OFFICIAL FILING
BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric for Approval of Proposed Changes to its Parallel Generation Tariffs	3270-TE-114

DIRECT TESTIMONY OF DIVITA BHANDARI ON BEHALF OF RENEW WISCONSIN

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Divita Bhandari and I am a Senior Associate with Synapse Energy Economics, Incorporated (Synapse). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q. Please summarize your professional experience.

A. At Synapse, I provide research and consulting services on a wide range of energy and electricity issues, focusing on grid infrastructure issues, resource planning, policies around distributed energy resources, energy efficiency, and electricity markets. I also have significant experience with electric system modeling, and the development of avoided costs including avoided energy, transmission, and capacity costs for different jurisdictions including New England, New York, District of Columbia, Hawaii, and Puerto Rico.

I have been employed at Synapse since 2018. Before that, I was a Senior Energy Analyst at DNV GL. My early career was spent working as an electrical engineer on gas turbine, wind turbine, and solar product development.

Q. Please summarize your educational background.

A. I hold a Master of Environmental Management from the Yale School of Forestry and Environmental Studies, a Master of Science in Electrical Engineering, specializing in Electric Power systems, from the Georgia Institute of Technology, and a Bachelor of Science in Electrical Engineering, also from the Georgia Institute of Technology. A copy of my current resume is attached as Ex.-RENEW-Bhandari-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of RENEW Wisconsin, Inc. (RENEW).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate the reasonableness of Madison Gas and Electric's (MGE) proposed avoided transmission and capacity costs, including the methodologies underlying the calculation for the proposed avoided costs. I present alternative avoided cost calculation methodologies, values, and credit structures that more appropriately capture the value of avoided costs for transmission and capacity. I also evaluate the reasonableness of MGE's proposed application of those avoided costs to front-of-the-meter (FTM) and behind-the-meter (BTM) Qualifying Facilities (QFs) through buyback rates in the Company's proposed tariffs.

Q. Have you testified previously before the Public Service Commission of Wisconsin?

A. Yes, I have previously provided direct testimony in Docket No. 4220-TE-109 which is Northern States Power Company Wisconsin's (NSPW) application for updates to its parallel generation tariffs. I have also provided direct testimony in Docket No. 6880-TE-107, which is Wisconsin Power and Light Company's (WPL) application for updates to its parallel generation tariffs and Docket No. 6630-TE-107 and Docket No. 6690-TE-114, which are Wisconsin Electirc Power Company's (WEPCO) and Wisconsin Public Service Corporation's (WPSC) application for updated to parallel generation tariffs. My testimony in this proceeding includes many of the same concepts that I discussed in my testimony in Docket No. 4220-TE-109, Docket No. 6880-TE-107, Docket No. 6630-TE-107 and Docket No. 6690-TE-114.

I have also submitted expert testimony in Colorado in a proceeding regarding Public Service Company of Colorado's 2021 Electric Resource and Clean Energy Plan on behalf of the Colorado Energy Office (Proceeding No. 21A-0141E). I have also assisted in preparing testimony in proceedings related to rate cases and infrastructure investment programs in New Jersey, evaluating distribution system investments on behalf of the New Jersey Division of Rate Counsel.

Q. Have you developed methodological approaches for avoided costs used by utilities when evaluating the cost-effectiveness of DERs?

A. I co-wrote the chapter on Avoided Transmission and Distribution costs for the Avoided Energy Supply Components (AESC) study which outlines a methodological approach for the development of avoided costs in New England for cost-effectiveness testing of energy efficiency programs. The study is sponsored by a combination of electric and gas utilities and efficiency program administrators in New England.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. I conclude that:

- MGE's proposed value of zero for avoided transmission cost ignores the benefit that QFs provide through load reduction.
- The Company does not justify its proposal to credit BTM resources with a capacity credit based on capacity auction results.
- The Company has not appropriately addressed the application of loss factors to avoided transmission, capacity and energy.

Q. Please summarize your primary recommendations.

A. I recommend that the Commission:

- Approve the value of $70.82/kW-year for avoided transmission costs;
- Approve my proposed methodology that accounts for marginal load growth-related transmission investments going forward and require that the utilities conduct a similar analysis and provide all stakeholders

transparency concerning the inputs, assumptions, and results from such analysis;

- Approve the use of marginal losses for both avoided transmission and avoided capacity, valued at double the average losses on MGE's system;
- Approve the use of marginal losses for avoided energy valued at 1.5 the average losses on MGE's system;
- Approve the application of the Midcontinent Independent System Operator's (MISO) Cost of New Entry (CONE) to BTM resources similar to the proposed avoided cost applied to FTM resources;
- Approve the application of transmission credits to FTM resources on a $/kW-month basis similar to the proposed methodology for capacity credits; and
- Approve the application of transmission credits to BTM resources on a $/kWh basis similar to proposed methodology for capacity credits.

III. AVOIDED TRANSMISSION COSTS

A. Concerns with MGE's Proposal

Q. Does MGE propose to credit QFs for avoided transmission costs?

A. No. The Company has not proposed to credit parallel generation resources for avoided transmission costs.

Q. How does the Company explain its failure to identify avoided transmission costs resulting from parallel generation resources?

A. The Company has included a transmission service credit of $0.00/kWh as a placeholder and acknowledged that Customer-Owned Generation Systems

(COGS) may impact utility transmission costs. However, MGE claims that due to the large growth of COGS in MGE's and other utility service territories, any transmission value should be calculated from a holistic view with the collaboration of American Transmission Company (ATC) (Direct-MGE-Denu-8).

Q. How do you respond to MGE's claims regarding avoided transmission costs resulting from parallel generation resources?

A. It is my understanding that the Commission asked MGE to model avoided transmission costs in its May 4, 2021 Order in Docket 5-EI-157. However, MGE did not do so in advance of filing its application. I agree that the transmission costs are driven by the transmission owner's (American Transmission Company or ATC) costs and these costs should ideally be developed in collaboration with ATC. MGE had an opportunity to collaborate with ATC in order to obtain an avoided transmission credit but has not done so. However, the Company's failure to work with ATC in developing this value does not justify using a zero avoided transmission cost as placeholder.

Q. How should MGE have evaluated avoided transmission costs?

A. I will describe my methodology for developing avoided transmission costs in further detail below. My analysis is based on publicly available data including transmission costs and load growth obtained through the MISO Transmission Expansion Planning Process (MTEP) and the Strategic Energy Assessment (SEA) respectively. Given the availability of public data, the Company should have evaluated avoided transmission costs by evaluating its *marginal load-growth-*

related costs in order to arrive at a reasonable estimate for avoided transmission costs instead of assuming a zero avoided transmission cost.

Q. Why should the Company develop avoided transmission costs based on marginal costs?

A. Distributed generation resources can avoid (or cause) changes in utility infrastructure needs going forward; they cannot change past investments. Load reductions from distributed generation can contribute to avoiding the further addition of load-related transmission facilities. Marginal costs are defined as the change in per unit costs as the result of a small change in output and therefore represent the cost of having to produce an incremental unit of output. A marginal cost approach aims to capture the forward-going avoidable costs, while not including past, embedded costs. Where data are available, the marginal costs should be based on prospective transmission capital investments for the purpose of accommodating load growth.

Historical data regarding investment and load growth would only be used in circumstances where forward looking costs are not available or when there is not substantial relevant data available into the future. Historical load growth related capital costs are not the same as embedded costs since they represent load growth related investments in the transmission system whereas embedded costs represent the revenue requirements that have been developed for the purpose of setting rates. The methodologies applied to developing revenue requirements do not capture the costs that can be avoided since they are developed for an entirely different purpose. In cases where historical data are used to develop marginal costs, the capital investments would likely already be a part of the embedded transmission revenue requirements. However, they can still present the best available way to value avoided costs going forward since they calculate a value based on investment that could have been avoided through load reductions from distributed generation.

Q. Please explain why the Company should focus on load growth-related investments to evaluate its avoided transmission costs.

A. Not all transmission investments are avoidable. Transmission-related investments can fall into numerous categories. This may include investments meant to replace aging assets, investments required to meet reliability standards, investments required to interconnect new generation resources, and load growth-related investments.

Load growth-related investments are those that are required to accommodate increased peak demand on the transmission system. This may also include "upsizing" of assets built for a non-load growth-related purpose. For example, if a transformer needs to be replaced due to its age or condition, the utility may choose to "upsize" it by replacing it with a larger transformer in anticipation of forecasted load growth. Therefore, for every kW of peak load growth that is reduced on the transmission system through investments in distributed generation, there is an equivalent transmission-related cost (in $/kW) that can be avoided due to these investments.

Q. Does MGE own transmission assets?

A. My understanding is that MGE does not own transmission assets. Transmission assets in MGE's territory are owned and operated by ATC. ATC is the transmission owner for transmission assets that serve WEPCO, MGE, WPSC, WPL and for investor-owned utilities in the Upper Peninsula of Michigan.

Q. Have you estimated MGE's avoided transmission costs?

A. Yes. However, since MGE itself does not own transmission, the transmission needs assessment is driven by planning initiatives conducted by ATC which serves transmission needs in parts of Wisconsin including MGE territory. Therefore, our assessment of avoided transmission costs is based on estimated costs and future transmission needs that are identified by ATC and which will eventually be passed down to customers within MGE territory. In Section III.B. of my testimony, I will describe methods that can be used to estimate ATC's (and thereby MGE's) avoided transmission costs within a reasonable range of certainty. I will also describe my application of those methods and the results of my analysis.

Q. Please describe your next concern with MGE's proposal for calculating and crediting avoided transmission costs for QFs.

A. My next concern is that the Company has not addressed how these avoided transmission costs can be translated to applied rates. As discussed above, since the Company has not identified a value for avoided transmission costs, they have also chosen to ignore how these costs could be translated to rates if they were to identify a transmission value in the future. I discuss this concern in greater detail in Section VI of my testimony—Application of Avoided Costs in Rates—and suggest a methodology for how these transmission costs can be translated into rates for different resources.

B. Proposed Methodology for Calculating Avoided Transmission Cost

Q. You mentioned earlier that it is possible to estimate the value of avoided transmission within a reasonable range of certainty. Please describe your proposed method for calculating avoided transmission cost.

A. The following method can be used to calculate avoided transmission costs:

- Step 1: Select a time period for the analysis, which may be historical, prospective, or a combination of the two. (A prospective period is preferred if data are available.)
- Step 2: Determine the actual or expected relevant load growth in the analysis period, in megawatts (MW).
- Step 3: Estimate the load-related transmission investments in dollars incurred to meet that load growth.
- Step 4: Divide the result of Step 3 by the result of Step 2 to determine the cost of load growth in $/MW or $/kW.
- Step 5: Multiply the results of Step 4 by a levelized annual carrying charge to derive an estimate of the avoidable capital cost in $/kW per year.
- Step 6: Add an allowance for operation and maintenance (O&M) of the equipment, to derive the total avoidable cost in $/kW per year.

Q. Have you analyzed MGE's avoided transmission costs based on this six-step methodology?

A. Yes. As discussed above, our assessment of avoided transmission costs is based on the costs incurred by ATC to meet load growth within the region (which includes MGE territory). Therefore, I have analyzed ATC's avoided transmission costs that will be passed down to MGE customers. As indicated in Ex.-RENEW-Bhandari-2, based on zonal rates for February 2022, the $/MW-year rate for each of ATC's Wisconsin customers is identical. Therefore, my analysis of MGE's avoided transmission costs is substantially identical to my analysis of avoided transmission costs for each of the other three utilities that drive ATC transmission costs in Wisconsin (WEPCO, WPL and WPSC). Below, I describe my analysis of avoided transmission costs for all four utilities in Wisconsin that fall within ATC transmission service territory.

Q. Please describe each step of your analysis, starting with your choice of a time period for the analysis (Step 1).

A. My choice of time period was based on the availability of data for historical and future transmission capital investments. Based on the publicly available data, I selected an analysis period that extends from 2021 to 2029. This is consistent with transmission planning and modeling processes that typically look five to ten years into the future.[1] However, the value represents forward-looking costs and can continue to be used outside of this analysis period.

---

[1] On an annual basis, MISO builds 2-year out, 5-year out, and 10-year out power flow models.

Q. How did you determine the actual or expected relevant load growth during the analysis period (Step 2)?

A. In order to determine the relevant load growth in the analysis period, I used the various filings from the 2028 SEA data labeled Assessment of Electric Demand and Supply Conditions Monthly Peak Demand (MW) (Ex.-RENEW-Bhandari-3) for each of the utilities that drive ATC transmission costs in Wisconsin. These utilities include WPL, MGE, WPSC and WEPCO. Based on the respective attached monthly peak demand data, I added up the monthly peak load growth for each of the utilities to derive the transmission load on ATC's system for each month. I then took the maximum combined peak growth over the year to represent the annual peak demand on ATC's transmission system in Wisconsin. As discussed above, the load growth timeframes were based on the availability of the transmission-related capital cost data which I will discuss in Step 3.[2] I present a few different load growth estimates below based on the SEA load forecast. My eventual analysis used the load growth from 2021–2029.[3] However, in **Table 1** below, I have provided some sample load growths based on some different analysis periods for illustrative purposes.

[2] I have presented my analysis in the order that transmission planning typically occurs. A transmission planning process would typically involve estimating the required load growth on the system and then identifying the transmission investments required to meet that load growth. However, given that ATC conducts transmission planning, I have first gathered data on investments identified by ATC and then attempted to assess the load growth on which ATC has based these identified investment needs.

[3] SEA load growth forecasts only extended out until 2028. The 2029 load forecast was based on the growth rate from prior five years.

Table 1. Load Growth across different timeframes.

Load Growth Timeframe	Load Growth (MW)
2021- 2024	338
2021-2026	348
2020- 2028	439
2021-2029	348

Q. How did you estimate the load-related transmission investments to meet that load growth (Step 3)?

A. The MISO MTEP is conducted on an annual basis and evaluates studies and planning initiatives that help MISO address future grid needs. As an outcome of this study, MTEP identifies specific transmission infrastructure improvements that are required to address a variety of needs including reliability, aging infrastructure, load growth investments, etc.

Based on the latest MTEP data, I identified load growth-related investments identified by ATC in both Wisconsin and Michigan. I calculated the total load growth investments made by ATC for each state in order to isolate the portion of investments that span both states.

Table 2. State Specific Transmission Investments made by ATC

State	Capital Expenditure ($)	% Total
MI	$21,393,000	21%
WI	$80,642,672	79%
WI and MI	$85,056,542	-

Based on the above, for load growth-related investments that span Wisconsin and Michigan, I allocated 79% of costs to Wisconsin. Table 3 below illustrates ATC's load growth-related transmission investments by year for the state of Wisconsin after removing the load growth related investments in Michigan and allocating Wisconsin's portion of projects that span both states.

Table 3. Annual capital expenditure data for load growth projects in Wisconsin (after removing capital expenditures for load growth investments in Michigan)

Year	Capital Expenditure ($)
2021	$217,565
2022	$27,712,567
2023	$48,667,677
2024	$44,365,232
2025	$26,903,050
Total	**$147,866,092**

In addition to the MTEP data, there are transmission line investments identified through SEA through 2028 (Ex.-RENEW-Bhandari-4: Schedule 11).[4] However, I concluded that projects identified through SEA did not consist of any projects that could be directly classified as load growth related projects. In addition, SEA projects overlapped significantly with MTEP data and I removed these projects from further analysis to be conservative. If any projects identified through SEA are not included in MTEP, the avoided transmission cost results should be adjusted for these projects.

[4] Since MGE is not a transmission owner, the respective SEA Schedule 11 identifying transmission lines is not applicable. However, ATC (i.e., the transmission owner) also submits SEA data on new transmission lines as part of Schedule 11.

Q. Does the table above capture all of MGE's load growth-related transmission investments in the analysis period?

A. No. Based on my experience, certain transmission investments that are not explicitly classified as "load growth-related" could potentially have a load growth component. In other words, while a project may be classified as "Reliability", "Age and Condition", or some other category that is not "Load Growth," the project may nevertheless serve a load-growth purpose.

For example, to illustrate this issue, I discuss one project that NSPW proposed, which involves relocating and rebuilding two existing transmission lines between Gingles substation in Ashland and its Ironwood substation. (Ex.-RENEW-Bhandari-5). The project costs are anticipated to range from approximately $131 million to $139 million depending on the final route selected. NSPW states that the identified project will "address all reliability concerns and increase load-serving capability in the area to meet anticipated customer needs through the mid-century." (Ex.-RENEW-Bhandari-5). Although I cannot confirm with certainty, it appears that this project may have been identified in MTEP20 but was not classified explicitly as a load growth project. However, while the transmission line rebuild between the Gingles substation and the Ironwood substation is not expressly classified as a "load-growth-related" project, the utility's own description indicates that the project has a load-growth purpose, among other purposes.

Q. How do you determine the load growth component of projects that serve more than one purpose and are not classified as "load growth-related"?

A. This is challenging and we cannot be certain about the exact load growth component. The load growth-related component of projects that serve more than one purpose may vary substantially from project to project. As a proxy, I estimate that ten percent of the costs of projects not explicitly classified as "load growth-related" is associated with aspects of the projects that will address load growth needs going forward. I have assumed that this proxy estimate includes projects that are either being built sooner because of load growth or are being built to a larger capacity due to load growth.

Q. How did you identify the capital expenditures associated with projects that have a load growth component but are not classified as load growth-related?

A. I used a process very similar to my assessment of capital expenditures associated with load growth-related projects. I identified all the projects from MTEP that could have a load growth-related component but were not explicitly classified as load growth-related projects. These categories are: 1) Reliability projects, 2) Age and Condition, 3) Other Local Needs, 4) Distribution and 5) Unclassified projects. I then applied my proxy estimate of ten percent as discussed above to estimate the portion of the costs associated with these projects that may be load growth-related. As discussed earlier, I concluded that the SEA projects overlapped significantly with MTEP data and removed these projects from further analysis to be conservative. If any projects identified through SEA are not included in MTEP, the avoided transmission cost results should be adjusted for these projects.

In **Table 4** below, I show annual capital expenditure data for transmission projects that may have a load growth component but are not explicitly classified as load growth-related projects. I have estimated load growth-related costs based on my estimate that ten percent of these costs will be load growth-related. In addition, MTEP indicated that amongst the projects identified there are some project costs that would be shared with other transmission owners. For projects that are expected to have a cost sharing component, I assumed that 50% of the costs would be incurred by ATC's customers (i.e., customers in the respective utility territories served by ATC). This assumption may vary significantly on a project-by-project basis. However, according to the last set of new project cost allocations from MTEP21, the total allocation of costs to ATC (for which ATC is the transmission owner) ranged from approximately 80% to 100% of the total project costs (Ex.-RENEW-Bhandari-6: Appendix A-1). In addition, I continue to assume that for projects that span Michigan and Wisconsin, 79% of the total costs are allocated to Wisconsin.

Table 4. Capital cost of projects that are expected to have a load growth-related component but are not directly classified as load growth projects; 50% project cost allocation and 79% state cost allocation

In Service Year	ATC Load related Capital Expenditure ($)	ATC's Wisconsin Capital Expenditure Portion ($)
2021	$126,493,395	$21,493,395
2022	$320,487,035	$252,186,930
2023	$554,763,307	$385,092,343
2024	$315,638,402	$238,550,020
2025	$105,943,551	$87,869,945
2028	$21,090,000	$21,090,000
Total Estimated Cost	$1,444,415,690	$1,006,282,633
Load Growth Related Costs		**$100,628,263**

Q. Please describe how you used your estimate of load growth and your estimate of load growth-related investments to determine the cost of load growth-related investments in $/MW or $/kW (Step 4).

A. In calculating the avoided transmission cost, I matched the timing of the capital investments with the timing of load growth. Investments and utility spending to address load growth typically occur in advance of when the load growth actually occurs on the system. In other words, to maintain reliable service, a load-growth-related investment precedes the year in which the expected load requires the asset to be in service. Therefore, in order to determine the cost of load growth-related transmission investment, it is necessary to understand the utility's process of mapping these investments to the specific time period that is driving those investments. As a simple example: an investment in 2019 may be driven by some future load growth expected to occur in 2020 while another 2019 investment may be driven by some load growth expected in 2022.

Mapping load growth to capital expenditures can be challenging, partly because capital expenditure data are lumpy. I do not have full insight into what load growth is driving the above capital expenditures since I do not have insight into ATC's transmission planning process. If the utility (with relevant insight from ATC) had conducted an analysis that did not have the gaps I identified above, we would have better data with which to conduct this analysis.

I based my load growth timeframe on the expected need dates for each of the transmission investments as indicated in MTEP, based on the assumption that load-growth-related investments would not be built too far in advance of when they are required. I took the relevant load growth based on Step 2 and applied it to the capital expenditures in Step 3 to get a $/kW value. First, I looked at only the projects that have been explicitly identified as load-growth-related. These projects have investment dates that range from May 2021 through December 2025, so I assume they are caused by load growth between 2021 and 2026, as shown in **Table 5** below.[5]

Table 5. $/kW for projects classified as load growth-related

Load Growth Timeframe	2021 -2026
Capex Timeframe	2021-2025
Load Growth (MW)	348
Load Growth related Capital Expenditure (000's)	147,866
$/kW	425

Second, for capital expenditures that were not explicitly classified as load growth-

[5] I assumed that any investments made after August were being made for purposes of addressing the following year's peak since the monthly forecasted peak starts declining beyond August. So, investments with in-service dates between September and December were driven by the following year's peak growth.

related (but may have a load growth-related component), I performed a similar calculation as shown in **Table 6** below. The timeframe for this analysis is longer because I have information about planned capital projects through 2028, which I associate with load growth through 2029.[6]

Table 6. $/kW for projects not classified as load growth-related (but still may have a load growth component); assuming 10% load growth portion

Load Timeframe	2021-2029
Capex Timeframe	2021-2028
Load Growth (MW)	348
Load Growth related Capital Expenditure (000's)	100,628
$/kW	289

Q. Please describe how you estimated the avoidable transmission cost in $/kW per year (Step 5 and 6).

A. To turn an upfront capital cost into an annual value reflecting what ratepayers would actually pay, I annualized the $/kW values developed in Step 4 based on my calculation of the nominal levelized revenue requirement (or carrying factor). I based this nominal levelized revenue requirement on historical FERC Form 1 data, book depreciation factors based on NSPW's rate case filing, and Attachment O submitted to MISO.[7] The calculation accounts for recovering the capital invested (through depreciation), the asset owner's return on the capital (both debt and equity), and both property and income taxes. While the annual cost of a given

[6] I assumed that any investments made after August were being made for purposes of addressing the following year's peak. The investments with in service dates between September and December were driven by the following year's peak growth.
[7] My calculations are based on publicly available data. I was not able to determine book depreciation factors for ATC so I based my calculations on book depreciation factors for transmission investments from NSPW's rate case filings.

asset varies over the asset's life, I developed a levelized result because the purpose of our analysis is to develop a factor that transforms a portfolio of future avoided assets into a single avoided cost to apply over time. Assets that are not constructed also do not have operation and maintenance (O&M) costs, so I also included an allowance for avoided O&M in the derivation of the levelized nominal revenue requirements. The resulting annual levelized carrying cost factor is 9.91 percent.

Q. What are the annual avoided transmission costs resulting from your analysis?

A. Based on the process described above, I calculated the annual levelized values for each component of the avoided transmission costs (i.e., load growth-related and projects that may have a load growth portion). **Table 7** below shows the annual avoided transmission costs for load growth-related projects and **Table 8** shows the annual avoided transmission costs for the approach using capital expenditures that were not classified as load growth-related (but may have a load growth-related component).

Table 7. $/kW-Year for projects classified as load growth

Load Growth Timeframe	2021 - 2026
Capex Timeframe	2021-2025
Load Growth (MW)	348
Load Growth related Capital Expenditure (000's)	147,866
$/kW	425
Carrying Charges	9.91%
Annualized ($/kW-Year)	42.14

Table 8. $/kW-Year for projects not classified as load growth (but still may have a load growth component); assuming 10% load growth portion

Load Timeframe	2021-2029
Capex Timeframe	2021-2028
Load Growth (MW)	348
Load Growth related Capital Expenditure (000's)	100,628
$/kW	289
Nominal Carrying Charges	9.91%
Annualized ($/kW-Year)	28.68

Per this analysis above, the avoided transmission cost associated with projects that are explicitly classified as load growth projects is $42.14/kW-year, which should serve as the floor value for avoided transmission costs.

The avoided transmission costs associated with projects that are not explicitly classified as load growth-related projects is more uncertain. This could be higher or lower depending on the assumptions made concerning the portion of projects that may have a load growth-related component. As discussed above, I have proposed a proxy estimate of ten percent which results in an avoided transmission cost of $28.68/kW-year. I believe this is a reasonable estimate based on our analysis of FERC data (to be presented below in my testimony) and that this results in a value that is in the range of avoided transmission costs across other jurisdictions.

Therefore, per my analysis, and as described in **Table 9** below, ATC's total avoided transmission cost (exclusive of losses) is $70.82/kW-year. This includes both the avoided transmission cost of load growth projects and the avoided cost of transmission for projects for which a portion of the costs may be load growth-related.

Table 9. Total annualized avoided transmission costs (not including losses)

Avoided Transmission Costs	Annualized $/kW
Projects classified as load growth-related	42.14
Load Growth Component of projects not expressly classified as load growth-related	28.68
Total Avoided Transmission Costs	**70.82**

Q. Could concentration of growth in localized areas complicate the calculation of avoided transmission costs?

A. Yes. For my analysis I have used system-wide peak growth, because this is the publicly available information. However, it is possible that peak growth may not be uniform across ATC's transmission system, and that localized growth is driving transmission investments. With more information, it would be possible to identify the areas of load growth and calculate area-specific avoided transmission values. In these particular areas, the value of avoided transmission costs would likely be higher (because all of the load-growth-related transmission costs would be assigned to a smaller portion of overall load), and it would likely be lower in other areas.

However, I believe it is sufficient and appropriate to calculate an area-wide average value for the purpose of avoided transmission value attributed to QFs. This is because the purpose of this proceeding is to set a single value across MGE's service territory. The locations of future load growth (and associated transmission costs) may vary drastically across the system if assessed on a locational basis (some locations will have a high value and some locations may have a lower value). However, the single system wide value allows us to capture these differences across these different locations in the longer term.

Q. Please describe the checks and calibration that you conducted on your analysis.

A. I based my avoided transmission cost analysis on bottom-up data related to future expenditures on a project-by-project basis, which is the correct way to conduct avoided transmission cost analysis. However, as a cross-check, I compared my results with results produced using historical top-down accounting data from ATC's annual FERC Form 1 filing. I used historical transmission capital expenditures for the period from 2016 to 2020 and associated this with load growth between two separate timeframes (2017 – 2021) and (2016 – 2020).[8] This is because the load growth in 2017 dips significantly resulting in a very high load growth estimate between 2017-2021. I present results for both these ranges in order to indicate the sensitivity to assuming a certain load growth timeframe in developing the avoided transmission values. Because these historical expenditures are not classified based on purpose, I had to make an assumption about what portion could have been avoided with lower loads. I analyzed results assuming that 5 percent, 10 percent, or 15 percent of these costs were associated with load growth (the 5 percent, 10 percent, and 15 percent ranges chosen are conservative estimates). The estimated percentage of total load growth related projects across MISO is 20 percent. (Ex.-RENEW-Bhandari-7). Similarly, the overall estimated percentage of projects that are load growth related in Wisconsin is approximately

---

[8] 2017–2020 loads were actuals and not forecasts.

14 percent based on Wisconsin's Strategic Energy Assessment – 2026, Table 2-1 (Ex.-RENEW-Bhandari-8).

In my cross-check analysis, I used the same levelized carrying cost for annualization as I did for my bottom-up analysis. **Table 10-12** below illustrate the results of my cross-check analysis, which produces an annualized avoided transmission cost ranging from $12.80 to $84.49/kW-year (before adjusting for losses). Assuming between 10 percent and 15 percent of the capital expenditures are load growth-related results in a value that aligns closely with the $70.82/kW-year avoided transmission cost value that my bottom-up analysis produced. This suggests that my bottom-up analysis produces a reasonable estimate.

Table 10. Avoided Transmission Cost based on FERC Form 1; assuming 5% capital expenditures are load growth related

Load Timeframe	2017 - 2021	2016-2020
Capex Timeframe	2016-2020	2016-2020
Load Growth (MW)	748	340
Load Growth related Capital Expenditure (000's)	96,628	96,628
$/kW	129	284
Carrying Charges	9.91%	9.91%
Annualized ($/kW-Year)	12.80	28.16

Table 11. Avoided Transmission Cost based on FERC Form 1; assuming 10% capital expenditures are load growth related

Load Timeframe	2017 - 2021	2016-2020
Capex Timeframe	2016-2020	2016-2020
Load Growth (MW)	748	340
Load Growth related Capital Expenditure (000's)	193,255	193,255
$/kW	258	568
Carrying Charges	9.91%	9.91%
Annualized ($/kW-Year)	25.60	56.33

Table 12. Avoided Transmission Cost based on FERC Form 1; assuming 15% capital expenditures are load growth related

Load Timeframe	2017 - 2021	2016-2020
Capex Timeframe	2016-2020	2016-2020
Load Growth (MW)	748	340
Load Growth related Capital Expenditure (000's)	289,883	289,883
$/kW	388	853
Carrying Charges	9.91%	9.91%
Annualized ($/kW-Year)	38.41	84.49

Q. How does this compare with other jurisdictions?

A. Based on my review, an avoided transmission cost of $70.82/kW-year (before adjusting for losses) is within the range of avoided transmission costs produced in other jurisdictions. Based on a study conducted in 2014, a review of nationwide averages show that the values can vary substantially. The average results are $20.21/kW-year, while the values range from $0 to $88.64. (Ex.-RENEW-Bhandari-9). Based on a study conducted by Regulatory Assistance Project (RAP), in 2011, the avoided transmission costs ranged from $20/kW-year to $100/kW-year for transmission (Ex.-RENEW-Bhandari-10). In Northern States Power – Minnesota's MN Value of Solar proceeding, Xcel proposed an avoided transmission cost of $49.72/kW-year (Ex.-RENEW-Bhandari-11). These results suggest that the value that I have derived is reasonable.

Q. Would you like to add anything else regarding your analysis of MGE's avoided transmission costs?

A. I have developed these values based on publicly available data. This is particularly challenging given limited insight into ATC's transmission planning processes and data. I believe that our analysis estimates the avoided transmission cost within a reasonable range of certainty. Our key challenges in developing this estimate relate to the fact that transmission planning is a process that remains largely under the purview of the utilities (and in this case ATC). Hence, the data required for the analysis is often not readily available to external stakeholders or regulators. This results in significant information asymmetry that makes it difficult to capture the future investment needs and appropriately value the contribution of distributed energy resources.

Q. Please summarize your recommendations regarding avoided transmission cost.

A. I recommend that the Commission (1) adopt an avoided transmission cost of $70.82/kW-year for both contracted FTM resources as well as BTM resources, and (2) direct MGE to use the above methodology and conduct a similar analysis of avoided transmission costs. The utility should be clear and transparent and make their analysis readily available to stakeholders.

IV. AVOIDED CAPACITY COSTS

Q. Please describe MGE's proposal for calculating and crediting avoided capacity costs for FTM resources.

A. For FTM resources obtaining credit under the proposed Schedule DC-1 offerings, the Company proposes to use the MISO CONE value for the relevant Local Resource Zone (LRZ) and planning year to calculate and credit avoided capacity costs. Based on the Company's calculations, for LRZ 2, the calculated CONE value is \$0.249/kW-day based on the 2021/2022 planning year (Ex.-MGE-Denu-1, Sheet E-7.1.0). Capacity will be based on the accredited capacity of the participant COGS multiplied by the number of days in the billing month and the capacity credit rate. The accredited capacity is determined using MISO's Best Practices Manual (Direct-MGE-Denu-6). This includes solar capacity credit methodology stated in MISO's Resource Adequcy Business Practice Manual and wind capacity credit based on MISO's ELCC study (Ex.-MGE-Denu-1,Sheet E-7.1.1).

Q. Will similar avoided capacity costs apply to BTM QFs?

A. No. For BTM resources covered under Schedule Pg-2, the Company retains the Miscelleneous Service Credits (Schedule MSC-2) tariff methodology for crediting BTM generators for capacity. Under Schedule MSC-2, the capacity credit will be based on the most recent MISO capacity auction results for the relevant LRZ (Ex.-MGE-Denu-1, Sheet E-2.2.0).

Q. Do you have any concerns with MGE's proposed avoided capacity credit for FTM resources?

A. I do not have concerns with MGE's proposed avoided capacity credit for FTM resources. I agree with MGE's proposal to base the avoided capacity payments on MISO's CONE value for LRZ 2 since this represents the long-term value of capacity. I also agree with the capacity accreditation process for individual resources based on MISO's capacity accreditation methodologies since this methodology reflects the contribution of the resource in achieving MISO's zonal capacity obligations.

Q. What are your concerns with MGE's proposed avoided capacity credit for BTM resources?

A. I disagree with MGE's rationale for crediting BTM resources based on MISO's capacity auction results.The capacity auction results only represent a short term value for capacity and do not represent the longer term value for avoided capacity. Therefore, MGE's proposal treats BTM resources as if they will provide only "short-term" capacity and ignores the fact that these resources will provide avoided capacity value for periods over the long-term. The capacity credit for such resources should be based on the duration over which they provide a capacity contribution to the system, rather than on the short term capacity value only.

In addition, MGE has not offered any rational basis for why the avoided capacity cost associated with BTM and FTM resources should differ. BTM resources (particularly those that generate and export during the peak hours of the day) reduce peak demand and thereby reduce the cost that MGE incurs to meet that peak demand through additional capacity acquisitions. In their proposal, the Company has ignored the contribution of BTM resources towards meeting peak demand. Every unit of energy exported by a BTM resource during peak hours has at least as much impact on peak reduction (and thereby avoided capacity costs) as a unit of energy exported by an FTM resource during peak hours.[9] Therefore, BTM resources should receive the same avoided capacity credit as a FTM resource. This same argument also holds for avoided transmission value, which is also driven by a BTM resource's contribution to reducing peak demand.

Q. What are your suggestions?

A. I suggest that the Commission approve the use of MISO CONE for LRZ 2 to credit QF capacity. MISO CONE in LRZ 2 for the 2022/2023 planning year is $89.49/kW-year (Ex.-RENEW-Bhandari-12, Attachment B). This aligns with MGE's proposed methodology. I further recommend that this avoided capacity cost apply to both BTM and FTM resources.

For multi-year contracts, avoided capacity costs can be projected by applying an anticipated inflation rate to the latest CONE value. There is significant uncertainty in inflation going forward, so for simplicity I assume a 2 percent inflation rate. The value of capacity in the 2023/2024 planning year, for example, would be calculated by applying one year of inflation to the CONE

[9] A BTM resource may actually provide a higher impact on peak reduction since it avoids more losses compared with an FTM resource.

value for the 2022/2023 planning year. This process would be repeated for all future years.

V. AVOIDED LOSSES

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I will outline a methodology for application of losses in the determination of avoided costs.

Q. What is a "loss factor" and how is this relevant to energy, transmission and capacity avoided costs?

A. Loss factors represent the energy loss on the transmission and distribution system between the point of generation and the point of consumption. Since DERs typically provide load reduction through reduced use of the distribution and transmission system (i.e., they provide energy close to the site of consumption), they reduce losses. This results in further reduced energy generation, reduced need for generating capacity, and reduced need for transmission capacity.

Q. Please describe the relationship between loading and losses.

A. The amount of energy loss in any hour is affected by a number of factors including resistance in wires, system utilization rates, and weather conditions. The formulae for losses is I^2R or the square of the current multiplied by resistance. The "I" on the system is a direction function of the load on the system and therefore increases proportionally with load. Therefore, loss factors are generally higher when loads are higher and are significantly higher during peak periods because resistive losses in wires increase proportional to the square of the load.

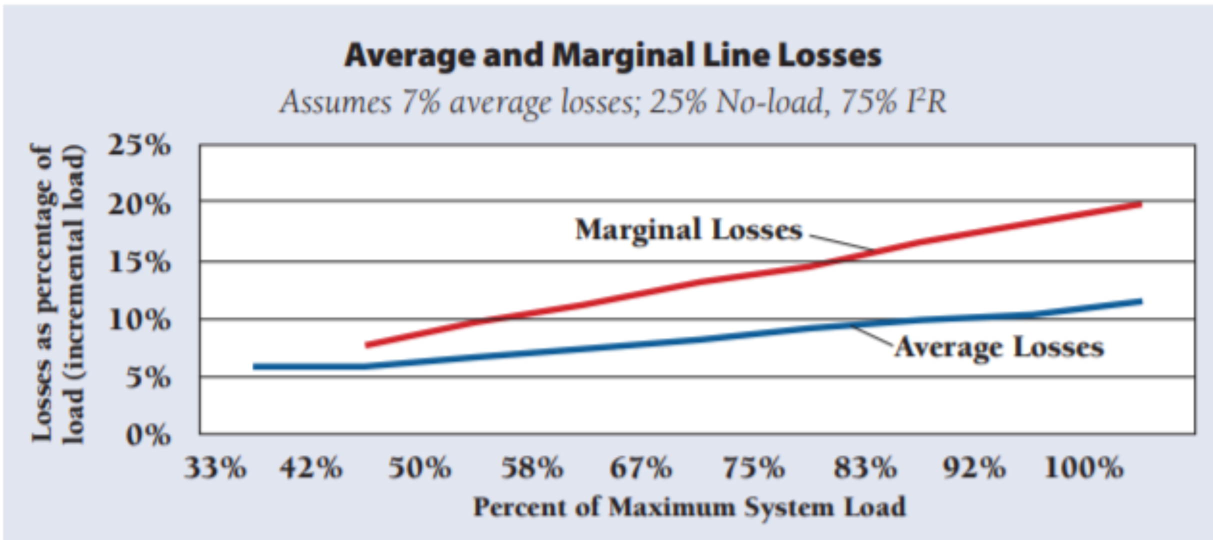
Q. How do marginal and average loss factors differ?

A. There are two types of loss factors that exist i.e., average losses and marginal losses. The average losses represent the average system wide losses. When the system is loaded during peak hours, the average losses are higher because of the relationship between losses and load as described above. The second factor is the marginal loss. The marginal loss reflects the losses incurred to meet incremental demand at any point in time. These losses are always higher than average losses, especially during the peak hours. This is because of the I^2R nature of losses, wherein the derivative of losses with respect to load goes up in proportion to load. Therefore, the marginal loss factors during peak hours are significantly higher than the marginal or average loss factors during off peak hours during the year. This means that line losses for incremental loads ("marginal losses") that would be avoided by resources that contribute to peak load are higher than average line losses.

Q. Please elaborate.

A. A 2011 RAP paper, "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements," discusses line losses in detail (Ex.-RENEW-Bhandari-10). This paper presents an example of line losses and demonstrates how marginal and average losses vary at different system load levels as shown in Figure 1 below. This Figure shows that the increases in marginal losses are greater than the increases in average losses as the system load levels increase. For example, when the system is loaded at 50 percent of the capacity, average and marginal losses are approximately 6 percent and 8 percent respectively. In contrast, when the system is loaded at near its capacity, average and marginal losses are approximately 12 percent and 20 percent respectively.

Figure 1: Average and Marginal Line Losses



Q. Why is it not reasonable to apply average loss factors to avoided transmission and capacity costs?

A. The costs for transmission and capacity are driven by load growth on the system during peak hours of the year. The avoided costs represent the marginal costs in meeting an incremental unit of demand (an incremental unit of demand that a QF would avoid). As discussed above, the marginal losses during peak hours would represent the incremental losses that would occur due to a small increase in demand during peak hours. Loss factors are significantly higher during peak periods due to the relationship between losses and load as described above. Therefore, average losses underestimate the value of avoided transmission and capacity during the peak hours. For this reason, the utility should apply marginal loss factors to avoided transmission and capacity costs.

Q. Should marginal loss factors apply to avoided energy costs as well?

A. Yes, the utility should apply marginal loss factors to avoided energy costs as well. However, as I will explain below, the marginal loss factors that apply to energy are lower than the marginal loss factors that apply to transmission and capacity since the marginal loss factors for energy apply across all hours of the year and across all ranges of system utilization and not just the peak hours.

Q. Did MGE provide an average or marginal loss factor for its system?

A. MGE has provided average loss factors across the distribution system that would be applied to avoided energy and capacity costs. Based on response to discovery issued by RENEW, the Company indicated that they would be applying a primary voltage multiplier of 1.0323 and a secondary voltage multiplier of 1.0195 to both avoided energy and avoided capacity (Ex.-RENEW-Bhandari-13). In addition, the Company indicated that they would not be applying a loss adjustment to avoided transmission costs since the transmission losses are already accounted for in the Day-Ahead Locational Marginal Prices (LMP) (Ex.RENEW-Bhandari-13). The Company also indicated that their average transmission losses across the MGE local balancing authority are 1.846% (Ex.-RENEW-Bhandari-13).

Q. Do you have any concerns with the Company's proposed approach to applying losses?

A. Yes, I have several concerns. There are significant gaps and a lack of clarity in how the Company proposes to adjust its avoided energy, capacity and transmission costs based on these distribution and transmission losses to account for the system wide avoided losses.

My concerns include the following:

- It is unclear why the Company has not proposed loss factors to account for losses across the transmission system that would be used to adjust avoided energy, capacity and transmission costs and the rationale for proposing only primary and secondary voltage multipliers. Where applicable, transmission loss factors should be applied.
- The Company has not demonstrated the application of the proposed loss factors to the avoided costs and it is unclear how the Company intends to apply the primary and secondary voltage multipliers to account for the loss adjustments.

I disagree with the Company regarding their claim that the adjustments to the avoided transmission costs are already included in the loss component of the Day Ahead LMP. The loss component of the LMP only captures the short term value of these transmission losses. The LMP do not include the long-run transmission losses that may be avoided or deferred over the useful life of a resource when it reduces the need for a transmission investment.

Q. How have you estimated loss factors for the purposes of adjusting avoided energy, transmission and capacity cost values?

A. Despite these above mentioned concerns, I have based my calculations on the average losses provided by MGE in response to RENEW's discovery. I will describe how we can derive marginal loss factors using these average loss factors and describe how these can be applied to transmission, capacity and energy. Should MGE choose to clarify its application of loss factors in rebuttal testimony, I reserve the right to incorporate those clarifications into my calculations in surrebuttal testimony.

Q. Were you able to estimate a marginal loss factor for MGE's system based on the average losses that MGE provided?

A. To estimate marginal losses associated, I would need to know the system utilization factor at peak hours, or in other words, the degree to which the transmission and distribution system is stressed. While the utilization rates at the peak hours are by definition higher than the average rate for an entire year, detailed data for system utilization rates for the entire MGE system during peak hours is not readily available.

As established, in any hour, across all ranges of system utilization, the marginal losses are higher than the average losses. Therefore, in order to accurately estimate annual average marginal losses, the RAP paper suggests a rule of thumb value that marginal losses are about 1.5 times average losses. Thus, we use a factor of 1.5 to convert annual average line losses to marginal line losses.

For transmission and capacity, in addition to the higher marginal loss factors we also have to account for the higher system utilization rates since the investments are driven by hours that are at the highest peak. I have estimated a marginal loss factor based on MGE's average loss factor, and using the relationship between marginal and average losses illustrated in Figure 1 above (from the RAP paper) at high system utilization rates. Based on the data in Figure 1, marginal losses are 1.4 times greater than average losses at 50 percent system utilization, and 2.6 times greater than average losses at 92 percent system utilization. Based on this range, I rely on a simple factor of 2.0 to convert average losses to marginal losses during higher system utilization periods, including at peak (and thus for generation and transmission capacity).

Q. How do you propose to adjust the avoided transmission costs you calculated above to account for losses?

A. Energy losses increase when demand on the system increases (i.e., at higher system utilization rates) and increase exponentially during peak hours. The avoided transmission costs should be adjusted based on the higher peak-hour marginal loss factors instead of the average loss factors in order to account for higher losses during peak hours. Based on the data provided in discovery which include a transmission loss of 1.846% and distribution losses of 3.13%, I have adjusted the avoided transmission and capacity costs to account for marginal losses. For purpose of my analysis, I assume that the marginal losses include losses across the transmission, primary and secondary networks.[10] Based on my estimates, the combined system wide average losses result in a system wide average loss factor of 1.0524. The results shown in Table 13 below are based on marginal losses identified at the secondary voltage.

[10] This is a conservative estimate given the distribution losses are significantly lower than typical utility losses. In addition, based on the responses to discovery, it is unclear if the utility intends to apply both the primary and secondary voltage multiplier to the avoided costs. I have assumed total combined losses of 4.97% in order to yield a conservative result.

Table 13. Avoided Costs for Transmission including marginal losses at secondary voltages[11]

Avoided Cost Component	$/kW-year before marginal losses are applied	$/kW-year after marginal losses are applied
Transmission	70.82	78.24

Q. How do you propose to adjust the avoided capacity costs you calculated above to account for losses?

A. Energy losses increase when demand on the system increases (i.e., at higher system utilization rates) and increase exponentially during peak hours. The avoided capacity costs should be adjusted based on the higher peak-hour marginal loss factors instead of the average loss factors in order to account for higher losses during peak hours. Similar to transmission, the results shown in Table 14 below are based on losses identified at the secondary voltage.

Table 14. Avoided Costs for Capacity including marginal losses at secondary voltages

Avoided Cost Component	$/kW-year before marginal losses are applied	$/kW-year after marginal losses are applied
Capacity	89.49	98.87

[11] I have grossed up the avoided transmission and capacity costs by 10.48% (i.e., 5.24%*2) in order to account for marginal losses.

VI. APPLICATION OF AVOIDED COSTS IN RATES

Q. What is MGE's current proposal for translating avoided transmission and capacity costs to credits for FTM resources?

A. For service offerings under DC-1 that is relevant to FTM resources, the Company has proposed a monthly capacity credit based on MISO's capacity accreditation methodology for the individual resources. The Company has indicated that this resulting credit would be derived by multiplying the avoided capacity cost rate by the number of days in the billing month (Direct-MGE-Denu-6).

The Company has not addressed the application of transmission avoided costs in rates for FTM resources because the Company has not proposed any avoided transmission value associated with QF generation.

Q. What is MGE's current proposal for translating avoided transmission and capacity costs to credits for BTM resources?

A. For service offerings under Schedule MSC-2, the Company has proposed that the capacity credit will be based on the net excess kilowatt hours received by the Company during the peak hours (Ex.-MGE-Denu-2, Sheet E-11.2.0). As indicated earlier however, the Company will base this credit on the capacity auction results for the relevant LRZ (Ex.-MGE-Denu-1, Sheet E-2.2.0).

The Company has not addressed the application of transmission avoided costs in rates for BTM resources because the Company has not proposed an avoided transmission value associated with QF generation.

Q. What are your concerns with the Company's proposed design of capacity and transmission credits for FTM QFs?

A. I have no concerns with the Company's proposed design of capacity credits for FTM resources. I agree with the Company's proposal that the monthly capacity credit be based on based on the MISO Capacity Accreditation rules for each resource type (i.e, solar, wind, thermal, hybrid etc.) since this methodology reflects the resource's availability during the peak hours and should be used as the basis for estimating the total annual avoided transmission and capacity cost. This methodology reflects the value these resources provide in meeting MISO's zonal capacity obligations. The Company has indicated that this will be a monthly capacity credit which we interpret as being offered on a $/kW-month basis.

As indicated earlier, the Company has not addressed the application of transmission avoided costs in rates. Since both investments are driven by peak load, I propose that transmission avoided costs for FTM resources be credited on a $/kW-month basis based on MISO's capacity accreditation methodology similar to the methodology proposed by MGE for avoided generation capacity.

Q. How should avoided capacity and transmission payments for BTM resources be designed?

A. I agree with MGE's proposed methodology of crediting resources for capacity based on net exports during peak hours of the year. However, as discussed earlier, it is not reasonable to offer BTM generation resources an avoided capacity credit based on capacity auction results. The avoided capacity credit for BTM resources should be based on the CONE similar to FTM resources.

Similarly, the avoided transmission costs that I propose in my testimony should apply equally to BTM and FTM resources. BTM resources should receive avoided transmission credits for their exports during peak hours in the same way that avoided capacity is credited under Schedule MSC-2.

VII. RECOMMENDATIONS AND CONCLUSIONS

Q. Please summarize your primary conclusions.

A. I conclude that:

- MGE's proposed value of zero for avoid transmission cost ignores the benefit that QFs provide through load reduction.
- The Company does not justify its proposal to credit BTM resources with a capacity credit based on capacity auction results.
- The Company has not appropriately addressed the application of loss factors to avoided transmission, capacity and energy.

Q. Please summarize your primary recommendations.

A. I recommend that the Commission:

- Approve the value of $70.82/kW-year for avoided transmission costs;
- Approve my proposed methodology that accounts for marginal load growth-related transmission investments going forward and require that the utilities conduct a similar analysis and provide all stakeholders transparency concerning the inputs, assumptions, and results from such analysis;
- Approve the use of marginal losses for both avoided transmission and avoided capacity, valued at double the average losses on MGE's system;

- Approve the use of marginal losses for avoided energy valued at 1.5 the average losses on MGE's system;
- Approve the application of MISO's CONE to BTM resources similar to the proposed avoided cost applied to FTM resources;
- Approve the application of transmission credits to FTM resources on a $/kW-month basis similar to the proposed methodology for capacity credits; and
- Approve the application of transmission credits to BTM resources on a $/kWh basis similar to the proposed methodology for capacity credits.

Q. Does this conclude your testimony?

A. Yes, it does.