SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
A CENTERPOINT ENERGY COMPANY
(VECTREN SOUTH)

IURC CAUSE NO. 43354 MCRA24

DIRECT TESTIMONY
OF
JUSTIN M. JOINER
DIRECTOR, POWER SUPPLY SERVICES

ON

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR
COST AND REVENUE ADJUSTMENT (MCRA)

SPONSORING PETITIONER'S EXHIBIT NO. 2
ATTACHMENTS JMJ-1 THROUGH JMJ-6

DIRECT TESTIMONY OF JUSTIN M. JOINER

I. INTRODUCTION

Q. Please state your name and business address.

A. Justin M. Joiner
One Vectren Square
Evansville, Indiana 47708

Q. What position do you hold with Petitioner, Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc., a CenterPoint Energy Company ("Vectren South", "Petitioner", or "the Company")?

A. I am Director of Power Supply Services for CenterPoint Energy, the immediate parent company of Vectren South.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Economics and Finance and a Master's degree in Business Administration, both from Southern Illinois University at Edwardsville.

Q. Please describe your professional experience.

A. I have been employed by the Company since January 2015. I began my career in the energy industry at Ameren Corporation and worked in a variety of roles in both the regulated and merchant divisions from 2008 to 2013. Prior to joining the Company, I worked at Midcontinent Independent System Operator ("MISO") in the Strategy and Business Development segment where I helped to attract and retain membership within MISO, implemented Process Improvement measures for member analysis procedures, and was Secretary of the Internal Risk and Audit Committee.

Q. What are your present duties and responsibilities as Director of Power Supply Services?

A. My current role as Director of Power Supply Services involves oversight of the

Wholesale Power Marketing, Market Settlements, Market Development, and Generation Planning divisions. Through this role, I am responsible for Vectren South's participation in the wholesale energy markets, as well as Vectren South's triennial submittal of its Integrated Resource Plan to the Commission.

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

A. Yes. I have testified before the Commission on behalf of Vectren South in Cause No. 43354 MCRA23.

Q. Are you sponsoring any attachments in this proceeding?

A. Yes. I am sponsoring, and will discuss in greater detail below, the following attachments in this proceeding:

- Petitioner's Exhibit No. 2, **Attachment JMJ-1**: MISO 2020-2024 Budget.
- Petitioner's Exhibit No. 2, **Attachment JMJ-2**: Non Vectren MTEP Projects 2021-2022.
- Petitioner's Exhibit No. 2, **Attachment JMJ-3**: 2021-2022 Estimated GG
- Petitioner's Exhibit No. 2, **Attachment JMJ-4**: Schedule 26A Indicative Annual Charges Projected
- Petitioner's Exhibit No. 2, **Attachment JMJ-5**: RECB Cost Allocation
- Petitioner's Exhibit No. 2, **Attachment JMJ-6**: Schedule 26 Calculations

Q. What is the purpose of your testimony in this proceeding?

A. I describe the estimated non-fuel related MISO Energy and Operating Reserves Market charges recoverable in the Company's MCRA mechanism. I also address the actual non-fuel costs applicable to the period of July 2019 through June 2020 (the "Reconciliation Period"). I will also describe Vectren South's projects approved by MISO for Regional Expansion Criteria and Benefit ("RECB") treatment and how those costs are captured for recovery in MCRA24. Finally, I will discuss the complaints before the Federal Energy Regulatory Commission ("FERC") involving the Return on Equity ("ROE") captured in the Company's formula rate mechanism applicable to its RECB projects, and how these complaints impact the costs included for recovery in the MCRA.

II. NON-FUEL CHARGES

Q. Please describe the impact of the ramp capability products on the Day Ahead ("DA") and Real Time ("RT") Markets.

A. Beginning May 1, 2016 MISO implemented two charges, DA Ramp Capability Amount and RT Ramp Capability Amount. These charge types represent an Asset Owner's compensation for up and/or down ramp capability in the DA and RT Markets. Ramp capability products are designed to manage net load variations and uncertainties over a defined response time to maintain the real time power balance. Ramp capability is simultaneously co-optimized with energy and ancillary services, so the most economical resources are selected to serve load and fulfill reserve and ramp requirements. This ramp product is most like an ancillary services product as it was evaluated and determined by MISO and its stakeholders as a better option than increasing regulation and contingency reserve requirements. The Ramp Capability Distribution will be uplifted through the existing RT Revenue Neutrality Uplift Amount ("RT RNU") balancing mechanism. The Revenue Neutrality Uplift is a charge type that acts as a revenue distribution mechanism for charges and credits that have no other method of distribution to the Asset Owners. This charge type is comprised of charges and credits that are distributed to the Asset Owners via Load Ratio Share ("LRS"). Here, the uplift creates a mismatch between the Asset Owner payment for the ramp product through DA and RT pricing, which is recovered through the Vectren South fuel adjustment clause ("FAC") quarterly filings, and the RT RNU funding mechanism which is recovered through Vectren South's semi-annual MCRA filings.

In order to more accurately align revenues and expenses, Vectren South included the DA and RT Ramp Capability revenues, as well as, the Ramp Capability Distribution Uplift Amount charges in the prior FAC112 filing. Vectren South will continue to include the revenues in future quarterly FAC filings and reclassify the charges for the Ramp Capability Distribution Uplift charge type from RT RNU for the same FAC periods to reflect the matching of revenues and expense. For this MCRA reconciliation period, July 2019 – June 2020, $10,927 was reclassified to several of Vectren South's FAC filings. $3,674 was included in FAC 125, $3,340 was included in FAC126, $1,534 was included in FAC 127, $1,436 was included in FAC 128, and $943 will be included in Vectren South's future FAC129 filing.

Q. For which months are estimated non-fuel related MISO Energy and Operating Reserves Market charges included in this MCRA?

A. The estimated non-fuel related MISO charges for the months of January 2021 through December 2021 ("the MCRA Period") are included in this MCRA.

Q. Do estimates in this Petition include MISO Ancillary Services Market ("ASM") costs?

A. Yes. Calculations for Schedule 17 utilize MISO's 2021 budget billing rates per MWh. I have also included an estimate for RT RNU, which contains the ASM RT Contingency Reserve Deployment Failure Charge Uplift Amount.

Q. What is the basis for the estimated non-fuel related MISO charges?

A. Three (3) methods are used to estimate these charges. The MISO Annual Revenue Requirement 2021 budget billing rates for Schedules 10 and 17 are multiplied by Vectren South's forecasted retail load. For Schedule 16, the MISO 2021 budget billing rate is multiplied by Vectren South's Financial Transmission Rights ("FTR") volumes based on awards from the 2020-2021 FTR Annual Auction. The projected 2021 Schedule 10 FERC rates were multiplied by Vectren South's forecasted retail load for the forecast period January 2021 to December 2021. For Schedule 26 and 26-A, the estimates are based on data found in MISO Transmission Expansion Plans ("MTEP") for charges by other market participants applicable to Vectren South plus estimates for Vectren South retail charges, as provided by the Company's Regulatory Implementation and Analysis group. Historical averaging was used for all remaining charges.

Q. Are estimates from MISO included in your forecasts?

A. Yes. MISO's Annual Revenue Requirement 2020-2024 budget (shown in

Petitioner's Exhibit No. 2, Attachment JMJ-1) billing rates were used for Schedules 10, 16 and 17. Schedule 26 estimates utilize MTEP06 through MTEP19. Refer to Petitioner's Exhibit No. 2, Attachment JMJ-2 which summarizes MISO participant project data financially impacting Vectren South and Petitioner's Exhibit No. 2, Attachment JMJ-3 which summarizes Vectren South's project data. For Schedule 26-A, which includes the cost of MISO Multi-Value Projects ("MVP"), the estimates are based on the July 30, 2020 estimated rates provided on the MISO website at Planning/MTEP Studies/Indicative annual charges for approved MVPs (Schedule 26-A) times a factor of 0.9 based on actual historical averages (reference Petitioner's Exhibit No. 2, Attachment JMJ-4).

Q. Are estimates from FERC included in your forecasts?

A. Yes. The current Schedule 10-FERC rate of $0.053/MWh was used for the forecast period January 2021 to December 2021, Vectren South's forecasted retail load was then multiplied by the FERC rate for months January 2021 through December 2021.

Q. For which months are historical, actual non-fuel related MISO Energy and Operating Reserves Market charges included in this MCRA?

A. Applicable non-fuel related MISO Energy and Operating Reserves Market charges for the Reconciliation Period are included in this MCRA filing.

Q. Are there any new non-fuel related MISO charges included with the reconciliation or forecast period?

A. Yes, Transmission Schedule 26-C and the Real Time Schedule 49 Cost Distribution Amount. In January 2020 MISO began charging Schedule 26-C for cost recovery of Targeted Market Efficiency Projects ("TMEP's) to reflect updates from MISO and PJM Interconnection LLC ("PJM"). The charges are relatively small in nature and average around $190 per month. This activity was included in the actual amounts for the reconciliation period and included in the forecast of future periods consistent with the treatment of other Schedule 26 charges. A description of the Real Time Schedule 49 Cost Distribution Amount is included with the discussion of the Southwest Power Pool ("SPP") settlement in Section III.

Q. Are the components of the actual non-fuel related MISO Energy and Operating Reserves Market charges identical to the components of the estimated charges?

A. Yes, with one exception. RT Miscellaneous charge is a mechanism that allows MISO to issue charges and/or credits based on specific requirements to either one Asset Owner or the whole market. There is no basis on which to reasonably estimate these charges. As stated in Vectren's South FAC 112 filing, the Ramp Capability Uplift Amount component of RT RNU has been reclassified as a fuel cost adjustment in order to match revenues and expense. Therefore, this component is omitted from Other RT RNU listed below as well as the forecast period for this filing.

The following components are included in both the actual and estimated charges.

- Schedule 1 Scheduling, System Control, and Dispatch Service
- Schedule 2 Reactive Supply and Voltage Control from Generation or Other Source Service
- Schedule 9 Network Integration Transmission Service
- Schedule 10 MISO Cost Adder – Demand and Energy
- Schedule 10- FERC Annual Charges Recovery
- Schedule 16 Financial Transmission Rights Market Administration Amount
- Schedule 17 DA and RT Market Administration Amount
- Schedule 24 DA and RT Allocation Amount
- Schedule 24 RT Distribution Amount
- Schedule 26 Network Upgrade Charge from Transmission Expansion Plan
- RT Revenue Sufficiency Guarantee ("RSG") Second Pass Distribution Amount (component of RNU)
- Other RT RNU Components:
    - Joint Operating Agreement ("JOA") Uplift Amount
    - Carve-out Grandfathered Agreement Congestion Rebate Distribution Amount Uplift
    - Total Uninstructed Deviation Uplift Amount
    - RT Contingency Reserve Deployment Failure Charge Amount

- Revenue Inadequacy Uplift
- Option B Grandfathered Agreement ("GFA") Financial Bilateral Transaction Congestion Rebate Distribution Amount Uplift
- RT Price Volatility Make Whole Payment Uplift Amount
- Demand Response Compensation Uplift
- Additional Regulation Mileage Compensation Uplift
- RT MVP Distribution Amount
- RT Schedule 49 Cost Distribution Amount

As noted above, because RT Miscellaneous Amounts are not subject to reasonable estimation, they are included in actual charges but are excluded from estimated charges.

Q. Why are charges for Schedules 2 included for this reconciliation period?

A. In September of 2018 Vectren South began receiving Schedule 2 charges on its native load reservation. This was attributable to the addition of the Cannelton Hydro generators to Vectren South's pricing zone. In December 2019 Alcoa's Warrick Unit 4 was also added to Vectren South's pricing zone. Schedule 2 is not charged to the native load reservations in a pricing zone as long as the Schedule 2 generators in the zone are affiliated with the Transmission Owner ("TO"). When a generator that is not affiliated with the TO is added to the zone, MISO will charge Schedule 2 on the native load reservation in order to fully compensate all generators in the zone. The TO ("SIGE") receives revenue and the Transmission Customer ("SIGW") incurs expenses as a result of this change. These two amounts are netted, and the expense included in the Reconciliation Period.

Q. Why are charges estimated for Schedules 1 and 9 for the period January 2021 – December 2021?

A. The estimated charges for Schedules 1 and 9 are a result of a Transmission, Distribution, Storage Improvement Charge ("TDSIC") modernization project to move a Vectren South owned circuit out of the Holiday World substation. The project was completed and placed in service in January 2020. The estimated Schedule 1 and Schedule 9 amounts are attributable to this activity. A small portion of the estimated Schedule 2 amounts are also attributable to this project.

Q. Please describe the process Vectren South uses to verify non fuel related amounts identified above which are included in MISO Energy and Operating Reserves Market invoices.

A. Vectren South currently uses a shadow settlement system to verify MISO invoices. An independent calculation is performed using internal data sources and the MISO market rules; these results are then compared to the published settlement statements for accuracy.

Q. Please identify the variance between the non-fuel cost base level and the actual non-fuel costs.

A. The variance between actual costs and the base level is $12,881,750 which is the net of the following:

- The base rate level of non-fuel costs for the Reconciliation Period is $3,231,252, (as shown in Petitioner's Exhibit No. 1, Attachment KJT-2, Schedule 4 page 1 of 3, sum of line 6).
- The actual non-fuel costs for the Reconciliation Period is $16,113,000 (as shown in Petitioner's Exhibit No. 1, Attachment KJT-2, Schedule 4, page 2 of 3, sum of line 11).

Q. Please explain the charge types that account for the majority of the $12.8 million variance.

A. The majority of the non-fuel cost variance of $12.8 million relates to Schedule 26 and 26-A charges, which are not represented in base rates, as these are RECB returns. The variance for all other charge types is $515.1K

Q. Please explain Petitioner's Exhibit No. 2, Attachment JMJ-6, titled Network Upgrade Charge for RECB and MVP Projects, Summary of Schedule 26 and 26A Charges.

A. In response to the Docket Entry dated May 12, 2014 in the MCRA14 filing, the Commission asked the Company to provide a schedule supporting the calculation of Petitioner's Exhibit No. 1, SMK-2, Schedule 3, titled "Vectren South MISO Cost and Revenue Adjustment Determination of Non-Fuel Component and MISO Revenue Amount to Be Recovered or Credited through MCRA", Line 10, estimated Schedule 26 and 26A. The Company agreed to provide the Commission's requested supporting schedule in its case-in-chief in future MCRA filings, herein Petitioner's Exhibit No. 2, Attachment JMJ-6. Petitioner's Exhibit No. 2, Attachment JMJ-6, Line D, Total Network Upgrade Charges ties to Petitioner's Exhibit No. 1, Attachment KJT-2, Schedule 3, Line 10, Total Estimated Schedule 26 and Schedule 26A Charges.

Q. Please explain how the actual non-fuel charges are allocated between native and non-native customers?

A. Generated megawatt hours in excess of what is required for native load are allocated to wholesale sales. The MISO charges applicable to these excess sales are allocated based on the ratio of excess megawatt hours to total megawatt hours generated. The allocated charges applicable to the excess sales include First Pass RSG, Energy Market Administration Fees, Schedule 24 Allocations and Distributions, Price Volatility Make Whole Payments, RSG Make Whole Payments, Net Inadvertent Distribution Amount, Net Regulation Adjustment, and RT Miscellaneous. Transactions associated with Wholesale Contracts (non-native customers), whether purchased or generated, are allocated Energy Market Administration Fees, Schedule 24 Allocations and Distributions, First Pass RSG, Second Pass RSG, ASM Cost Distribution Charges, and Demand Response Allocation Uplift charges. As of February 28, 2015, all Wholesale Contracts with third parties have expired.

Q. Is an RSG Benchmark methodology reflected in this Petition?

A. Yes. For the Reconciliation Period, the benchmark procedure utilized a daily standard to compare each hourly RSG Reference Point. This method follows the RSG Settlement Agreements approved by the Commission on July 16, 2008 in Cause No. 43475 and on June 30, 2009 in Cause No. 43672.

Q. Are the Contestable RSG charges for which recovery is sought in this MCRA reasonable?

A. Yes. Included in this filing is a total of $8,521 of contestable First Pass RSG Distribution charges. The amounts, by month, are:

Jul 2019	$1,214
Aug 2019	$1,846
Sep 2019	$ 820
Oct 2019	$1,387
Nov 2019	$ 821
Dec 2019	$ 261
Jan 2020	$ 173
Feb 2020	$ 234
Mar 2020	$ 142
Apr 2020	$ 685
May 2020	$ 67
Jun 2020	$ 871
Total	$ 8,521

Of the total 8,784 hours in the Reconciliation Period, 391 hours (or approximately 4.45%) had an hourly reference point above the daily standard. The reference point is the sum of the RT Energy component of the locational marginal price ("LMP") and the DA Deviation and Headroom Charge Distribution Rate ("DDC Rate"). The LMP is established by MISO and is the result of market activity. The daily benchmark is established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 btu/kWh, using the day ahead natural gas prices for the NYMEX Henry Hub, plus a $0.60/mmbtu gas transport charge for a generic gas-fired GT. Of the 391 hours with contestable RSG, 346 hours (88%) had hourly contestable RSG less than $50. For the 45 remaining hours with contestable RSG greater than $50, the Daily Standard ranged from $27.00 to $41.56 and the Hourly RSG Reference Point ranged from $30.08 to $585.56. The greatest spread between the Reference Point and the Daily Standard occurred on November 13, 2019 Hour Ending ("HE") 8 which resulted in contestable RSG of $281.71.

Q. What are the total RSG Charges for the period July 2019 through June 2020 and how are they recovered?

A. The total RSG Amount for the Reconciliation Period is ($232,833) of which $87,311 in charges are included in this filing. The remaining $(320,144) is included in Vectren South's FAC, Cause No. 38708. The detail breakdown of the total is as follows: First Pass RSG Distribution Amount, $201,273; RSG Make Whole Payment Amount, $(521,417); Contestable First Pass Distribution Charges, $8,521; Second Pass RSG Distribution Uplift Amount, $78,790.

III. STATUS OF OUTSTANDING SETTLEMENTS OR ALTERNATIVE DISPUTE RESOLUTIONS

Q. Please describe the Southwest Power Pool ("SPP") Settlement.

A. In January 2020 MISO implemented the new Schedule 49 Cost Distribution Amount charge type. The charge type is designed to recover the Available System Capacity Usage costs payable to SPP, and the Joint Parties based on tariff Schedule 49. These amounts had previously been collected by MISO using Miscellaneous adjustments. Currently, Schedule 49 does not define a Cost Allocation method after January 31, 2021. MISO's current plan is to make a filing with Federal Energy Regulatory Commission ("FERC") to extend the current cost allocation method through February 1, 2023. The current cost allocation method is 90% flow-based, and 10% postage stamp.

Q. What amounts is Petitioner proposing to include in MCRA 24 relating to the SPP Settlement?

A. The amounts included in MCRA24 are $160,077 and cover the period May 2019 through April 2020 and the true-up adjustments for March 2019 through February 2020.

Q. Are there other known settlement issues that impact this or future MCRA filings?

A. Yes, later in my testimony I will discuss the pending ROE Complaints and impacts to the current and future MCRA filings.

Q. Are there any other Alternative Dispute Resolutions ("ADR") that impact this or future MCRA filings?

A. No, not at this time.

IV. REGIONAL EXPANSION & CRITERIA BENEFIT ("RECB") PROJECT COST

Q. Please define RECB.

A. The RECB process is MISO's cost sharing, or cost allocation, process for transmission projects' revenue requirements. MISO's RECB program is part of the MTEP planning process. The fundamental goal of the MTEP process is to reduce the wholesale cost of energy delivery for the consumer by addressing local and regional reliability needs. For a project to qualify for RECB treatment it must first qualify as an MTEP project and then it must demonstrate certain regional benefits. MISO's MTEP process considers numerous factors, including the following: must ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements, and enable a competitive electricity market to benefit all customers. To be eligible for inclusion in the MTEP as a RECB project, certain additional criteria must be met, including, for example, minimum voltage criteria, project costs in excess of $5 million, and relief of an identified future reliability criteria violation. When a project qualifies as a RECB project, its costs are allocated among the MISO members whose systems benefit from the project. Currently, projects are classified into one of six main groups: Participant Funded ("Other"), Transmission Delivery Service Project ("TDSP"), Generation Interconnection Project ("GIP"), Baseline Reliability Project ("BRP"), Market Efficiency Project ("MEP"), and MVP. Transmission delivery service and Other project costs are entirely paid for by the requestor. GIP costs are generally paid by the project requestor with 10% of costs distributed among all market participants based on load. BRP costs are limited to projects of 345 kV and above and are paid by the local pricing zone. MEP costs are limited to projects of 345 kV and above and shared 80% by planning sub-regions commensurate with Adjusted Production Costs ("APC") and the remaining 20% of costs are shared by all remaining market participants based on load. MVP costs are shared 100% by all market participants based on load.

Q. Has Vectren South proposed, in this MCRA, recovery of costs for projects approved by MISO for RECB treatment?

A. Yes.

Q. Please describe the basis for recovery of these costs in this proceeding.

A. The basis for the recovery of these particular costs is the Settlement Agreement approved in Cause No. 43111 ("Settlement") and reaffirmed in Vectren South's most recently approved electric rate case, Cause No. 43839. The Settlement states that RECB costs will be tracked, and non-RECB costs will not be tracked. RECB costs will be charged to the Company under MISO Schedule 26 -- this will include charges related to the Company's own RECB projects as well as its allocation of costs related to other third-party RECB projects. Through Schedule 26, the Company will receive partial cost recovery for its projects from other TOs in the MISO footprint on an allocated basis. The Company will be authorized to retain the allocated portion of cost recovery from native load customers as calculated under Schedule 26 as well as the revenues received from other MISO TOs under Schedule 26 -- all such Schedule 26 recoveries shall be treated as non-jurisdictional and outside the earnings test to allow the Company to recover its costs. The Company's RECB projects will not be included in retail rate base (Settlement pages 20-21).

Q. Please describe MISO's process for approving transmission projects for RECB treatment.

A. The MISO MTEP is an annual study of projects proposed by MISO members to strengthen and improve electric grid performance in the MISO footprint. MISO evaluates proposed MTEP projects under the criteria mentioned above. MISO may also recommend additional or alternate projects to those submitted by the members that have better regional benefits that still meet the needs of the members. In accordance with the MISO Transmission Owners' Agreement ("TOA"), approval of the MTEP by the MISO Board certifies MISO's plan for meeting the transmission needs of all stakeholders, subject to any required regulatory approval. The MTEP is developed and discussed with MISO stakeholder committees at all stages of development. For the purposes of the MTEP process, planned projects are first submitted in Appendix B of the MTEP. In general, Appendix B contains projects that are still in the MISO review and recommendation process. Some projects eligible for cost sharing are, at this point in the process, not yet ready for MISO recommendation and are held in Appendix B until the MISO review process is completed. All projects in Appendix B have documented system needs associated with them. In general, after the MISO staff recommends and the MISO Board of Directors ("BOD") approves the proposed Appendix B projects, they are then listed in Appendix A of the MTEP.

Q. When did MISO approve Vectren South's projects included in the Company's MCRA 24 filing for RECB treatment?

A. The MISO BOD approved three Vectren South projects, 1004, 1259, and 1970, for RECB treatment on June 21, 2007. The fourth project, 1257, was approved by the MISO BOD on December 4, 2008. The fifth project, 3212, was approved by the MISO BOD as a supplemental facility of upgrades by IPL on December 13, 2012. The sixth project, 10142, was approved by the MISO BOD as part of an MEP on December 10, 2015.

Q. Please describe Vectren South's projects for which the Company has received approval from MISO for RECB treatment.

A. The six Vectren South projects approved by MISO for RECB treatment are the following:

- MISO Project ID 1004, a 345/138 kV substation near Francisco, Indiana and related 138 kV lines. The project (both the substation and transmission lines) was placed in service on July 11, 2007, at an actual project cost of $25,061,496;
- MISO Project ID 1257, a 345 kV line and terminals that connects Duke Energy's Gibson plant, Vectren South's A. B. Brown plant, and Big Rivers Electric Corporation's Reid Station in Sebree, Kentucky. The project was placed in service December 19, 2012, at an actual cost of $107,277,664;

- MISO Project ID 1259, a 138 kV line connecting the Company's Dubois Substation to its Newtonville Substation. This project was placed in service on July 9, 2007, at an actual cost of $15,998,866;
- MISO Project ID 1970, a 345/138 kV substation located near West Franklin, Indiana. The project was placed in service on November 22, 2010, at an actual cost of $7,750,909;
- MISO Project ID 3212, an existing 138 kV Z84-3 transmission line from IPL Petersburg to Vectren South's Duff substation will be upgraded to allow more power to flow on the upgraded Breed-Wheatland-Petersburg 345 kV line. This project was placed in service July 25, 2013 at an actual cost of $1,611,400.
- MISO Project ID 10142 involves upgrades to Vectren South's Duff substation to accommodate the construction of the new Duff to Coleman 345 kV single circuit transmission line that is being built to relieve market congestion in Southern Indiana. This project was placed in service on June 11, 2020, at an actual cost of $3,118,414.

Q. How are MISO approved RECB project costs assigned?

A. When MISO approves projects for RECB treatment, MISO develops cost allocation factors to determine which customers will pay the network upgrade charge for the projects. Of the total network upgrade charge, MISO allocated to Vectren South 68.04% on Project ID 1004, 28.91% on Project ID 1257, 54.04% on Project ID 1259, 69.41% on Project ID 1970, 5.89% on Project ID 3212 and 4.06% on Project ID 10142.

Q. How are network upgrade charges developed for MISO RECB approved projects?

A. The network upgrade charges for RECB approved projects are calculated in MISO Attachment GG, using information from MISO Attachment O. In Attachment GG, an allocation factor for return, which includes transmission related income taxes, and an allocation factor for transmission-related expenses, which includes taxes other than income taxes, operation and maintenance expenses, and general and common depreciation expenses, is developed. The allocation factor for transmission-related expenses is multiplied by the project's gross plant investment to develop the annual expense charge. The allocation factor for return is multiplied by the project's net plant investment to develop the return charge. The expense charge and return charge are added to the project depreciation expense to derive the annual revenue requirement.

Because these calculations involve estimates, there is always the possibility that actual costs will be higher or lower than the estimate leading to an over- or under-recovery. In the event of an over-recovery, the process "trues-up" by subtracting that over-recovery from the annual revenue requirement to determine the network upgrade charge. When an under-recovery occurs, the process "trues-up" by adding the under-recovery to the annual revenue requirement to determine the network upgrade charge. Details for these calculations are shown in Petitioner's Exhibit No. 2, Attachment JMJ-3, pages 1 - 4.

Q. What is the estimated network upgrade charge for Vectren South's six (6) RECB approved projects included in MCRA 24?

A. The estimated network upgrade charges, in millions, are as follows:

- Project ID 1004: $1.448
- Project ID 1257: $2.836
- Project ID 1259: $0.730
- Project ID 1970: $0.480
- Project ID 3212: $0.009
- Project ID 10142: $0.013

Q. How was the RECB network upgrade charge amount included in MCRA 24 determined?

A. Vectren South used the network upgrade charge information contained in Attachment GG. Vectren South then used MISO's cost allocations for the six (6) projects to determine the amount of network upgrade charge to assign to the Company. Historically, Vectren South retail customers account for approximately 90% of the Company's total transmission load, with the remaining 10% wholesale load. Because costs are based on Megawatt hours, Vectren South used projected peak load data to determine what percentage of annual load occurs in the months of January 2021 through December 2021. Costs were assigned based on those monthly load percentages. Details are shown in Petitioner's Exhibit No. 2, Attachment JMJ-5.

Q. The OUCC has requested that Vectren South provide information related to each of its MTEP projects for which it will seek cost recovery in future MCRA filings. Are any such descriptions included in this MCRA?

A. No. Currently, Vectren South has not identified any MTEP projects that will be included in future MCRA filings.

V. FERC ROE COMPLAINTS

Q. Please describe the complaints filed with FERC regarding the ROE used for the Attachment O and GG calculations.

A. On November 12, 2013, certain parties representing a group of industrial customers within the MISO footprint filed a joint complaint (FERC Case No. EL14-12) against MISO and various MISO TOs, including Vectren South, seeking a FERC order reducing the 12.38% base return on equity used in the MISO TOs' rates calculated under Attachment O. The complaint covered the ROE's in effect from November 12, 2013 through February 11, 2015, representing the first refund period. A second complaint was filed (FERC Case No. EL15-45) covering the period from February 12, 2015 through May 11, 2016, representing the second refund period. On September 27, 2016, FERC issued a final order in Case No. EL14-12, establishing a base ROE of 10.32% for the first complaint period, with any additional incentive adders to this ROE applicable to each MISO TO. The refunds associated with this order were executed in January and May 2017. On November 15, 2018, the FERC proposed changes to its methodology for evaluating and setting the Commission allowed ROE. This would impact the first complaint, EL14-12, that was previously decided by establishing a corrected ROE for the first complaint period and subsequent period from the date of the original order on September 28, 2016. On November 21, 2019, FERC adopted a new methodology for determining whether a jurisdictional public utility's ROE is just and reasonable under section 206 of the Federal Power Act. Applying the new methodology in a pair of complaints against the MISO TOs, the Commission determined that the MISO TOs' current base ROE should be 9.88 percent, or 10.38% inclusive of the 50 basis point TO adder. The order grants rehearing on the first complaint (EL14-12), finds the existing 12.38 percent ROE unjust and unreasonable, and directs the MISO TOs to adopt a 9.88 percent ROE, or 10.38% inclusive of the 50 basis point TO adder, effective September 28, 2016, and to provide refunds. The order also dismisses the second complaint (EL15-45) and finds the record in that proceeding does not support a finding that the 9.88 percent ROE established in the first complaint proceeding has become unjust and unreasonable. On January 21, 2020, FERC issued an order granting rehearing for the limited purpose of further consideration of the Commission's order issued on November 21, 2019, in this proceeding. On May 21, 2020, FERC issued an order on rehearing setting the MISO TOs ROE at 10.02% with a total or maximum ROE including incentives not to exceed 12.62%, effective as of September 28, 2016. The order further directs MISO and MISO TOs to provide refunds, with interest calculated pursuant to 18 C.F.R § 35.19a (2019), by December 23, 2020, for the 15-month refund period for the First Complaint from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016 to the date of the order. Additionally, the order directs MISO and MISO TOs to file a refund report detailing the principal amounts plus interest paid to each of their customers by December 23, 2020. Finally, the order granted in part and denied in part a rehearing of Opinion No. 569, issued on November 21, 2019. On July 22, 2020, FERC issued a Notice of Denial or requests for rehearings of the Commission's order issued on May 21, 2020.

Q. How do the ROE complaints impact the MCRA?

A. MISO Non-Fuel Costs (through Schedule 26) and MISO Revenue Amounts (through Schedules 7, 8, and 9) are billed through transmission rates that are derived from revenue requirement calculations that include an ROE component. Schedule 26 charges are recovered through the MCRA. Schedule 7, 8, and 9 revenues are presented in the MCRA for informational purposes in the exhibits of Vectren South witness Katie J. Tieken but are not included for recovery or credit through the MCRA. The outcomes of the ROE complaints impact the amount of the Schedule 26 non-fuel costs recovered through the MCRA. These impacts will include both past charges for the refund period (administered through the refund process) and future charges projected in subsequent MCRA proceedings.

Q. Were any ROE refunds included in the Reconciliation Period?

A. Yes, MCRA 24 includes Schedule 26 refunds of $11,375 for the period November 22, 2019 through December 31, 2019 issued in the February 2020 billing cycle, and $265,808 for the period November 12, 2013 through February 11, 2015 issued in the April 2020 billing cycle. Due to the new FERC order issued on May 21, 2020 changing the ROE from 9.88% to 10.02% MISO stopped the resettlement process until the July 2020 billing cycle. Additional ROE resettlement amounts will be included in future MCRA filings based on the reconciliation period in which MISO issues the refund.

VI. CONCLUSION

Q. Does this conclude your prepared direct testimony?

A. Yes, at the present time.

MISO Annual Revenue Requirement
2020-2024 Budget
($ in thousands, except Billing Rates)

	Budget 2020	2021	2022	2023	2024
Billing Rates					
Schedule 10 - Demand Based- $ per MWh	$ 0.0701	$ 0.0713	$ 0.0742	$ 0.0757	$ 0.0764
Schedule 10 - Energy- $ per MWh	$ 0.0987	$ 0.1007	$ 0.1049	$ 0.1069	$ 0.1080
Schedule 10 - Total- $ per composite MWh	$ 0.169	$ 0.172	$ 0.179	$ 0.183	$ 0.184
Portion of Sch 10 - Demand Based	50%	50%	50%	50%	50%
Portion of Sch 10 - Energy	50%	50%	50%	50%	50%
Schedule 16 - $ per FTR MW Volume	$ 0.005	$ 0.005	$ 0.006	$ 0.006	$ 0.006
Schedule 17 - $ per MWh (Load+Generation+Virtuals)	$ 0.084	$ 0.086	$ 0.084	$ 0.085	$ 0.086
Capital Expenditures	$ 30,367	$ 30,000	$ 25,000	$ 25,000	$ 23,000
Cost per MWH of Energy					
Schedule 10	$ 0.20	$ 0.20	$ 0.21	$ 0.21	$ 0.22
Schedule 16	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02
Schedule 17	$ 0.19	$ 0.20	$ 0.19	$ 0.20	$ 0.20
Total Cost / MWh of Schedule 10 Energy	$ 0.41	$ 0.42	$ 0.42	$ 0.43	$ 0.43

NOTES:

This reflects the budget presented to the MISO Board of Directors on December 12th, 2019.

Vectren Energy Delivery South
Cause No. 43354 - MCRA24
MTEP06 through MTEP19 NON Vectren Projects to be Allocated to Vectren in 2020-2025

MTEP Plan	Area	Project ID	TO Member	Project Name	Estimated Shared Project Cost	Estimated In-Service Date**	Vectren Total Allocation	Annual Revenue Requirement*	True Up Allocation	ARR Alloc %	Annual Zonal Charge	Zonal True Up Allocation	2020 Estimated Charge	2021 Estimated Charge	2022 Estimated Charge	2023 Estimated Charge	2024 Estimated Charge	2025 Estimated Charge
06	Central	91	CIN	Hillcrest 345/138 substation	17,687,496	06/01/2008	16,468	2,749,021	-	0.09311%	2,560	-	2,304	2,234	2,167	2,102	2,039	1,978
06	West	345	ATC LLC	Morgan-Werner West 345 kV project	141,290,700	09/29/2009	343,188	15,642,359	(1,378,491)	0.24289%	37,994	(3,348)	31,182	30,246	29,339	28,459	27,605	26,777
06	East	481	METC	Tallmadge 345/138 kV TB3 transformer #3	9,913,090	11/17/2008	15,215	1,254,074	(67,675)	0.15348%	1,925	(77)	1,663	1,613	1,565	1,518	1,472	1,428
06	East	686	ITC	Majestic 345/120 kV switching station	8,800,000	06/01/2007	1,457	1,742,071	(139,787)	0.01656%	289	(20)	242	234	227	220	214	207
06	East	890	FE	North Medina 345/138 kV Substation	8,540,000	06/01/2008	8,598	1,644,829	-	0.10068%	1,656	-	1,490	1,446	1,402	1,360	1,320	1,280
06	East	910	ITC	Coventry Station upgrade	25,600,000	04/05/2008	7,044	3,596,765	(279,658)	0.02752%	990	(66)	831	806	782	759	736	714
06	East	911	ITC	Placid 345/120 transformer #2	5,550,000	06/06/2008	12,631	1,165,807	(86,967)	0.22758%	2,653	(175)	2,230	2,163	2,098	2,035	1,974	1,915
06	East	1326	FE	Add Capacitor Banks at Harding and Juniper 345 kV	5,454,346	06/01/2008	13,248	933,393	-	0.24289%	2,267	-	2,040	1,979	1,920	1,862	1,806	1,752
06	West	1457	NSP	G287 - 200 MW wind generation, Nobles County, MN	18,817,500	12/31/2009	418	488,622	(67,023)	0.00222%	11	(2)	8	8	8	8	7	7
06	West	1458	NSP	G349 - 200 MW wind generation, Brookings County, SD	14,890,000	11/30/2011	1,596	51,281	(7,036)	0.01072%	6	(1)	4	4	4	4	4	4
07	East	612	NIPS	Hiple - Add 2nd 345-138 kV Transformer	5,799,614	05/01/2009	3,460	662,867	(115,319)	0.05965%	395	(69)	294	285	277	268	260	252
07	Central	1263	DEM (DEI)	G431 - Edwardsport	3,793,500	04/28/2010	9,020	620,070	-	0.23779%	1,474	-	1,327	1,287	1,249	1,211	1,175	1,140
07	East	1817	METC	Midland - Out-of Cycle Project	24,625,205	12/31/2009	29,356	3,273,017	(174,658)	0.11921%	3,902	(153)	3,374	3,273	3,175	3,079	2,987	2,897
08	West	286	GRE	Capx_Twin Cities - Fargo 345kV project	490,000,000	04/02/2015	1,123,616	23,412,915	(3,049,976)	0.22931%	53,688	(6,994)	42,025	40,764	39,541	38,355	37,204	36,088
08	West	286	MP	Capx_Twin Cities - Fargo 345kV project				13,776,467	(1,506,969)	0.22931%	31,591	(3,456)	25,322	24,562	23,825	23,110	22,417	21,745
08	West	286	MRES	Capx_Twin Cities - Fargo 345kV project				9,284,869	(647,360)	0.22931%	21,291	(1,484)	17,826	17,291	16,772	16,269	15,781	15,308
08	West	286	NSP	Capx_Twin Cities - Fargo 345kV project				23,868,178	(2,522,279)	0.22931%	54,732	(6,167)	43,709	42,397	41,126	39,892	38,695	37,534
08	West	286	OTP	Capx_Twin Cities - Fargo 345kV project				9,437,449	(1,347,404)	0.22931%	21,641	(3,090)	16,696	16,195	15,709	15,238	14,781	14,338
08	West	356	ATC	ATC_Rockdale/Albion - Cardinal/West Middleton 345kV project	230,056,310	02/19/2013	519,987	16,142,045	(1,023,495)	0.22603%	36,485	(2,313)	30,755	29,832	28,937	28,069	27,227	26,410
08	West	1024	NSP	Capx_Twin Cities - La Crosse 345kV project	241,526,270	09/16/2016	481,632	26,657,990	(3,382,826)	0.19941%	53,159	(7,086)	41,466	40,222	39,015	37,845	36,709	35,608
08	West	1024	RPU	Capx_Twin Cities - La Crosse 345kV project				3,075,593	(686,628)	0.19941%	6,133	(1,369)	4,287	4,159	4,034	3,913	3,796	3,682
08	West	1024	SMMPA	Capx_Twin Cities - La Crosse 345kV project				6,657,891	-	0.19941%	13,277	-	11,949	11,591	11,243	10,906	10,578	10,261
08	West	1024	WPPI	Capx_Twin Cities - La Crosse 345kV project				2,160,081	-	0.19941%	4,307	-	3,877	3,760	3,648	3,538	3,432	3,329
08	Central	2068	AMIL	AMIL2068_Br_Latham_to_Oreana_New_345	15,039,400	10/30/2013	35,534	2,414,198	(354,840)	0.23627%	5,704	(838)	4,379	4,248	4,120	3,997	3,877	3,760
08	Central	2069	AMIL	AMIL2069_South Bloomington	17,600,000	05/15/2015	25,990	3,195,372	(460,935)	0.14767%	4,719	(681)	3,634	3,525	3,419	3,317	3,217	3,121
09	East	1828	METC	Argenta-Palisades 345kV ckt. 1 & 2	10,880,000	06/03/2010	27,199	765,191	(39,870)	0.25000%	1,913	(76)	1,653	1,603	1,555	1,509	1,463	1,420
09	Central	2053	IPL	Petersburg 345/138kV East and West Autotransformers and 2B 345kV breaker	13,400,000	11/30/2014	1,228,637	1,727,849	-	9.16893%	158,425	-	142,583	138,305	134,156	130,131	126,227	122,441
09	Central	2472	AMIL	New 345kV Supply at Fargo Substation (Facilities-4444, 4445, 4446)	66,019,000	05/26/2016	140,815	5,655,404	(818,013)	0.21330%	12,063	(1,745)	9,286	9,008	8,737	8,475	8,221	7,974
09	Central	2829	AMIL	Coffeen Plant-Coffeen, North - 2nd. Bus tie	5,591,000	11/29/2010	96,991	543,160	(86,590)	1.73478%	9,423	(1,502)	7,128	6,915	6,707	6,506	6,311	6,121
10	West	2793	ATC	G883/4 Uprate Point Beach-Sheboygan EC 345-kV	1,450,000	03/01/2010	3,299	29,217	(28,174)	0.22750%	66	(64)	2	2	2	2	2	2
10	West	2837	ATC	Uprate Cypress-Arcadian 345 kV line	100,000	12/02/2009	227	67,470	(10,679)	0.22750%	153	(24)	116	113	109	106	103	100
10	West	3104	NSP	G514 Heartland Wind Transferred to NSP 1/1/14 Wilmarth Sub (Facility 5439)	398,000	10/19/2010	905	34,175	(6,833)	0.22750%	78	(12)	59	58	56	54	53	51
11	Central	2306	AMMO	Northwest Cape Area 345/161 kV Substation	30,751,000	04/01/2016	44,838	6,623,687	-	0.14581%	9,658	-	8,692	8,431	8,178	7,933	7,695	7,464
11	West	3191	ITCM	G164-Lakefield Jct 345 kV Breaker & Half	4,074,000	04/29/2011	10,047	934,607	(65,326)	0.24662%	2,305	(186)	1,907	1,850	1,794	1,740	1,688	1,637
11	West	3206	ATC	G833/4 Long Term Solution	86,539,748	02/28/2018	171,639	3,335,186	(356,420)	0.19834%	6,615	(707)	5,317	5,158	5,003	4,853	4,707	4,566
12	Central	3212	IPL	TCFS Option 3A - rating upgrade on Breed-Wheatland-Petersburg 345kV	14,500,000	12/08/2015	854,327	892,086	-	5.89191%	52,561		47,305	45,886	44,509	43,174	41,879	40,622
12	West	3679	ATC	BRP - Green Bay to Plains 345 kV project and Menominee Co to Delta Co 138 kV double circuit line	275,700,000	09/25/2018	378,122	28,539,736	(4,352,273)	0.13715%	39,142	(5,969)	29,856	28,960	28,091	27,249	26,431	25,638
12	West	3721	MEC	GIP - Fallow Avenue Substation, interconnection and 345 kV line taps	658,000	09/15/2012	8,937	62,083	(2,723)	1.35820%	843	(37)	726	704	683	662	642	623
12	East	3835	METC	GIP - J132-Beebe Wind Farm, 125 MW wind farm connecting at new	5,033,400	10/15/2012	13,761	822,642	(44,117)	0.27339%	2,249	(89)	1,944	1,886	1,829	1,775	1,721	1,670
12	East	3837	ITC	GIP - 867 Fermi 3 Nuclear Plant	80,814,000	07/14/2025	219,523	-	-	0.27164%	-		-	-	-	-	-	-
14	East	4364	ITC	GIP - J075 Generation Interconnection 3-breaker 345 kV substation and loopin the 345 kV Bauer-Rapson #1 circuit.	4,872,000	11/27/2013	13,110	627,242	(41,492)	0.26910%	1,688	(94)	1,434	1,391	1,350	1,309	1,270	1,232
14	East	4365	ITC	GIP - J161 Generation Interconnection. 3-breaker 345kV substation and loop in 345kV Bauer-Rapson #1 circuit.	4,884,500	08/28/2014	13,144	682,422	(39,371)	0.26910%	1,836	(87)	1,574	1,527	1,481	1,437	1,394	1,352
14	East	4713	ITC	GIP - J235 Generation Interconnection. 3-breaker 345kV substation and loop in 345kV Bauer-Rapson #2 circuit.	4,930,500	10/30/2014	13,268	691,463	(45,770)	0.26910%	1,861	(104)	1,581	1,533	1,487	1,443	1,399	1,358
15	West	8240	OTP	GIP - Jamestown replace existing 345/115/41.6 kV transformers 1 & 2 with 3369 MVA transformers and add 2 25	170,000	10/31/2016	2,221	25,682	(4,272)	1.30642%	336	(56)	252	244	237	230	223	216
15	West	9523	NSP	GIP - 826 Crandal Switching Station	1,201,800	12/01/2015	15,701	78,169	(19,689)	1.30642%	1,021	(243)	700	679	659	639	620	601
15	Central	10142	Republic	Duff-Rockport-Coleman 345 kV	67,443,248	01/31/2021	2,734,890	5,432,072	-	4.05510%	220,276	-	198,248	192,301	186,532	180,936	175,508	170,243
15	Central	10142	BREC	Duff-Rockport-Coleman 345 kV				-	-	4.05510%	-	-	-	-	-	-	-	-
15	Central	10142	Hooiser	Duff-Rockport-Coleman 345 kV				-	-	4.05510%	-	-	-	-	-	-	-	-
16	East	10425	ITC	ITC MTEP16-J340 Generation Interconnection	7,575,000	12/31/2018	1,912	1,660,918	48,290	0.02524%	419	16	391	380	368	357	347	336
16	East	10743	METC	GIP - Covert Gen Interconnection (PJM-T94)	360,500	09/30/2020	4,880	84,402	(9,401)	1.35358%	1,142	(110)	930	902	875	848	823	798
16	West	10867	MEC	Obrien County Substation	300,000	08/07/2016	4,035	19,855	(872)	1.34494%	267	(12)	230	223	216	210	203	197
16	West	10868	MEC	Ida County Substation	575,000	07/15/2016	7,733	47,049	(2,067)	1.34494%	633	(28)	544	528	512	497	482	468
16	East	11043	ITCT	GIP - Replace 345kV terminal equipment at Monroe on the Monroe - Bay Shore circuit	25,000	04/04/2016	336	6,623	(799)	1.34494%	89	(10)	71	69	67	65	63	61
16	West	11203	MEC	Rolling Hills Substation	288,200	12/30/2011	3,876	6,478	(301)	1.34494%	87	(4)	75	73	70	68	66	64
16	West	11204	MEC	Lehigh Substation	75,410	11/01/2012	1,014	25,990	(1,158)	1.34494%	350	(16)	301	292	283	274	266	258
16	East	11583	ITCT	New 345 kV line created by looping the Bauer-Ringle 345 kV line into Kirk.	4,406,000	10/15/2018	11,852	834,324	204,585	0.26899%	2,244	550	2,515	2,439	2,366	2,295	2,226	2,160
16	East	11584	ITCT	New 345 kV line created by looping in the Greenwood-Rapson #2 line into Helena.	4,374,000	09/01/2017	11,766	673,767	-	0.26899%	1,812	-	1,631	1,582	1,535	1,489	1,444	1,401
16	East	11603	ITCT	New 345 kV line created by looping the Greenwood-Rapson #2 345 kV line into Stringer substation.	4,350,000	09/01/2017	11,701	-	-	0.26899%	-		-	-	-	-	-	-
16	West	11883	Various	Huntley Wilmarth - MEP	54,000,000	01/01/2022	145,253	-	-	0.26899%	-		-	-	-	-	-	-
17	West	11645	GRE	H081 - Hawk's Nest Lake Substation	1,087,500	09/01/2017	14,892	3,595	435	1.36937%	49	6	50	48	47	45	44	43
17	West	11645	MRES	H081 - Hawk's Nest Lake Substation				-	-	1.36937%	-		-	-	-	-	-	-
17	West	11645	NSP	H081 - Hawk's Nest Lake Substation				108,789	68,567	1.36937%	1,490	939	2,186	2,120	2,057	1,995	1,935	1,877
17	West	11645	OTP	H081 - Hawk's Nest Lake Substation				630	56	1.36937%	9	1	8	8	8	8	7	7
17	West	12167	ITCM	J416 Generator Interconnection	1,011,953	07/15/2019	13,857	81,746	-	1.36937%	1,119	-	1,007	977	948	919	892	865
17	West	12168	ITCM	J278 Hazleton-Mitchell 345kV Uprate	336,000	12/31/2020	4,601	-	-	1.36937%	-	-	-	-	-	-	-	-
17	West	12665	MEC	J498 Beaver Creek	1,000,000	09/01/2017	13,694	-	-	1.36937%	-	-	-	-	-	-	-	-
17	West	12723	MEC	J499 Network Upgrades and Affected System Upgrades	1,000,000	09/01/2018	13,694	-	-	1.36937%	-	-	-	-	-	-	-	-
17	West	12725	MEC	J500 Network Upgrades and Affected System Upgrades	2,457,100	04/01/2019	33,647	-	-	1.36937%	-	-	-	-	-	-	-	-
17	West	13103	ATC	West Riverside GIC J390 Kittyhawk Substation	24,750,000	04/11/2019	67,784	2,650,838	-	0.27387%	7,260	-	6,534	6,338	6,148	5,963	5,784	5,611
17	East	13444	METC	Installation of 4-345 kV breakers	2,140,500	09/01/2020	5,896	77,193	-	0.27544%	213	-	191	186	180	175	169	164
17	West	13584	MEC	Interconnection Substation	1,000,000	07/01/2018	13,694	-	-	1.36937%	-		-	-	-	-	-	-
17	West	13644	MEC	Interconnection substation	1,000,000	10/01/2019	13,694	4,467	-	1.36937%	61	-	55	53	52	50	49	47
17	West	13645	MEC	Interconnection substation	1,000,000	09/15/2018	13,694	-	-	1.36937%	-		-	-	-	-	-	-
17	East	14264	NIPSCO	Reconfigure Munster substation (NIPS) to a ring bus	840,000	06/01/2020	37,128	-	-	4.42000%	-		-	-	-	-	-	-
18	Central	13619	AMIL	New Ruby 345 kV breaker substation	3,766,568	10/01/2019	47,006	67,556	-	1.24799%	843	-	759	736	714	693	672	652
18	Central	13796	DEI	Cayuga CT 345kV Ring Bus Expansion	1,618,971	06/01/2019	20,205	-	-	1.24799%	-	-	-	-	-	-	-	-
18	West	14625	MEC	J475/J555 North English	1,375,000	07/01/2018	17,160	-	-	1.24799%	-	-	-	-	-	-	-	-
18	East	15496	METC	J533 Network Upgrades	728,000	10/01/2019	1,827	96,966	-	0.25091%	243	-	219	212	206	200	194	188
18	East	16228	IPL	Gibson - Petersburg 345 kV	4,300,000	06/01/2021	90,300	-	-	2.10000%	-		-	-	-	-	-	-
19	West	15304	MDU	OTP Twin Brooks 345kV Switching Station - J436/J437 (MDU Portion)	540,225	07/06/2020	5,223	-	-	0.96691%	-	-	-	-	-	-	-	-
19	West	15304	OTP	OTP Twin Brooks 345kV Switching Station - J436/J437 (OTP Portion)				31,920	-	0.96691%	309	-	278	269	261	254	246	239
19	Central	15325	AMIL	New 345 kV ring bus for J757 Interconnection	100,000	05/31/2021	967	-	-	0.96691%	-	-	-	-	-	-	-	-
19	East	16084	NIPS	J351 Network Upgrades	669,290	03/01/2020	6,471	-	-	0.96691%	-	-	-	-	-	-	-	-
19	East	16445	NSP	Blazing Star 1 - J460	556,350	04/30/2020	5,379	-	-	0.96691%	-	-	-	-	-	-	-	-
19	West	16445	OTP	Blazing Star 1 - J460				1,186	-	0.96691%	11	-	10	10	10	9	9	9
19	Central	16548	AMMO	New Hughes 345 kV Substation (J541) for wind Interconnection	1,000	05/01/2020	967	-	-	0.96691%	-	-	-	-	-	-	-	-
19	West	16805	OTP	OTP Deuel Switching Station - J526	1,117,779	06/26/2020	10,808	75,538	-	0.96691%	730	-	657	638	618	600	582	564
19	West	16825	MDU	OTP Twin Brooks 345 kV Switching Station Expansion-J488 (MDU Portion)	53,665	06/01/2020	519	-	-	0.96691%	-	-	-	-	-	-	-	-
19	West	16825	OTP	OTP Twin Brooks 345 kV Switching Station Expansion-J488 (OTPMDU Portion)				1,386	-	0.96691%	13	-	12	12	11	11	11	10
19	West	16964	OTP	OTP Astoria 345kV Switching Station - J493/J510 (OTP Portion)	656,782	04/30/2020	6,350	44,423	-	0.96691%	430	-	387	375	364	353	342	332
19	West	16964	NSP	OTP Astoria 345kV Switching Station - J493/J510 (NSP Portion)				-	-	0.96691%	-	-	-	-	-	-	-	-
				Total MTEP 06 through 19 Estimated Project Costs Allocated to Vectren			**9,303,870**	**238,082,406**	**(22,953,603)**		**905,185**	**(47,052)**	**772,320**	**749,150**	**726,675**	**704,875**	**683,729**	**663,217**

*Revenue Requirements and True-Up adjustments based on July 2020 MISO Schedule 26 file
**New project estimated in service dates updated based on MTEP 19 New Project List

Vectren Energy Delivery South
Cause No. 43354 - MCRA 24
Formula Rate calculation

Rate Formula Template
Utilizing Attachment O Data
To be completed in conjunction with Attachment O.

Attachment GG
For the 12 months ended 12/31/2021

Line No.	(1)	(2) **Attachment O Page, Line, Col.**	(3) **Transmission**	(4) **Allocator**
1	Gross Transmission Plant - Total	Attach O, p 2, line 2 col 5 (Note A)	556,522,999	
2	Net Transmission Plant - Total	Attach O, p 2, line 14 col 5 (Note B)	400,576,697	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach O, p 3, line 8 col 5	7,404,083	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	1.33%	1.33%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Attach O, p 3, lines 10 & 11, col 5 (Note H)	533,893	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.10%	0.10%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach O, p 3, line 20 col 5	1,789,411	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	0.32%	0.32%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, and 8**		**1.75%**
	INCOME TAXES			
10	Total Income Taxes	Attach O, p 3, line 27 col 5	6,349,381	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2 col 3)	1.59%	1.59%
	RETURN			
12	Return on Rate Base	Attach O, p 3, line 28 col 5	25,142,725	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2 col 3)	6.28%	6.28%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**7.86%**

Vectren Energy Delivery - South
Cause No. 43354 - MCRA 24
Network Upgrade Charge Calculation By Project - Vectren Owned Projects Only

Formula Rate calculation
Rate Formula Template
Utilizing Attachment O Data

Attachment GG
For the 12 months ended 12/31/2021

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**MTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**Network Upgrade Charge**
			(Note C)	(Page 1 line 9)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 14)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	345/138 kV Substation at Francisco	1004	25,061,496	1.747886%	$438,046	18,666,244	7.861692%	1,467,483	459,539	2,365,068	-	2,365,068
1b	Transmission line Dubois to Newtonville	1259	15,998,866	1.747886%	$279,642	10,745,418	7.861692%	844,772	377,493	1,501,907	-	1,501,907
1c	345kV Transformer at AB Brown	1970	7,750,909	1.747886%	$135,477	6,293,435	7.861692%	494,770	137,966	768,214	-	768,214
1d	Gibson to AB Brown to Reid 345kV	1257	107,277,664	1.747886%	$1,875,091	84,594,729	7.861692%	6,650,577	2,374,536	10,900,204	-	10,900,204
1e	Upgrade Breed-Wheatland-Petersburg 345kV	3212	1,611,400	1.747886%	$28,165	1,286,229	7.861692%	101,119	40,930	170,214	-	170,214
1f	Duff Transformer	10142	3,118,414	1.747886%	$54,506	3,000,239	7.861692%	235,870	56,333	346,709	-	346,709
2	Annual Totals		**160,818,749**		**2,810,928**	**124,586,294**		**9,794,591**	**3,446,797**	**16,052,316**	**-**	**16,052,316**
3	Rev. Req. Adj For Attachment O									$ 16,052,316		

Note Letter	
A	Gross Transmission Plant is that identified on page 2 line 2 of Attachment O and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
B	Net Transmission Plant is that identified on page 2 line 14 of Attachment O and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
C	Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base less any prefunded AFUDC, if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
D	Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E	Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment O page 3 line 12.
F	True-Up Adjustment is included pursuant to a FERC approved methodology, if applicable.
G	The Network Upgrade Charge is the value to be used in Schedules 26, 37 and 38.
H	The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Vectren Energy Delivery South
Cause No. 43354 - MCRA 24
Formula Rate calculation

Rate Formula Template
Utilizing Attachment O Data
To be completed in conjunction with Attachment O.

Attachment GG
For the 12 months ended 12/31/2022

Line No.	(1)	(2) **Attachment O Page, Line, Col.**	(3) **Transmission**	(4) **Allocator**
1	Gross Transmission Plant - Total	Attach O, p 2, line 2 col 5 (Note A)	588,444,337	
2	Net Transmission Plant - Total	Attach O, p 2, line 14 col 5 (Note B)	426,030,357	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach O, p 3, line 8 col 5	7,552,165	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	1.28%	1.28%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Attach O, p 3, lines 10 & 11, col 5 (Note H)	542,739	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.09%	0.09%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach O, p 3, line 20 col 5	1,949,205	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	0.33%	0.33%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, and 8**		**1.71%**
	INCOME TAXES			
10	Total Income Taxes	Attach O, p 3, line 27 col 5	6,622,698	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2 col 3)	1.55%	1.55%
	RETURN			
12	Return on Rate Base	Attach O, p 3, line 28 col 5	26,174,702	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2 col 3)	6.14%	6.14%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**7.70%**

Vectren Energy Delivery - South
Cause No. 43354 - MCRA 24
Network Upgrade Charge Calculation By Project - Vectren Owned Projects Only

Formula Rate calculation
Rate Formula Template
Utilizing Attachment O Data

Attachment GG
For the 12 months ended 12/31/2022

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**MTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**Network Upgrade Charge**
			(Note C)	(Page 1 line 9)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 14)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	345/138 kV Substation at Francisco	1004	25,061,496	1.706892%	$427,773	18,206,705	7.698372%	1,401,620	459,539	2,288,932	-	2,288,932
1b	Transmission line Dubois to Newtonville	1259	15,998,866	1.706892%	$273,083	10,367,925	7.698372%	798,161	377,493	1,448,738	-	1,448,738
1c	345kV Transformer at AB Brown	1970	7,750,909	1.706892%	$132,300	6,155,469	7.698372%	473,871	137,966	744,137	-	744,137
1d	Gibson to AB Brown to Reid 345kV	1257	107,277,664	1.706892%	$1,831,114	82,220,193	7.698372%	6,329,616	2,374,536	10,535,265	-	10,535,265
1e	Upgrade Breed-Wheatland-Petersburg 345kV	3212	1,611,400	1.706892%	$27,505	1,245,299	7.698372%	95,868	40,930	164,302	-	164,302
1f	Duff Transformer	10142	3,118,414	1.706892%	$53,228	2,943,906	7.698372%	226,633	56,333	336,194	-	336,194
2	Annual Totals		**160,818,749**		**2,745,002**	**121,139,497**		**9,325,769**	**3,446,797**	**15,517,568**	**-**	**15,517,568**
3	Rev. Req. Adj For Attachment O									$ 15,517,568		

Note Letter

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment O and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment O and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base less any prefunded AFUDC, if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment O page 3 line 12.
F True-Up Adjustment is included pursuant to a FERC approved methodology, if applicable.
G The Network Upgrade Charge is the value to be used in Schedules 26, 37 and 38.
H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Vectren Energy Delivery - South

Cause No. 43354 - MCRA 24

***Indicative* Multi-Value Project (MVP) Schedule 26-A Indicative Annual MVP Usage Rate for Approved MVPs**

THE VALUES SHOWN BELOW (IN Nominal $) ARE INTENDED TO BE INDICATIVE ONLY, ARE BASED UPON MISO PROJECTIONS, ARE NOT INTENDED BY MISO TO BE RELIED UPON FOR SETTLEMENT OR RATEMAKING PURPOSES. THE VALUES ARE SUBJECT TO CHANGE DEPENDING UPON ACTUAL PROJECT COSTS INCLUDING CONSTRUCTION WORK IN PROGRESS, ACTUAL IN-SERVICE DATES, AND ACTUAL ANNUAL CHARGE RATES FOR TRANSMISSION OWNERS

Figure 1. Approved MVPs

Project ID	Project Name	Geographic Location by TO Member System	Estimated In-Service Date	Estimated Project Cost (Nominal $)
[1]	[2]	[3]	[4]	[5]
1203	Brookings, SD - SE Twin Cities 345 kV	XEL/GRE/OTP/MRES/CMMPA (represents TO ownership)	3/26/2015	$670,039,761
2202	Reynolds to Greentown 765 kV line	Pioneer, NIPS	6/25/2018	$348,368,000
2220	Ellendale to Big Stone South	OTP, MDU	2/5/2019	$247,000,000
2221	Big Stone South to Brookings	OTP, NSP	9/8/2017	$122,896,532
2237	Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	ATXI	12/1/2020	$409,740,819
2239	Sidney to Rising 345 kV line	ATXI	9/1/2016	$88,121,836
2248	Adair - Ottumwa 345	AMMO, ITCM, MEC	7/1/2019	$216,258,799
2844	Pleasant Prairie-Zion Energy Center 345 kV line	ATC	12/6/2013	$36,200,000
3017	Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	ATXI	12/20/2017	$723,229,856
3022	Fargo-Galesburg-Oak Grove 345 kV Line	ATXI, MEC	2/21/2018	$200,980,896
3127	N LaCrosse-N Madison-Cardinal -Spring Green - Dubuque area 345-kV	ATC, NSP, ITCM	12/31/2023	$1,033,927,000
3168	Michigan Thumb Wind Zone	ITC	12/31/2015	$504,000,000
3169	Pawnee to Pana - 345 kV Line	ATXI	10/27/2017	$134,576,365
3170	Adair-Palmyra Tap 345 kV Line	AMMO	12/15/2019	$171,711,053
3203	Reynolds to E. Winnamac to Burr Oak to Hiple 345 kV	NIPS	9/30/2018	$404,800,000
3205	Lakefield Jct. - Winnebago - Winco - Burt area & Sheldon - Burt Area - Webster 345 kV line	MEC, ITCM	9/27/2018	$691,614,770
3213	Winco to Hazelton 345 kV line	MEC, ITCM	7/15/2019	$564,397,636
			Total	$6,567,863,323

Figure 2. Indicative MVP Usage Rates (MUR) for Approved MVPs (in Nominal $/MWh)

Year	Total Indicative MVP Usage Rate ($/MWh)
2020	$1.70
2021	$1.69
2022	$1.70
2023	$1.69
2024	$1.77
2025	$1.71
2026	$1.69
2027	$1.67
2028	$1.65
2029	$1.64
2030	$1.62
2031	$1.60
2032	$1.59
2033	$1.57
2034	$1.55
2035	$1.54
2036	$1.52
2037	$1.50
2038	$1.49
2039	$1.47

Date: 7/30/2019

Notes:

1) Indicative MVP Usage Rate based on approved Multi Value Projects through July2019; Information provided by Transmission Owners via the MTEP quarterly project status reporting process

2) Annual MISO Withdrawals, including exports to PJM, are based on 2017 values with years 2019-2038 escalated assuming an annual energy growth rate of 0.40% consistent with the MTEP19 Continued Fleet Change Future.

3) Annual Revenue Requirement calculated using an estimated Annual Charge Rate for each constructing Transmission Owner based on the methodology described in Attachment MM. Annual Charge Rate estimated using Transmission Owner's Attachment O data as of June 2019and assumes 40-year straight-line depreciation.

4) For approved projects with recovery for Construction Work in Progress, charges are phased-in based on an assumed schedule, see "Construction Work in Progress" tab.

5) The MVP usage rate reflects FERC's July 13, 2016 Order in ER10-1791 which directed MISO to charge the MVP rate on exports to PJM.

6) Please contact Ben Stearney at bstearney@misoenergy.org with any questions.

Figure 3. *Indicative* Annual MVP Charges for Approved MVPs by Local Balancing Authority for 2020-2039 (in Millions of Nominal Dollars

LBA	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
ALTE	$21.99	$21.96	$22.13	$22.17	$23.24	$22.53	$22.38	$22.24	$22.10	$21.95	$21.81	$21.67	$21.52	$21.38	$21.24	$21.09	$20.95	$20.81	$20.66	$20.52
ALTW	$23.72	$23.69	$23.87	$23.92	$25.07	$24.30	$24.15	$23.99	$23.84	$23.68	$23.53	$23.37	$23.22	$23.06	$22.91	$22.75	$22.60	$22.44	$22.29	$22.13
AMIL	$74.54	$74.46	$75.02	$75.18	$78.80	$76.37	$75.88	$75.40	$74.91	$74.42	$73.94	$73.45	$72.97	$72.48	$71.99	$71.51	$71.02	$70.53	$70.05	$69.56
AMMO	$61.00	$60.93	$61.39	$61.52	$64.48	$62.50	$62.10	$61.70	$61.30	$60.90	$60.51	$60.11	$59.71	$59.31	$58.91	$58.52	$58.12	$57.72	$57.32	$56.93
BREC	$8.80	$8.79	$8.85	$8.87	$9.30	$9.01	$8.96	$8.90	$8.84	$8.78	$8.73	$8.67	$8.61	$8.56	$8.50	$8.44	$8.38	$8.33	$8.27	$8.21
CIN	$65.17	$65.09	$65.58	$65.72	$68.88	$66.76	$66.34	$65.91	$65.49	$65.06	$64.64	$64.21	$63.79	$63.36	$62.94	$62.51	$62.09	$61.66	$61.24	$60.81
CONS	$71.19	$71.11	$71.64	$71.80	$75.25	$72.94	$72.47	$72.01	$71.54	$71.08	$70.61	$70.15	$69.68	$69.22	$68.76	$68.29	$67.83	$67.36	$66.90	$66.43
CWLD	$2.25	$2.24	$2.26	$2.26	$2.37	$2.30	$2.29	$2.27	$2.26	$2.24	$2.23	$2.21	$2.20	$2.18	$2.17	$2.15	$2.14	$2.12	$2.11	$2.10
CWLP	$3.08	$3.07	$3.10	$3.10	$3.25	$3.15	$3.13	$3.11	$3.09	$3.07	$3.05	$3.03	$3.01	$2.99	$2.97	$2.95	$2.93	$2.91	$2.89	$2.87
DECO	$81.31	$81.22	$81.83	$82.00	$85.95	$83.30	$82.77	$82.24	$81.71	$81.18	$80.65	$80.12	$79.59	$79.06	$78.53	$78.00	$77.47	$76.94	$76.41	$75.88
DPC	$0.72	$0.72	$0.73	$0.73	$0.76	$0.74	$0.74	$0.73	$0.73	$0.72	$0.72	$0.71	$0.71	$0.70	$0.70	$0.69	$0.69	$0.68	$0.68	$0.68
GRE	$20.31	$20.29	$20.44	$20.48	$21.47	$20.81	$20.68	$20.54	$20.41	$20.28	$20.15	$20.01	$19.88	$19.75	$19.62	$19.48	$19.35	$19.22	$19.09	$18.95
HE	$1.14	$1.14	$1.15	$1.15	$1.20	$1.17	$1.16	$1.15	$1.14	$1.14	$1.13	$1.12	$1.11	$1.11	$1.10	$1.09	$1.08	$1.08	$1.07	$1.06
IPL	$23.44	$23.42	$23.59	$23.64	$24.78	$24.02	$23.86	$23.71	$23.56	$23.40	$23.25	$23.10	$22.95	$22.79	$22.64	$22.49	$22.33	$22.18	$22.03	$21.88
MDU	$5.68	$5.67	$5.71	$5.72	$6.00	$5.81	$5.78	$5.74	$5.70	$5.67	$5.63	$5.59	$5.56	$5.52	$5.48	$5.44	$5.41	$5.37	$5.33	$5.30
MEC	$46.10	$46.05	$46.39	$46.49	$48.73	$47.23	$46.93	$46.63	$46.33	$46.03	$45.73	$45.43	$45.12	$44.82	$44.52	$44.22	$43.92	$43.62	$43.32	$43.02
MGE	$5.62	$5.61	$5.65	$5.66	$5.94	$5.75	$5.72	$5.68	$5.64	$5.61	$5.57	$5.53	$5.50	$5.46	$5.42	$5.39	$5.35	$5.32	$5.28	$5.24
MUIP	$3.25	$3.24	$3.27	$3.28	$3.43	$3.33	$3.31	$3.29	$3.26	$3.24	$3.22	$3.20	$3.18	$3.16	$3.14	$3.12	$3.09	$3.07	$3.05	$3.03
MP	$19.07	$19.05	$19.19	$19.23	$20.16	$19.53	$19.41	$19.29	$19.16	$19.04	$18.91	$18.79	$18.66	$18.54	$18.42	$18.29	$18.17	$18.04	$17.92	$17.79
MPW	$1.51	$1.51	$1.52	$1.52	$1.60	$1.55	$1.54	$1.53	$1.52	$1.51	$1.50	$1.49	$1.48	$1.47	$1.46	$1.45	$1.44	$1.43	$1.42	$1.41
NIPS	$32.95	$32.91	$33.16	$33.23	$34.83	$33.75	$33.54	$33.32	$33.11	$32.90	$32.68	$32.47	$32.25	$32.04	$31.82	$31.61	$31.39	$31.18	$30.96	$30.75
NSP	$77.47	$77.38	$77.96	$78.13	$81.89	$79.36	$78.86	$78.35	$77.85	$77.34	$76.84	$76.33	$75.83	$75.32	$74.82	$74.31	$73.81	$73.30	$72.80	$72.29
OTP	$16.22	$16.20	$16.32	$16.36	$17.15	$16.62	$16.51	$16.41	$16.30	$16.19	$16.09	$15.98	$15.88	$15.77	$15.67	$15.56	$15.45	$15.35	$15.24	$15.14
SIGE	$10.00	$9.99	$10.06	$10.08	$10.57	$10.24	$10.18	$10.11	$10.05	$9.98	$9.92	$9.85	$9.79	$9.72	$9.66	$9.59	$9.53	$9.46	$9.40	$9.33
SIPC	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
SMP	$2.76	$2.76	$2.78	$2.79	$2.92	$2.83	$2.81	$2.80	$2.78	$2.76	$2.74	$2.72	$2.71	$2.69	$2.67	$2.65	$2.63	$2.62	$2.60	$2.58
UPPC	$1.84	$1.84	$1.85	$1.85	$1.94	$1.88	$1.87	$1.86	$1.85	$1.83	$1.82	$1.81	$1.80	$1.79	$1.77	$1.76	$1.75	$1.74	$1.73	$1.71
WEC	$50.13	$50.07	$50.45	$50.55	$52.99	$51.35	$51.03	$50.70	$50.37	$50.05	$49.72	$49.39	$49.07	$48.74	$48.41	$48.09	$47.76	$47.43	$47.10	$46.78
WPS	$23.43	$23.40	$23.58	$23.63	$24.77	$24.00	$23.85	$23.70	$23.54	$23.39	$23.24	$23.08	$22.93	$22.78	$22.63	$22.47	$22.32	$22.17	$22.02	$21.86
Exports and Wheel-Throughs including those sinking in PJM	$9.14	$9.13	$9.20	$9.22	$9.66	$9.37	$9.31	$9.25	$9.19	$9.13	$9.07	$9.01	$8.95	$8.89	$8.83	$8.77	$8.71	$8.65	$8.59	$8.53
Total	$763.86	$762.98	$768.70	$770.36	$807.44	$782.55	$777.57	$772.59	$767.61	$762.63	$757.64	$752.66	$747.68	$742.70	$737.72	$732.74	$727.75	$722.77	$717.79	$712.81

Date: 7/30/2019

Indicative **Multi-Value Project (MVP) Schedule 26-A Indicative Annual MVP Usage Rate for Approved MVPs**

THE VALUES SHOWN BELOW (IN Nominal $) ARE INTENDED TO BE INDICATIVE ONLY, ARE BASED UPON MISO PROJECTIONS, ARE NOT INTENDED BY MISO TO BE RELIED UPON FOR SETTLEMENT OR RATEMAKING PURPOSES. THE VALUES ARE SUBJECT TO CHANGE DEPENDING UPON ACTUAL PROJECT COSTS INCLUDING CONSTRUCTION WORK IN PROGRESS, ACTUAL IN-SERVICE DATES, AND ACTUAL ANNUAL CHARGE RATES FOR TRANSMISSION OWNERS

Figure 1. Approved MVPs

Project ID	Project Name	Geographic Location by TO Member System	Estimated In-Service Date	Estimated Project Cost (Nominal $)
[1]	[2]	[3]	[4]	[5]
1203	Brookings, SD - SE Twin Cities 345 kV	XEL/GRE/OTP/MRES/ CMMPA (represents TO ownership)	3/26/2015	$670,039,761
2202	Reynolds to Greentown 765 kV line	Pioneer, NIPS	6/25/2018	$348,368,000
2220	Ellendale to Big Stone South	OTP, MDU	2/5/2019	$247,000,000
2221	Big Stone South to Brookings	OTP, NSP	9/8/2017	$122,896,532
2237	Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	ATXI	12/1/2020	$409,740,819
2239	Sidney to Rising 345 kV line	ATXI	9/1/2016	$88,121,836
2248	Adair - Ottumwa 345	AMMO, ITCM, MEC	7/1/2019	$220,760,544
2844	Pleasant Prairie-Zion Energy Center 345 kV line	ATC	12/6/2013	$36,200,000
3017	Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	ATXI	12/20/2017	$723,229,856
3022	Fargo-Galesburg-Oak Grove 345 kV Line	ATXI, MEC	2/21/2018	$200,980,896
3127	N LaCrosse-N Madison-Cardinal -Spring Green - Dubuque area 345-kV	ATC, NSP, ITCM	12/31/2023	$1,033,927,000
3168	Michigan Thumb Wind Zone	ITC	12/31/2015	$504,000,000
3169	Pawnee to Pana - 345 kV Line	ATXI	10/27/2017	$134,576,365
3170	Adair-Palmyra Tap 345 kV Line	AMMO	12/15/2019	$171,711,053
3203	Reynolds to E. Winnamac to Burr Oak to Hiple 345 kV	NIPS	9/30/2018	$404,800,000
3205	Lakefield Jct. - Winnebago - Winco - Burt area & Sheldon - Burt Area - Webster 345 kV line	MEC, ITCM	9/27/2018	$691,614,770
3213	Winco to Hazelton 345 kV line	MEC, ITCM	7/15/2019	$564,397,636
			Total	$6,572,365,067

Figure 2. Indicative MVP Usage Rates (MUR) for Approved MVPs (in Nominal $/MWh)

Year	Total Indicative MVP Usage Rate ($/MWh)
2021	$1.67
2022	$1.65
2023	$1.64
2024	$1.77
2025	$1.75
2026	$1.73
2027	$1.72
2028	$1.70
2029	$1.69
2030	$1.67
2031	$1.65
2032	$1.64
2033	$1.62
2034	$1.61
2035	$1.59
2036	$1.58
2037	$1.56
2038	$1.55
2039	$1.53
2040	$1.52

Date: 8/5/2020

Notes:

1) Indicative MVP Usage Rate based on approved Multi Value Projects through July2020; Information provided by Transmission Owners via the MTEP quarterly project status reporting process

2) Annual MISO Withdrawals, including exports to PJM, are based on 2019 values with years 2020-2039 escalated assuming an annual energy growth rate of 0.40% consistent with the MTEP20 Continued Fleet Change Future.

3) Annual Revenue Requirement calculated using an estimated Annual Charge Rate for each constructing Transmission Owner based on the methodology described in Attachment MM. Annual Charge Rate estimated using Transmission Owner's Attachment O data as of July 2020 (base ROE 10.02%) and assumes 40-year straight-line depreciation.

4) The MVP usage rate reflects FERC's July 13, 2016 Order in ER10-1791 which directed MISO to charge the MVP rate on exports to PJM.

5) In-Service Date and Estimated Project Cost for Figure 1 are from the MTEP Project Database (Q1). Costs used in the actual indicative rate calculations are gross plant cost information as reported in Attachment MM (where available)

6) Please contact Dan Mittelstaedt at dmittelstaedt@misoenergy.org with any questions.

Figure 3. *Indicative* Annual MVP Charges for Approved MVPs by Local Balancing Authority for 2020-2040 (in Millions of Nominal Dollars)

LBA	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ALTE	$21.84	$21.73	$21.62	$23.43	$23.31	$23.19	$23.07	$22.95	$22.83	$22.71	$22.58	$22.46	$22.34	$22.22	$22.10	$21.98	$21.86	$21.73	$21.61	$21.49
ALTW	$22.58	$22.47	$22.35	$24.23	$24.10	$23.98	$23.85	$23.73	$23.60	$23.48	$23.35	$23.23	$23.10	$22.97	$22.85	$22.72	$22.60	$22.47	$22.35	$22.22
AMIL	$74.53	$74.14	$73.76	$79.97	$79.55	$79.14	$78.72	$78.31	$77.90	$77.48	$77.07	$76.65	$76.24	$75.82	$75.41	$74.99	$74.58	$74.17	$73.75	$73.34
AMMO	$60.42	$60.10	$59.79	$64.82	$64.49	$64.15	$63.82	$63.48	$63.14	$62.81	$62.47	$62.14	$61.80	$61.47	$61.13	$60.79	$60.46	$60.12	$59.79	$59.45
BREC	$10.58	$10.52	$10.47	$11.35	$11.29	$11.23	$11.17	$11.12	$11.06	$11.00	$10.94	$10.88	$10.82	$10.76	$10.70	$10.65	$10.59	$10.53	$10.47	$10.41
CIN	$64.11	$63.77	$63.44	$68.78	$68.43	$68.07	$67.71	$67.36	$67.00	$66.65	$66.29	$65.93	$65.58	$65.22	$64.86	$64.51	$64.15	$63.79	$63.44	$63.08
CONS	$68.14	$67.79	$67.43	$73.11	$72.73	$72.35	$71.97	$71.60	$71.22	$70.84	$70.46	$70.08	$69.70	$69.32	$68.94	$68.56	$68.19	$67.81	$67.43	$67.05
CWLD	$2.19	$2.18	$2.17	$2.35	$2.34	$2.33	$2.31	$2.30	$2.29	$2.28	$2.27	$2.25	$2.24	$2.23	$2.22	$2.20	$2.19	$2.18	$2.17	$2.16
CWLP	$2.97	$2.95	$2.94	$3.18	$3.17	$3.15	$3.13	$3.12	$3.10	$3.09	$3.07	$3.05	$3.04	$3.02	$3.00	$2.99	$2.97	$2.95	$2.94	$2.92
DECO	$78.93	$78.52	$78.11	$84.69	$84.25	$83.81	$83.37	$82.93	$82.49	$82.05	$81.62	$81.18	$80.74	$80.30	$79.86	$79.42	$78.98	$78.54	$78.10	$77.67
DPC	$1.08	$1.08	$1.07	$1.16	$1.15	$1.15	$1.14	$1.14	$1.13	$1.12	$1.12	$1.11	$1.11	$1.10	$1.09	$1.09	$1.08	$1.08	$1.07	$1.06
GRE	$22.64	$22.52	$22.41	$24.29	$24.17	$24.04	$23.92	$23.79	$23.66	$23.54	$23.41	$23.29	$23.16	$23.03	$22.91	$22.78	$22.66	$22.53	$22.40	$22.28
HE	$1.01	$1.01	$1.00	$1.08	$1.08	$1.07	$1.07	$1.06	$1.06	$1.05	$1.04	$1.04	$1.03	$1.03	$1.02	$1.02	$1.01	$1.01	$1.00	$0.99
IPL	$23.23	$23.11	$22.99	$24.92	$24.79	$24.66	$24.54	$24.41	$24.28	$24.15	$24.02	$23.89	$23.76	$23.63	$23.50	$23.37	$23.24	$23.11	$22.99	$22.86
MDU	$5.65	$5.62	$5.59	$6.06	$6.03	$6.00	$5.97	$5.94	$5.91	$5.87	$5.84	$5.81	$5.78	$5.75	$5.72	$5.69	$5.66	$5.62	$5.59	$5.56
MEC	$48.48	$48.23	$47.98	$52.01	$51.75	$51.48	$51.21	$50.94	$50.67	$50.40	$50.13	$49.86	$49.59	$49.32	$49.05	$48.78	$48.51	$48.24	$47.97	$47.70
MGE	$5.48	$5.45	$5.42	$5.88	$5.85	$5.82	$5.79	$5.76	$5.72	$5.69	$5.66	$5.63	$5.60	$5.57	$5.54	$5.51	$5.48	$5.45	$5.42	$5.39
MUIP	$5.33	$5.31	$5.28	$5.72	$5.69	$5.66	$5.63	$5.60	$5.57	$5.54	$5.51	$5.49	$5.46	$5.43	$5.40	$5.37	$5.34	$5.31	$5.28	$5.25
MP	$19.09	$18.99	$18.89	$20.48	$20.38	$20.27	$20.16	$20.06	$19.95	$19.85	$19.74	$19.63	$19.53	$19.42	$19.32	$19.21	$19.10	$19.00	$18.89	$18.78
MPW	$1.48	$1.47	$1.46	$1.59	$1.58	$1.57	$1.56	$1.56	$1.55	$1.54	$1.53	$1.52	$1.51	$1.51	$1.50	$1.49	$1.48	$1.47	$1.46	$1.46
NIPS	$30.55	$30.39	$30.23	$32.78	$32.61	$32.44	$32.27	$32.10	$31.93	$31.76	$31.59	$31.42	$31.25	$31.08	$30.91	$30.74	$30.57	$30.40	$30.23	$30.06
NSP	$73.62	$73.23	$72.85	$78.99	$78.58	$78.17	$77.76	$77.35	$76.94	$76.53	$76.12	$75.71	$75.30	$74.89	$74.48	$74.08	$73.67	$73.26	$72.85	$72.44
OTP	$16.03	$15.95	$15.87	$17.20	$17.11	$17.02	$16.94	$16.85	$16.76	$16.67	$16.58	$16.49	$16.40	$16.31	$16.22	$16.13	$16.04	$15.95	$15.87	$15.78
SIGE	$10.02	$9.97	$9.92	$10.75	$10.70	$10.64	$10.58	$10.53	$10.47	$10.42	$10.36	$10.31	$10.25	$10.19	$10.14	$10.08	$10.03	$9.97	$9.92	$9.86
SIPC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SMP	$2.68	$2.67	$2.65	$2.88	$2.86	$2.85	$2.83	$2.82	$2.80	$2.79	$2.77	$2.76	$2.74	$2.73	$2.71	$2.70	$2.68	$2.67	$2.65	$2.64
UPPC	$1.95	$1.94	$1.93	$2.09	$2.08	$2.07	$2.06	$2.04	$2.03	$2.02	$2.01	$2.00	$1.99	$1.98	$1.97	$1.96	$1.95	$1.94	$1.93	$1.91
WEC	$47.68	$47.43	$47.19	$51.16	$50.89	$50.63	$50.36	$50.10	$49.83	$49.57	$49.30	$49.04	$48.77	$48.51	$48.24	$47.98	$47.71	$47.45	$47.18	$46.92
WPS	$22.87	$22.75	$22.64	$24.54	$24.41	$24.29	$24.16	$24.03	$23.91	$23.78	$23.65	$23.52	$23.40	$23.27	$23.14	$23.02	$22.89	$22.76	$22.63	$22.51
Exports and Wheel-Throughs including those sinking in PJM	$8.99	$8.95	$8.90	$9.65	$9.60	$9.55	$9.50	$9.45	$9.40	$9.35	$9.30	$9.25	$9.20	$9.15	$9.10	$9.05	$9.00	$8.95	$8.90	$8.85
Total	$754.13	$750.23	$746.34	$809.17	$804.97	$800.78	$796.59	$792.39	$788.20	$784.01	$779.81	$775.62	$771.43	$767.23	$763.04	$758.85	$754.65	$750.46	$746.27	$742.07

Date: 8/5/2020

VECTREN SOUTH
MISO Cost and Revenue Adjustment
Summary of Network Upgrade Charge for RECB Projects
from Vectren 2021 Attachment GG Page 2 lines 1a - 1e

Project Name	Project Number	Total Charges Applicable to MCRA24	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
New 345/138 kV Substation at Francisco	1004	$ 1,448,273	$ 114,924	$ 109,326	$ 102,067	$ 96,403	$ 127,069	$ 144,559	$ 147,341	$ 153,442	$ 141,710	$ 95,166	$ 104,552	$ 111,714
Gibson to AB Brown and 345 /138 kV substation at AB Brown	1257	$ 2,836,124	$ 225,054	$ 214,091	$ 199,875	$ 188,784	$ 248,837	$ 283,087	$ 288,535	$ 300,483	$ 277,508	$ 186,361	$ 204,743	$ 218,766
New transmission line Dubois to Newtonville	1259	$ 730,466	$ 57,964	$ 55,141	$ 51,480	$ 48,623	$ 64,090	$ 72,911	$ 74,314	$ 77,392	$ 71,474	$ 47,999	$ 52,733	$ 56,345
New 345 /138 kV substation at AB Brown	1970	$ 479,896	$ 38,081	$ 36,226	$ 33,821	$ 31,944	$ 42,105	$ 47,901	$ 48,822	$ 50,844	$ 46,957	$ 31,534	$ 34,644	$ 37,017
Upgrade Breed-Wheatland-Petersburg 345kV	3212	$ 9,024	$ 716	$ 681	$ 636	$ 601	$ 792	$ 901	$ 918	$ 956	$ 883	$ 593	$ 651	$ 696
Duff Transformer	10142	$ 12,652	$ 1,004	$ 955	$ 892	$ 842	$ 1,110	$ 1,263	$ 1,287	$ 1,341	$ 1,238	$ 831	$ 913	$ 976
Total Annual Network Upgrade Charge for MCRA 24		**$ 5,516,435**	**$ 437,743**	**$ 416,420**	**$ 388,771**	**$ 367,197**	**$ 484,003**	**$ 550,622**	**$ 561,217**	**$ 584,458**	**$ 539,770**	**$ 362,484**	**$ 398,236**	**$ 425,514**

VECTREN SOUTH
MISO Cost and Revenue Adjustment
Network Upgrade Charge for RECB Projects
from Vectren 2021 Attachment GG Page 2 lines 1a - 1e

Project Name	Project Number	Project Net Plant	Network Upgrade Charge *	MISO Allocation to Vectren South	Vectren South Annual Network Upgrade Charge	
New 345/138 kV Substation at Francisco	1004	$ 18,666,244	$ 2,365,068	68.04%	$ 1,609,192	$ 1,448,273
Gibson to AB Brown and 345 /138 kV substation at AB Brown	1257	$ 84,594,729	$ 10,900,204	28.91%	$ 3,151,249	$ 2,836,124
New transmission line Dubois to Newtonville	1259	$ 10,745,418	$ 1,501,907	54.04%	$ 811,630	$ 730,467
New 345 /138 kV substation at AB Brown	1970	$ 6,293,435	$ 768,214	69.41%	$ 533,217	$ 479,895
Upgrade Breed-Wheatland-Petersburg 345kV	3212	$ 1,286,229	$ 170,214	5.89%	$ 10,026	$ 9,023
Duff Transformer	10142	$ 3,000,239	$ 346,709	4.06%	$ 14,059	$ 12,653
Total Annual Network Upgrade Charge			**$ 16,052,316**		**$6,129,373**	
Retail Allocation					90.00%	
Total Annual Network Upgrade Charge Allocated to Retail					**$5,516,436**	

	2021 System Peak Projection (MWh)											
	Jan-21	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
Forecasted 2020 System Peak	812.9	773.3	722.0	681.9	898.8	1,022.5	1,042.2	1,085.4	1,002.4	673.1	739.5	790.2
Percent of 2020 Annual Peak	7.94%	7.55%	7.05%	6.66%	8.77%	9.98%	10.17%	10.59%	9.78%	6.57%	7.22%	7.71%
Estimated Retail Schedule 26 Charges	$437,743	$416,421	$388,770	$367,197	$484,003	$550,623	$561,217	$584,458	$539,770	$362,484	$398,237	$425,513

Network Upgrade Charge includes True-Up Adjustment if applicable

VECTREN SOUTH
MISO Cost and Revenue Adjustment
Network Upgrade Charge for RECB and MVP Projects
Summary of Schedule 26 and Schedule 26-A Charges

		1	2	3	4	5	6	7	8	9	10	11	12	13
		Total Charges Applicable to MCRA 24	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
A	Total of Network Upgrade Charges for Non Vectren MVP Projects (Schedule 26-A)	$ 7,999,761	$ 685,885	$ 607,296	$ 618,300	$ 574,720	$ 626,909	$ 732,677	$ 827,612	$ 817,973	$ 668,476	$ 596,939	$ 608,054	$ 634,920
			*(E1 * I1*.9)*	*(E1 * I2*.9)*	*(E1 * I3*.9)*	*(E1 * I4*.9)*	*(E1 * I5*.9)*	*(E1 * I6*.9)*	*(E1 * I7*.9)*	*(E1 * I8*.9)*	*(E1 * I9*.9)*	*(E1 * I10*.9)*	*(E1 * I11*.9)*	*(E1 * I12*.9)*
B	Total of Network Upgrade Charges for Non Vectren RECB Projects-Schedule 26 (Applicant's Attachment JMJ-2)	$ 749,150	$ 64,231	$ 56,871	$ 57,902	$ 53,821	$ 58,708	$ 68,613	$ 77,503	$ 76,600	$ 62,600	$ 55,901	$ 56,942	$ 59,458
			*(F1 * J1)*	*(F1 * J2)*	*(F1 * J3)*	*(F1 * J4)*	*(F1 * J5)*	*(F1 * J6)*	*(F1 * J7)*	*(F1 * J8)*	*(F1 * J9)*	*(F1 * J10)*	*(F1 * J11)*	*(F1 * J12)*
C	Total of Network Upgrade Charges for Vectren RECB Projects-Schedule 26 (Applicant's Attachment JMJ-5)	$ 5,516,435	$ 437,743	$ 416,420	$ 388,771	$ 367,197	$ 484,003	$ 550,622	$ 561,217	$ 584,458	$ 539,770	$ 362,484	$ 398,236	$ 425,514
D	Total Network Upgrade Charges	$ 14,265,346	$ 1,187,859	$ 1,080,587	$ 1,064,973	$ 995,738	$ 1,169,620	$ 1,351,912	$ 1,466,332	$ 1,479,031	$ 1,270,846	$ 1,015,324	$ 1,063,232	$ 1,119,892
E	MCRA-24 2020 Estimated MVP Usage Rate ($/MWh) based on actual charges (Applicant's Attachment JMJ-4)	$1.67												
F	2020 Annual Estimated Revenue Requirement (Applicant's Attachment JMJ-2)	$749,150												

		2021 System Peak Actual_Projection (MW)												
		Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Annual
G	**Forecasted 2021 System Peak**	812.9	773.3	722.0	681.9	898.8	1,022.5	1,042.2	1,085.4	1,002.4	673.1	739.5	790.2	10,244.274
H	**Percent of 2021 System Peak**	7.94%	7.55%	7.05%	6.66%	8.77%	9.98%	10.17%	10.59%	9.78%	6.57%	7.22%	7.72%	100.00%

		2021 System Load Actual_Projection (MWh)												
		Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Annual
I	**Forecasted 2021 System Load**	456,343.8	404,055.7	411,376.9	382,381.8	417,105.0	487,476.4	550,640.4	544,226.8	444,761.3	397,164.9	404,560.4	422,434.9	5,322,528.3
J	**Percent of 2021 System Load**	8.57%	7.59%	7.73%	7.18%	7.84%	9.16%	10.35%	10.22%	8.36%	7.46%	7.60%	7.94%	100.00%