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|---|---|
| Exhibit No.: | |
| Issue: | Unit Commitment; Market Offers |
| Witness: | John R. Carlson |
| Type of Exhibit: | Rebuttal Testimony |
| Sponsoring Party: | Evergy Missouri Metro and Evergy Missouri West |
| Case No.: | EO-2020-0262 (Lead - Consolidated)<br>EO-2020-0263 (Consolidated) |
| Date Testimony Prepared: | December 4, 2020 |

**MISSOURI PUBLIC SERVICE COMMISSION**

**CASE NOS.: EO-2020-0262 (Lead - Consolidated)**
**EO-2020-0263 (Consolidated)**

# REBUTTAL TESTIMONY

**OF**

**JOHN R. CARLSON**

**ON BEHALF OF**

**EVERGY MISSOURI METRO**
**and EVERGY MISSOURI WEST**

**Kansas City, Missouri**
**December 2020**

**REBUTTAL TESTIMONY**

**OF**

**JOHN R. CARLSON**

**Case Nos. EO-2020-0262 (Lead - Consolidated)**
**EO-2020-0263 (Consolidated)**

**Q: Please state your name and business address.**

A: My name is John R. Carlson. My business address is 1200 Main, Kansas City, Missouri 64105.

**Q: By whom and in what capacity are you employed?**

A: I am employed by Evergy Metro, Inc. and serve as Senior Manager of Missouri Operations for Evergy Metro, Inc. d/b/a Evergy Missouri Metro ("Evergy Missouri Metro") and Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West").

**Q: Who are you testifying for?**

A: I am testifying on behalf of Evergy Missouri Metro and Evergy Missouri West (collectively, "Evergy" or "the Company").

**Q: Are you the same John R. Carlson who previously filed direct testimony in these dockets?**

A: Yes.

**Q: What is the purpose of your rebuttal testimony?**

A: The purpose of my rebuttal testimony is to respond to portions of the direct testimonies of Sierra Club witness Tyler Comings and Office of the Public Counsel witness Lena Mantle.

## RESPONSE TO DIRECT TESTIMONY OF TYLER COMINGS

**Q: How do you respond to Sierra Club witness Comings' recommendation that the Company should market-commit its resources as often as possible?**

A: As discussed in my direct testimony, since 2017, the Company has increased its market commitment and correspondingly reduced its self-commitment of generation. Through continued focus on flexible operations at its generating stations, the Company has increased its percent market commitment of generation to 97% year-to-date through September 2020.

The Company will continue focusing on market-committing generation most of the time, understanding that self-commitments will still be required for limited situations.

**Q; Please give specific examples of when Evergy would self-commit rather than market-commit its resources?**

A: Evergy would self-commit its generation for safety, reliability, and/or environmental compliance reasons. After a generator outage there are times when testing of repairs is required. The Company wants to ensure the unit can operate safely and reliably before committing to the market. One example would be after a turbine overhaul when testing of turbine vibration is done at running speed and with load on the turbine. Ideally, this testing is completed as soon as possible after an outage rather than waiting for a market commitment, for two reasons. First, this testing requires specialty equipment and a contractor to run that equipment, and they typically move on to their next assignment after an outage; they don't wait around for the unit to be committed by the market. Second, this testing reduces the risk of being unreliable when the unit is needed for a market-commitment and ensures safe operation (i.e., reduced likelihood of equipment damage later due to work performed during the overhaul).

Cold weather can cause reliability issues in a steam-fired power plant due to water lines freezing, oil systems becoming too cold and even coal freezing. When facing weather-related operational issues such as these, the Company may choose to self-commit a resource to protect that resource's equipment and thus ensuring its reliable operation.

Lastly, self-commitment of resources is sometimes required for compliance testing. Evergy is required by various governing bodies to regularly test resources for reasons such as emissions performance. While the Company attempts to schedule environmental testing when plants are operating under market-committed conditions, there are times when self-committing a resource is required to ensure it is online and available to satisfy testing requirements.

**Q: Regarding the self-commitment of resources, do you agree that Evergy should provide clear justification for those decisions?[1]**

A: Yes, I do, and the Company currently tracks when a unit was self-committed and will continue to do so. The Company started tracking self-commitments more

[1] Direct testimony of Sierra Club witness Comings, page 4, lines 11-12.

stringently in 2019, coincident with its increased efforts around flexible operations.

**Q: Are variable operations and maintenance costs ("VOM") recovered through the Company's Fuel Adjustment Clause?**

A: No, they are not. VOM costs are recovered via the Company's base rates. Company witness Lisa Starkebaum discusses this more in her rebuttal testimony.

**Q: Are the Sierra Club's arguments associated with VOM costs relevant to this proceeding?**

A: The recommendation that the Company implement a more refined process for capturing its VOM costs is something the Company agrees with and has started to implement with new systems in place to capture more granularity around expenses.

However, any disallowance attributed to VOM costs is not relevant to this case and should be addressed in a standard rate case proceeding.

**Q: Please respond to Sierra Club's allegation on Page 5 of Witness Comings' direct testimony that Evergy uses a "simplistic" calculation to delineate between fixed and variable O&M costs**.

A: The baseload units, except for the Jeffrey Energy Center ("Jeffrey"), use a percentage of all non-fuel operations and maintenance expenses to determine the VOM cost to use in market offers. This process was approved by the SPP Market Monitoring Unit.

The Jeffrey units, because their expenses are accounted for in legacy Westar systems, have a more robust process for capturing and accounting for

VOM costs at a more granular level. As mentioned in my direct testimony, the Company is implementing processes that should allow for more detailed tracking and accounting of VOM expenses in the future.

**Q: How has Sierra Club witness Comings calculated his proposed disallowance(s)?**

A: The Sierra Club calculated hourly dispatch costs for all unit offers, using unit offer data provided by the Company, and then separated them into fuel and VOM components (these were referred to, in the aggregate, as "bid costs" in Mr. Comings' testimony). Then, Mr. Comings calculated fuel and VOM costs, utilizing data provided in data requests (referred to as "actual costs" in Mr. Comings' testimony). Next, actual market revenues were compared to each cost calculation to derive net revenues, and the results were rolled up to a monthly summary. If the difference in net revenues for any month was negative ("bid cost" net revenues minus the "actual cost" net revenues), considering unit outages, then the Sierra Club assumed the Company was imprudent for that month.

**Q: Focusing on the VOM component first, please describe how the Company calculates VOM costs used in its market offers?**

A: For all the baseload units except for Jeffrey, VOM was calculated and updated on a quarterly basis, using historical non-fuel operations and maintenance and generation data.[2] The historical data was current year-to-date plus the previous three years. For example, for the third quarter of 2018 the non-fuel operations and

[2] As discussed in "Sierra Club_20200623-Sierra Club-2.5-Question", 20% of total non-fuel operations and maintenance expenses were treated as variable, a process in place since 2003 and implemented after studying multiple methods for calculating VOM.

maintenance expenses and MWHs of generation used in calculating VOM would be the nine months of 2018 plus the annual totals from 2015, 2016 and 2017.[3]

Starting in August 2018, the Jeffrey VOM was calculated using the Evergy Kansas Central ("KS Central") approach. Expenses from FERC accounts 512, 513 and 553 are broken down by work class and work category and reviewed to ensure that non-variable expenses are removed. Consistent with Appendix G.2.4 of the SPP Market Protocols ("Protocols")[4], VOM is calculated using the sum of the previous 10 years of expenses divided by the sum of the previous 10 years of generation MWHs, applying annual escalation factors (on the expenses) as appropriate. These values are calculated and updated annually, applied to the following year's market offers (2018 calculated VOM, using 10-year history, is applied to 2019 market offers).

**Q: Why does the Company calculate an average VOM value over multiple years for use in its market offers?**

A: Averaging over multiple years allows for a more consistent value that smooths out variability that could occur if calculated annually.

**Q: How does the Company account for differences between bid costs and actual costs at the Jeffrey units, from a VOM perspective, as identified by witness Comings on Page 24 of his direct testimony?**

A: The calculated VOM costs, the "actual costs" portion, were calculated by Sierra Club witness Comings using incorrect data, mainly due to not having been

[3] These calculations can be found in Q1.3_CONF_VOM 2015-2016-2017-2018 thru 09-30-18.xls, an attachment to DR 1.3.

[4] The latest edition of the SPP Market Protocols can be found at https://spp.org/spp-documents-filings/?id=18162.

initially provided with the correct information. Witness Comings relied primarily on information supplied in the Company's initial response to Sierra Club data requests ("DR") 1.3 and 2.5 for this part of his analysis. In these DRs, the Company was asked to provide information used to make dispatch decisions, to indicate which production costs are considered variable, and to include a breakdown of those costs, and the Company responded with information used to calculate its VOM cost used in market offers. The Company also provided a supplemental response to DR 1.3 to correct VOM information for the Jeffrey units. As discussed previously, the KS Central process for calculating VOM was more refined, so beginning in August 2018 the Company used that process for calculating the VOM at Jeffrey. The discrepancy occurred when witness Comings used data from DRs 1.3 and 2.5 to estimate the actual VOM costs at Jeffrey, which was then used to calculate "actual" versus "bid" net revenues.

**Q: What is the discrepancy in witness Comings' "actual" versus "bid" net revenues?**

A: The data witness Comings used for actual VOM costs at Jeffrey was incorrect. The VOM information provided by the company was historical in nature and supported how it calculated VOM for its market offers for 2018 and 2019. In its initial response to DR 1.3 the Company mistakenly included the Evergy Missouri West estimate of 2019 Jeffrey VOM, even though it was no longer using the Evergy Missouri West process for calculating VOM (i.e., using a percentage of non-fuel operations and maintenance expense). DR 1.3S was an attempt to correct this error by providing the more granular Jeffrey VOM data, used for 2018 and

2019 market offers, as calculated by KS Central. The actual 2019 VOM costs for Jeffrey were not previously provided because they would only apply to 2020 market offers. For the purpose of comparing "actual" versus "bid" net revenues in witness Comings' testimony, the Company has provided a breakdown of actual Jeffrey VOM costs for 2018 and 2019, using the more granular data available from the KS Central work management system.[5] Updating witness Comings' analysis with the actual VOM costs produces the results shown in the table below:

[5] See Carlson rebuttal workpapers.

**Table 1 – Monthly Net Revenue Losses CONFIDENTIAL**

| Unit | Year | Month | Losses | Losses from fuel only | Self-commit % (non-outage) |
|---|---|---|---|---|---|
| **[redacted]** | 2018 | Sept | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | Jan | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | Feb | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | May | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | June | **[redacted]** | **[redacted]** | **[redacted]** |
| **[redacted]** | 2018 | Sept | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | Jan | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | Feb | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | June | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | Sept | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | Dec | **[redacted]** | **[redacted]** | **[redacted]** |
| **[redacted]** | 2018 | Sept | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | Feb | **[redacted]** | **[redacted]** | **[redacted]** |
| | 2019 | Dec | **[redacted]** | **[redacted]** | **[redacted]** |
| **TOTAL** | | | **[redacted]** | **[redacted]** | |

**Q: Should the Commission grant a disallowance due to the Company's VOM for market offers being **[redacted]** actual VOM costs for the FAC audit period?**

A: No, it should not. The VOM portion of the corrected net revenue losses in the proceeding table are the difference between the total "Losses" and the total "Losses from fuel only", or **[redacted]**. The process of calculating an average VOM cost over a multi-year horizon will result in some years' actual VOM costs being slightly over the 10-year average and some years' being slightly under the 10-year average.

**Q: What about the fuel component of witness Comings' calculated disallowance?**

A: The net revenue losses calculated by witness Comings, attributed to fuel, are a result of the total fuel-related costs ("TFRC") associated with an old fuel contract for Jeffrey.

**Q: How is the TFRC calculated for Jeffrey?**

A: As described in Appendix G of the Protocols, the TFRC is the sum of basic fuel cost, other fuel related cost, emission allowance cost, and VOM cost. Fixed charges for transportation equipment (e.g. train car leases, train car maintenance) should be excluded from the market TFRC.

Evergy is party to three multi-year full requirements contracts for both the commodity (**[redacted]** mine) and rail transportation (**[redacted]** & **[redacted]** railroads) at Jeffrey. Components of these contracts include minimum annual volumes ("MAV") and, in the case of the commodity contract, two-tier pricing. Evergy adjusts the fuel procurement plans for Jeffrey as refinements are made to the near-term forecasts. If the near-term forecasts reflect estimated volumes above the MAVs and/or Tier I pricing volume, then no adjustment is made to the TFRC. If near-term forecasts reflect an estimated volume that falls below any of the MAVs, then adjustments to the TFRC may be made to reflect the financial impact of contractual MAVs from those contracts. If the market prices don't promote increased fuel burn when utilizing the lower TFRC, paying the MAV shortfall amount is typically the better option for the customer. If the market prices do promote increased fuel burn when utilizing the lower TFRC, the decreased market revenue is typically the lower cost option for the customer. The multi-year full requirements contracts for Jeffrey expire in December 2020.

**Q: Please expand on the referenced Jeffrey fuel contract.**

A: This contract was finalized in the early 1990's, with subsequent amendments, and utilizes a two-tier pricing structure as discussed above. **[redacted]** pricing was approximately **[redacted]**[6] pricing during the audit period. From a commodity contract perspective, **[redacted]** pricing would go into effect only after Jeffrey burned at least **[redacted]** of fuel on an annual basis. At the time the contract was finalized, **[redacted]** pricing was competitive to market pricing and there were minimal concerns about meeting the contract MAVs.

With energy offers representing the cost of the next MW of generation, if fuel burn forecasts showed that the Company would burn at least **[redacted]**, the Company priced fuel at the **[redacted]** level. Pricing at the **[redacted]** rate would have **[redacted]**. While the Company can never be sure how the SPP market would have responded with such an offer change, using Tier I pricing

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[6] See the CONFIDENTIAL workpapers on Jeffrey fuel pricing.

to offer Jeffrey would have increased the likelihood of not meeting the contract MAVs.

**Q: How is pricing Jeffrey at the **[redacted]** level advantageous?**

A: At the time of the SPP IM going live, the **[redacted]**.

A hypothetical example of a liquidated damages calculation for the transportation portion of the Jeffrey contracts is shown below. As discussed earlier in my testimony, the transportation contracts **[redacted]**.

**

## Transportation Liquidated Damages Example

**CONFIDENTIAL**

[redacted]

**

In this example, the hypothetical burns at Jeffrey, **[redacted]**, fall above the **[redacted]**, but below the **[redacted]**. Therefore, the Company would owe liquidated damages to the **[redacted]**.

**Q: How is the Jeffrey TFRC and forecasting process represented in the results shown in Table 1?**

A: In witness Comings' analysis, corrected with actual VOM costs and shown in Table 1, the net revenue losses for fuel only equate to **[redacted]**. These calculated losses are primarily a result of pricing Jeffrey offers using the **[redacted]**. By pricing in this manner, the Company attempted to optimize the contract in the market versus locking into potential penalties for customers later.

**Q: Should the Commission grant a disallowance due to the Company's fuel costs for market offers being **[redacted]** actual fuel costs for the FAC audit period?**

A: No, it should not. The Company acted prudently in seeking to minimize downside risk from an old contract by pricing the Jeffrey units **[redacted]** for market offers. The alternative was to price at the higher tier of the commodity contract and increase the likelihood of paying more in penalties at the end of the year. As previously stated, this contract expires in December 2020.

## RESPONSE TO DIRECT TESTIMONY OF LENA MANTLE

**Q: Please explain your understanding of Witness Mantle's recommended disallowance.**

A: Witness Mantle's recommendation includes five parts. The first and second parts assume disallowances for prudently incurred expenses for Montrose and Sibley retirements. These recommendations are addressed by Company witness Lisa Starkebaum.

The third recommended disallowance involves capacity sales expenses and the potential impact on the Company's preferred plan as it relates to its 2017 integrated resource plan. I will provide some background on capacity sales within the Southwest Power Pool ("SPP"), with the recommendation being addressed by Company witness Kayla Messamore.

Ms. Mantle's fourth and fifth recommendations suggest that the Company should have called demand response programs more frequently to potentially reduce energy charges and SPP Schedule 11 fees. I will address these two recommendations in this testimony.

**Q: Regarding Ms. Mantle's recommendation around capacity sales, please explain how capacity purchases and sales are made in the SPP.**

A: Capacity purchases and sales made in the SPP market are bilateral in nature, meaning they are contracted between two counterparties outside of the SPP marketplace. Unlike other regional transmission organizations or independent system operators, like the Midcontinent Independent System Operator ("MISO"), SPP does not have a functioning capacity market. Absent this capacity market, it is incumbent upon market participants to canvas the market and find a counterparty interested in buying or selling capacity as needed. This canvasing manifests itself in many ways, some of which include: responding to capacity requests for proposal, contacting counterparties the Company contracted with in the past, following up on past conversations where an entity may have shown interest, cold-calling entities to get an update on their operations and how they are positioned in the market, or contacting existing customers to see if they have information on the market or know of other entities that might have a need.

**Q: Does Evergy routinely canvas the marketplace for potential off-system sales?**

A: Yes, we do. Our origination group's primary responsibility is to develop relationships with counterparties (i.e. utilities, energy marketers, municipalities, financial institutions and independent power producers) so that when a need arises Evergy is considered a viable option to respond to a request for proposal ("RFP") or sell capacity and/or energy on a bilateral basis.

**Q: Why did Evergy not enter into any short-term capacity agreements during the FAC audit period?**

A: Despite the Company's best efforts, there were no agreements to be made on a short-term basis during this FAC audit period.

**Q: Do you agree with Ms. Mantle's recommendation regarding energy charges and the calling of demand response programs?**

A: No, I do not. Ms. Mantle's recommendation is based on assumptions made by Staff in its current MEEIA-2 prudency audit (EO-2020-0227). In that proceeding, Staff argued that the Company should have called its demand response programs more frequently, specifically during high day-ahead ("DA") locational marginal price ("LMP") hours, in order to reduce expenses for its customers.

**Q: What is a DA LMP?**

A: The SPP market is comprised of a day-ahead and a real-time market. The DA LMPs are the prices at which energy is purchased and sold through the SPP market on a day-ahead basis. Market participants like Evergy offer generation for sale and bid load for purchase into the SPP market daily. This information is submitted to the SPP on a day-ahead basis, meaning on a Monday Evergy would submit data to the SPP for Tuesday's operating day. Using Monday as an example, submittals are due by 9:30 Monday morning, and results are released around 1:00 in the afternoon. The results at that time are for Tuesday's operating day and include the generation that will be running, when that generation will start/stop, megawatt ("MW") levels for that generation for every hour of Tuesday, prices for that generation, MWs of load cleared and prices for that load. The prices at each generator and load point are known as LMPs, and the DA LMPs are the LMPs for Tuesday that were calculated by SPP on Monday. Likewise, same day energy purchases and sales done in the market are priced at the real-time locational marginal price ("RT LMP").

**Q: Do you agree with OPC's calculation of the value of the potential SPP savings if it reduced load during high DA LMP periods?**

A: No, I don't. As I discussed in the MEEIA 2 audit proceeding, picking high DA LMP hours is not a "slam dunk". In OPC's analysis they used the five highest hourly DA LMP values for each month of the summer season, June through September, and calculated a theoretical amount the Company could have saved customers by calling demand response events. Absent the crystal ball that retroactively picking hours affords you, this would be hard to do given the complexity of the SPP market.

An example of this complexity is looking at August 6, 2019 in the Evergy Missouri West jurisdiction. OPC's analysis assumes that the Company should have called demand response for hour-ending ("HE") 16, the hour that starts at 3:00 pm and ends at 4:00 pm, when the DA LMP was higher than the average of the DA LMP for the summer season, June – September. Remember, the Company would have had to make this determination by 9:30 am on August 5th. In actuality, the Company would not call an event for one hour, but typically a minimum of three hours. The actual market results for those three hours that included HE 16 were the following:

| August 6, 2019 – Evergy Missouri West Load LMP | | |
|---|---|---|
| **Hour-ending (HE)** | **DA LMP ($/MWh)** | **RT LMP ($/MWh)** |
| 15 | 58.41 | 1,125.22 |
| 16 | 72.99 | 118.07 |
| 17 | 65.44 | 25.34 |

Assuming 57.41 MW of demand response, and calling an event for a three-hour window from HE 15 – 17, with an 80% assumed success rate on the demand response event, would yield the following market results:

| August 6, 2019 – Evergy Missouri West Results | | | | | |
|---|---|---|---|---|---|
| **Hour-ending (HE)** | **Requested Reduction** | **Actual Reduction (80%)** | **DA LMP ($/MWh)** | **RT LMP ($/MWh)** | **Hypothetical Benefit** |
| 15 | 57.41 | 45.93 | 58.41 | 1,125.22 | ($9,564.21) |
| 16 | 57.41 | 45.93 | 72.99 | 118.07 | $2,834.18 |
| 17 | 57.41 | 45.93 | 65.44 | 25.34 | $3,466.01 |
| **Total Benefit / (Cost)** | | | | | **($3,264.02)** |

In the above example the Company guesses correctly that sometime around HE 16 there will be high DA LMPs. Any difference between the load we bid into the DA market and the actual load in the RT market is settled in the RT market at RT LMPs. The Benefits are calculated as:

**Hypothetical Benefit = (Requested Load Reduction x DA LMP) – ((Requested Reduction – Actual Reduction) x RT LMP).**

In a different scenario, over the same three hours, the results could look like the following:

| August 6, 2019 – Evergy Missouri West Potential Results | | | | | |
|---|---|---|---|---|---|
| **Hour-ending (HE)** | **Requested Reduction** | **Actual Reduction** | **DA LMP ($/MWh)** | **RT LMP ($/MWh)** | **Hypothetical Benefit** |
| 15 | 57.41 | 0.00 | 58.41 | 1,125.22 | ($64,598.88) |
| 16 | 57.41 | 0.00 | 72.99 | 118.07 | ($6,778.40) |
| 17 | 57.41 | 0.00 | 65.44 | 25.34 | ($1,454.77) |
| **Total Benefit / (Cost)** | | | | | **($72,832.05)** |

In the "Potential Results" scenario the Company initially planned for 57.41 MW but decided on the day of the event not to call because of a change in weather (cloud coverage or rain chances increased). The Company had already bid its load in the SPP Market, on a day-ahead basis, adjusted down by 57.41 MW betting that LMPs would be high the next day. Because load reduction did not occur, the Company had to buy those MWs in the RT market at the RT price. This resulted in the total loss shown above.

While this example centers around weather, the reality is that the Company never really knows what causes high LMPs in the SPP market. The price spike shown in the RT market on August 6, 2019 at HE 16 could have been the result of a transmission-related issue, a substation-related issue, a power plant tripping offline, a localized congestion issue or any number of events. The Company could have cancelled the demand response event in the above example, assuming the RT LMPs would be lower due to cloud coverage, and still be impacted by high RT LMPs because of some other event in the SPP.

**Q: Are OPC's disallowances due to energy charges related to not calling demand response events valid?**

A: No, they are not. OPC's recommendation that the Company use demand response programs to place bets on the DA LMP is not a zero-sum proposition. If Evergy bets wrong – a distinct possibility given the vicissitudes of the weather and market dynamics – and the RT LMP is significantly higher than the DA LMP then customers would not only fail to see a benefit, but in fact would bear the cost of such a wrong bet.

**Q: Please describe the SPP Schedule 11 fees and how they are calculated.**

A: Schedule 11 fees are those expenses that transmission customers within the SPP pay the transmission owners for the build out of the SPP transmission system. The regional portion of the Schedule 11 fees, those costs that are socialized across all transmission customers because the benefits of those upgrades are regional in scale, are allocated based on a company's load ratio share. The load ratio share is simply the ratio of an entity's average of their 12 monthly peaks to the average of SPP's twelve monthly peaks, expressed as a percentage. As an example, if the regional portion of SPP's Schedule 11 costs was $100 million and a market participant had a load ratio share of 5% then their allocated portion of Schedule 11 fees would be $5 million. It is the regional portion of the Schedule 11 fees that could be impacted from reductions in peak load because it would directly impact the load ratio share.

**Q: How would one attempt to reduce Schedule 11 fees using demand response programs?**

A: If one could determine, in advance, the day and hour of a monthly peak during the four summer months of the demand response season, and called a demand response event at that time, one could reduce Schedule 11 fees. By reducing the monthly peak, a company would then see its load ratio share reduced, and subsequently its Schedule 11 fees reduced. Of course, this is unrealistic because it is not possible to consistently predict the day and hour of a monthly peak in advance.

**Q: How would this strategy align with the current demand response program design?**

A: This strategy of chasing the monthly demand peaks would not align at all with the Company's current demand response programs. Company witness Brian File addresses this in his rebuttal testimony.

**Q: Validity aside, are the estimates of disallowance attributable to SPP Schedule 11 fees, as calculated by OPC, correct?**

A: No, they are not. Like the Staff's calculations in the MEEIA proceeding, OPC has used the incorrect year's data to estimate the Schedule 11 fees. Adjusting for the correct years results in a reduction to $270,175 for Evergy Missouri West and $161,123 for Evergy Missouri Metro. These amounts would need to be further reduced by applying the appropriate transmission percentage applicable to SPP transmission service costs, and any jurisdictional adjustments, as well as the 95% FAC sharing mechanism adjustment found in each Company's FAC tariff.

**Q: Does this conclude your testimony?**

A: Yes, it does.

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**

| | | |
|---|---|---|
| In the Matter of the Third Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Evergy Missouri West Inc., d/b/a Evergy Missouri West | ) ) ) ) | File No. EO-2020-0262 |
| In the Matter of the Third Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Evergy Metro, Inc., d/b/a Evergy Missouri Metro | ) ) ) ) | File No. EO-2020-0263 |

**AFFIDAVIT OF JOHN R. CARLSON**

**STATE OF MISSOURI )**
**) ss**
**COUNTY OF JACKSON )**

John R. Carlson, being first duly sworn on his oath, states:

1. My name is John R. Carlson. I work in Kansas City, Missouri, and I am employed by Evergy Metro, Inc. and serve as Senior Manager Missouri Operations – Generation Resources for Evergy Metro, Inc. d/b/a Evergy Missouri Metro ("Evergy Missouri Metro) and Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West").

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Evergy Missouri Metro and Evergy Missouri West consisting of twenty-two (22) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

John R. Carlson

Subscribed and sworn before me this 4th day of December 2020.

Notary Public

My commission expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021