FILED
July 2, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

VERIFIED DIRECT TESTIMONY
OF
JOHN A. VERDERAME

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

Petitioner's Exhibit 23

July 2, 2019

DIRECT TESTIMONY OF JOHN A. VERDERAME, MANAGING DIRECTOR, TRADING AND DISPATCH ON BEHALF OF DUKE ENERGY INDIANA, LLC BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John A. Verderame, and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Progress, Inc. (Duke Energy Progress) as Managing Director, Trading and Dispatch. Duke Energy Progress is the utility formerly known as Progress Energy Inc., (Progress Energy) located in North and South Carolina. As part of the merger integration process, Duke Energy Progress now provides various administrative and other services to the regulated affiliated companies within Duke Energy Corporation (Duke Energy Corp.), including Duke Energy Indiana, LLC., (Duke Energy Indiana).

Q. PLEASE DESCRIBE BRIEFLY YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Economics from the University of Rochester in 1983, and a Master's in Business Administration in Finance from Rutgers University in 1985. I have worked in the energy industry for 18 years. Prior to that, from 1986 to 2001, I was a Vice President in the United States (US) Government Bond Trading Groups at the Chase Manhattan Bank and Cantor Fitzgerald. My responsibilities as a US

Government Securities Trader included acting as the Firm's market maker in US Government Treasury securities. I joined Progress Energy, in 2001, as a Real-Time Energy Trader. My responsibilities as a Real-Time Energy Trader included managing the real-time energy position of the Progress Energy regulated utilities. In 2005, I was promoted to Manager of the Power Trading group. My role as manager included responsibility for the short-term capacity and energy position of the Progress Energy regulated utilities in the Carolinas and Florida.

In 2012, upon consummation of the merger between Duke Energy Corp. and Progress Energy, Progress Energy became Duke Energy Progress and I was promoted to my current position.

Q. PLEASE SUMMARIZE YOUR DUTIES AS MANAGING DIRECTOR, TRADING AND DISPATCH.

A. As Managing Director, Trading and Dispatch I am responsible for Power and Natural Gas Trading and Generation Dispatch on behalf of Duke Energy's regulated utilities in the Carolinas, Florida, Indiana, Ohio, and Kentucky. I direct teams that are responsible for Duke Energy Indiana's generation dispatch, unit commitment, 24-hour real-time operations, natural gas procurement, and short-term generation maintenance planning. My team is also responsible for managing the Company's capacity position with respect to meeting its capacity obligations under the Resource Adequacy Process as a member of the Midcontinent Independent System Operator, Inc. ("MISO"), and for the submission of the Company's supply offers and demand bids in MISO's day-ahead and real-time electric and ancillary services markets. My teams also manage the Company's short-term and mid-term supply position to ensure that the Company has adequate economic resources committed or available to serve its retail customers' electricity needs. In that respect, my teams are also responsible for any financial hedging done to mitigate exposure to short-term fuel price, energy price, and transmission congestion risk. Finally, I manage a team of meteorologists responsible for providing weather analysis to support operations and planning decisions across the enterprise.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. On behalf of Duke Energy Indiana, I will provide an overview of MISO, specifically its energy and capacity markets and how Duke Energy Indiana interacts with those markets. I provide background and rationale that supports proposed changes to 1) cost allocation, non-native revenue sharing methodologies, and the scope of transactions related to non-native capacity and energy sales margins captured in Standard Contract Rider No. 70, currently filed as Cause No. 44348 SRA XX; 2) the effectiveness and necessity of the historical purchased power benchmark concept; and 3) treatment of charges and credits received from the PJM Interconnection LLC. ("PJM") that result from operation of the Ohio-based Madison Generation Station as an Indiana resource in MISO. In addition, I describe recent MISO capacity market changes that potentially impact the value of Madison Station as a Duke Energy Indiana customer asset. The changes proposed in my testimony support and recognize experience gained by Duke Energy Indiana in MISO as energy markets have matured and evolved since the Company's previous general rate case.

II. OVERVIEW OF MISO

Q. PLEASE BRIEFLY DESCRIBE MISO.

A. MISO is a non-profit, member-based organization that administers an electric power market covering parts of 15 states and one Canadian province, including Indiana. MISO administers electric energy, capacity, ancillary services, and congestion management markets. As Company witness Mr. Timothy A. Abbott discusses in his testimony, MISO also plans and has functional control of the high voltage transmission system in its footprint.

A. The Capacity Market

Q. PLEASE PROVIDE AN OVERVIEW OF THE MISO RESOURCE ADEQUACY CONSTRUCT.

A. Resource Adequacy is the general term for the MISO process to ensure sufficient generation resources are in place to meet system requirements across MISO's footprint. MISO's yearly capacity auction is known as the Planning Resource Auction ("PRA"), which is a MISO-administered auction where market participants can purchase capacity credits to meet resource adequacy requirements or offer to sell capacity for auction revenue.

Load Serving Entities ("LSEs"), such as Duke Energy Indiana, are required to provide sufficient capacity to meet a specific load obligation defined by MISO. In MISO, as in other structured markets, both energy and capacity value is locational meaning that through the PRA, MISO procures capacity to meet projected peak load requirements in each of 10 internal zones. The zones represent geographical and transmission system boundaries of Local Balancing Authorities ("LBA") and States. Additional external zones were added for the 2019/2020 PRA.

Generation owners offer capacity, at a price in Dollars per Megawatt Day into the PRA; and the auction clears at the marginal Megawatt of generation that satisfies the load requirement. LSEs are required to purchase sufficient capacity to meet their specific load obligation, as defined by MISO. The specific market rules that govern the Resource Adequacy process are described in the MISO Open Access Transmission Tariff ("OATT")[1] and Business Practice Manual 011 – Resource Adequacy.[2]

Q. PLEASE EXPLAIN HOW DUKE ENERGY INDIANA PARTICIPATES IN THE MISO CAPACITY MARKET.

A. Duke Energy Indiana participates fully in the PRA process described above. As MISO secures capacity for all of Duke Energy Indiana's assigned obligation and offers all available generation into the capacity market, the Company manages an economic as well as a physical capacity position. Prior to the PRA, Duke Energy Indiana is assigned a capacity obligation by MISO based on projected peak load and other reliability margins.

In addition to the capacity auction process administered by MISO, a bilateral market for capacity also exists. In this market, participants can transact MISO capacity credits directly. If the position is determined to be deficient, or short, Duke Energy Indiana can either engage the bilateral capacity market for PRA eligible capacity credits, or simply allow MISO to secure its capacity in the PRA. If Duke Energy Indiana

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[1] https://cdn.misoenergy.org/Tariff%20-%20As%20Filed%20Version72596.pdf
[2] http://www.apscservices.info/pdf/13/13-028-U_240_3.pdf

determines it has an excess capacity, or a long position, it can either sell those capacity credits in the bilateral market or offer them in the PRA. The ability to manage this economic position financially in the short term and physically in the longer term through the Integrated Resource Plan ("IRP") is one of the great advantages of participation in MISO. In MISO, generation assets serve a role as hedges against short-term capacity and energy prices. The capacity markets can be utilized to efficiently fill short gaps and monetize periods of excess capacity. The MISO PRA market is limited to one Delivery Year, while the bilateral market can provide capacity price certainty through multiple years.

Q. WHEN DUKE ENERGY INDIANA IS PLANNING FOR ITS CAPACITY NEEDS, WHAT RESERVE MARGIN IS THE COMPANY REQUIRED TO MAINTAIN?

A. Duke Energy Indiana plans to two reserve margins, one to meet MISO requirements and another used for the long-term planning done in the IRP process.

The MISO Planning Reserve Margin affects the capacity that MISO will secure for Duke Energy Indiana load through the PRA. A specific MISO reserve margin is determined for each planning year. The PRA is run annually just prior to the upcoming planning year that begins in June. Recently, the MISO reserve margin, which is defined in unforced capacity, or UCAP, has been in the 7-8% range. UCAP is an acronym for capacity that defines a generator's capacity adjusted for a historical outage rate. The total reserve margin that MISO will secure capacity to also includes a system-wide forced outage rate assumption.

For long-term IRP planning purposes, Duke Energy Indiana uses a reserve margin of 15% in its most recent IRP. The IRP reserve margin is defined in installed capacity, or ICAP. ICAP is an acronym for capacity that refers to a generator's rated capacity. A 15% ICAP planning assumption is consistent with the range of assumption utilized by utilities across the country that plan generation through an IRP.

Both UCAP and ICAP planning recognize that generation does not always perform to its rated rating. Generally speaking, a Regional Transmission Organization ("RTO") can plan to use a lower reserve margin and value generation on a UCAP basis, or it can plan using a higher reserve margin but value generation at the nameplate capacity. Duke Energy Indiana believes that its long-term IRP planning assumption is consistent with historical MISO planning reserve margins.

Q. DOES DUKE ENERGY INDIANA CURRENTLY HAVE SUFFICIENT CAPACITY TO MEET ITS INDIANA CUSTOMER LOAD OBLIGATIONS?

A. Yes, Duke Energy Indiana currently has sufficient capacity to meet its load obligations; however, as described above, short-term capacity purchases may be necessary to maintain sufficient reserves and meet the MISO capacity obligations. It is important to note that the MISO capacity obligation is a short-term requirement, the single pending delivery year. In any given year, Duke Energy Indiana's ability to meet the obligation is a function of more transient inputs such as unit performance factors; while the IRP view of capacity sufficiency is a longer-term planning model. Membership in MISO allows Duke Energy Indiana to manage short-term variations in the net capacity position. Later in my testimony, I will discuss how Duke Energy Indiana proposes to address any short-term capacity shortfalls and how those costs are proposed to be recovered.

Q. DOES DUKE ENERGY INDIANA PROPOSE ANY CHANGES TO THE WAY IT RECOVERS COSTS AND CREDITS REVENUES ASSOCIATED WITH THE MISO CAPACITY AND ENERGY MARKETS?

A. As to the recovery of costs and crediting of revenues, Duke Energy Indiana does not propose any changes; the Company proposes to continue to track these items through its Rider 70 filing. This will be discussed in more detail in Company witness Ms. Suzanne E. Sieferman's testimony in this proceeding. However, the Company is proposing to expand the scope of net margins from sales of excess capacity and energy that flow through Rider 70. I will explain this proposal as well as special considerations surrounding Madison Generation Station later in my testimony.

B. MISO Energy Market

Q. PLEASE GENERALLY DESCRIBE MISO'S ENERGY MARKETS.

A. On April 1, 2005, under Federal Energy Regulatory Commission ("FERC") approval, MISO began independently administering both day-ahead and real-time markets ("Energy Markets") for electric energy. The day ahead energy market operates as a planning market for serving anticipated load requirements in the MISO footprint, whereas the real-time energy market functions as a real-time balancing market for electricity. Demand bids in the day-ahead market and supply offers in both markets for energy are submitted to MISO by market participants, including both generator owners (as sellers) and load serving entities (as buyers). Thus, the Company functions as both a seller and buyer in the Energy Markets to serve its retail electric customers in Indiana. Typically, the results of these markets determine which Duke Energy Indiana units are committed and dispatched. In addition, MISO administers day ahead and real time ancillary services markets ("ASM") for regulating and contingency reserves.

Q. PLEASE EXPLAIN HOW THE COMPANY MODELS THE DISPATCH OF ITS GENERATING STATIONS.

A. The Company utilizes a commercially available production cost model (GenTrader) to develop the forecast utilized in the Company's quarterly fuel clause filings, as well as its energy, gas, and congestion position management. All the Company's generating units are represented in the model with their key characteristics, such as capacity, fuel type, heat rate, and emission rate. Other inputs include projected fuel costs for each unit, planned outages, anticipated forced outage rates, the market value for emission allowances, the market price for energy, and the Company's load forecast for native load customers. The GenTrader model simulates the economic dispatch of the Company's generating fleet and projects market generation sales to MISO and power purchases from MISO to meet the forecasted load for future periods, as well as fuel consumption and emission production. The model also allocates generation between native load and non-native sales.

III. NON-NATIVE SALES

Q. WHAT TYPE OF WHOLESALE POWER TRANSACTIONS DOES DUKE ENERGY INDIANA ENGAGE IN?

A. Duke Energy Indiana engages in both non-native and native load wholesale transactions.

Q. PLEASE DEFINE THE TERMS "NON-NATIVE SALES" AND "NATIVE LOAD SALES."

A. Currently, Duke Energy Indiana does not engage in physical energy sales beyond the MISO border. In an RTO construct, non-native energy sales are an accounting concept only. All generation is dispatched into the MISO market and parsed as native or non-native after the fact. Non-native sales are energy sales that take place in the MISO Energy Markets when dispatched generation exceeds native load customer requirements. Native Load Wholesale Sales refers to the historically long-term sales of energy and capacity to wholesale customers such as Hoosier Energy, Indiana Municipal Power Agency, and Wabash Valley Power Association. Because these are long-term sales commitments, Duke Energy Indiana plans and builds for these long-term sales.

Q. DO NON-NATIVE SALES PROVIDE BENEFITS TO NATIVE LOAD CUSTOMERS?

A. Yes. By maximizing the value of our generating assets when they are not being used to serve native load customers, and by sharing that value with our customers, non-native sales of energy and capacity can reduce costs to customers. Typically, energy sales provide opportunistic energy margins to be shared with customers, while bilateral capacity sales act as a hedge against the risk of simply selling capacity at the historically low PRA auction clearing prices.

Q. IS DUKE ENERGY INDIANA CHANGING ITS NON-NATIVE SALES STRATEGY?

A. Yes. Previously, Duke Energy Indiana pursued energy-only and capacity-only sales to MISO. To continue to monetize the value of customer assets and adapt to a rapidly evolving energy market landscape, Duke Energy Indiana is also pursuing a non-native sales strategy that includes short-term bundled sales of market-priced capacity and energy to wholesale customers.

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S CURRENT NATIVE LOAD WHOLESALE CONTRACT PORTFOLIO.

A. Duke Energy Indiana currently has five contracts totaling roughly 425 megawatts of traditional wholesale formula rate commitments of capacity and energy, with termination dates ranging from 2023 to the mid-2030s.

Q. HOW HAS THE WHOLESALE ENERGY MARKET CHANGED SINCE DUKE ENERGY INDIANA JOINED MISO?

A. Over the past decade, both structured and traditional energy markets such as MISO across the country have experienced tremendous change. This change has been driven by several key factors including; increased regulatory focus on the environmental impact of energy generation, the impact of technological advances in natural gas production driving sustained low natural gas prices, and increasing renewable energy penetration. Several of these factors are driving a significant shift away from coal-fired generation and toward natural-gas fired generation. The combination of sustained low natural gas prices and efficient generation sources has created an extremely competitive short-term market environment. Duke Energy Indiana has planned and built a generation fleet as a balanced and diverse portfolio that provides and will continue to provide customer value through a variety of market conditions over the long term.

Q. HOW DO THESE CHANGES IMPACT THE TRADITIONAL LONG -TERM NATIVE WHOLESALE SALES?

A. The traditional wholesale rate structure that assigns average system costs of a diverse fleet of resources is not currently competitive against independent power producer pricing based on costs of an undiversified portfolio or even a single generator. Consequently, utilities such as Duke Energy Indiana have experienced erosion in wholesale sale portfolios as long-term contracts based on embedded system cost expire. Additionally, the capacity constructs in structured markets like MISO and PJM have failed to fully price the fixed costs associated with building and maintaining generation. With market prices consistently below Duke Energy Indiana's full cost of production, the portfolio of Native Load Wholesale Sales contracts that support total system costs is expected to continue to diminish.

Q. DO THESE CHANGES HAVE AN IMPACT ON RETAIL CUSTOMERS?

A. Yes. The consequence to customers of this erosion is as these traditional contracts terminate, the balance of Duke Energy Indiana's wholesale and retail load shifts. More of the system costs are necessarily shifted and absorbed by retail customers. Eventually, unchecked, as wholesale load decreases, the embedded costs assigned to retail customers represent capacity that would only be monetized through very short-term MISO capacity and energy markets, as opposed to potentially more attractive bilateral contractual arrangements.

Q. GIVEN THIS CONTEXT, PLEASE DESCRIBE DUKE ENERGY INDIANA'S STRATEGY FOR NON-NATIVE WHOLESALE SALES GOING FORWARD.

A. As wholesale markets become more competitive, Duke Energy Indiana recognizes the need to adapt and be innovative in its approach to non-native wholesale sales. Wholesale customers currently desire shorter-term commitments, while Duke Energy Indiana is looking to capture value closer to embedded cost than current MISO markets produce. If current potential wholesale customers consider longer term commitments, they generally look to Power Purchase Agreements tied to specific assets, such as new build efficient gas resources from independent power producers, that can offer very competitive capacity and energy pricing. Accordingly, for Duke Energy Indiana to remain competitive, it needs to negotiate short-term non-native bundled sale contracts that augment the more traditional contracts it has used in the past. These bundled short-term non-native sales meet a changing wholesale customer need and can compete at current market prices. These new bundled short-term non-native wholesale agreements will allow Duke Energy Indiana to more fully maximize the utilization of its generation portfolio, better monetize its assets, and importantly, minimize additional cost allocation to retail customers as current agreements terminate. Contributions to fixed costs captured through these new agreements, even if they do not fully recover embedded costs, will lower the costs which would be re-allocated to retail customers as current agreements expire that may not be renewed.

Q. PLEASE DESCRIBE THESE BUNDLED SHORT-TERM NON-NATIVE CONTRACTS.

A. These contracts are non-native sales of capacity and energy for a contract term of five years or less. Short-term bundled non-native sales will be negotiated and priced competitively to the market; and bundled contract prices will cover expected energy costs and contribute to fixed costs. Faced with a shrinking wholesale portfolio, these contracts will create interim value to customers while generation fleet system costs remain above market.

Q. WHY CAN'T DUKE ENERGY INDIANA JUST CONTINUE TO OFFER EXCESS CAPACITY AND ENERGY DIRECTLY INTO THE MISO MARKETS?

A. Although Duke Energy Indiana could simply offer excess capacity and energy directly into the MISO market in the yearly capacity auctions and daily energy markets, expanding non-native sales beyond these very short-term markets offers a strategic opportunity to capture the natural risk premiums built into term markets. Although, wholesale counterparties may not have a current appetite for the 15 or 20-year contracts they have purchased in the past, they do recognize that there is value in locking in some price certainty through shorter term contracts, limiting exposure to capacity and energy price fluctuations. Duke Energy Indiana customers similarly benefit from locking in some certainty as well, rather than selling excess capacity into very short-term auctions such as MISO's PRA. For example, in recent years the value of capacity clearing in the annual PRA has been very low, $1.50, $10, and $2.99 per megawatt day for the past three PRAs. In contrast, bilateral markets have indicated significantly higher capacity prices prior to the running of the PRA for each planning year. Retail customers also benefit by retaining the flexibility in managing the generation portfolio with shorter commitments.

Q. HAS DUKE ENERGY INDIANA ENTERED INTO ANY SHORT-TERM BUNDLED NON-NATIVE CONTRACTS?

A. Yes. The Company entered into a 5-year 100 MW contract for capacity and energy that expires in 2021.

Q. HOW HAS DUKE ENERGY INDIANA TREATED COSTS AND REVENUES ASSOCIATED WITH THIS AGREEMENT?

A. Duke Energy Indiana Witness Ms. Suzanne Sieferman describes the current treatment in her direct testimony.

Q. GOING FORWARD, HOW DOES DUKE ENERGY INDIANA PROPOSE TO TREAT COSTS AND REVENUES ASSOCIATED WITH THIS AND ANY OTHER POTENTIAL SHORT-TERM BUNDLED NON-NATIVE WHOLESALE SALES CONTRACTS?

A. The Company proposes to share the associated costs and revenues exactly how other non-native margins are shared with customers today through Rider 70, with one adjustment as explained below.

IV. NON-NATIVE SHARING PROPOSAL

Q. DOES DUKE ENERGY INDIANA CURRENTLY HAVE A SHARING MECHANISM FOR THE PROCEEDS FROM NON-NATIVE SALES?

A. Yes. As established in the Company's last base rate proceeding, Cause No. 42359, Duke Energy Indiana has $14.7 million[3] built into base rates. Any amount above or below this amount is split evenly between customers and the Company, and trued up in Cause No.

[3] $18.7 million minus *pro forma* trading expenses of $3,953,000.

44348 SRA XX, which Duke Energy Indiana files annually. The Commission also found that the Company cannot apply a net annual off-system sales profit of less than zero.

Q. DOES DUKE ENERGY INDIANA PROPOSE ANY CHANGES TO ITS SHARING MECHANISM?

A. Duke Energy Indiana proposes to track the entire amount of non-native sales, with no specific amount embedded in rates. The Company also proposes that Customers share fully in positive as well as potentially negative margins from non-native sales. Otherwise, Duke Energy Indiana proposes no further changes. The Company will continue to share the proceeds of its non-native sales evenly with customers and will use its Rider 70 to track them.

Q. EXPLAIN WHY IT IS REASONABLE TO EXCLUDE NON-NATIVE SALES MARGINS FROM BASE RATES?

A. As I described above, power markets have experienced, and are expected to further experience, volatility. If Duke Energy Indiana's non-native margins were stable or expected to remain stable, it might be appropriate to include some expected amount in rates. In fact, margins from non-native sales have varied considerably since the $14.7 million base level was established, rarely actualizing at that threshold. See Petitioner's Exhibit 23-A (JAV), which provides historical data on Duke Energy Indiana's net non-native sales. The margin threshold was established in an energy market environment that simply is not comparable to current conditions. Consequently, the Company believes that the level of margin volatility experienced is more appropriately accounted for through a tracker rather than a fixed rate component. Duke Energy Indiana's requested tracking of non-native margins is reasonable due to the material variability of non-native margins, and the fact that, with the exception of strategic activities such as the proposed extended non-native contracts, realization of margins is largely outside of the Company's control. Removing an embedded margin level from base rates recognizes current and expected market price uncertainty. It also strikes a fair balance between ensuring that customers continue to receive substantial benefits from non-native sales; while not imposing unnecessary and undue risk on Duke Energy Indiana in establishing a level of margins that ongoing market conditions may not support.

Q. WHY IS IT REASONABLE TO SHARE THE PROFITS FROM NON-NATIVE SALES EQUALLY WITH CUSTOMERS?

A. Margin sharing mechanisms are well established attributes of good ratemaking, aligning interests and driving creativity and innovation to create incremental value. Despite the level of margins established in Duke Energy Indiana's last rate case addressed in the Company's proposal above, the Rider 70 sharing mechanism operates as intended, providing value to customers and the Company and establishing each as partners in optimizing the value of the generation fleet in short-term markets. The existing sharing of non-native margins aligns customer and shareholder interests, and appropriately incents Duke Energy Indiana to maximize non-native margins through its fleet of generating resources. Regardless of the existence of a margin sharing mechanism, Duke Energy Indiana is committed to investing in and maintaining plants for reliability and availability. An important role of the Duke Energy Indiana generation fleet is to provide a reliable physical hedge against short-term energy and capacity market prices. The fleet accomplishes this mission by performing well during peak periods. The fleet also provides value to customers, particularly in a structured market environment by being available to provide capacity and energy to the market beyond customer requirements. Permitting the Company to share non-native sales margins provides Duke Energy Indiana with an appropriate incentive to maintain and operate its generating units to fully maximize and capitalize on market opportunities for the benefit of both customers and the Company.

Duke Energy Indiana's sharing proposal recognizes that the Company takes on potential costs and potential financial risks whenever the Company creates non-native margins for customers. The proposed sharing mechanism enhancements appropriately compensate the Company without imposing undue risk.

Q. WHY IS IT REASONABLE TO INCLUDE NEGATIVE (OR NET LOSS) NON-NATIVE MARGINS IN THE SHARING MECHANISM?

A. Quite simply, sharing both opportunities and risks equally is an appropriate and necessary component of any partner relationship. Structural asymmetry of risk and reward potentially drives unduly conservative or suboptimal decision making, and consequently, suboptimal financial outcomes. Under the current sharing mechanism, the Company has experienced periods of negative non-native margins. These negative margins generally occur for short periods during off-peak hours, when market prices are below marginal costs, but native load requirements fall below actual generation levels. These situations are no fault of the Company and in fact the Company has accepted these losses in the larger picture of committing long lead-time units so that they are available for native customers, even if that means absorbing an unrecoverable loss during off-peak. Although the Company recognizes that these instances are just one component of its regulatory commitment to customers, it seeks to remedy this imbalance. The negative non-native margins are an artifact of operating a power system for the greater good of native retail customers, and assigning financial responsibility for these losses solely to the Company is a punitive consequence of the current mechanism that is easily and appropriately remedied.

V. PROPOSED STACKING OF NATIVE/NON-NATIVE COST ALLOCATIONS

Q. HOW DOES THE COMPANY CURRENTLY DETERMINE WHAT FUEL COSTS ARE ALLOCATED TO NATIVE CUSTOMERS AND WHAT COSTS ARE ALLOCATED TO NON-NATIVE CUSTOMERS?

A. Company personnel perform post-dispatch after the fact analysis to allocate these costs.

Q. HOW DOES THE POST-ANALYSIS TEAM PERFORM THESE ANALYSES?

A. The primary tool used in the Midwest is a production costing model, Sumatra, which is jointly supported by Power Costs, Inc. and Duke Energy information technology resources. The model incorporates generator information such as heat rates, emission rates, generating unit fuel costs, emissions allowance costs, and variable operating and maintenance costs. This is the same data used in the Energy Cost Manual, which is also the basis for the supply offers to MISO. Additional model inputs include actual hourly data, native load demand, generating unit output (*i.e.,* megawatt-hour generation) received from MISO, and purchased power agreement billing data.

Sumatra then "economically dispatches" or matches, on an hourly basis, the demand (load) with available supply resources (*i.e*., generation or purchases) that are economically stacked. With the exception of generation online for testing or reliability, certain joint owner agreements, and power purchased or produced specifically from renewable resources, the unit stacking is prioritized based on average production costs, ranked lowest cost to highest cost. The Sumatra model economically allocates the average production costs for serving native load.

Q. ARE ALL OF THE COMPANY'S GENERATING RESOURCES INCLUDED AS RESOURCES IN THIS PROCESS?

A. Generally, yes. Post-analysis data includes the impact of actual unit forced and maintenance outages. In recognition that the MISO day-ahead and real-time markets are separate markets (for both energy and ancillary services), Company personnel also restrict the availability of certain specific generating capacity that cleared in the day-ahead market for non-native MISO demand.

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S CURRENT STACKING PROCESS.

A. The post-process team stacks all day-ahead energy market generation awards from MISO against the day-ahead load cleared by MISO, providing Duke Energy Indiana native customers first call to the lowest average cost generation in the day-ahead market. Average cost generation represents the total variable costs incurred by a generator divided by a specified hourly output. Generation that clears the day-ahead market in excess of day-ahead load demand is committed in the model to day-ahead non-native sales. Utilizing actual real-time generation and load, generation is restacked, and Duke Energy Indiana native customers are assigned the lowest average cost generation that did not clear for non-native demand in the day-ahead market. If Duke Energy Indiana's real-time native load is greater than the available real-time generation not committed in the day-ahead energy market to non-native, then Duke Energy Indiana will allocate energy purchased from MISO to make-up the difference. If Duke Energy Indiana's real-time native load is less than the available real-time generation not committed in the day-ahead market to non-native, then any excess generation is allocated as a real-time non-native energy market sale. All costs associated with generators that clear day-ahead for non-native energy market sales or in real-time for non-native energy market sales are assigned non-native cost allocation. Duke Energy Indiana native customers are only allocated fuel costs and/or MISO charges associated with units that are assigned to native load. Fuel costs associated with non-native energy sales are allocated through Rider 70, described above.

Q. DOES DUKE ENERGY INDIANA PROPOSE A CHANGE TO THE CALCULATION OF THE NATIVE/NON-NATIVE SALES STACKING MECHANISM?

A. Yes. Duke Energy Indiana proposes to change the stacking logic from average production cost basis to incremental production cost basis for long-term commitment generating units such as coal fired and combined cycle natural gas units. Duke Energy Indiana would continue to allocate costs for short-term commitment units, such as combustion turbines, on the existing average cost basis. Average production cost logic allocates total unit production costs between native and non-native sales. Incremental cost represents the additional cost incurred by a generator to produce additional generation divided by that incremental generation quantity. The proposed incremental cost logic creates incremental cost blocks and allocates each block individually between native and non-native. The minimum load block includes the cost of fuel necessary to maintain a generator at the speed required to produce up to the first megawatt (no-load cost). The incremental blocks above minimum load includes incremental costs only. MISO requires generators to be offered as incremental cost blocks and then economically optimizes system dispatch based on the received incremental offers. This logic more appropriately recognizes that the cost of incremental non-native sales is related to the cost of incremental changes in generation output and will better align fuel cost allocation with actual dispatch and commitment operations.

Q. WHY IS DUKE ENERGY INDIANA PROPOSING THIS CHANGE?

A. Duke Energy Indiana is proposing this change because the current average cost stacking logic does not comport with MISO's incremental dispatch logic. The average cost of a generator includes no-load cost, which is a sunk cost and remains the same regardless of unit loading. It is therefore appropriate that non-native sales be allocated cost blocks representing the incremental cost of incremental excess generation and not costs incurred for native load. Utilization of incremental cost assures that each additional MW of power generated in the MISO system is sourced from the generator that will incur the least marginal cost. This concept of incremental dispatch is fundamental to efficient system operation.

Q. WHY IS DUKE ENERGY INDIANA PROPOSING THIS STACKING CHANGE ONLY FOR LONG-TERM COMMITMENT UNITS?

A. Although long-term commitment units occasionally provide non-native margins, they are committed for, and predominantly serve, native load requirements. Because short-term commitment units, such as combustion turbines, more often, and occasionally exclusively, contribute to non-native sales, it would be inappropriate to always assign no-load costs to native load.

Q. HOW WILL THIS PROPOSED CHANGE IMPACT COST ALLOCATION BETWEEN NATIVE AND NON-NATIVE LOAD?

A. Generally, the minimum load block of long-term commitment units will be allocated to native load. As the minimum block includes the no load cost required to maintain the unit online for native load use, more of these costs will shift to native load allocation. It is appropriate to allocate this cost to native load given that native load will be entitled to the first call on all generation resources, and these units are committed for the benefit of native load. Non-native sales to MISO occur only when generation is available in excess of what is required to serve native load. However, during periods of low native demand, when the sum of all minimum load blocks exceeds native load demand, minimum load blocks would be allocated to non-native.

Q. IS THIS APPROACH REASONABLE AND IN THE PUBLIC INTEREST?

A. Yes. The incremental cost approach will better align post-analysis results and actual dispatch logic used by MISO. It provides additional granularity and will more equitably and appropriately allocate fuel cost between native and non-native sales.

Q. ARE THERE OTHER CHANGES TO THE ALLOCATION PROCESS THAT DUKE ENERGY INDIANA PROPOSES?

A. Yes. Currently, Duke Energy Indiana performs a two-pass stacking process, day ahead and real time. In the day-ahead first pass, if a unit's output is entirely allocated to non-native in the day ahead market, that unit remains allocated to non-native in the real-time market second pass. The two-pass stacking protocol was intended to replicate the two-settlement market in MISO. Under incremental cost stacking, the two-pass process unnecessarily complicates cost allocation. Going forward, Duke Energy Indiana proposes to perform the stacking process exclusively in the real-time market given that long-term commitment units are unlikely to be entirely allocated to non-native when split into incremental cost blocks. Under the current protocol, native load does not have access to units cleared and committed in the day ahead market to non-native load. This change improves native load resource optionality to respond economically to deviations in real time load or generation; and recognizes the shift of additional no load costs that accompany the transition to incremental stacking.

VI. <u>FAC BENCHMARK FOR PURCHASE POWER</u>

Q. DOES DUKE ENERGY INDIANA CURRENTLY HAVE A PURCHASE POWER BENCHMARK, AS ESTABLISHED IN CAUSE NOS. 41363, 38706-FAC-45, 38708-45, 38707 FAC-56, AND 38707 FAC-59.

A. Yes.

Q. PLEASE EXPLAIN HOW THE PURCHASE POWER BENCHMARK IS CALCULATED.

A. In accordance with the orders referenced above, Duke Energy Indiana first determines the benchmark generating unit, which is defined as: the most economic, available unit that did not serve native load that is more expensive than the most expensive unit that did economically serve native load at any time during a given month. The costs used in determining the benchmark unit are fuel, variable O&M and emission allowances. The benchmark price of the unit is then determined utilizing the fuel cost at the peak load hour of the month and the average heat rate of the benchmark unit at full load. Full load represents a units most efficient loading, and thus lowest cost. The benchmark price includes only fuel.

Q. WHAT IS THE PURPOSE OF THE PURCHASE POWER BENCHMARK?

A. The purpose of the purchase power benchmark is to set a "requirement that the reasonableness of purchases in excess of the benchmark be specifically addressed in the pre-filed testimony supporting the FAC." (IURC Cause No 41363 Order, page 9). The benchmark does not create a disallowance; rather the costs incurred for purchase power above the benchmark can be recovered through the FAC if the utility demonstrates reasonableness.

Q. WHY DID THE COMMISSION ESTABLISH A PURCHASE POWER BENCHMARK?

A. The purchase power benchmark was established as a result of a Commission investigation into "the escalation in spot market purchased energy observed in June 1998, in particular, and changes in the wholesale power market, in general" (IURC Cause No 41363 Order, page 1). Further, the Order stated that the "benchmark is not a cap" and that if a benchmark is exceeded the utility would have the opportunity to submit additional evidence demonstrating the reasonableness of its power purchases for cost recovery purposes (page 11).

Q. WHAT FACTS AND CIRCUMSTANCES HAVE CHANGED SINCE THE COMMISSION'S ORDER IN CAUSE NO. 41363?

A. The benchmark procedures established in Cause No. 41363 were initiated at a time when the MISO energy market did not yet exist and purchases were executed on a negotiated bilateral basis. Since then Duke Energy Indiana has become a full participant in the organized MISO energy market and Duke Energy Indiana purchases all of its energy requirements from the MISO. As a member of MISO, Duke Energy Indiana's generation, along with all generation participating in the MISO's day-ahead and real-time energy markets, is economically dispatched and the Company's customers thereby have access to all generation resources in MISO to meet their needs. Purchases made from MISO are, definitionally, by the efficient nature of MISO's dispatch, the most economic purchase available to meet customer load. Furthermore, as noted in my testimony above, the impact of low natural gas prices and increasing renewable energy penetration, among other factors, has had a significant downward impact on the average market price of energy. These factors suggest that the price and bilateral trading risks that the benchmark was intended to monitor have been heavily mitigated. The customer benefit of access to the most efficient generation of the entire MISO footprint far outweighs any risk customers have from transient price spikes. The fact that some generation does not provide energy during any particular month is testament to this value proposition. A purchased power benchmark is anachronistic in the energy market that Duke Energy Indiana operates in today, and provides no real value.

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S BENCHMARK PROPOSAL.

A. Duke Energy Indiana proposes that the generic purchase power procedures established in Cause No. 41363 be permanently waived upon the effective date of the Commission's Order in this proceeding.

Q. DOES THIS PROPOSAL IN ANYWAY PROHIBIT REVIEW OF DUKE ENERGY INDIANA'S PURCHASE POWER TRANSACTIONS?

A. No, not at all. The Company's purchase power costs and its offers into MISO would continue to remain subject to review and approval in each of Duke Energy Indiana's FAC filings.

VII. <u>MADISON GENERATING STATION</u>

Q. DOES DUKE ENERGY INDIANA HAVE ANY GENERATING ASSETS THAT ARE NOT LOCATED WITHIN THE MISO FOOTPRINT?

A. Yes. The Company owns and operates the Madison Generating Station, which is located in Butler County, Ohio.

Q. PLEASE DESCRIBE MADISON GENERATING STATION AND THE UNIQUE STRUCTURE OF THIS GENERATING STATION IN MISO AND PJM?

A. The Madison Generating Station consists of 8 simple cycle combustion turbines, each with 88 MW Net Winter Capability Ratings, for a site total of 704 MW. The station is physically located and connected to the PJM transmission grid. Energy from the station is transferred to MISO using firm transmission service through a Pseudo-Tie. From an energy perspective, Madison is essentially like all other units inside the MISO geographic footprint. Duke Energy Indiana personnel provide generation and ancillary service offers to MISO, receive unit commitment and dispatch instructions from MISO, and receive settlement charges and credits from MISO. Additionally, Duke Energy Indiana receives a settlement statement from PJM as Madison station injects energy into the PJM grid and Duke Energy Indiana exports an equivalent amount from PJM into MISO.

Q. PLEASE DESCRIBE THE SETTLEMENTS IMPACT FROM THE OPERATION OF THE MADISON GENERATING UNIT?

A. Charges and credits from MISO related to the operation of the Madison Generating Station have been included in various company filings with the Commission since Duke Energy Indiana began participating in the MISO energy market in 2005. For these units to remain part of the MISO energy and ancillary services market after January 1, 2012, a transmission pseudo-tie from PJM to MISO was established. As a result, Duke Energy Indiana began receiving a settlement statement from PJM for charges and credits related to the firm transmission, congestion and loss charges or credits, and other charges or credits. Since 2012, the Company has paid or received all the charges and credits on this statement, known as Billing Line Items ("BLI") and these costs or credits have not impacted retail customers to date because Duke Energy Indiana has not passed them onto customers.

Q. PLEASE DESCRIBE THE NET IMPACT OF THE CHARGES AND CREDITS BETWEEN JANUARY 1, 2012 AND TODAY?

A. The charges and credits on the PJM portion of the Madison settlement statement from PJM vary from month to month. The charges and credits are related to many different factors, but most are related to transmission related charges and credits, congestion and losses associated with the difference in LMPs between the Madison nodal pricing point and the MISO interface price in PJM, and other miscellaneous smaller charges and credits. The total net of these charges and credits between January 1, 2012 and December 31, 2018 have resulted in a net payment from PJM of approximately $1.6 M. The net amount of these charges and credits are a charge in some months and a credit in other months, with the total impact being a credit over the entire time period. Petitioner's Exhibit 23-B (JAV) shows the annual amount of charges and credits from inception through December 31, 2018.

Q. WHAT IS THE COMPANY PROPOSING FOR THE RECOVERY OF THESE COSTS?

A. The Company proposes that all PJM charges and credits related to Madison be recovered through, as appropriate, either FAC, RTO, or Rider 70. A list of the current PJM BLI and proposed recovery method is included as Petitioner's Exhibit 23-C (JAV). Note that that this list could change over time as PJM amends or changes these Billing Line Items.

Q. WHY IS THE PROPOSED CHANGE IN RECOVERY OF THESE ITEMS APPROPRIATE?

A. As I have mentioned previously in my testimony, the Company believes that risks and benefits of plant operation are best apportioned symmetrically. Madison Generating Station is operated for the benefit of Duke Energy Indiana customers and as such customers should be allocated appropriate revenues and costs. The unique situation at Madison was simply not envisioned at the time of the Company's last rate case. This proposed change appropriately modifies cost and revenue tracking.

Q. HAVE THERE BEEN CHANGES TO THE MISO RESOURCE ADEQUACY CONSTRUCT THAT IMPACT DUKE ENERGY INDIANA'S POTENTIAL USE OF MADISON STATION AS A CAPACITY RESOURCE?

A. Yes. MISO recently received permission from the FERC[4] to modify the way it values capacity resources located outside the MISO footprint. This change took effect with the 2019/2020 Delivery Year, which began June 1, 2019. As I described earlier in my testimony, MISO identifies 10 delivery zones in its footprint for capacity market purposes. MISO Zone 6 is described as the geographic state boundaries of Indiana. MISO capacity rules prior to the 2019/2020 provided Duke Energy Indiana the ability to virtually claim the Madison Generating Station as within those boundaries of Zone 6. Beginning with the 2019/2020 Delivery Year, Madison Generating Station is no longer eligible for consideration as a Zone 6 resource. It is instead considered a PJM external Zone resource. As MISO zones could clear the PRA auction at different prices, the potential impact to Duke Energy Indiana customers would be a separation of zonal prices between Indiana Zone 6 and the new PJM external Zone. No separation in RPA capacity prices occurred in the 2019 / 2020 Delivery Year auction. However, separation could

[4] https://elibrary.ferc.gov/idmws/common/downloadOpen.asp?downloadfile=20181031-3074(33221992).docx&folder=13145292&fileid=15087578&trial=1

occur in the future if there were insufficient resources within Indiana proper to meet the reliability requirements the MISO establishes for Zone 6.

Q. COULD THIS CHANGE RESULT IN A MISMATCH IN FUNDS PAID FOR THE CUSTOMERS CAPACITY OBLIGATION AND FUNDS RECEIVED FROM THE MADISON GENERATING STATION?

A. Yes. Duke Energy Indiana is responsible to purchase sufficient capacity in the PRA for all its Indiana load. If Zone 6 were to clear at a capacity price above the clearing price of the PJM external Zone, customers would be exposed to the difference in zonal clearing price on the amount of capacity that it did not have inside of the Indiana Zone.

In recognition of Madison and similarly situated generation units, MISO has established some financial relief. MISO has created a hedge instrument it calls Historic Unit Consideration or, HUC. HUCs are allocated to generators like Madison station that have been long-term dedicated network generation resources. For the 2019/2020 PRA, Duke Energy Indiana was awarded sufficient HUCs to cover the full capacity value of Madison Station. In concept, the value of HUCs serve as a financial offset to exposure Duke Energy Indiana customers have to any shortfall in capacity revenues; however, it is possible that the HUCs value will not completely offset the shortfall in future planning years.

Q. HOW DOES DUKE ENERGY INDIANA PROPOSE TO TREAT COSTS AND REVENUES ASSOCIATED WITH MADISON STATION CAPACITY UNDER THIS NEW MISO RULE?

A. The Company proposes that costs and revenues associated with Madison Station be modified because of the MISO capacity market change. Currently, margin from non-native capacity sales, that is, capacity above the MISO assigned capacity obligation is shared with the Company through Rider 70. That structure was appropriate when all Duke Energy Indiana generation was in the same MISO zone. The capacity position going forward is actually two positions, the MISO Zone 6 position which may or may not be "short" as there will always be some load requirement, and the MISO PJM external Zone, which will always be "long" as there is no Duke Energy Indiana load in that zone. The net revenues from this arrangement create positive revenues in Zone 6, charges in Zone 6, and revenues in the PJM external zone. If the two zones separate in capacity price, these net revenues and charges should balance as long as the HUC payment mechanism fully funds the differential. To mitigate potential exposure customers may experience relative to any mismatch between total charges and revenues that could occur if the HUC funding does not completely offset any Zonal price differential, the Company proposes that all capacity revenues and HUC payments be allocated to native customers first up to the level of capacity charges assigned to native load by MISO. The Company proposes that going forward, regardless of location of assets or source of capacity revenues, no capacity revenues will flow through the Rider 70 non-native sharing mechanism until the native load charges have been met. Once that revenue requirement has been satisfied, further revenues from capacity sales and HUC payments will be allocated as non-native margin, and shared through Rider 70. If capacity charges for native-load exceeds all capacity revenues, the differential will be recovered the same as it is today.

VIII. CONCLUSION

Q. IN YOUR OPINION, ARE THE PROPOSALS PRESENTED IN YOUR DIRECT TESTIMONY REASONABLE AND IN THE PUBLIC INTEREST?

A. Yes. Duke Energy Indiana has several proposals that it believes are both reasonable and in the public interest. These proposals are in response to the evolution of energy markets since its last general rate case.

For Duke Energy Indiana to remain competitive in the marketplace, it needs the ability to negotiate short-term bundled non-native sale contracts that augment the more traditional contracts it has used in the past. These new short-term bundled non-native wholesale agreements will allow Duke Energy Indiana to more fully maximize the utilization of its generation portfolio, better monetize its assets, and importantly, minimize additional cost allocation to retail customers as current agreements terminate. Retail customers benefit by retaining the flexibility in managing the generation portfolio with shorter commitments.

The existing Rider 70 sharing mechanism operates as intended, providing value to customers and the Company and establishing each as partners in optimizing the value of the generation fleet in short-term markets. Because the energy market landscape has changed, the company proposes that customers share fully in positive as well as potentially negative margins from non-native sales. Removing an embedded margin level from base rates recognizes current and expected market price uncertainty. It also strikes a symmetrical balance of risks and rewards between the company and its customers.

It is reasonable to change the methodology under which Duke Energy Indiana stacks its generating units to allocate costs between native and non-native sales. Moving from average production cost basis to incremental production cost basis for long-term commitment generating units such as coal fired and combined cycle natural gas units better aligns with MISO's incremental dispatch logic and will provide additional granularity and more equitably and appropriately allocate fuel cost between native and non-native sales.

Duke Energy Indiana proposes that the generic purchase power procedures established in Cause No. 41363 that created the benchmark purchased power test, be permanently waived. Purchases made from MISO are the most economic purchase available to meet customer load. A purchased power benchmark is anachronistic in the energy market that Duke Energy Indiana operates in today.

Finally, the Company proposes that all charges and credits from PJM and changes to the MISO capacity construct for the Madison Generating Station be recovered through either FAC, RTO, or Rider 70, as appropriate. Madison Generating Station is operated for the benefit of Duke Energy Indiana customers, and as such, customers should be allocated appropriate revenues and costs.

In conclusion, the Company's proposals modernize the partnership between customers and the Company and addresses significant changes that have occurred in energy markets since its last base rate case. I believe that these proposals will create an equitable framework for future years.

Q. WERE PETITIONER'S EXHIBIT 23-A (JAV), THROUGH EXHIBIT 23-C (JAV) PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes, they were.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes it does.

DUKE ENERGY INDIANA, LLC

Historic Bulk Power Marketing Tracking and Results

	Rate Case, Cause 42359 12 ME Sep'02 1/	Cause 42695 12 ME Sep'04 2/	Cause 42870 12 ME Sep'05	Cause 43074 12 ME Sep'06	Cause 43302 12 ME Sep'07	Cause 43505 12 ME Sep'08	Cause 43715 12 ME Sep'09	Cause 43906 12 ME Sep'10	Cause 44035 12 ME Sep'11
Margin Calculation Before Sharing									
Gross Profit / (Loss)	$ 18,700,000	$ 356,100	$ 7,205,943	$ 20,970,448	$ 16,200,403	$ 21,234,976	$ 6,342,358	$ 5,364,711	$ 2,973,299
PACE Prior Period ADJ	-	-	-	(6,426,234)	(1,776,948)	160,710	(278,327)	(16,080)	(23,192)
Net Profit	18,700,000	356,100	7,205,943	14,544,214	14,423,455	21,395,686	6,064,031	5,348,631	2,950,107
Fixed Trading Expense Deduction	3,953,000	(1,404,071)	(3,953,000)	(3,953,000)	(3,953,000)	(3,953,000)	(3,953,000)	(3,953,000)	(3,953,000)
Net Profit Before Jurisdictional Allocation	$ 14,747,000	(1,047,971)	3,252,943	10,591,214	10,470,455	17,442,686	2,111,031	1,395,631	(1,002,893)
"Sharing" Mechanism									
Retail Allocator	N/A	91.791%	91.791%	91.791%	91.791%	91.791%	91.791%	91.791%	91.791%
Net Retail Profit *(No Losses Permitted)*	$ 14,747,000	(961,943)	2,985,909	9,721,781	9,610,935	16,010,816	1,937,736	1,281,064	(920,566)
BPM Profits in Base Rates	N/A	5,238,006	14,747,000	14,747,000	14,747,000	14,747,000	14,747,000	14,747,000	14,747,000
Basis for Sharing	N/A	5,238,006	11,761,091	5,025,219	5,136,065	(1,263,816)	12,809,264	13,465,936	15,667,566
Recovery or (Credit) in Tracker	N/A	2,619,003	5,880,546	2,512,610	2,568,032	(631,908)	6,404,632	6,732,968	7,373,500
Stakeholder Financial Results									
BPM Profits Retained By Retail Customers	N/A	2,619,003	8,866,454	12,234,390	12,178,968	15,378,908	8,342,368	8,014,032	7,373,500
Total BPM Profit / (Loss) to Shareholders 3/	N/A	(3,580,946)	(5,880,546)	(2,512,610)	(2,568,032)	631,908	(6,404,632)	(6,732,968)	(8,294,066)
Net Profit / (Loss)		$ (961,943)	$ 2,985,908	$ 9,721,780	$ 9,610,936	$ 16,010,816	$ 1,937,736	$ 1,281,064	$ (920,566)

	Cause 44214 12 ME Sep'12	Cause 44348 12 ME Sep'13	Cause 44348 SRA1 8 ME May'14 4/	Cause 44348 SRA2 12 ME May'15	Cause 44348 SRA3 12 ME May'16	Cause 44348 SRA4 12 ME May'17	Cause 44349 SRA5 12 ME May'18	Total RIDER 70
Margin Calculation Before Sharing								
Gross Profit / (Loss)	$ (5,517,389)	$ 113,512	$ 3,440,325	$ 4,441,792	$ (4,687,820)	$ 4,770,396	$ 1,829,192	$ 85,038,246
PACE Prior Period ADJ	(33,477)	(58,538)	15,061	-	85,791	535,240	771,451	(7,044,543)
Net Profit	(5,550,866)	54,974	3,455,386	4,441,792	(4,602,029)	5,305,636	2,600,643	77,993,703
Fixed Trading Expense Deduction	(3,953,000)	(3,953,000)	(2,635,333)	(3,953,000)	(3,953,000)	(3,953,000)	(3,953,000)	(55,428,404)
Net Profit Before Jurisdictional Allocation	(9,503,866)	(3,898,026)	820,053	488,792	(8,555,029)	1,352,636	(1,352,357)	23,917,656
"Sharing" Mechanism								
Retail Allocator	91.791%	91.791%	91.791%	91.791%	91.791%	91.791%	91.791%	91.791%
Net Retail Profit *(No Losses Permitted)*	(8,723,694)	(3,578,037)	752,735	448,667	(7,852,747)	1,241,598	(1,241,342)	20,712,912
BPM Profits in Base Rates	14,747,000	14,747,000	9,831,333	14,747,000	14,747,000	14,747,000	14,747,000	206,780,339
Basis for Sharing	23,470,694	18,325,037	9,078,598	14,298,333	22,599,747	13,505,402	15,988,342	185,105,484
Recovery or (Credit) in Tracker	7,373,500	7,373,500	4,539,299	7,149,167	7,373,500	6,752,701	7,373,500	81,394,550
Stakeholder Financial Results								
BPM Profits Retained By Retail Customers	7,373,500	7,373,500	5,292,034	7,597,833	7,373,500	7,994,299	7,373,500	125,385,789
Total BPM Profit / (Loss) to Shareholders 3/	(16,097,194)	(10,951,537)	(4,539,299)	(7,149,167)	(15,226,247)	(6,752,701)	(8,614,842)	(104,672,879)
Net Profit / (Loss)	$ (8,723,694)	$ (3,578,037)	$ 752,735	$ 448,666	$ (7,852,747)	$ 1,241,598	$ (1,241,342)	$ 20,712,910

1/ Amounts in the test year were rounded to 000's by Commission Order for tracker administration which commenced in Cause 42695

2/ Prorated amounts due to mid-year post general rate order effective date (May 21, 2004)

3/ Shareholders subsidize actual BPM sales losses to the extent they occur and the amounts paid to customers in "loss years". Wholesale formula rates pass back the wholesale portion of gains & losses (i.e. wholesale margins).

4/ This filing reflected a stub period of 8 months in order to transition to the MISO planning year of June through May.

Monthly PJM Charges/Credits Due Madison Generating Station Operation

Positive represents a charge to DEI; Negative represents a credit

Invoice Date	Monthly Billing Net Total	Cumulative Total
January-12	$96,931	$96,931
February-12	$98,313	$195,244
March-12	$99,162	$294,406
April-12	$56,526	$350,931
May-12	-$35,541	$315,390
June-12	$67,727	$383,116
July-12	$412,760	$795,877
August-12	$148,007	$943,883
September-12	$119,590	$1,063,473
October-12	$94,163	$1,157,637
November-12	$94,734	$1,252,371
December-12	$89,447	$1,341,818
January-13	$153,073	$1,494,891
February-13	$134,459	$1,629,351
March-13	$122,966	$1,752,317
April-13	$188,410	$1,940,726
May-13	$69,364	$2,010,091
June-13	$113,765	$2,123,856
July-13	$58,278	$2,182,134
August-13	$199,414	$2,381,548
September-13	$32,463	$2,414,011
October-13	$133,419	$2,547,430
November-13	$128,390	$2,675,820
December-13	$122,838	$2,798,657
January-14	-$372,437	$2,426,221
February-14	$64,622	$2,490,843
March-14	$866,049	$3,356,892
April-14	$103,614	$3,460,505
May-14	-$14,357	$3,446,148
June-14	-$2,107	$3,444,041
July-14	$130,123	$3,574,164
August-14	$113,550	$3,687,714
September-14	$78,449	$3,766,163
October-14	$117,665	$3,883,828
November-14	$94,178	$3,978,006
December-14	$104,517	$4,082,524
January-15	-$55,166	$4,027,358
February-15	-$4,056	$4,023,302
March-15	$208,774	$4,232,076
April-15	$101,845	$4,333,922
May-15	-$177,748	$4,156,174
June-15	-$428,903	$3,727,271
July-15	-$89,449	$3,637,822
August-15	$49,202	$3,687,024
September-15	-$37,707	$3,649,317
October-15	$77,329	$3,726,646
November-15	$72,771	$3,799,417
December-15	$23,544	$3,822,961
January-16	-$4,371	$3,818,590
February-16	$38,674	$3,857,264
March-16	$61,800	$3,919,064
April-16	-$60,075	$3,858,989
May-16	$68,106	$3,927,095
June-16	$174,610	$4,101,705
July-16	$52,283	$4,153,988
August-16	$259,938	$4,413,926
September-16	$265,142	$4,679,068
October-16	$77,341	$4,756,409
November-16	$71,723	$4,828,132
December-16	$82,526	$4,910,658
January-17	$132,499	$5,043,157
February-17	$134,218	$5,177,374
March-17	-$18,730	$5,158,644
April-17	$93,693	$5,252,337
May-17	-$253,008	$4,999,329
June-17	$211,338	$5,210,667
July-17	-$81,541	$5,129,126
August-17	$62,812	$5,191,938
September-17	$106,634	$5,298,572
October-17	$90,817	$5,389,389
November-17	$97,285	$5,486,674
December-17	-$311,820	$5,174,854
January-18	-$2,180,015	$2,994,838
February-18	$64,361	$3,059,199
March-18	-$125,372	$2,933,827
April-18	-$134,584	$2,799,243
May-18	-$1,018,276	$1,780,968
June-18	-$1,177,088	$603,880
July-18	-$795,166	-$191,287
August-18	-$462,367	-$653,653
September-18	-$581,712	-$1,235,366
October-18	-$555,748	-$1,791,114
November-18	$65,957	-$1,725,156
December-18	$85,580	-$1,639,576

Billing Line Item Number	BILLING LINE ITEM NAME	Fuel or Non-Fuel Related Charge/Credit?		ASM Related Charge/Credit?		Related to Load, Generation, or Both?			Allocation
		Fuel	Non-Fuel	ASM	Non-ASM	Load	Generation	Both	
<u>Charges</u>									
1210	Day-ahead Transmission Congestion	X			X		X		Split between Native in FAC and Non-Native in Rider 70
1215	Balancing Transmission Congestion	X			X		X		Split between Native in FAC and Non-Native in Rider 70
1220	Day-ahead Transmission Losses	X			X		X		Split between Native in FAC and Non-Native in Rider 70
1225	Balancing Transmission Losses	X			X		X		Split between Native in FAC and Non-Native in Rider 70
1301	PJM Scheduling, System Control and Dispatch Service - Control Area Administration		X		X				Allocated to 100% Native in RTO
1303	PJM Scheduling, System Control and Dispatch Service - Market Support		X		X				Allocated to 100% Native in RTO
1307	PJM Scheduling, System Control and Dispatch Service - Market Support Offset		X		X				Allocated to 100% Native in RTO
1308	PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration		X		X				Allocated to 100% Native in RTO
1310	PJM Scheduling, System Control and Dispatch Service Refund - Market Support		X		X				Allocated to 100% Native in RTO
1313	PJM Settlement, Inc.		X		X				Allocated to 100% Native in RTO
1314	Market Monitoring Unit (MMU) Funding		X		X				Allocated to 100% Native in RTO
1315	FERC Annual Recovery		X		X				Allocated to 100% Native in RTO
1316	Organization of PJM States, Inc. (OPSI) Funding		X		X				Allocated to 100% Native in RTO
1320	Transmission Owner Scheduling, System Control and Dispatch Service		X		X				Allocated to 100% Native in RTO
1330	Reactive Supply and Voltage Control from Generation and Other Sources Service		X	X					Allocated to 100% Native in RTO
1380	Black Start Service		X	X					Allocated to 100% Native in RTO
1980	Miscellaneous Bilateral	X	X	X	X	X	X	X	Allocation is situation dependent
1999	PJM Customer Payment Default	X			X				Allocated to 100% Native in FAC
<u>Credits</u>									
2215	Balancing Transmission Congestion	X			X		X		Split between Native in FAC and Non-Native in Rider 70
2220	Transmission Losses	X			X		X		Split between Native in FAC and Non-Native in Rider 70
2330	Reactive Supply and Voltage Control from Generation and Other Sources Service		X	X					Allocated to 100% Native in RTO

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: ______________________
John A. Verderame

Dated: 7/2/2019