measures that pass the Societal Test, but not the UCT.

Other Issues

- The Company does note that the Societal Test in previous BENCOST models through 2019 have applied the Societal Discount Rate to all utility system benefits, even though it is stated that Input 13 is limited to just the environmental damage factor. This means that the test used to screen DSM measures and programs for cost effectiveness has not used the Utility Discount Rate for any input

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Decision

Docket No. E999/CIP-18-783

Dated this 20th day of May 2019

/s/Sharon Ferguson

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ATTACHMENT BH-3

414 Nicollet Mall
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April 1, 2016

—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: COMMENTS
IN THE MATTER OF AVOIDED ELECTRIC COST ASSUMPTIONS FOR 2017-2019 CONSERVATION IMPROVEMENT PROGRAM TRIENNIAL PLAN
DOCKET NOS. CIP-16-115, CIP-16-116, CIP-16-117, CI-08-133

Dear Deputy Commissioner Grant:

Northern States Power Company, doing business as Xcel Energy, submit these Comments pursuant to Minnesota Rules part 7690.1400 and the schedule established by the Department's March 17, 2016 Proposal Filing in the matter of Avoided Electric Cost Assumptions for 2017-2019 Conservation Improvement Program Triennial Plan in the above referenced dockets.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Chris Barthol at christopher.barthol@xcelenergy.com or 612-321.3237 if you have any questions regarding this filing.

Sincerely,

/s/

SHAWN WHITE
MANAGER, DSM & RENEWABLE REGULATORY STRATEGY AND PLANNING

Enclosures
c: Service List

BEFORE THE
COMMISSIONER OF THE DEPARTMENT OF COMMERCE

IN THE MATTER OF AVOIDED COST ASSUMPTIONS FOR 2017-2019 CONSERVATION IMPROVEMENT PROGRAM TRIENNIAL PLAN

DOCKET NOS. E,G002/CIP-16-115; E,G002/CIP-16-116; E,G002/CIP-16-117; AND E,G999/CI-08-133

COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, respectfully submits these Comments in its March 17, 2016 Proposal submitted by the Minnesota Department of Commerce, Division of Energy Resources in the above-referenced Dockets. In its proposal, the Department describes the methods Xcel Energy, Minnesota Power, and Ottertail Power Company use in determining the avoided costs to calculate the benefits resulting from demand-side management (DSM), for the three following types of electric system benefits:

- Avoided Capacity Costs;
- Avoided Marginal Energy Costs; and
- Avoided Transmission and Distribution (T&D) Costs.

The Department also seeks comments by interested parties on each of these methods, with the specific questions for each type of electric system benefits:

- Do parties agree with each individual IOU's methodology?
- To the extent that the parties are able to review the actual values proposed by individual utilities, do they agree with the avoided capacity assumptions?
- Should the methodologies and/or values be standardized? If so, why?

In these comments we address each of these questions and recommend several minor changes to the current methods or values used for each type of electric system benefit:

- The methodology for Avoided Capacity Costs should be standardized across IOU's based entirely on the plants included in the expansion plans of the integrated resource plans for each IOU, instead of using market capacity prices for short-term assumptions.
- The methodology for Avoided Marginal Energy Costs should be allowed to vary among utilities and the values should be specific to each utility.
- Avoided Transmission and Distribution (T&D) costs have been estimated through widely varying methods in the past and some standardization of the method should be implemented.

Additionally, we believe that the timing and the possible impact on the upcoming Triennial Plans should be considered. A decision on this matter of avoided costs is scheduled for May 16, 2016. Utilities will file plans by June 1. Any significant changes in avoided cost methodologies could be quite difficult to implement by June 1.

COMMENTS

A. Background

On June 1, 2016 public utilities in MN will file Conservation Improvement Program (CIP) Triennial Plans covering the 2017-2019 time period[1]. These Plans include cost-benefit results for proposed DSM programs, segments, and portfolios. The composition of the DSM portfolio proposed in these Plans is dependent on these cost-benefit results. The majority of these benefits are electric system benefits calculated by applying the expected impacts from the DSM measures installed to assumptions of avoided electric system costs. At the conclusion of each year, the public utilities file Status Reports which include cost-benefit results based on the actual DSM achievement. The majority of these benefits are electric system benefits that are based on the same assumptions of avoided electric system costs filed in the CIP Triennial Plans. These Status Reports include a proposed incentive awarded which is based primarily on the cost-benefit results and net benefits of the Utility Test. In this way, the net benefits filed in the CIP Triennial Plans have significant effect on the DSM programs the utilities implement over the 2017-2019 time period,

[1] Minnesota Statute §216B.241 subd. 2 (a) requires investor-owned utilities (IOUs) to file conservation improvement plans by June 1, on a schedule determined by order of the commissioner, but at least every three years. In addition, Minnesota Rules 7690.0500 establishes specific time and content requirements for IOUs filing Conservation Improvement Program (CIP) plans. Minnesota Rules 7690.1450 allows the Deputy Commissioner to modify the filing dates and other due dates outlined in Chapter 7690 if the person requesting the change has shown good cause for the modification. On August 1, 2014, the Deputy Commissioner of the Department of Commerce, Division of Energy Resources modified the filing dates for MN utilities in order to simplify the Technical Reference Manual update process and simplify the review process by consolidating all utilities on the same triennial schedule.

and the incentives awarded and associated with actual DSM achievements over that time period.

B. Avoided Capacity Costs

The impacts of DSM include a reduction in the electric generation capacity required to serve customers. To calculate the value of this impact, an estimate of avoided electric generation capacity is derived. This is referred to as Avoided Capacity Costs.

The Department describes in their March 17, 2016 Proposal the methods used by Minnesota Power and Otter Tail Power as basing the short-term Avoided Capacity Costs on costs related to existing capacity purchases and forecasts of market capacity prices. For long-term Avoided Capacity Costs, Minnesota Power and Otter Tail Power use the costs of future plants identified in each utilities' Integrated Resource Plan (IRP). This methodology is based on the assumption that avoided generation should be based on market capacity prices in years that do not require new generation capacity, as identified in the expansion plans of the IRP.

Xcel Energy bases all Avoided Capacity Costs on the costs of future plants rather than market capacity prices, regardless of the need for the construction of a new power plant in specific years. We believe this is a more accurate method of quantifying the value of avoided generation capacity.

When determining the avoided generation capacity, two important factors must be considered:

- First, the time required to build new generation is significant, and all of the previous resource plans affecting the build plans each year must be considered; and
- Second, the cumulative impact of DSM achievements must be considered since the magnitude of incremental DSM achievements each year are significantly smaller than the capacity of individual power plants that are built.

Decisions to construct new generation capacity for a specific year are made in previous IRPs. For example, if a utility files IRPs in 2010, 2013 and 2016, the decision to build new generation capacity in 2017 is made in the 2010 and 2013 IRPs. It may be shown in the 2010 and 2013 IRPs that expected cumulative 2017 DSM achievements avoided new generation capacity in 2017. However, in the 2016 IRP, which would include plants built as a result of the 2010 and 2013 IRP decisions, the need for additional capacity in 2017 may now not exist and any additional capacity may be met through market capacity purchases. This ignores the fact that expected 2017 DSM achievements avoided new generation capacity in 2017 in previous IRPs.

Also, each IOU includes expansion plans in their IRPs which do not include new build plants each year in the future, resulting in annual gaps in plants. For long-term avoided generation capacity, these gaps have been ignored with the assumption that each year avoided new build plants. The absence of new build plants short-term represents one of these gaps in plants. The same rationale for ignoring these gaps long-term should apply short-term, leading to the assumption of avoided new build across the entire forecast period.

For public utilities that have system capacity growth, there is no difference between the types of capacity avoided long-term and short-term. Short-term capacity avoidance may appear different in the most recent IRP due to the relatively small impact of a single year of DSM achievement. All public utilities have some level of system capacity growth, especially when the impact of DSM is removed from load forecasts, and that long-term avoided generation capacity is the most accurate measure of avoided generation capacity results from DSM.

In regard to the Department's three questions, we provide the following responses:

- *Do parties agree with each individual IOU's methodology?*
  No. The Minnesota Power and Otter Tail Power methodologies should be adjusted to use the costs of future plants identified in each utilities' IRP for all years, rather than using existing purchases and forecasts of market capacity prices short-term.
- *To the extent that the parties are able to review the actual values proposed by individual utilities, do they agree with the avoided capacity assumptions?*
  Yes. All utilities base their values on values filed in recent IRPs.
- *Should the methodologies and/or values be standardized? If so, why?*
  The methodology should be standard but the values should be specific to each utility.

C. Avoided Marginal Energy Costs

The impacts of DSM include a reduction in the electric generation energy required to serve customers each hour in a year. To calculate the value of this impact, an estimate of the hourly cost of electric generation energy that is avoided must be made. This is referred to as Avoided Marginal Energy Costs.

The Department describes in their March 17, 2016 proposal the methods utilized by all three electric utilities as producing hourly marginal energy estimates based on the most recently filed or available data. The software used for each electric utility differs, but each produces the same type of data.

The single difference in Avoided Marginal Energy methodologies is that Minnesota Power uses the hourly difference between marginal energy assuming no future DSM and marginal energy with 50 MW of future DSM each hour. In contrast, Otter Tail Power and Xcel Energy both use the marginal energy after future DSM impacts are considered. This difference makes the Minnesota Power method more accurate as it approximates the band of marginal energy avoided by DSM while the Otter Tail and Xcel Energy methods approximate the last kWh avoided by DSM, which may underestimate the impact of DSM. However, it is not known how significant of a difference this represents. The Minnesota Power method is also imperfect as the DSM is not accurately represented by a constant 50 MW across all hours.

In regard to the Department's three questions, we provide the following responses:

- *Do parties agree with each individual IOU's methodology?*
  Yes.
- *To the extent that the parties are able to review the actual values proposed by individual utilities, do they agree with the avoided capacity assumptions?*
  Yes. All utilities base their values on values filed in recent resource plans or most current data available.
- *Should the methodologies and/or values be standardized? If so, why?*
  The methodologies should be allowed to vary among utilities and the values should be specific to each utility.

D. Avoided Transmission and Distribution Costs

The impacts of DSM include a reduction in the capacity required on electric transmission and distribution systems required to serve customers. To calculate the value of this impact, an estimate of the cost of electric transmission and distribution capacity that is avoided is derived. This is referred to as Avoided Transmission and Distribution (T&D) Costs.

The estimation of Avoided T&D Costs is much more difficult and complicated than the estimation of Avoided Capacity Costs and Avoided Marginal Energy Costs. Avoided Capacity Costs rely on periodic IRPs which both itemize the impacts of DSM which aides in determining the type of generation capacity avoided by DSM, and includes fully-vetted costs of the generation capacity. Avoided Marginal Energy similarly is based on IRP modeling or other modeling periodically performed by the utility.

In the case of Avoided T&D Costs, there are no other filings or internal modeling that can be relied on to estimate the effect of DSM on these costs. Several factors must be considered in the estimation of these costs including:

- The level of constraint on the current T&D systems;
- The costs of new equipment to meet load growth; and
- The coincidence of DSM savings to the peak times served by the Transmission system, and the individual components of the Distribution system.

When developing our 2007-2009 CIP Triennial Plan, we conducted a T&D Study to estimate these avoided costs. However, when developing our 2010-2012 CIP Triennial Plan, we realized that the T&D avoided costs derived from that study were significantly higher than avoided T&D values utilized in other states in our service territory. We therefore utilized a T&D avoided cost value that was consistent with our New Mexico and Colorado service territories. Since then, we have utilized escalation rates from our Corporate Assumption memos to escalate these costs. While developing our 2017-2019 CIP Triennial Plan, we looked at a T&D benchmarking study conducted by the Mendota Group. This study concluded that there are a number of methodologies to calculate T&D avoided costs and that there is no single approach to estimating these costs[2]. Further, the T&D avoided costs utilized in our CIP Plans for 2010-2016 have fallen within range of T&D avoided costs given in the Mendota study.

In regard to the Department's three questions, we provide the following responses:

- *Do parties agree with each individual IOU's methodology?*
  Yes.
- *To the extent that the parties are able to review the actual values proposed by individual utilities, do they agree with the avoided capacity assumptions?*
  Yes. All utilities base their T&D avoided cost values based on values specific to the utility using reasonable methods.
- *Should the methodologies and/or values be standardized? If so, why?*
  The methodologies should be allowed to vary among utilities and the values should be specific to each utility.

[2] The Mendota Group, LLC, *Estimates of Transmission and Distribution Costs Avoided by Energy Efficiency Investments*, September 16, 2014.

CONCLUSION

Xcel Energy respectfully requests that the Deputy Commissioner:

- Approve Avoided Generation Capacity Costs for all Minnesota electric utilities based wholly on the costs of future plants identified in each utilities' IRP and exclude any short-term avoidance based on existing purchases or market prices;
- Consider the timing of a May 16 Decision and the June 1 filing of CIP Triennial Plans; and
- Approve all other methodologies and values as proposed.

These changes will provide accurate and defensible values included in CIP Triennial Plans, Status Reports and Incentive Mechanisms while still allowing for reasonable changes that can be implemented in the upcoming 2017-2019 CIP Triennial Plans filed on June 1.

Dated: April 1, 2016

Northern States Power Company

CERTIFICATE OF SERVICE

I, Jim Erickson, 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 Nos.: E,G999/CI-08-133; E,G002/CIP-16-115; E,G002/CIP-16-116; E,G002/CIP-16-117; and CIP Special Service List

Dated this 1st day of April.

/s/

Jim Erickson
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_16-115_G002,E002.CIP-16-115
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Jill	Curran	jcurran@mnchamber.com	Minnesota Waste Wise	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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_16-115_G002,E002.CIP-16-115
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Steve	Downer	sdowner@mmua.org	MMUA	3025 Harbor Ln N Ste 400 Plymouth, MN 554475142	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Charles	Drayton	charles.drayton@enbridge.com	Enbridge Energy Company, Inc.	7701 France Ave S Ste 600 Edina, MN 55435	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Chris	Duffrin	chrisd@thenec.org	Neighborhood Energy Connection	624 Selby Avenue St. Paul, MN 55104	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Jim	Erchul	jerchul@dbnhs.org	Daytons Bluff Neighborhood Housing Sv.	823 E 7th St St. Paul, MN 55106	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Greg	Ernst	gaernst@q.com	G. A. Ernst & Associates, Inc.	2377 Union Lake Trl Northfield, MN 55057	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Melissa S	Feine	melissa.feine@semcac.org	SEMCAC	PO Box 549 204 S Elm St Rushford, MN 55971	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kelsey	Genung	kelsey.genung@xcelenergy.com	Xcel Energy	414 Nicollet Mall, Fl. 6 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Angela E.	Gordon	angela.e.gordon@lmco.com	Lockheed Martin	1000 Clark Ave. St. Louis, MO 63102	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Pat	Green	N/A	N Energy Dev	City Hall 401 E 21st St Hibbing, MN 55746	Paper Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Jason	Grenier	jgrenier@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Stephan	Gunn	sgunn@appliedenergygroup.com	Applied Energy Group	1941 Pike Ln De Pere, WI 54115	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
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_16-115_G002,E002.CIP-16-115
Patty	Hanson	phanson@rpu.org	Rochester Public Utilities	4000 E River Rd NE Rochester, MN 55906	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Norm	Harold	N/A	NKS Consulting	5591 E 180th St Prior Lake, MN 55372	Paper Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Jared	Hendricks	hendricksj@owatonnautilities.com	Owatonna Public Utilities	PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Anne E.	Heuer	anne.e.heuer@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall 7th Floor Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115

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Karolanne	Hoffman	kmh@dairynet.com	Dairyland Power Cooperative	PO Box 817 La Crosse, WI 54602-0817	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Randy	Hoffman	rhoffman@eastriver.coop	East River Electric Power Coop	121 SE 1st St PO Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Tom	Holt	tholt@eastriver.coop	East River Electric Power Coop., Inc.	PO Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Jim	Horan	Jim@MREA.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
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_16-115_G002,E002.CIP-16-115
Dave	Johnson	dave.johnson@aeoa.org	Arrowhead Economic Opportunity Agency	702 3rd Ave S Virginia, MN 55792	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Joel W.	Kanvik	joel.kanvik@enbridge.com	Enbridge Energy Company, Inc.	4628 Mike Colalillo Dr Duluth, MN 55807	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Deborah	Knoll	dknoll@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Tina	Koecher	tkoecher@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kelly	Lady	kellyl@austinutilities.com	Austin Utilities	400 4th St NE Austin, MN 55912	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Martin	Lepak	Martin.Lepak@aeoa.org	Arrowhead Economic Opportunity	702 S 3rd Ave Virginia, MN 55792	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
John	Lindell	agorud.ecf@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_16-115_G002,E002.CIP-16-115
Nick	Mark	nick.mark@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Scot	McClure	scotmcclure@alliantenergy.com	Interstate Power And Light Company	4902 N Biltmore Ln PO Box 77007 Madison, WI 537071007	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
John	McWilliams	jmm@dairynet.com	Dairyland Power Cooperative	3200 East Ave SPO Box 817 La Crosse, WI 54601-7227	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
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David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Susan K	Nathan	snathan@appliedenergygroup.com	Applied Energy Group	2215 NE 107th Ter Kansas City, MO 64155-8513	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
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_16-115_G002,E002.CIP-16-115
Gary	Oetken	goetken@agp.com	Ag Processing, Inc.	12700 West Dodge Road P.O. Box 2047 Omaha, NE 681032047	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Audrey	Partridge	audrey.peer@centerpointenergy.com	CenterPoint Energy	800 Lasalle Avenue - 14th Floor Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Lisa	Pickard	lpickard@minnkota.com	Minnkota Power Cooperative	1822 Mill Rd PO Box 13200 Grand Forks, ND 582083200	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Bill	Poppert		Technology North	2433 Highwood Ave St. Paul, MN 55119	Paper Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
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Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
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SaGonna	Thompson	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Steve	Tomac	stomac@bepc.com	Basin Electric Power Cooperative	1717 E Interstate Ave Bismarck, ND 58501	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Sharon N.	Walsh	swalsh@shakopeeutilities.com	Shakopee Public Utilties	255 Sarazin St Shakopee, MN 55379	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_16-115_G002,E002.CIP-16-115
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_16-115_G002,E002.CIP-16-115

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Lisa	Beckner	lbeckner@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Mathias	Bell	mathias.bell@opower.com	Opower	1515 N Courthouse Rd Arlington, VA 22201	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
William	Black	bblack@mmua.org	MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Gary	Connett	gconnett@grenergy.com	Great River Energy	12300 Elm Creek Blvd N Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Jill	Curran	jcurran@mnchamber.com	Minnesota Waste Wise	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116

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Steve	Downer	sdowner@mmua.org	MMUA	3025 Harbor Ln N Ste 400 Plymouth, MN 554475142	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Charles	Drayton	charles.drayton@enbridge.com	Enbridge Energy Company, Inc.	7701 France Ave S Ste 600 Edina, MN 55435	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Chris	Duffrin	chrisd@thenec.org	Neighborhood Energy Connection	624 Selby Avenue St. Paul, MN 55104	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Jim	Erchul	jerchul@dbnhs.org	Daytons Bluff Neighborhood Housing Sv.	823 E 7th St St. Paul, MN 55106	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Greg	Ernst	gaernst@q.com	G. A. Ernst & Associates, Inc.	2377 Union Lake Trl Northfield, MN 55057	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Melissa S	Feine	melissa.feine@semcac.org	SEMCAC	PO Box 549 204 S Elm St Rushford, MN 55971	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116

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Angela E.	Gordon	angela.e.gordon@lmco.com	Lockheed Martin	1000 Clark Ave. St. Louis, MO 63102	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Pat	Green	N/A	N Energy Dev	City Hall 401 E 21st St Hibbing, MN 55746	Paper Service	No	OFF_SL_16-116_E017.CIP-16-116
Jason	Grenier	jgrenier@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Stephan	Gunn	sgunn@appliedenergygroup.com	Applied Energy Group	1941 Pike Ln De Pere, WI 54115	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
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_16-116_E017.CIP-16-116
Patty	Hanson	phanson@rpu.org	Rochester Public Utilities	4000 E River Rd NE Rochester, MN 55906	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Norm	Harold	N/A	NKS Consulting	5591 E 180th St Prior Lake, MN 55372	Paper Service	No	OFF_SL_16-116_E017.CIP-16-116
Jared	Hendricks	hendricksj@owatonnautilities.com	Owatonna Public Utilities	PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Holly	Hinman	holly.r.hinman@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116

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Randy	Hoffman	rhoffman@eastriver.coop	East River Electric Power Coop	121 SE 1st St PO Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Tom	Holt	tholt@eastriver.coop	East River Electric Power Coop., Inc.	PO Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Jim	Horan	Jim@MREA.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
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_16-116_E017.CIP-16-116
Dave	Johnson	dave.johnson@aeoa.org	Arrowhead Economic Opportunity Agency	702 3rd Ave S Virginia, MN 55792	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Joel W.	Kanvik	joel.kanvik@enbridge.com	Enbridge Energy Company, Inc.	4628 Mike Colalillo Dr Duluth, MN 55807	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Deborah	Knoll	dknoll@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Tina	Koecher	tkoecher@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Kelly	Lady	kellyl@austinutilities.com	Austin Utilities	400 4th St NE Austin, MN 55912	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116

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Jeff	Legge	jlegge@otpco.com	Otter Tail Power Company	215 South Cascade St. P.O. Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Martin	Lepak	Martin.Lepak@aeoa.org	Arrowhead Economic Opportunity	702 S 3rd Ave Virginia, MN 55792	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
John	Lindell	agorud.ecf@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_16-116_E017.CIP-16-116
Nick	Mark	nick.mark@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Scot	McClure	scotmcclure@alliantenergy.com	Interstate Power And Light Company	4902 N Biltmore Ln PO Box 77007 Madison, WI 537071007	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
John	McWilliams	jmm@dairynet.com	Dairyland Power Cooperative	3200 East Ave SPO Box 817 La Crosse, WI 54601-7227	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Brian	Meloy	brian.meloy@stinson.com	Stinson,Leonard, Street LLP	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116

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Susan K	Nathan	snathan@appliedenergygroup.com	Applied Energy Group	2215 NE 107th Ter Kansas City, MO 64155-8513	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
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_16-116_E017.CIP-16-116
Gary	Oetken	goetken@agp.com	Ag Processing, Inc.	12700 West Dodge Road P.O. Box 2047 Omaha, NE 681032047	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Audrey	Partridge	audrey.peer@centerpointenergy.com	CenterPoint Energy	800 Lasalle Avenue - 14th Floor Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Lisa	Pickard	lpickard@minnkota.com	Minnkota Power Cooperative	1822 Mill Rd PO Box 13200 Grand Forks, ND 582083200	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Bill	Poppert		Technology North	2433 Highwood Ave St. Paul, MN 55119	Paper Service	No	OFF_SL_16-116_E017.CIP-16-116
Dave	Reinke	dreinke@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024-9583	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Christopher	Schoenherr	cp.schoenherr@smmpa.org	SMMPA	500 First Ave SW Rochester, MN 55902-3303	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Anna	Sherman	anna.sherman@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall PO Box 59038 Minneapolis, MN 55459	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Leo	Steidel	N/A	The Weidt Group	5800 Baker Rd Minnetonka, MN 55345	Paper Service	No	OFF_SL_16-116_E017.CIP-16-116
Richard	Szydlowski	rszydlowski@mncee.org	Center for Energy & Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401-1459	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
SaGonna	Thompson	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Steve	Tomac	stomac@bepc.com	Basin Electric Power Cooperative	1717 E Interstate Ave Bismarck, ND 58501	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Sharon N.	Walsh	swalsh@shakopeeutilities.com	Shakopee Public Utilties	255 Sarazin St Shakopee, MN 55379	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_16-116_E017.CIP-16-116
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_16-116_E017.CIP-16-116

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	Yes	OFF_SL_16-117_E015.CIP-16-117
Tom	Balster	tombalster@alliantenergy.com	Interstate Power & Light Company	PO Box 351 200 1st St SE Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Lisa	Beckner	lbeckner@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Mathias	Bell	mathias.bell@opower.com	Opower	1515 N Courthouse Rd Arlington, VA 22201	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
William	Black	bblack@mmua.org	MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Gary	Connett	gconnett@grenergy.com	Great River Energy	12300 Elm Creek Blvd N Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Jill	Curran	jcurran@mnchamber.com	Minnesota Waste Wise	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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_16-117_E015.CIP-16-117
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Steve	Downer	sdowner@mmua.org	MMUA	3025 Harbor Ln N Ste 400 Plymouth, MN 554475142	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Charles	Drayton	charles.drayton@enbridge.com	Enbridge Energy Company, Inc.	7701 France Ave S Ste 600 Edina, MN 55435	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Chris	Duffrin	chrisd@thenec.org	Neighborhood Energy Connection	624 Selby Avenue St. Paul, MN 55104	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Jim	Erchul	jerchul@dbnhs.org	Daytons Bluff Neighborhood Housing Sv.	823 E 7th St St. Paul, MN 55106	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Greg	Ernst	gaernst@q.com	G. A. Ernst & Associates, Inc.	2377 Union Lake Trl Northfield, MN 55057	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Melissa S	Feine	melissa.feine@semcac.org	SEMCAC	PO Box 549 204 S Elm St Rushford, MN 55971	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kelsey	Genung	kelsey.genung@xcelenergy.com	Xcel Energy	414 Nicollet Mall, Fl. 6 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Angela E.	Gordon	angela.e.gordon@lmco.com	Lockheed Martin	1000 Clark Ave. St. Louis, MO 63102	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Pat	Green	N/A	N Energy Dev	City Hall 401 E 21st St Hibbing, MN 55746	Paper Service	No	OFF_SL_16-117_E015.CIP-16-117
Jason	Grenier	jgrenier@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Stephan	Gunn	sgunn@appliedenergygroup.com	Applied Energy Group	1941 Pike Ln De Pere, WI 54115	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
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_16-117_E015.CIP-16-117
Patty	Hanson	phanson@rpu.org	Rochester Public Utilities	4000 E River Rd NE Rochester, MN 55906	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Norm	Harold	N/A	NKS Consulting	5591 E 180th St Prior Lake, MN 55372	Paper Service	No	OFF_SL_16-117_E015.CIP-16-117
Jared	Hendricks	hendricksj@owatonnautilities.com	Owatonna Public Utilities	PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Karolanne	Hoffman	kmh@dairynet.com	Dairyland Power Cooperative	PO Box 817 La Crosse, WI 54602-0817	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Tom	Holt	tholt@eastriver.coop	East River Electric Power Coop., Inc.	PO Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Jim	Horan	Jim@MREA.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
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_16-117_E015.CIP-16-117
Dave	Johnson	dave.johnson@aeoa.org	Arrowhead Economic Opportunity Agency	702 3rd Ave S Virginia, MN 55792	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Joel W.	Kanvik	joel.kanvik@enbridge.com	Enbridge Energy Company, Inc.	4628 Mike Colalillo Dr Duluth, MN 55807	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Deborah	Knoll	dknoll@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Tina	Koecher	tkoecher@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kelly	Lady	kellyl@austinutilities.com	Austin Utilities	400 4th St NE Austin, MN 55912	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Martin	Lepak	Martin.Lepak@aeoa.org	Arrowhead Economic Opportunity	702 S 3rd Ave Virginia, MN 55792	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
John	Lindell	agorud.ecf@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_16-117_E015.CIP-16-117
Nick	Mark	nick.mark@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Scot	McClure	scotmcclure@alliantenergy.com	Interstate Power And Light Company	4902 N Biltmore Ln PO Box 77007 Madison, WI 537071007	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
John	McWilliams	jmm@dairynet.com	Dairyland Power Cooperative	3200 East Ave SPO Box 817 La Crosse, WI 54601-7227	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
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Herbert	Minke	hminke@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Gary	Myers	garym@hpuc.com	Hibbing Public Utilities	1902 E 6th Ave Hibbing, MN 55746	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Susan K	Nathan	snathan@appliedenergygroup.com	Applied Energy Group	2215 NE 107th Ter Kansas City, MO 64155-8513	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
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_16-117_E015.CIP-16-117
Gary	Oetken	goetken@agp.com	Ag Processing, Inc.	12700 West Dodge Road P.O. Box 2047 Omaha, NE 681032047	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Audrey	Partridge	audrey.peer@centerpointenergy.com	CenterPoint Energy	800 Lasalle Avenue - 14th Floor Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Lisa	Pickard	lpickard@minnkota.com	Minnkota Power Cooperative	1822 Mill Rd PO Box 13200 Grand Forks, ND 582083200	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Bill	Poppert		Technology North	2433 Highwood Ave St. Paul, MN 55119	Paper Service	No	OFF_SL_16-117_E015.CIP-16-117
Dave	Reinke	dreinke@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024-9583	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117

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_16-117_E015.CIP-16-117
Cindy	Schweitzer Rott	cindy.schweitzer@clearesult.com	CLEAResult's	S12637A Merrilee Rd. Spring Green, WI 53588	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Anna	Sherman	anna.sherman@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall PO Box 59038 Minneapolis, MN 55459	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Leo	Steidel	N/A	The Weidt Group	5800 Baker Rd Minnetonka, MN 55345	Paper Service	No	OFF_SL_16-117_E015.CIP-16-117
Richard	Szydlowski	rszydlowski@mncee.org	Center for Energy & Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401-1459	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
SaGonna	Thompson	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Steve	Tomac	stomac@bepc.com	Basin Electric Power Cooperative	1717 E Interstate Ave Bismarck, ND 58501	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Sharon N.	Walsh	swalsh@shakopeeutilities.com	Shakopee Public Utilties	255 Sarazin St Shakopee, MN 55379	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_16-117_E015.CIP-16-117

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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_16-117_E015.CIP-16-117

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
Mathias	Bell	mathias.bell@opower.com	Opower	1515 N Courthouse Rd Arlington, VA 22201	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST
William	Black	bblack@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
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	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST
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

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Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	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
Chris	Duffrin	chrisd@thenec.org	Neighborhood Energy Connection	624 Selby Avenue St. Paul, MN 55104	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
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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@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST
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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
Holly	Hinman	holly.r.hinman@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 7th Floor 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
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Karolanne	Hoffman	kmh@dairynet.com	Dairyland Power Cooperative	PO Box 817 La Crosse, WI 54602-0817	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST
Tom	Holt	tholt@eastriver.coop	East River Electric Power Coop., Inc.	PO Box 227 Madison, SD 57042	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST
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
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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 Company, Inc.	4628 Mike Colalillo Dr Duluth, MN 55807	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST
Deborah	Knoll	dknoll@mnpower.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	kellyl@austinutilities.com	Austin Utilities	400 4th St NE Austin, MN 55912	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST

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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
John	Lindell	agorud.ecf@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
Nick	Mark	nick.mark@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST
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
Scot	McClure	scotmcclure@alliantenergy.com	Interstate Power And Light Company	4902 N Biltmore Ln PO Box 77007 Madison, WI 537071007	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST
John	McWilliams	jmm@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@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	SPL_SL__CIP SPECIAL SERVICE LIST
Gary	Myers	garym@hpuc.com	Hibbing Public Utilities	1902 E 6th Ave Hibbing, MN 55746	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
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ATTACHMENT BH-4

THE MENDOTA GROUP, LLC
the power of bright ideas

Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments

for Public Service Company of Colorado

October 23, 2014

Table of Contents

Executive Summary

Energy efficiency (EE) program cost-effectiveness evaluations assess the value (benefits) of these programs to a utility's system and aim to determine whether benefits exceed costs. The value of the generation and delivery system investments *avoided* or *deferred* by EE are components of the estimates of such benefits. Although estimates of avoided investments in and operation of generating units are fairly straightforward and tend to focus on a limited number of types of such units estimates of avoided investments in and operation of transmission and distribution (T&D) system components tend to be less straightforward. The following analysis examines ways in which utilities in the United States estimate EE program avoided transmission and distribution costs and provides a survey of current estimates.

Utilities have used a number of methods for estimating avoided T&D and there is no one "best" approach to developing these estimates. This report conducts a fairly broad benchmarking study of other utilities' estimates of avoided T&D costs. The benchmarking study produced a wide range of estimates for avoided T&D, underscoring the diverse nature of the methods used to calculate avoided costs. Although the process of estimating avoided transmission and distribution costs for EE programs has a long history it appears that it remains a dynamic area that will continue to evolve in the years to come. With this in mind, it would serve PSCo well to revisit this issue in the coming years.

A. Study Purpose

Xcel Energy (the "Company" or "PSCo") uses estimates of transmission and distribution facilities avoided or deferred by investments in energy efficiency in its EE cost-effectiveness evaluations. However, these estimates were developed nearly 10 years ago. It is useful at this point to refresh the Company's understanding of the way that U.S. utilities are calculating their avoided T&D for use with EE program cost-benefit analyses. The Company has requested assistance in researching other utilities' T&D estimates and the basis for those values.

To this end, the consultants sought to accomplish the following tasks:

- **Task 1. Research methods of estimating avoided T&D costs –** Consultant will survey methods used in most recent estimates of T&D avoided costs.
- **Task 2. Identify comparable utilities/systems and benchmark –** Consultant will identify at least five comparable utilities with which to compare and benchmark estimates for the Company.
- **Task 3. Conduct surveys/research of comparable utilities –** T&D cost assumptions and the methodologies used to derive them are often not readily available through publicly available information. Thus, Consultant may need to contact some of utilities to determine avoided T&D information.

The following report is the product of these tasks and seeks to answer each of the questions raised.

B. Issue Overview

Utility-administered electric energy efficiency programs benefit utility ratepayers by reducing the amount of electricity end-use customers consume for a given amount of production (e.g. lumens, cooling load, production from an assembly line, etc.). For the utility, this reduced electricity use translates to less electricity that its power plants must produce (or that the utility must purchase) to meet customer requirements. Over the longer term, it also reduces the need to construct new or expand existing generating facilities. These investments in end-user energy efficiency may also reduce the T&D system capacity needed to transport electricity from power plants to customers.

With respect to T&D systems, it is feasible that EE can avoid or delay T&D upgrades, and reduce construction and associated operations and maintenance costs, including cost of capital, taxes and insurance. If EE measures help reduce demand during peak periods, EE investments can also reduce the timing of maintenance, because frequent peak loads at or near design capacity will reduce the life of some types of T&D equipment.[1]

EE program administrators typically use estimates of investments in generation, transmission, and distribution (GT&D) "avoided" to calculate the cost-effectiveness of investments in energy efficiency programs. According to the *California Standard Practice Manual,* "the benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction."[2] The *National Action Plan for Energy Efficiency* (NAPEE) explains,

> The resource benefits of energy efficiency fall into two general categories:
> (1) Energy-related benefits that affect the procurement of wholesale electric energy and natural gas, and delivery losses,
> (2) Capacity-related benefits that affect wholesale electric capacity purchases, construction of new facilities, and system reliability.[3]

However, while estimates of avoided supply costs associated with the reduction in generation and capacity costs have more narrowly focused on capacity costs associated with a natural gas-fueled combustion turbine (CT) generating unit (and occasionally a combined cycle unit) and system-wide marginal energy costs,[4] estimates of avoided costs associated with T&D have varied

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[1] "Assessing the Multiple Benefits of Clean Energy, A Resource for States," U.S. Environmental Protection Agency, Revised September 2011, p. 75.

[2] "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects," California Public Utilities Commission, October 2001, p. 18.

[3] "National Action Plan for Energy Efficiency," U.S. Department of Energy, U.S. Environmental Protection Agency, July 2006, p. 3-3.

[4] "Best Practices in Energy Efficiency Program Screening," Synapse Energy Economics for National Home Performance Council, July 23, 2012, p. 23. In some states, administrative rules dictate what type of generating unit will be used to calculate costs (see Iowa and Texas as examples).

widely. Although some of this variation may result from actual cost differences between utilities, much appears to also relate to variations in the way utilities calculate such costs.

Estimating avoided transmission and distribution costs is inherently more complex than generation because T&D benefits from EE tend to be location-specific, system-wide and time dependent. In other words, large amounts of EE investment in a specific part of the distribution grid could more significantly impact, say, required upgrades to a specific substation. On the other hand, system-wide energy efficiency investments can effectively reduce overall loading on transmission and distribution lines but still may not affect T&D investments unless the measures are coincident with system peaks.

Transmission and distribution systems are designed to carry extreme peak loads, which increases costs. States that use marginal cost of service studies to set rates regularly look at the cost to add T&D capacity. Put plainly,

> The capital cost of augmenting transmission capacity is typically estimated at $200 to $1,000 per kilowatt and the cost of augmenting distribution capacity ranges between $100 and $500 per kilowatt. Annualized values (the average rate of return multiplied by the investment over the life of the investment) are about 10% of these figures, or $20 to $100 per kilowatt-year for transmission and $10 to $50 per kilowatt-year for distribution. There are also marginal operations and maintenance costs for transmission and distribution capacity, but these are modest in comparison to the capital costs.[5]

But not all forecast T&D investments are deferrable or avoidable. "Some will be required to address time-related deterioration of equipment or other factors that are independent of load."[6] One of the primary drivers of investment is the growth in the number of customers, which is not avoidable load growth. Other investments only a portion of which may be deferrable/avoidable from EE include modernization projects to improve technology, reliability improvements related to changes in reliability or safety standards, and projects to accommodate non-native load or supply, among others.

Authors Chris Neme and Rich Sedano categorize the manner in which efficiency programs can defer T&D investments as "passive" or "active". Passive refers to deferred investments in transmission and distribution that occur as a byproduct of EE investments whereas active deferrals are those that result from EE initiatives targeted at specific locations. Active deferrals have the express purpose of deferring T&D investments. The authors cite a host of reasons as to why active deferrals are uncommon.[7]

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[5] "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements," Jim Lazar, Xavier Baldwin, Regulatory Assistance Project, August 2011, p. 6.

[6] "US Experience with Efficiency As a Transmission and Distribution System Resource," Chris Neme (Energy Futures Group), Rich Sedano (Regulatory Assistance Project), February 2012, p. i.

[7] "US Experience with Efficiency As a Transmission and Distribution System Resource," p. i. Among the reasons active deferrals lack popularity are: utility disincentives, difficulty in conducting T&D planning holistically, technical limitations, system engineers biased against demand resources, and risk aversion, among others.

Further to this point, "passive deferral occurs when the growth in load or stress on feeders, substations, transmission lines, or other elements of the T&D system is reduced as a result of broad-based (e.g., statewide or utility service territory-wide) efficiency programs."[8] Estimates of savings from EE investments "are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load) by the forecast growth in system load."[9] Section C discusses in more detail the different ways that utilities estimate avoided transmission and distribution costs.

It bears repeating that investments in transmission and distribution systems have other benefits beyond meeting load growth, including providing reliable service and meeting the needs of a growing number of customers. Investments in system improvements can also provide production cost savings through reduced line losses and reduced congestion, generation capacity cost savings by providing access to lower cost resources, and increased employment activities, among others.[10] This is relevant because it points out that while energy efficiency investments may defer or avoid transmission and distribution investments that such investments may provide other benefits that contribute (and are economically valuable) to the electricity system (thereby arguing that avoided cost estimates may be mitigated somewhat by ancillary benefits associated with these improvements). The next section discusses some common methods for calculating avoided T&D costs.

C. Common T&D Avoided Cost Calculation Methodologies

As previously discussed, there is little consistency between jurisdictions in terms of how avoided T&D costs are calculated. Unlike estimates of avoided energy and generating capacity, estimates of avoided T&D tend to require a fair amount of subjectivity in determining what to include in and what to exclude from calculations. Each utility has a different take on the topic and regulators to the extent they become involved in the issue also differ. Some utilities do not include estimates of avoided T&D in their evaluations, believing that EE does not defer T&D investments.[11] Other utilities, like those in Idaho, may include avoided transmission costs in calculations but place the value at zero because the generating unit avoided is close to load, thereby deferring no transmission.[12]

As such, determining what constitutes "best practice" becomes difficult, particularly because none of the different approaches are necessarily *wrong*. It is just that there are a variety of methods for developing the estimates, and each <u>may</u> be capable of producing valid estimates.

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[8] "US Experience with Efficiency As a Transmission and Distribution System Resource," p. 3.

[9] "US Experience with Efficiency As a Transmission and Distribution System Resource," p. 3.

[10] "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," The Brattle Group, July 2013, p. 10.

[11] See "Consumers Energy: 2012-2015 Amended Energy Optimization Plan," Submitted to Michigan Public Service Commission (Case No: U-16670), August 1, 2011, p. 25.

[12] "Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and A Proposed Path for Reform," Prepared by Carolyn Elefant, 2011, p. 31.

The uncertainty stems, in part, from the nature of energy efficiency as relying upon the counterfactual (i.e., the determination of what would have happened on the system if the EE program did not exist). To devise an analytical tool that enables one to assess the benefits and costs of EE requires that practitioners develop "good" estimates of the benefits EE investments produce. Good estimates are those based on sound principles as discussed in the following sections. The following section outlines a number of the methods while Appendix A provides an assessment of the strengths and weaknesses of the different approaches. Section D follows with a survey of a number of utilities' avoided cost estimates.

a. System Planning Approach

According to the U.S. Environmental Protection Agency's (EPA's) "Assessing the Multiple Benefits of Clean Energy (September 2011)," the *system planning approach* is the best way to estimate avoided T&D costs. "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 the original T&D investment projects and the present value of deferred T&D projects."[13]

The U.S. EPA endorses this approach and suggests use of proprietary models of T&D system operation (two cited are PowerWorld Corp's model and the Siemens [PSS®E] model) to identify location and timing of system stresses. The system planning approach may well be the best way to estimate avoided T&D costs; however, the approach seems primarily to have been used to analyze investments in specific T&D projects rather than to analyze the system as a whole. The approach has been used to estimate the value of distributed generation and energy efficiency at ConEdison, Bonneville Power Administration, Efficiency Vermont, Detroit Edison, and Southern California Edison, among others.[14] However, these projects all appear to be aimed at "active" deferrals rather than the more typical passive deferrals.

b. Mix of Historical and Forecast Information Approach[15]

The ICF Tool, developed by ICF International, Inc. best exemplifies the Mix of Historical and Forecast Information approach. ICF developed a calculation methodology as part of a 2005 report prepared for the Avoided-Energy-Supply-Component (AESC) Study Group, whose members included utilities in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.[16] The report was commissioned to review energy supply costs avoided in the Northeast through energy efficiency programs. The AESC report has been updated biennially since 2005, but there have been no substantive changes to the calculator.

At its core, the ICF Tool collects data on historical and forecast T&D investments, determines what portions are due to load growth, and weights the historical and forecast contributions to

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[13] "Assessing the Multiple Benefits of Clean Energy," p. 76.

[14] "Best Practices in Energy Efficiency Program Screening," p. 25.

[15] This is a made-up label. Some have called this "projected embedded cost analysis" (see "Best Practices in Energy Efficiency Program Screening," p. 24.

[16] "Avoided Energy Supply Costs in New England: 2005 Report," Prepared for Avoided-Energy-Supply-Component (AESC) Study Group by ICF Consulting, December 23, 2005.

arrive at transmission and distribution T&D capacity marginal costs in $/kW-year. The tool takes the form of an Excel spreadsheet with four schedules (Schedule 1 is a summary) and an appendix. The Tool recommends that the user input 15 years of historical data and 10 years of forecast data for T&D capital investments and peak load. In addition, the user must input a variety of values from their FERC Form 1, including: property taxes, insurance costs, and operation and maintenance expenses. The user must also estimate the portions of investments identified in FERC Form 1 that are related to increasing load.[17]

The benefits of this methodology are that the Tool is well established, much of the data is available through FERC Form 1, and utilities and Commissions in the Northeast have been vetting it for nearly ten years. Many utilities continue to use the approach. The concerns with this method are that despite data being available from the FERC Form 1, the Tool still requires the user to make a subjective analysis of the proportion of investments resulting from increasing load. In addition, the 2009 AESC Report pointed out a number of potential calculation errors in the spreadsheet.[18]

c. Current Values Approach

The Current Values approach is well exemplified by MidAmerican Energy Company in its multiple state demand-side management (DSM) filings. MidAmerican has a standardized approach to calculating T&D capacity avoided costs in each of the states where it offers energy efficiency programs including Iowa, Illinois and South Dakota. This methodology is detailed in the direct testimony of Jennifer L. Long, in Iowa Docket No. EEP-2012-0002.

MidAmerican calculates T&D avoided costs as follows,

> The average cost to serve existing load is calculated for both the transmission and distribution systems by dividing each system's net cost by each system's peak capability. MidAmerican's Federal Energy Regulatory Commission (FERC) Form 1 data is used to calculate the net costs of the transmission and distribution systems by taking MidAmerican's original cost of plant less accumulated depreciation for each respective system. Yearly, MidAmerican load data and generation capability data is used to approximate the capacity of each system. The end result of the calculation is a $/kW cost for each system.[19]

The biggest strength of this method is its simplicity, which lends itself to frequent updates.

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[17] FERC Form 1, submitted annually by large utilities, provides comprehensive financial and operating results of the utility for the previous year. Investments specifically targeted for addressing load growth are not identified therein.

[18] "Avoided Energy Supply Costs in New England: 2009 Report," Prepared for Avoided-Energy-Supply-Component (AESC) Study Group by Synapse Energy Economics, Inc., August 21, 2009, p. 6-67.

[19] "Direct Testimony of Jennifer L. Long," Application for Approval of Energy Efficiency Plan for 2014-2018 (Docket EEP-2012-0002), Submitted to Iowa Public Utilities Board by MidAmerican Energy Company, Feb. 1, 2013, p. 4. Note that MidAmerican modified its approach to incorporate on peak load data instead of generation capability data.

d. Rate Case Marginal Cost Data with Allocators Approach

There are a few variations on the theme of using most recent marginal cost of service data from the utility rate case to develop estimates of avoided transmission and distribution costs. In California, T&D avoided costs are considered unique among other types of avoided costs in that both the value and hourly allocations are location specific. This information is combined with utility rate case information to calculate avoided costs separately for each utility.

As discussed in the 2011 update to the state's avoided costs,

> … the value of deferring distribution investments is highly dependent on the type and size of the equipment deferred and the rate of load growth, both of which vary significantly by location. Furthermore, some distribution costs are driven by distance or number of customers rather than load and are therefore not avoided with reduced energy consumption. However, expediency and data limitations preclude analysis at a feeder-by-feeder level for a statewide analysis of avoided costs. The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time ...[20]

The avoided cost calculations also allocate T&D capacity values in each climate zone to the hours of the year during which the system is most likely to be constrained and require upgrade (the hours of highest local load). Although these values were previously based on hourly temperature values for the individual climate zones the information has since been updated for cost-effectiveness calculators (but not yet incorporated into the EE calculator) due to the availability of utility information on actual substation load data.[21]

e. Rate Case Marginal Cost Data Approach

Ameren Missouri goes through a fairly detailed review of its distribution and transmission system investments to determine the marginal cost of system capacity as it relates to load growth. However, this is complicated by the fact that "projects serve a variety of purposes; capacity upgrades to serve incremental system load, capacity upgrades to serve relocated system load, and refurbishment or replacement of equipment to avoid imminent failure."[22] As Ameren points out, analyzing the system in aggregate rather than focusing on specific areas further complicates the estimates, mainly because energy efficiency programs are designed to target specific areas.

PacifiCorp includes avoided T&D credits in its assessment of resources as part of its IRPs filed in Oregon, Washington, Idaho, California, Wyoming, and Utah. Specifically, PacifiCorp uses a cost of service study to derive the estimates. As part of the study, PacifiCorp estimates the demand-related substation costs by taking the total substation capacity expansion investment for the subsequent five years, dividing by the total increased capacity in kVA and then annualizing this number by multiplying by a carrying charge. The method of estimating demand-related transmission costs is similar. All "growth-related" transmission investment (with some

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[20] "Energy Efficiency Avoided Costs 2011 Update," by Brian Horii, Eric Cutter (Energy and Environmental Economics, Inc.), December 19, 2011, p. 24.

[21] "Energy Efficiency Avoided Costs 2011 Update," p. 26.

[22] "Ameren Missouri - 2011 Integrated Resource Plan," File No. EO-2011-0271, February 23, 2011.

exceptions like bulk power lines) over the subsequent five years is divided by the forecasted change in peak over the same period and this value is annualized.[23]

In its 2013 IRP, Nevada Energy uses the marginal cost study associated with the utility's 2010 rate case (Docket No. 10-06001) to determine its avoided T&D costs. As the utility states in its filing, "the adopted valuation process reduces potential difficulties regarding uncertainty in load forecasts and T&D construction budgets, and takes into account the ripple effect or the effect of deferred construction investments during the useful life of energy efficiency measures."[24] The Company, in turn, utilizes the conservative value of 25 percent of $47.50/kW (annual revenue requirement for the marginal cost of transmission facilities and distribution system, not accounting for the distribution beyond substation) or $11.88/kW in cost effectiveness analysis, and escalates it in each year by applying a cost construction index. The company further acknowledged that this is a low value when compared to other states like California.

Selection of Other Approaches

Averaging Method

In a note to the Vermont Public Service Board, a consultant outlines the various options available for calculating avoided T&D costs and cites among the options the "New England Average Method."[25] This method proposes using a New England average avoided T&D cost of $83 calculated from the figures identified in the 2011 AESC report. Although Vermont did not adopt this method other utilities have used a similar approach. Wisconsin Focus on Energy, which does not have explicit avoided T&D costs in its cost-effectiveness calculations, used an Iowa average for its market potential study.[26] In the Pacific Northwest, the Northwest Conservation and Electric Power Plan uses an average of avoided costs from a selection of utilities.[27]

IRP Approach

Some utilities use a variant of the System Planning Approach by conducting with and without DSM analyses to estimate avoided T&D costs.[28] Tucson Electric Power (TEP) conducts a decrement study to assess how transmission costs are avoided and uses this calculation in the utility's EE cost-effectiveness evaluations. It does not appear that TEP includes avoided distribution costs in its calculations and the utility only publishes its total avoided capacity costs. The utility considers the details proprietary and, therefore, specific information is not available.

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[23] Correspondence with PacifiCorp representatives, August 22, 2014.

[24] Sierra Pacific Power Company d/b/a NV Energy Integrated Resource Plan 2014-2033, Demand Side Plan 2014-2016," p. 48.

[25] "List of Possible Methods for Determining Avoided Transmission and Distribution Costs," Submitted to Vermont Public Service Board, June 28, 2012, http://psb.vermont.gov/docketsandprojects/eeu/avoidedcosts/2011.

[26] "Minutes and Informal Instructions of the Open Meeting of Thursday, July 10, 2014," Public Service Commission of Wisconsin, p. 3.

[27] "Appendix E – Conservation Supply Curve Development" in Sixth Northwest Conservation and Electric Power Plan, February 1, 2010, p. E-13, https://www.nwcouncil.org/energy/powerplan/6/plan/.

[28] This version of the System Planning Approach is more frequently associated with calculations of avoided generation energy and capacity costs. See "The Role and Nature of Marginal and Avoided Capacity Costs in Ratemaking: A Survey," Hethie Parmesano and William Bridgman, National Economic Research Associates, January 1992, p. 13.

Others
The memo to the Vermont Public Service Board also identified a method termed the "Simple Method" which relies on taking representative samples of recent T&D upgrade projects, dividing by increased capacity and annualizing.[29] The formula follows:

(Cost of Upgrades) ÷ (Additional Capacity Achieved by the Upgrade) ÷ (Economic Life of Upgrade)

A final method entails looking at each potential cost category of T&D capital costs and operations and maintenance expenses and making educated guesses as to the percentage of the cost category that is deferrable by EE. This can be applied to historical and, if available, forecast costs to determine the annualized value as it applies to load growth.

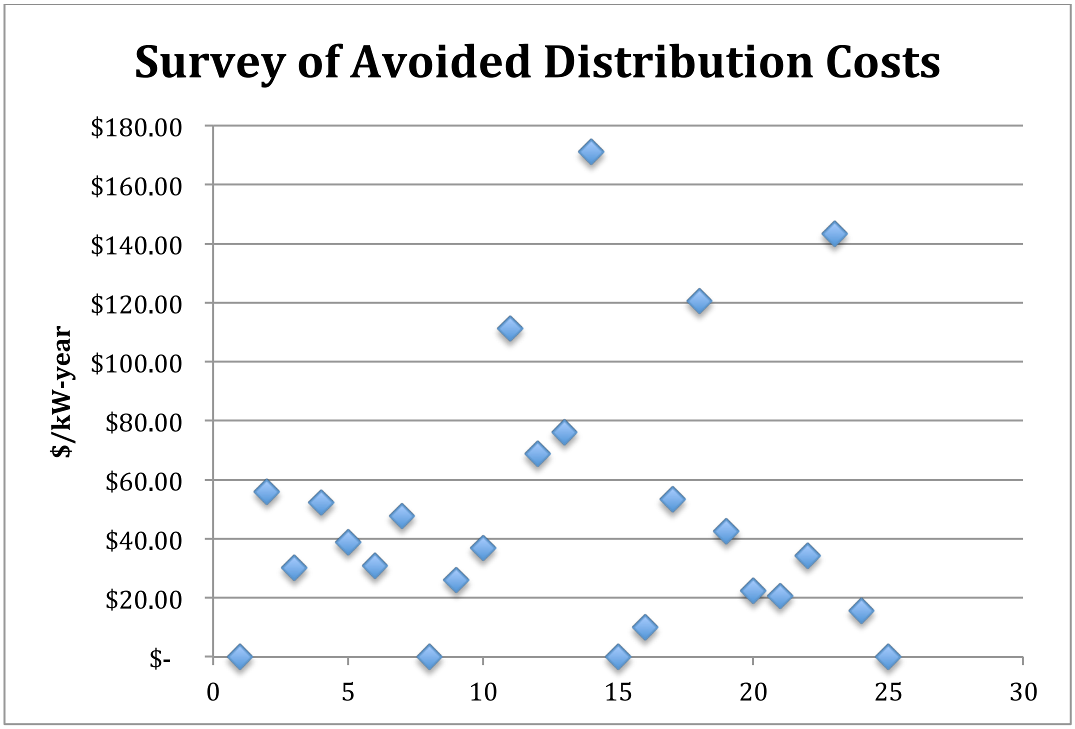
D. Survey of Other Utilities / Benchmarking

As part of Tasks 2 and 3, the authors collected avoided T&D data from a fairly broad cross-section of utilities. Data collection efforts sought to maximize the number of data points while also making an attempt to include utilities that might be most relevant to PSCo. However, it is unclear whether utility size or region has any bearing on estimated avoided costs and, therefore, the effort did not concentrate on the Rocky Mountain region or on comparably sized utilities. The survey does include some results from mountain states such as Arizona, Utah, Idaho and Nevada and also includes information from comparably sized (customers, sales) utilities (Consumers Energy [MI], Northern States Power [MN], Arizona Public Service [AZ]). Appendix B provides the detailed results of the survey. The range of data points for avoided Distribution cost estimates are provided below. The first section focus on distribution system estimates and it is followed by estimates of transmission system avoided costs. Combined estimates of avoided T&D are included in the final section.

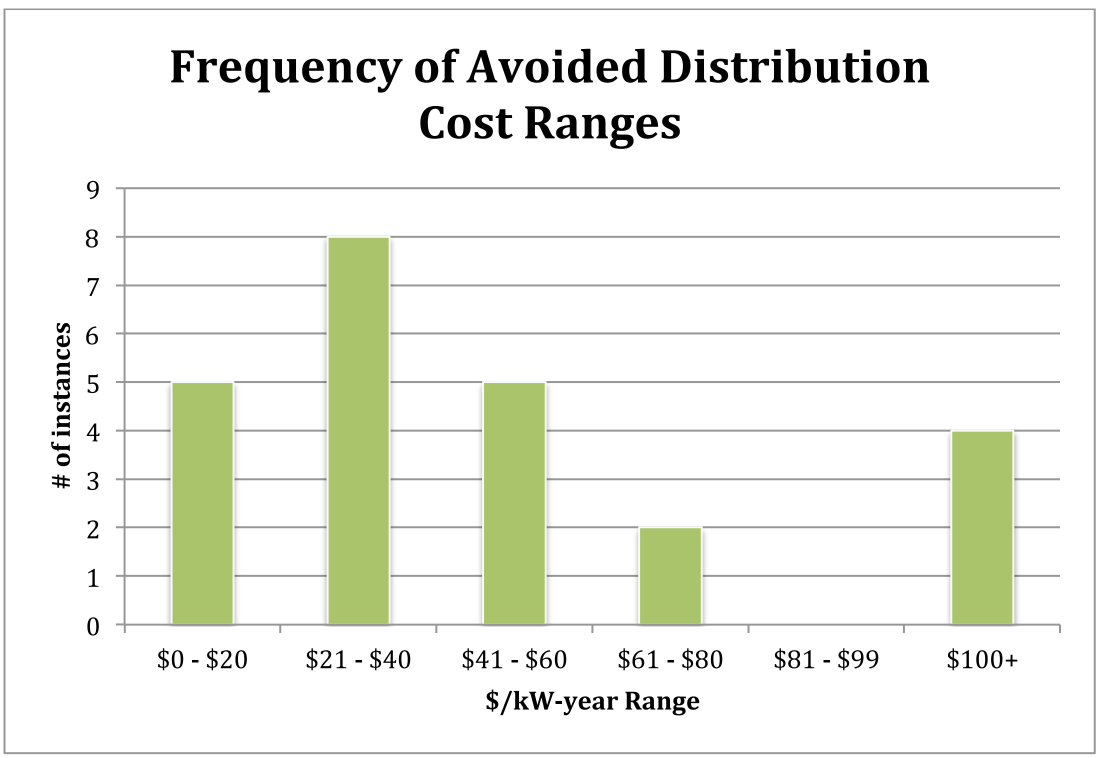
Estimates of Distribution System Avoided Costs

The average avoided distribution costs are $48.37 with a range from $0 to $171/kW-year.

[29] "List of Possible Methods for Determining Avoided Transmission and Distribution Costs," p. 2.

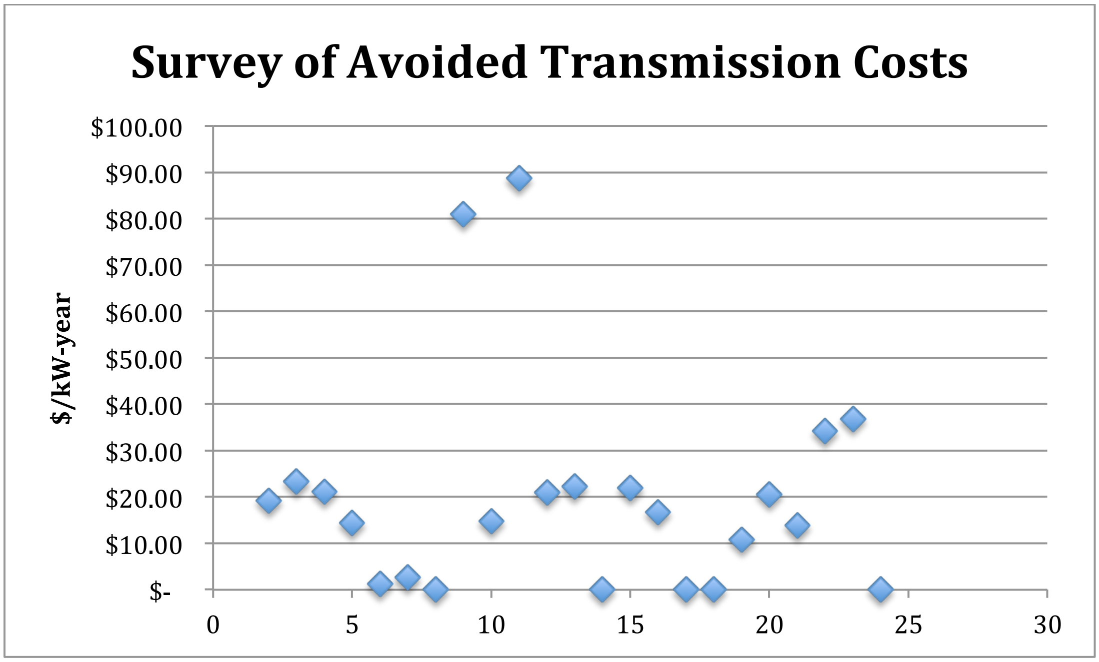


The values are most heavily concentrated in the $21 to $40 range with 8 of the samples falling in this range.

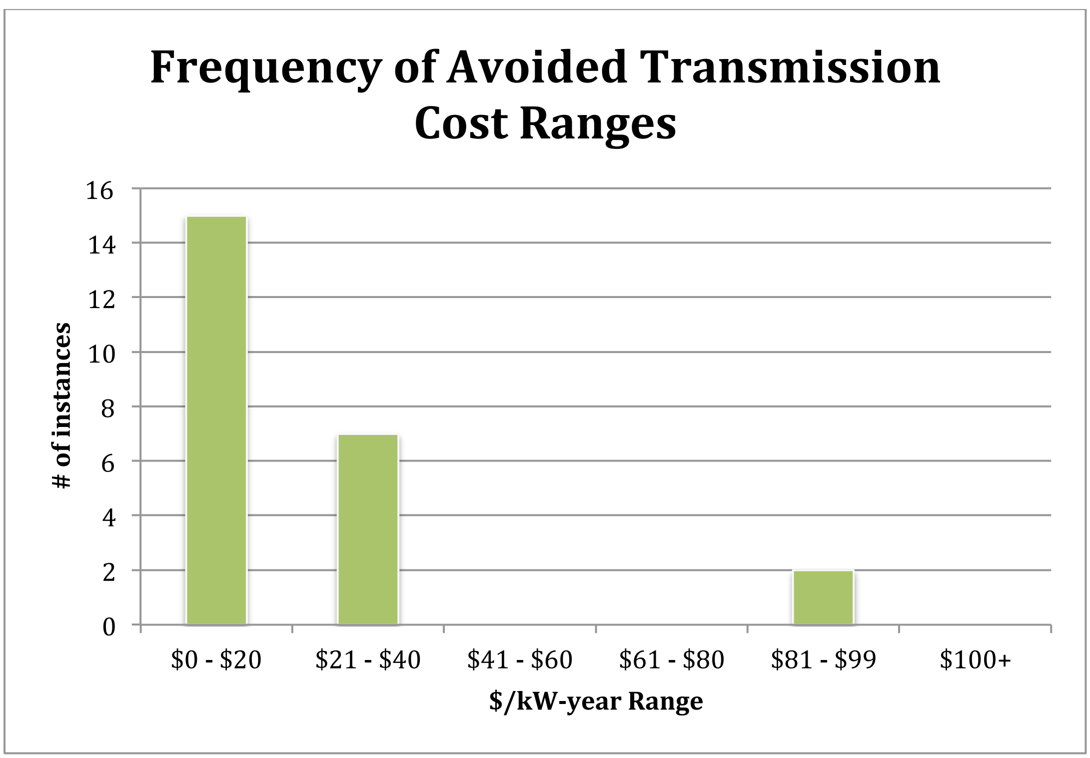


Estimates of Transmission System Avoided Costs

Average avoided transmission costs are $20.21 with a range from $0 to $88.64/kW-year.

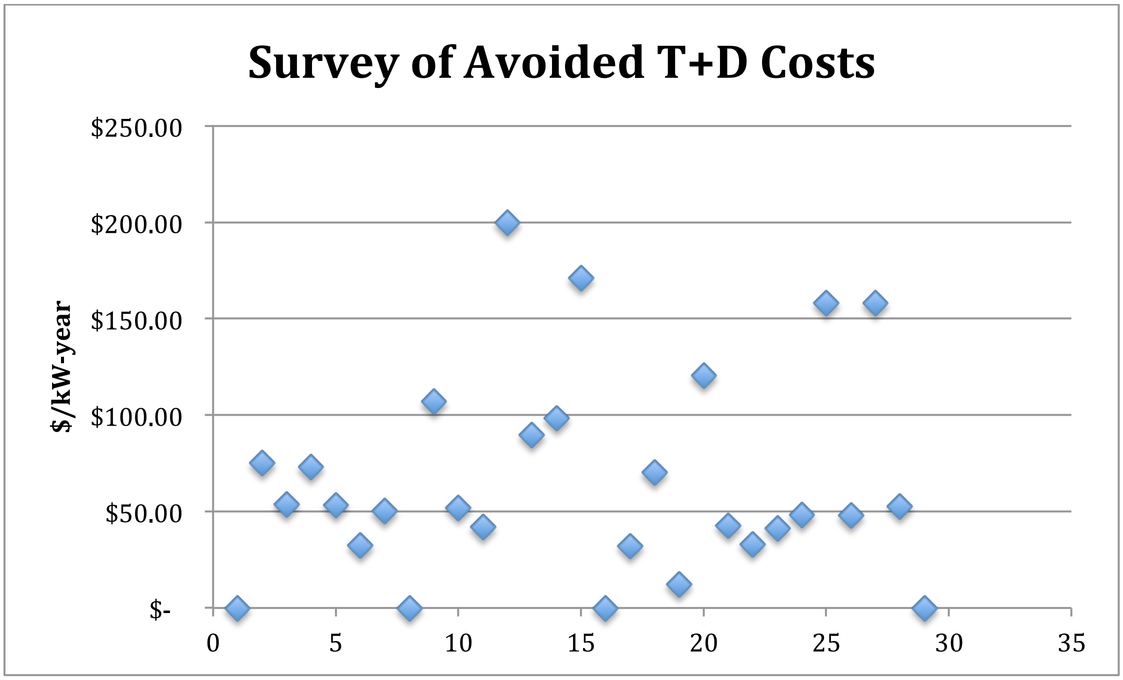


Transmission values are most heavily concentrated in the $0 to $20 range with 15 of the samples falling in this range

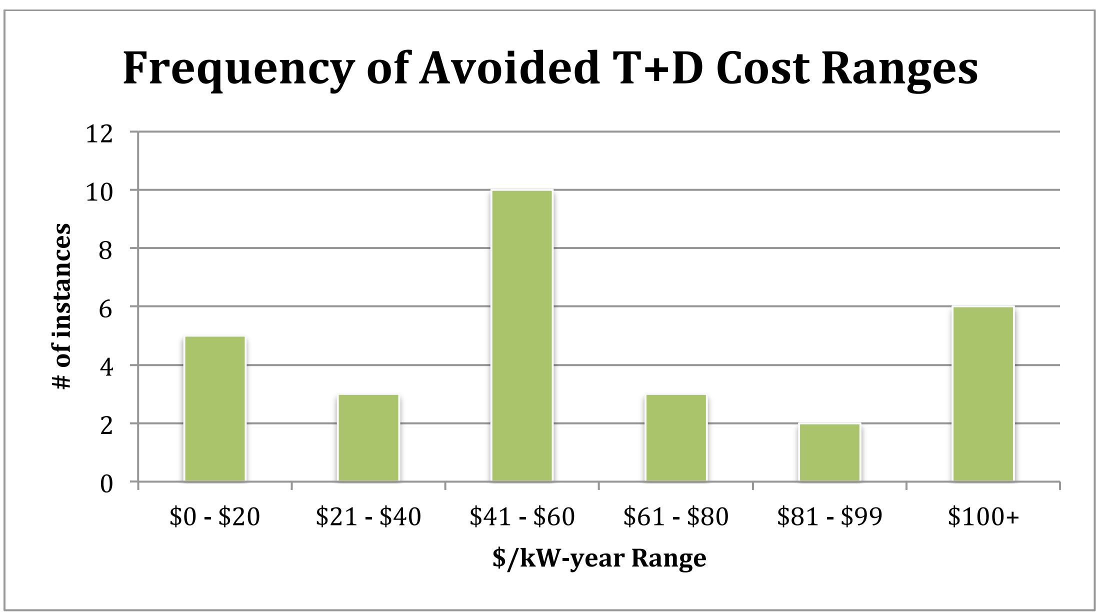


Estimates of T&D System Avoided Costs

Finally, the average avoided transmission + distribution costs are $66.03 with a range from $0 to $200.01/kW-year. It should be noted that there are more combined T&D results because some utilities did not break out T&D.



The values are most heavily concentrated in the $41 to $60 range with 10 of the samples falling in this range.



It should be further noted that the values for each entry were not adjusted for the applicable years, mainly because escalators were not available for all samples. The "oldest" data point is for 2011, so adjustments for inflation would not likely be significant.

Although this study did not explore the reasons for the differences between utility avoided costs, it is difficult to correlate relative values with overall utility retail rates or method of calculation. There can certainly be other factors that drive avoided T&D cost calculations. This is just to say that it is difficult to generalize and points out that there is a large amount of variability in estimated costs.

E. Conclusion

This study sought to investigate different ways that utilities in the United States estimated avoided transmission and distribution costs for energy efficiency cost-effectiveness evaluations that could inform its next DSM plan. The survey of methodologies and benchmarking determining that there are a variety of ways to estimate such values and a very broad range of estimates among the 35 utilities included. Given the dynamic state of the methodologies used to develop these estimates it is recommended that PSCo periodically revisit this issue and update the survey of current estimates and the methodologies used.

Appendix A – Selection of Approaches to Calculating Avoided T&D Costs

Method	Brief Description	Examples	Strengths	Weaknesses
System Planning Approach	• Uses costs and load growth for specific T&D projects based on a system planning study	• Vermont Electric Company (2003) – focused on specific transmission upgrade	• Potentially more accurate • Uses specific project data to develop estimates • Forces consideration of DER effects on project-by-project basis	• Costly and time consuming • May not be appreciably more accurate than other approaches • Dependent upon individual projects included in analysis
Mix of Historical and Forecast Information	• Uses data on historical and forecast T&D investments, determines what's related to load growth, and weights the historical and forecast contributions	• ICF Tool used in the Northeast, Vermont DPS variation	• Uses publicly available FERC Form 1 data • Easily calculated and updated • Uses a form of marginal costs • Addresses "lumpiness" of T&D investments • Used by multiple other states • Relies upon historical as well as forecast information	• Assumes it's possible to differentiate amount of T&D investment that corresponds to load growth rather than maintenance, reliability and customer growth • Does not incorporate variability associated with time/location differences • Can't readily handle low forecast growth
Current Values	• Develops average cost to serve existing load by dividing each system's net cost	• MidAmerican Energy (IA, IL, SD), Commonwealth Edison (IL)	• Uses publicly available FERC Form 1 data • Easily calculated and updated	• May tend to undervalue • Does not incorporate variability associated with time/location differences

Method	Brief Description	Examples	Strengths	Weaknesses
Rate case marginal cost data with allocators	• Uses T&D marginal cost of service data from utility rate cases and apply time and locational factors related to weather or specific substation loadings	• California IOUs	• Uses publicly available data (rate case portion) • Uses approach consistent with ratemaking • Uses time and location differentiated data • Uses marginal cost information	• Potentially costly and time consuming • May not be appreciably more accurate than other approaches • Somewhat assumes use of hourly avoided costs for Generation • Requires estimation of investments deferred by EE
Rate case marginal cost data	• Use T&D marginal cost of service data from most recent rate case	• Ameren (MO), PacifiCorp (OR, UT, WA), Nevada Energy, Consolidated Edison (NY)	• Uses publicly available data • Is approach consistent with ratemaking • Uses marginal cost information	• May not be appreciably more accurate than other approaches • Requires estimation of investments deferred by EE
IRP Method	• Uses without and without EE runs to determine avoided transmission costs	• Tucson Electric Power	• Is consistent with integrated resource plan	• Is highly dependent on IRP's model ability to calculate transmission costs • Requires integrated resource plan • Only updated as frequently as resource plan • Typically can only provide transmission
Averaging method	• Take simple average of a selection of similar	• Wisconsin Focus on Energy Market Potential Study (used Iowa)	• Uses publicly available data • Very easily calculated	• Must pick appropriate proxy utilities for averaging

Method	Brief Description	Examples	Strengths	Weaknesses
	jurisdictions	• Northwest Conservation and Electric Power Plan (used 8 utilities)		• Not specific to one utility
Simple Method	• Take representative sample of recent T&D upgrade projects, divide by increased capacity and annualize	• Unknown	• Very simple • Provides real information from specific example • Can be done for transmission, distribution and sub-transmission	• Project may not be system representative • Must still determine what portion of increased capacity relates to load growth

Appendix B – Survey of Utility Avoided Transmission and Distribution Costs

Estimated Values

State	Utility	Date of Estimate	Transmission	Distribution	O&M	Total T&D	Units
AZ	TEP	2013	N/A	N/A		$100.00	$/kW-year
AZ	APS	2013	$0	$0		$0	
CA	PG&E-Com	2011	$19.60	$55.97		$75.57	$/kW-year
CA	PG&E-Res	2011	$18.77	$55.85		$74.62	$/kW-year
CA	SCE-Com	2011	$23.39	$30.10		$53.49	$/kW-year
CA	SCE-Res	2011	$23.39	$30.10		$53.49	$/kW-year
CA	SDG&E-Com	2011	$21.08	$52.24		$73.32	$/kW-year
CA	SDG&E-Res	2011	$21.08	$52.24		$73.32	$/kW-year
CA	Weighted Average	2011	$21.20	$44.38		$65.59	$/kW-year
CT	CL&P	2013	$1.30	$30.94		$32.24	$/kW-year
CT	United Illuminating	2013	$2.64	$47.82		$50.46	$/kW-year
ID	Idaho Power	2014	$0	$0		$0	
IA	Interstate Power & Light	2014	$81.00	$26.00		$107.00	$/kW-year
IA	MidAmerican	2013	$14.85	$37.01		$51.86	$/kW-year
IL	Commonwealth Edison	2014	N/A	N/A		$42.00	$/kW-year
MA	National Grid	2013	$88.64	$111.37		$200.01	$/kW-year
MA	NSTAR	2011	$21.00	$68.79		$89.79	$/kW-year
MA	WMeco	2011	$22.27	$76.08		$98.35	$/kW-year
MA	Unitil	2013	$0	$171.15		$171.15	$/kW-year
MI	Consumer's Energy	2012	$0	$0		$0	
MN	Xcel	2014	$14.31	$38.85		$53.17	$/kW-year
MO	Ameren	2014	$22.00	$10.00		$32.00	$/kW-year
NH	PSNH	2013	$16.70	$53.35		$70.05	$/kW-year
NW	NW Conservation and Electric Power Plan utilities	2010	$0	$23.00		$66.59	$/kW-year

State	Utility	Date of Estimate	Transmission	Distribution	O&M	Total T&D	Units
NV	Sierra Pacific Power dba Nevada Energy	2013	N/A	N/A		$12.23	$/kW-year
NY	Consolidated Edison (Network)	2013	$0	$120.52		$120.52	$/kW-year
NY	Consolidated Edison (Non-Network)	2013	$0	$42.63		$42.63	$/kW-year
OR	PacifiCorp	2011	$36.89	$15.75		$52.64	$/kW-year
OR	PGE	2011	$10.80	$22.40		$33.20	$/kW-year
RI	National Grid	2013	$20.62	$20.62		$41.24	$/kW-year
SD	MidAmerican	2012	$13.79	$34.37		$48.16	$/kW-year
UT	PacifiCorp	2011	$36.89	$15.75		$52.64	$/kW-year
VT	Burlington Electric Department (Prescriptive Programs)	2013	N/A	N/A		$158	$/kW-year
VT	Burlington Electric Department (Custom Programs)	2013	N/A	N/A		$48	$/kW-year
VT	Efficiency Vermont	2013	$34.25	$93.25	$50.00	$158.15	$/kW-year
WA	PacifiCorp	2011	$36.89	$15.75		$52.64	$/kW-year
WI	Focus on Energy		$0	$0		$0	

N/A refers to instances where the utility did not break out the individual transmission and distribution values.

Methods and Data Sources

State	Utility	Method	Data Source for Calcs	Notes
AZ	TEP	Calculated avoided G&T using IRP. Developed $/kW-year based on G&T costs avoided by selected DSM portfolio.	IRP	TEP considers the avoided capacity costs confidential as part of their Resource Plan. They do not provide detail in their EE Plan beyond the SCT (Societal Cost Test). Not included in averaging calcs.
AZ	APS			Does not specifically incorporate an avoided capacity value for T&D. Includes line losses for energy and capacity.
CA	PG&E-Com	The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time with the addition of distributed energy resources.	General Rate Case	Only included PG&E Com/Res average in averaging calcs and graphs.
CA	PG&E-Res			
CA	SCE-Com		FERC Form 1	Only included one SCE in averaging calcs and graphs.
CA	SCE-Res		FERC Form 1	
CA	SDG&E-Com	The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time with the addition of distributed energy resources.	General Rate Case	Only included one SDG&E in averaging calcs and graphs.
CA	SDG&E-Res			They are the same values used for the 2011 CEC California Building Energy Standards, and the CPUC CSI and DR proceedings.
MN	Xcel		Internal	
CT	CL&P	ICF Tool	FERC Form 1	
CT	United Illuminating	Black & Veatch Report		United Illuminating Avoided Transmission & Distribution Cost Study Report, Black & Veatch, September 2009.
IA	Interstate Power & Light		MISO Att. O for T.	
IA	MidAmerican	The average cost to serve existing load is calculated for both the transmission and distribution systems by dividing each system's net cost by each system's peak capability. MidAmerican's Federal Energy Regulatory Commission (FERC) Form 1 data is used to calculate the net costs of the transmission	FERC Form 1	Iowa EE rules do not required avoided T&D. Is done as an alternative calculation - rules dictate use of a CT for avoided capacity costs and provides the formula. Ratepayer advocates currently advocating for use of MISO Attachment O rates for avoided transmission

State	Utility	Method	Data Source for Calcs	Notes
		and distribution systems by taking MidAmerican's original cost of plant less accumulated depreciation for each respective system. MidAmerican T&D avoided costs are calculated using depreciated original cost figures listed in FERC Form 1.		(Docket INU-2014-0001)
IL	Commonwealth Edison	ComEd conducted an updated analysis to place a value on the avoidance or deferral of new transmission and distribution capacity as a result of energy efficiency. The most recent analysis determined that an avoided T&D cost of $42/yr. is appropriate for cost-effectiveness analysis.		8-27-14: The avoided T&D cost is from an internal study and does not have a breakdown between T and D.
MA	National Grid	ICF Tool	FERC Form 1	
MA	NSTAR	ICF Tool	FERC Form 1	
MA	WMeco	ICF Tool	FERC Form 1	
MA	Unitil	ICF Tool	FERC Form 1	
MI	Consumer's Energy			*While the cost of building transmission and distribution systems -- by either building with less capacity or avoiding building completely – theoretically might be avoided, Consumers Energy's current transmission and distribution systems are typically adequate to meet customers' needs. The current situation, relative to numbers of customers and demand, would need to substantially change before costs of building transmission and distribution systems could be avoided.*
MN	Xcel		Internal	
MO	Ameren	Rate case marginal costs	2010 Rate Case	
NH	PSNH	ICF Tool	FERC Form 1	
NW	NW Conservation and Electric Power Plan utilities	Used benchmarked data to come up with "representative" value. Estimated a value of $25 for transmission, but did not adopt. See notes.	Regional Technology Forum (RTF)	Is part of 6th 5-year Power Plan. Planning for 7th began in 2014. "The Council adopted the RTF recommended value for distribution system avoided cost. However, because the value of avoiding the transmission system investments is

State	Utility	Method	Data Source for Calcs	Notes
				already included in the wholesale market prices produced by the AURORA model the Council did not use the RTF estimate of the benefits of deferring transmission system expansion so as to avoid double counting." (p. E-14).
NV	Sierra Pacific Power dba Nevada Energy	Is the annual revenue requirement for T&D impacted by EE. Submitted as marginal cost study with rate case. 13-06002	Rate case T&D costs	Uses "conservative value" of 25% of T&D revenue requirements of $49.92 (was $47.50 in 2010 rate case). Does not account for distribution costs beyond the substation. Uses "PortfolioPro" cost benefit model developed for them by Cadmus. However, in IRP NVEnergy recognizes that its T&D costs are low based on Synapse's best practices study.
NY	Consolidated Edison (Network)	Marginal costs associated with load growth	Utility marginal cost data	Study developed in response to requirement from NY Public Service Commission. Network resources are associated with underground low-voltage distribution systems such as in downtown NYC. Emergence of T avoided costs do not occur until 2017.
NY	Consolidated Edison (Non-Network)	Marginal costs associated with load growth	Utility marginal cost data	Study developed in response to requirement from NY Public Service Commission. Non-Network resources are associated with radial distribution systems. Emergence of T avoided costs do not occur until 2017.
OR	PacifiCorp	Regulation Department provides as input to the IRP. Represents "an average of the values from a marginal cost of service study from the company's last 5 general rate cases for demand-related substation and transmission costs."	Rate case T&D revenue requirements	The resource deferral fixed cost benefit is comprised of the deferred capital recovery and fixed operation and maintenance costs of a "next best alternative" resource—a combined- cycle combustion turbine (CCCT).
OR	PGE	ICF Tool	FERC Form 1	
RI	National Grid	ICF Tool	FERC Form 1	
SD	MidAmerican	Avoided distribution costs are calculated by determining the economic carrying charge associated with MidAmerican's net distribution investment on a $/kW basis; Avoided transmission capacity costs are calculated by determining the economic carrying charges associated with MidAmerican's net transmission investment on a	FERC Form 1 and utility discount rates	Same values as Iowa and, therefore, not duplicated in averaging calcs

State	Utility	Method	Data Source for Calcs	Notes
		$/kW basis, where kW refers to the total transmission system capacity.		
UT	PacifiCorp	See OR		Same values as Oregon, and, therefore, not duplicated in averaging calcs
VT	Burlington Electric Department (Prescriptive Programs)			Different values for prescriptive and custom programs. Prescriptive values decline over time. Is 2012 $. Order on 12/13/2012 in Docket EEU-2011-02
VT	Burlington Electric Department (Custom Programs)	VT Department of Public Service adapted ICF Tool. Method used by AESC 2013, applicable to Vermont.		
VT	Efficiency Vermont	VT Department of Public Service adapted ICF Tool. Method used by AESC 2013, applicable to Vermont.		The statewide estimates are based on load-related investments in the last decade for which Vermont experienced significant load growth, ending in 1996. Adds O&M and then subtracts a "T&D offset". Order on 12/13/2012 in Docket EEU-2011-02, See values below through 2040
WA	PacifiCorp	See OR		Same values as Oregon and, therefore, not duplicated in averaging calcs
WI	Focus on Energy	$-	$-	Does not currently include avoided T&D in FOE cost effectiveness evaluations. Discussed possibility but felt that the effort would require considerable analysis to determine what was avoided. Uses MISO forecasted LMPs as primary energy avoided costs (no capacity apparently). But LMPs theoretically incorporate all (G, T&D). ECW 2009 market potential study incorporate $30/kW-year value in its analysis based on Iowa utilities' calculations.

ATTACHMENT BH-5

STATE OF IOWA

BEFORE THE IOWA UTILITIES BOARD

IN RE:	:	
	:	
MIDAMERICAN ENERGY COMPANY	:	**Docket No. EEP-2018-0002**
	:	

**DIRECT TESTIMONY
OF
JENNIFER L. LONG**

Q. Please state your name and business address.

A. My name is Jennifer L. Long. My business address is 106 East Second Street, Davenport, Iowa 52801.

Q. By whom are you employed and in what capacity?

A. I am employed by MidAmerican Energy Company ("MidAmerican") as Senior Engineer – System Planning and Services.

Q. Please describe your educational and business experience.

A. I graduated from Iowa State University in 2009 with a Bachelor of Science degree in Electrical Engineering. I began working for MidAmerican in 2010 as an Engineer in the Electric System Planning Department. I am a licensed Professional Engineer in the state of Iowa. I am a member of the Institute of Electrical and Electronics Engineers.

Q. What are your principal responsibilities at MidAmerican?

A. My present duties include the development of short- and long-range plans for electric transmission line and transmission substation expansion projects, and electric distribution line and distribution substation expansion projects in the Council Bluffs/southwest Iowa area. I also support the development of the 10-year electric delivery capital budget for the Council Bluffs/southwest Iowa area, including the development of planning and capital budget studies demonstrating need and establishing the priority of Council Bluffs/ southwest Iowa capital projects. I conduct computer-based system power flow, voltage flicker, reliability, and economic analysis studies.

Q. Have you previously testified before the Iowa Utilities Board ("Board") or other regulatory bodies?

A. Yes, I provided written testimony for MidAmerican's Iowa Energy Efficiency filing in Docket No. EEP-2012-0002.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor part of the information MidAmerican is required to file under 199 IAC 35.9(7), Avoided Electric Capacity and Energy Costs in support of MidAmerican's 2019-2023 Energy Efficiency Plan filing ("Plan").

Q. Are you sponsoring an exhibit in the filing?

A. Yes. I am sponsoring Application Exhibit 12 Additional Requirements for Electric Utilities (4 of 4), which includes the following schedules regarding MidAmerican's avoided cost calculations:

- Schedule 1: Avoided Cost Calculation - Transmission
- Schedule 2: Avoided Cost Calculation - Distribution

Q. Which filing requirements contained in 199 IAC 35.9(7) does your testimony address?

A. My testimony describes the methodology, calculations, and results for determining avoided transmission and distribution ("T&D") costs.

Q. Do the current Iowa administrative rules concerning energy efficiency plan filings include a requirement to supply avoided T&D costs?

A. No, it is my understanding the rules do not require the filing of avoided T&D costs. However, the rules allow for filing an "alternative method." Section 35.9(7) includes the statement, "A party may submit, and the board shall consider, alternative avoided capacity and energy costs derived by an alternative method. A party submitting alternative avoided cost shall also submit an explanation of the alternative method." The avoided T&D costs submitted in my testimony and outlined in Application Exhibit 12 Additional Requirements for Electric Utilities (4 of 4) Schedule 1 and Schedule 2, should be considered an alternative method of computing a portion of the avoided capacity and energy costs. These avoided T&D costs are to be added to the avoided generation capacity costs that are submitted in MidAmerican witness Hammer's testimony and presented in his Application Exhibit 12 Additional Requirements for Electric Utilities (3 of 4) Schedule 8. The resultant totals, including addition of the avoided T&D costs, are shown in his Application Exhibit 12 Additional Requirements for Electric Utilities (3 of 4) Schedule 9.

Q. Why has MidAmerican prepared avoided T&D costs?

A. MidAmerican prepared avoided T&D costs because additional capacity demand on the T&D system may cause a need for T&D system additions and improvements. A reduction in the growth of system demand may delay the need for T&D system additions and improvements and, therefore, may have the benefit of avoiding these future transmission and distribution related costs.

Q. What characteristics should a methodology have to calculate avoided T&D costs?

A. Given the complexity of identifying the precise impacts of reduced system demand on T&D system additions and improvements, a fundamental aspect of an avoided cost methodology is that it should estimate the average avoided cost per kW associated with reduced system demand. A methodology for estimating the avoided cost should have the following features:

- Estimate actual average system avoided T&D cost; and
- Be transparent and reproducible.

Q: Is the approach used to determine T&D avoided cost in this Plan filing the same approach used in MidAmerican's prior energy efficiency filings?

A. Yes.

Q: Were any additional cost elements considered in this Plan filing that were not considered in MidAmerican's prior energy efficiency filings?

A. Yes. Since MidAmerican's last energy efficiency plan filing in 2012, the Midcontinent Independent System Operator, Inc. ("MISO") conceptualized and approved 17 transmission projects that make up a multi-state regional plan called Multi Value Projects ("MVP"). As a MISO member, MidAmerican not only constructed several MVP transmission lines, but also shares in the costs of these projects with the other MISO members. As explained below, these MVP costs are not included in my T&D avoided cost approach in support of the current Plan filing.

Q: You stated that costs associated with the MVPs should not be included in T&D avoided cost calculations. Why wasn't this adjustment needed in prior energy efficiency filings?

A. MidAmerican did not have any MVP costs in the test years used in prior energy efficiency filings. As such, no adjustments were needed.

Q. Please explain MidAmerican's methodology used to calculate avoided T&D costs.

A. Capital Costs. The average cost to serve existing load is calculated for both the T&D systems by dividing each system's net cost by each system's peak load. MidAmerican's Federal Energy Regulatory Commission ("FERC") Form 1 data is used as the basis to calculate the net capital costs of the T&D systems by taking MidAmerican's original cost of plant less accumulated depreciation for each respective system. Adjustments are also made to remove capital costs that are not dependent on system load levels, such as the MVPs. MidAmerican's annual load data is used to approximate the capacity of each system. The calculation results in a $/kW cost for each system.

Operations and Maintenance ("O&M") Costs. In addition to the capital costs, O&M costs are included in the calculations of T&D avoided cost. However, adjustments are made to remove the O&M costs that are not dependent on system load levels. The following transmission costs were removed from the transmission O&M costs found in FERC Form 1: 1) the MISO Schedule 26A charge; 2) MidAmerican's wheeling charge (MISO tariff Schedules 7, 8, 26 and 45); and 3) MVP O&M charges (see below for more detail). The resulting transmission O&M rate is 2.28% of net transmission plant. The following distribution costs were removed from the distribution O&M costs found in FERC Form 1: 1) street lighting and signal system expenses; 2) meter expenses; 3) maintenance of street lighting and signal systems; and 4) maintenance of meters. The resulting distribution O&M rate is 5.2% of net distribution plant.

In summary, MidAmerican's T&D avoided cost is calculated using depreciated original cost figures based on FERC Form 1 data with adjustments as noted above. These figures are used to calculate the net cost per kW of capacity on the transmission and distribution systems, respectively. This cost is then spread across the average book life of the transmission system (46 years) or distribution system (39 years), using the economic recovery method as shown in the Application Exhibit 12 Additional Requirements for Electric Utilities (4 of 4). This process results in a calculation of MidAmerican's yearly T&D avoided cost. Using MidAmerican's economic data and data from FERC Form 1, as shown in Application Exhibit 12 Additional Requirements for Electric Utilities (4 of 4) Schedule 1 for transmission or Schedule 2 for distribution, the year-one economic recovery rates are calculated to be 4.55% and 4.86%, respectively.

Q. Please explain why the costs associated with MidAmerican's investment in the MVPs were excluded in the calculation of T&D avoided cost in the Plan.

A. The FERC Form 1 data in 2016 was used to calculate MidAmerican's Plan avoided cost, and this data includes MVP costs. MidAmerican will continue to incur costs associated with its MVP investments for the foreseeable future. There are several reasons why these costs must be excluded in the T&D avoided cost calculation. First, including such costs would be contrary to the Board's order in MidAmerican's most recent retail electric rate case in Docket No. RPU-2013-0004. The Board required that transmission costs recoverable in MidAmerican's retail rates must be kept separate from costs recovered under the MISO rate mechanisms. To include MVPs costs as a driver in the energy efficiency program evaluations would be inconsistent with the Board's order.

Second, MidAmerican's MVP investments are segregated into separate accounts in recognition of the extraordinary nature of the MVPs in terms of where revenues are collected to pay for the projects. In RPU-2013-0004 the Board found that MidAmerican's MVP investments should be separately accounted for and that the portion of the MVP costs allocable to MidAmerican's Iowa retail customers should be recovered in the same manner as other regionally-based costs, such as the costs MISO assigns MidAmerican for all the other MVP investments across the MISO footprint. This separate accounting is appropriate because MidAmerican's MVP investments were not primarily incurred to serve MidAmerican's retail load and would not have been constructed solely on the basis of serving MidAmerican's retail load. Rather, the MVPs as a whole, including MidAmerican's MVP investments, were constructed to enable a series of benefits across the entire MISO region and the costs are allocated on that same basis.

Further, energy efficiency programs will have no effect on the MVP costs due to the nature of the MVPs. The MVP projects are driven by a series of benefit metrics across MISO's multi-state regional footprint, metrics that are not limited to only growing load, but include improving grid reliability, relieving transmission constraints, providing for generation resource optimization, and meeting state renewable portfolio requirements.

Q. Using the method described above, what is the calculated Transmission avoided cost for 2016?

A. The 2016 year-end balance of the total original cost for the MidAmerican transmission system is $1,722,416,645, which includes MVPs, depreciable and amortizable assets. Therefore, to obtain the system net cost, the MVP cost, $442,165,757 at year-end, and the transmission system accumulated depreciation, $462,476,215 at year-end, must both be deducted from the original cost. Subtracting accumulated depreciation and amortization from original cost results in a net cost of $817,774,673 for the MidAmerican transmission system.

Since the purpose of the transmission system is to provide a path for power flow from the generators to the distribution system, the capacity of the transmission system is assumed to be equal to the total MidAmerican peak load.[1] The FERC Form 1 reports MidAmerican's load of 4,698 MW in July 2016. To obtain a net cost per kW, the net cost of the transmission system is divided by the total load, which results in a net cost of $174.07 per kW. This cost is then spread across the average book-life of the transmission system (46 years) using the economic recovery method. The 46 years of annual revenue requirements for the $174.07 per kW cost are then calculated in Application Exhibit 12 Additional Requirements for Electric Utilities (4 of 4) Schedule 1, which results in a present value of the annual costs of $320.57. Multiplying this figure by the transmission economic recovery rate, 4.55%, results in a transmission year-one avoided cost of $14.59/kW.

Q. Using the approach described above, what is the calculated Distribution avoided cost for 2016?

A. The same basic approach described above to calculate the transmission avoided cost per kW is used for the distribution system. The original cost of the distribution system listed in FERC Form 1 is $2,727,507,099. However, this figure must be adjusted to calculate an avoided cost for the distribution system. The costs for "Services," "Meters" and "Street Lighting and Signal Systems," listed in FERC Form 1 are not included in calculating an avoided cost because these costs will not change as load is reduced. They are required to

[1] Due to reasons discussed above, this capacity assumption does not include MVPs.

serve customers with or without an energy efficiency load reduction; therefore, they are subtracted from the original cost figure. Removing the original costs of services, meters, street lighting and signal systems results in an adjusted distribution system cost of $2,395,117,790.

The total accumulated depreciation of the distribution system listed in FERC Form 1 is $1,113,977,616. The accumulated depreciations of the three removed items noted above must also be subtracted from the total accumulated depreciation. This results in an adjusted accumulated depreciation of $968,804,217. Subtracting adjusted accumulated depreciation from adjusted total distribution system cost results in a net cost of $1,426,313,573.

To determine a cost per kW, the net cost figure is divided by the capacity of the distribution system. The capacity of the MidAmerican distribution system is estimated to be the transmission system peak load less transmission (97.8 MW), high voltage distribution (5.4 MW), and generator step-up transformer losses (11.3 MW); the resulting 2016 net peak load was 4,583 MW. This number includes distribution system losses occurring from the distribution substation to the customer. Dividing the net cost of the distribution system by this figure results in a cost per kW of $311.22. This cost is then spread across the average book-life of the distribution system (39 years) using the economic recovery method. The 39 years of annual revenue requirements for the $311.22 per kW cost are then calculated in Application Exhibit 12 Additional Requirements for Electric Utilities (4 of 4) Schedule 2, and result in a present value of the annual costs of $657.28 per kW. Multiplying this figure by the distribution economic recovery factor, 4.86%, results in a distribution year-one avoided cost of $31.94/kW.

Q. Why are T&D system losses applied to the T&D avoided costs?

A. Some component of system loss always occurs when load is served from the T&D system. Therefore, the T&D avoided costs need to be increased by a loss factor. Since energy efficiency measures reduce energy usage at the customer meter, their impact on system capacity also includes losses incurred to serve loads at the meter. The transmission and distribution systems have loss factors of 2.559% and 4.936%, respectively. It is appropriate to increase the transmission avoided cost estimate by the sum of the two loss factors (7.495%), because avoided losses on either system will free capacity on the transmission system. The distribution avoided cost estimate is only increased by the distribution system loss factor (4.936%) because avoided losses on the transmission system will not affect the distribution system; only avoided distribution system losses will free capacity on the distribution system. The increase in avoided T&D costs to reflect reduced losses has been completed in Application Exhibit 12 Additional Requirements for Electric Utilities (4 of 4) Schedule 1 and Schedule 2.

Q. How are the T&D avoided costs modified to reflect that the energy efficiency programs begin in 2019?

A. Since the calculations used costs and loads from 2016, the T&D avoided costs are escalated to 2019 in order to represent MidAmerican's avoided costs associated with energy efficiency programs beginning in 2019. An escalation rate of 2.25% was used.

Escalating the avoided cost estimates by 2.25% to represent the three-year period 2016-2019 results in a 2019 avoided cost for transmission of $16.77 per kW and for distribution of $35.83 per kW. These values are shown in the "year 4" rows of Application Exhibit 12 Additional Requirements for Electric Utilities (4 of 4) Schedule 1 and Schedule 2. These figures estimate total T&D avoided costs to MidAmerican associated with load reductions from energy efficiency programs.

Q. The calculations for determining energy efficiency program cost-effectiveness require avoided costs for a 20-year period. Have you determined avoided T&D costs for years 2019 through and including 2039?

A. Yes, Application Exhibit 12 Additional Requirements for Electric Utilities (4 of 4) Schedule 1, years 4 through 24 on page 2, shows the transmission avoided costs for years 2019 through 2039, and Application Exhibit 12 Additional Requirements for Electric Utilities (4 of 4) Schedule 2, years 4 through 24 on page 2, shows the distribution avoided costs for years 2019 through 2039.

Q. Are there any energy efficiency programs that should not include the avoided T&D costs to determine the programs' benefits?

A. Yes. Load management programs may not provide savings on the distribution system because the programs are not operated based on peaks on the *distribution* system. For example, a residential distribution feeder or substation may peak on a hot evening after 7:00 p.m., while a residential air conditioner control program would only be called into operation between 2:00 and 7:00 p.m. Some load management programs can even have negative impacts on the distribution and/or transmission system, to the extent that customers increase loads in hours directly preceding or following curtailment events. For this reason, MidAmerican estimates no savings from avoided distribution capacity costs when evaluating load management programs.

Q. Does this conclude your direct testimony?

A. Yes, it does.