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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE PETITION OF DUKE ENERGY INDIANA, INC., PURSUANT TO THE COMMISSION'S MAY 18, 2004 ORDER IN CAUSE NO. 42359 AND IND. CODE § 8-1-2-42, FOR (1) AUTHORITY TO RECOVER VIA RIDER NO. 70 CERTAIN COSTS ASSOCIATED WITH PETITIONER'S POWERSHARE® PROGRAM AND SPECIAL CONTRACT DEMAND RESPONSE PROGRAM; (2) AUTHORITY TO SHARE NON-NATIVE SALES PROFITS/ LOSSES VIA RIDER NO. 70; (3) APPROVAL TO RECOVER MISO MODULE E-1 COSTS VIA RIDER 70; (4) APPROVAL OF THE TREATMENT OF MISO MODULE E AND MODULE E-1 REVENUES; AND (5) CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION RELATING TO PETITIONER'S POWER PURCHASES AND SALES AND NON-NATIVE SALES	)	**CAUSE NO. 44348** **APPROVED:** MAY 28 2014

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On May 31, 2013, Duke Energy Indiana, Inc. ("Petitioner", "the Company", or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") initiating this Cause.

On January 23, 2014, Duke Energy Indiana prefiled testimony, exhibits, verifications and applicable work papers in support of its Petition, including the testimony and exhibits of Duke Energy Business Services LLC employees Ms. Diane L. Jenner, Mr. Wenbin (Michael) Chen, Mr. Benjamin Passty, Mr. Bruce L. Sailers, and Mr. Roger A. Flick II and Duke Energy Carolinas, LLC employee Mr. Scott A. Burnside. Petitioner also filed a Motion for Protection of Confidential and Proprietary Information, together with supporting affidavits of Ms. Jenner and Mr. Jeffrey R. Bailey. On February 3, 2014, the Presiding Officers issued a docket entry finding that the information identified in the Motion should be held as confidential by the Commission on a preliminary basis. The designated confidential information was submitted under seal on February 6, 2014. On April 3, 2014, the OUCC filed the testimony and exhibit of Ms. Stacie R. Gruca. Petitioner filed the rebuttal testimony of Ms. Jenner on April 17, 2014.

Pursuant to notice published as required by law, proof of which was incorporated into the record, an evidentiary hearing was held in this Cause on May 9, 2014, at 9:30 a.m. in Room 224 PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the OUCC participated at the hearing. At the evidentiary hearing, Duke Energy Indiana and the OUCC offered their evidence, which was admitted into the record in this proceeding. No members of the general public appeared or sought to testify at the hearing.

Based on the applicable law and the evidence herein and being duly advised, the Commission now finds as follows:

1. **Notice and Commission Jurisdiction.** Due, legal and timely notices of the hearings in this Cause were given and published by the Commission as required by law. Petitioner is a public utility within the meaning of the Public Service Commission Act, as amended, Ind. Code § 8-1-2-1. Petitioner is subject to the Commission's jurisdiction for approval of its rates and charges pursuant to Ind. Code § 8-1-2-42. The Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Duke Energy Indiana is a public utility organized and existing under the laws of the State of Indiana, and has its principal office at 1000 East Main Street, Plainfield, Indiana 46168. Duke Energy Indiana is engaged in rendering electric utility service in the State of Indiana, and owns, operates, manages and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such electric service to the public. Duke Energy Indiana directly supplies electric energy to approximately 794,000 customers located in 69 counties in the central, north central, and southern parts of Indiana.

3. **Relief Sought.** Petitioner requests the Commission authorize it to: (1) recover PowerShare® and special contract demand response program costs for the period October 1, 2012 through September 30, 2013; (2) charge customers with the difference in costs associated with its PowerShare® program costs actually incurred and amounts included for the period of October 1, 2012, through September 30, 2013, compared to the amount included in Duke Energy Indiana's base rates;[1] (3) charge customers with 50% of Duke Energy Indiana's net off-system ("non-native") sales profits below the base amount included in Duke Energy Indiana's rates including the treatment and recovery of its non-native sales hedging activity; (4) approve Petitioner's treatment of Module E and Module E-1 revenues; (5) recover MISO Module E-1 costs; and (6) approve recovery of applicable reconciliation amounts. Petitioner further requests that the Commission find the following be treated as confidential "trade secrets": (1) all pricing and vendor information pertaining to sales made by Duke Energy Indiana for native load purposes; (2) power sales contracts; (3) information related to a customer-specific peak load management contract with Steel Dynamics, Inc.; (4) information from the Generating Availability Data System ("GADS") relating to statistical generation operating data; and (5) certain information relating to Duke Energy Indiana's non-native sales.

4. **Prior Applicable Commission Orders.** On May 18, 2004, in Cause No. 42359, Petitioner's last general retail base rate case, the Commission approved Petitioner's Rider 70, the Summer Reliability Rider, for the recovery of summer purchased power costs, PowerShare®

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[1] Pursuant to the Order in Cause No. 43737, in which the Commission approved, among other things, the recovery of Steel Dynamics, Inc. demand response payments via this tracker, Petitioner seeks to recover customer-specific peak load management costs as approved in that proceeding.

Program costs, and for the sharing of off-system sales profits above and below the level built into base rates.

On June 28, 2006, the Commission issued an Order in Cause No. 42870 approving Petitioner's Rider 70 for recovery of summer 2005 purchased power and PowerShare® costs (including revisions to Rider 70 to allow for recovery of year-round PowerShare® Program costs on the basis of a two-year pilot program pursuant to a settlement agreement with the OUCC), the sharing of off-system sales profits, and confidential treatment of certain information relating to summer 2005 power purchases and off-system sales.

On June 13, 2007, the Commission issued an Order in Cause No. 43074 approving Petitioner's Rider 70 for recovery of summer 2006 purchased power demand and PowerShare® Program costs, the sharing of off-system sales profits and revisions to Rider 70 language and formula.

On May 28, 2008, the Commission issued an Order in Cause No. 43302 approving Petitioner's Rider 70 for recovery of summer 2007 purchased power capacity, PowerShare® Program costs, and the sharing of off-system sales profits. Additionally, the Order authorized Petitioner to modify Rider 70 to include recovery of reliability power purchases on a year-round basis beginning January 11, 2008, and granted a two-year extension of the annual PowerShare® Program through May 31, 2010.

On June 17, 2009, the Commission issued an Order in Cause No. 43505 approving Petitioner's Rider 70 for recovery of summer 2008 purchased power capacity, the sharing of off-system sales profits, its fiscal year 2008 PowerShare® costs, its non-native sharing costs, its reconciliation amounts and was authorized to defer, as necessary to effectuate Rider 70, its reliability purchased power capacity costs, PowerShare® costs, and net non-native sales profits (losses). A portion of the recovery of costs was made interim and subject to refund pending a an order in Cause No. 38707 FAC76 S1. The final Order in Cause No. 38707 FAC76 S1 was issued on October 21, 2009, with no adjustments required.

On June 23, 2010, the Commission issued an Order in Cause No. 43715 approving PowerShare® for an additional two-year period on a year-round basis, to end on May 31, 2012. The Commission also approved Duke Energy Indiana's proposed treatment of Planning Resource Credits ("PRCs") sold into the Voluntary Capacity Auction ("VCA"), which netted the sale of surplus PRCs purchased for native load reliability against the cost of purchases and was reflected in the Capacity section of Rider 70; as to revenue from PRCs sold in excess of the number purchased for native load reliability or in months without PRC purchases, Petitioner will include this in its non-native load profit calculation in Rider 70, consistent with the treatment of sales of surplus generation not needed to meet native load needs. Finally, the Commission approved the purchase of 8 MW of capacity purchase from Logansport Municipal Utilities ("Logansport") for 2009, but declined to approve it as a long-term capacity purchase.

On May 25, 2011, the Commission issued an Order in Cause No. 43906 approving Petitioner's purchased power capacity costs, including an 8 MW capacity purchase from Logansport, for summer 2010; its PowerShare® costs, including costs associated with a special contract demand response program; its non-native sales sharing costs; its reconciliation of previously billed amounts; use of deferral accounting treatment, and authorized any sales of PRCs sold through the VCA to be netted monthly against total capacity purchases. The Order also removed the "subject to refund" designation on the recovery from Cause No. 43505 and made that recovery final.

On May 30, 2012, the Commission issued an Order in Cause No. 44035 approving Petitioner's purchased power capacity costs, including an 8 MW capacity purchase from Logansport for the month of June, and sales revenues for summer 2011; its PowerShare® costs, including costs associated with a special contract demand response program; its non-native sales sharing costs; its reconciliation of previously billed amounts; and Petitioner's treatment of revenues from sales of PRCs sold through the VCA. The Commission also found that Petitioner's non-native hedging strategy was reasonable and approved the requested reconciliation amount.

Most recently, on June 19, 2013 the Commission issued an Order in Cause No. 44214 approving Petitioner's treatment of capacity sales revenues for the twelve months ending September 2012; its PowerShare® costs, including costs associated with a special contract demand response program; its non-native sales sharing costs; and Petitioner's treatment of revenues from sales of PRCs sold through the VCA. The Commission also found that Petitioner's non-native hedging strategy was reasonable and approved the requested reconciliation amount.

5. Petitioner's Case-in-Chief.

A. Reliability Planning, Sales, and Purchases. Mr. Benjamin Passty, a lead analyst in the Load Forecasting group, testified as to Petitioner's load forecast for the fall of 2012, projecting a peak demand of 6,585 MW. Mr. Passty also testified that customers who were served under Duke Energy Indiana's economic development riders totaled 5.5 MWs of incremental load, which he noted is very small for purposes of summer capacity and Rider 70, resulting in no incremental costs related to serving economic development customers.

Mr. Bruce Sailers, Manager, Pricing and Rate Options, testified as to Petitioner's energy efficiency resources, including its traditional demand side management and demand response programs, customer specific contract offerings, and the PowerShare® program.

Ms. Diane Jenner testified that the Company continues to rely on a portfolio approach to meet its native load customers' demand requirements and that renewable resources, purchased power when needed, Energy Efficiency ("EE"), PowerShare® and other demand side management programs continue to play an important role in the Company's resource mix.

Ms. Jenner testified that due to the ability to perform a generator test and register a portion of the Edwardsport plant's capacity with the Midcontinent Independent Transmission System Operator, Inc. ("MISO") prior to it officially going in service, no PRC purchases were ultimately necessary for the summer of 2013. Duke Energy Indiana's capacity position was adequate to meet the minimum required reserve margin and as a result, the Company made forward capacity sales of 230 Zonal Resource Credits ("ZRCs") in the bilateral market ahead of MISO's Planning Resource Auction ("PRA") and additional net sales of 352.7 ZRCs in the PRA.

Ms. Jenner testified that Petitioner purchased 8 MW of installed capacity ("ICAP") from Logansport under a long-term contract that began in 2009, but the unit became unavailable in summer 2011 and has not been repaired. Therefore, no payments were made to Logansport under the contract between October 2012 and September 2013.

Without certain special contracts, and the PowerShare® impacts, Petitioner's reserve margin on an unforced capacity ("UCAP") basis, as required by MISO, was 9.7%. Ms. Jenner testified, altogether, the jurisdictional allocation of Rider 70 costs for Fiscal Year 2013 results in a request to recover a total of $14,397,679 before adjustment for Utility Receipts Tax via Rider 70 over a 12-month period, which amounts to an increase of $0.03 on the monthly bill for a typical residential customer. She stated this amount includes a combination of: (1) a charge for the amount of annual PowerShare® program costs above that reflected in base rates, (2) a charge for non-native sales profits (reflecting the fact that Duke Energy Indiana did not realize annual non-native sales profits above the level included in base rates), and (3) a charge resulting from reconciliation for Rider 70 costs approved in Cause No. 44035 to amounts collected.

Ms. Jenner testified that, beginning with the Planning Year June 1, 2009 - May 31, 2010, there is a requirement that the Loss of Load Expectation ("LOLE") due to resource inadequacy cannot exceed one occurrence in ten years. She explained that the MISO Planning Reserve Margin ("PRM") assigned to each load serving entity ("LSE") is on a UCAP basis, such that the PRM on an ICAP basis will be translated to PRM_{UCAP} by multiplying it by one minus the MISO system average equivalent forced outage rate excluding events outside of management control ("$XEFOR_d$"). Each capacity resource is valued at its unforced capacity rating *(i.e.,* installed rating multiplied by one minus the unit-specific $XEFOR_d$). She testified that under the MISO Module E construct, compliance was assessed monthly by comparing the amount of PRCs designated by each LSE with its monthly forecasted non-coincident peak load multiplied by one plus the PRM_{UCAP}. Under the new MISO Module E-1 construct, compliance is assessed annually by comparing the amount of ZRCs designated by each LSE with its annual forecasted peak load coincident with the MISO peak multiplied by one plus the PRM_{UCAP}.

For purposes of this filing, there were two different MISO Planning Years. For the 2012/2013 Planning Year (October 2012 through May 2013), to satisfy the LOLE requirement, MISO established a minimum 3.79% required reserve margin on an UCAP basis. For the 2013/2014 Planning Year (June 2013 through September 2013), Duke Energy Indiana was required to meet a PRM_{UCAP} of 6.2%. Ms. Jenner explained the difference in these numbers is due to the change from applying the PRM_{UCAP} to non-coincident peak load versus coincident peak load (*i.e.*, Module E vs. Module E-1).

Ms. Jenner testified, in all months, an offer was made into the VCA to attempt to sell the capacity surplus and that the Company was successful in all months and typically at low prices. She provided details of sales and clearing prices for the months of October 2012 through May 2013. She noted that under MISO's new Module E-1 construct, the monthly VCA has been replaced by an annual PRA, so May 2013 was the last VCA.

Ms. Jenner described Petitioner's treatment of VCA revenues, as approved in Cause No. 43906. Revenue from the sale of surplus PRCs that have been purchased for native load reliability will be netted against the cost of the purchases, effectively reducing the cost of the purchase, and will thereby be reflected in the Capacity section of Rider 70. Revenue from PRCs sold in excess of the number purchased for native load reliability or in months without PRC purchases will be included in the non-native load profit calculation in Rider 70, consistent with the treatment of sales of surplus generation not needed to meet native load needs. Ms. Jenner testified that because there weren't any purchase costs to offset, the revenue from the PRC sales was taken into account in the non-native load profits, as discussed by Mr. Burnside.

Ms. Jenner described how Petitioner used the MISO Module E-1 Reserve Margin requirements as the minimum for future capacity purchases, as required in Cause No. 43505. She explained Petitioner used the required PRM_{UCAP} of 6.2% in its assessment of its Supply versus Demand position. The surplus ZRCs were sold forward and/or offered into the PRA, and that for summer 2013, the resulting actual PRM_{UCAP} was 6.2%. Ms. Jenner stated that in future years it is not likely Petitioner would be able to meet the exact required PRM_{UCAP} because the ability to do so is highly dependent on the total number of ZRCs that are purchased, the block sizes available for purchase, and the marketability of any surplus. Nevertheless, Petitioner will continue to target the MISO Module E-1 PRM_{UCAP} as the appropriate minimum reserve requirement.

Ms. Jenner explained that although the Company's reserve margin was above the summer 2013 requirement even without taking into account special contracts and PowerShare®, the Company must take a long-term approach with regard to resource planning. She discussed the value in the PowerShare® program as well as special contracts in the long-term avoidance of additional generating capacity.

Ms. Jenner went on to explain that meeting the minimum reserve margin requirement does not ensure the need not to buy expensive energy from the spot market during the year. Factors like unexpected plant shutdowns or derates and extreme weather can increase reliance on the spot market at just the time that prices are increasing. She explained buying forward energy or price hedges limits exposure to price spikes. However, all PRCs and ZRCs are purely capacity products to meet MISO Resource Adequacy requirements.

Ms. Jenner testified that Duke Energy Indiana continues to be committed to a portfolio approach to meet its native load peak demand obligations. She noted that for summer 2013, Petitioner met native load customers' peak demand requirements through a resource mix consisting of 89.9% through its existing fleet of generating assets, 9.2% through a combination of conservation and demand response products, and 0.9% through renewable resources. Ms. Jenner testified that hourly spot purchases cannot take the place of firm capacity, but that hourly spot power is utilized when available and to the extent such power purchases are economic to meet short-term needs.

Ms. Jenner explained MISO's new Resource Adequacy construct (*i.e.,* Module E-1) beginning with Planning Year 2013/14 and how an LSE can meet its planning reserve margin requirements. She explained that although the changes to the construct involve changes to some of the Company's processes, there have not been any changes to the basic philosophy with regard to meeting Resource Adequacy requirements. The Company continues to use the MISO reserve requirement as the minimum reserve margin and pursues a balanced portfolio approach through its own generation, renewables, demand response, EE, and reliability purchases. She also testified that any surplus capacity above the MISO requirement is offered into the PRA to try to reduce costs to customers.

Ms. Jenner further testified that the permanent approval of PowerShare® on a year-round basis has positioned the Company well for the new construct. In addition, the use of a coincident peak forecast to which the PRM_{UCAP} is applied results in a higher Resource Adequacy requirement for the Company.

Ms. Jenner discussed the Commission's Order in Cause No. 43906, which stated that if MISO's Resource Adequacy construct was modified to an annual rather than monthly basis, that the time period to be used for netting purchases and sales would be revisited. She stated that because the settlements under MISO's new Resource Adequacy construct are daily, the costs and revenues for the period of time covered by this Rider for Planning Year 2013/14 (*i.e.,* June 1, 2013-September 30, 2013) can also be handled on a daily basis. She noted that the daily values can be aggregated to monthly values for reporting purposes. The Module E-1 purchase costs and sales revenues can be treated consistently with the treatment of purchase costs and sales revenues under the previous MISO Resource Adequacy construct. She explained that this methodology should continue to work in future Rider 70 filings, which will span two different Planning Years and will, thus, include different costs and revenues based on different PRM_{UCAP} requirements, different load, and different Auction Clearing Prices ("ACPs"). The Company is following this proposed process for the ZRC sales where the ZRC load charges and ZRC revenues are netted. This results in the net ZRC sales revenues taken into account in the non-native load profits, as discussed by Mr. Burnside. Ms. Jenner testified that the Company met with the OUCC in advance of filing this proceeding to discuss these principles for treating the new charges and revenues.

Mr. Wenbin Chen, Manager, Power Trading Midwest, described the bilateral capacity sales that were made for the 12 months ended September 30, 2013. Mr. Chen testified that there were bilateral capacity sales in 3 contracts with 3 counterparties with total sale proceeds of $311,192. He stated that the Company actively participated in MISO's new annual PRA auction, where it purchased capacity from MISO for native load and sold generation capacity to MISO, at the same ACP, resulting in net capacity sales from the Company to MISO. Mr. Chen testified that proceeds from the sales in both monthly and annual auctions were $45,694 for this Rider 70 proceeding, which is included in the calculation of non-native sales profits. He further testified that he believes the capacity sales were reasonable and only made after it was determined the Company had surplus capacity after complying with MISO's Resource Adequacy requirement. He stated the bilateral sales of the PRCs and ZRCs were the result of arms' length negotiations at then-prevailing market prices. Mr. Chen stated that the Company contracted with Logansport in 2009 for a capacity purchase from July 1, 2009 through December 31, 2018. He explained that although the capacity is available year-round, the payment is prorated from June through September each year of the contract. Because the Logansport unit became unavailable in July

2011, capacity payments were suspended and the capacity was removed from Petitioner's MISO Resource Adequacy compliance plans until the unit becomes available again in the future.

Mr. Chen sponsored a confidential exhibit that included all agreements or confirmations supporting the capacity sales.

B. <u>PowerShare® and Customer-Specific Peak Load Management Programs</u>. Mr. Sailers described Petitioner's PowerShare® Program. He stated that PowerShare® has been offered under Standard Contract Rider No. 23 ("Rider 23") since 2000. The program provides financial incentives to industrial and commercial customers to reduce their electric demand during Petitioner's peak load times and has two offerings: CallOption and QuoteOption. Under the CallOption component, customers commit to a pre-selected load reduction at a selected strike price. Mr. Sailers explained that CallOption customers are paid a monthly premium for their commitment and an energy credit when they are called upon to reduce their load. Mr. Sailers testified that the terms of the CallOption program vary depending on customer-selected parameters that include the contracted for option load, the strike price, the selected duration, and the maximum number of calls.

Mr. Sailers explained that QuoteOption customers may elect whether or not to reduce load when called upon. As a result, QuoteOption customers are not paid a monthly premium, but an energy credit is paid when load reductions are made in response to Petitioner's request. The QuoteOption is available year round, in accordance with the Commission's Order in Cause No. 42870.

Mr. Sailers testified that during the summer of 2013, there were four PowerShare® CallOption economic events and no PowerShare® QuoteOption events due to hot weather conditions and/or high marginal energy prices. During the winter of 2012/2013, there were no PowerShare® events. For summer 2013, Petitioner entered into 104 CallOption contracts.

Mr. Sailers described the PowerShare® attributes for the June 2014 through May 2015 planning year. He explained that with changes to MISO's Resource Adequacy framework the enrollment process will start before the upcoming planning year. The Company is currently marketing the program for next summer, with a goal for completion of MISO registrations by February 1, 2014. Mr. Sailers noted two changes for the 2014/2015 program: (1) event incentives will be paid only for load reduced during an event; and (2) a new PowerShare CallOption option is available which provides flexibility for economic event duration from 4 to 8 hours and shorter notice to customers of events.

Mr. Sailers described the PowerShare® attributes for the 2013/2014 winter period. He testified that participants enrolled in the CallOption programs may be called for a system emergency condition during any month of the year and that participants in the CallOption 15/5 program can be called for economic events during any month of the year. The only other program attribute that differs substantively from the summer 2013 program attributes is that the peak period from October 1 through May 30 is defined as 7:00 a.m. to 1:00 p.m., compared to 1:00 p.m. to 7:00 p.m. during the period of June through September.

Mr. Sailers testified regarding Duke Energy Indiana's customer-specific peak load management contract with Steel Dynamics, Inc. ("SDI"), which costs are recovered through Rider 70. He provided confidential testimony as to the total expenditures to be charged to customers resulting from the contract with SDI. Mr. Sailers testified that PowerShare® and any customer-specific peak-load management contracts are registered with MISO, as both Load-Modifying Resources ("LMRs") and Emergency Demand Response resources, which allow MISO to call on the programs when MISO declares the North American Energy Reliability Corporation's Energy Emergency Alert level 2 events or higher. However, for the planning year 2014/2015, Duke Energy Indiana will only utilize these programs as LMRs. He also testified that registering the programs as LMRs allows Petitioner to reduce its MISO Resource Adequacy requirements.

Mr. Sailers also provided an update on Duke Energy Indiana's EE efforts at the time of the filing. He explained that having received clarification from MISO, the applicable incremental impacts from Duke Energy Indiana's energy efficiency portfolio were incorporated in the coincident peak forecast submitted to MISO for the planning year 2014/2015.

C. <u>Sharing of Non-Native Sales Profits</u>. Ms. Jenner summarized Duke Energy Indiana's non-native sales strategy for the period of October 2012 through September 2013. She explained that Duke Energy Indiana has sold its surplus generation into the MISO markets since the advent of the MISO Day 2 energy markets, in addition to offering surplus capacity into the VCA and PRA, as previously discussed.

Mr. Roger Flick, Lead Rates and Regulatory Strategy Analyst, explained that in Petitioner's most recent retail electric base rate case, Cause No. 42359, the Commission provided for a sharing on a 50/50 basis, the differential between net non-native sales profits realized by Petitioner and the $14,747,000 net profit level for non-native sales included in the determination of Duke Energy Indiana's revenue requirement in that Cause. Mr. Flick testified that the Commission also found that Petitioner's base rates should reflect a reasonable level of trading expenses required to achieve those non-native sales profits in the amount of $3,953,000.

Mr. Scott Burnside, Manager – Post Analysis and Regulatory Support, described the types of non-native sales Petitioner made in the past year, including day ahead and real time sales to MISO, sales of capacity in the MISO VCA and PRA that do not offset reliability purchases, energy or capacity sales to non-MISO counterparties, realized margin from non-native sales of emission allowances, realized margin from non-native hedging activity, and non-firm retail contracts with special contract customers. Mr. Burnside explained how revenues and expenses allocable to non-native sales are determined.

Mr. Chen explained Petitioner's power hedging program and that the Company also hedges for non-native load with the objective to lock in a margin for the forecasted surplus generation not allocated to serve native load. Mr. Chen testified that he believes the Company's power hedging practices are reasonable. For the period at issue, the non-native hedges resulted in a gain of approximately $580,513.

Mr. Burnside stated that gross profits from non-native sales for October 1, 2012, through September 30, 2013, total $113,512 before trading expense reduction or prior period adjustment amounts. Mr. Burnside explained that due to MISO's settlement cycles, there may be further revisions to non-native sales calculations. Petitioner proposed to include such prior period adjustments in future Rider 70 filings. For this filing, Petitioner calculated a prior period adjustment of $58,538. This adjustment was made to reflect the fact that during the current Rider 70 non-native power sales period (October 1, 2012, through September 30, 2013), Petitioner received updated MISO settlement statements for operating dates impacting prior Rider 70 non-native power sales periods.

Mr. Burnside testified regarding the Post Analysis Cost Evaluator ("PACE") model and that it economically dispatches generating units on an hourly basis, matches the demand (load) with available supply resources (generation or purchases), and allocates those production costs for serving native load and non-native sales. Mr. Burnside testified that there are new developments affecting the dispatch of the Company's units. Starting in late February 2012, a price decrement was applied to the dispatch costs of Gibson 1-5, Wabash River 2-6, and Cayuga 1-2 generating units to correctly reflect the economics of additional costs associated with avoiding or reducing surplus coal inventories. He explained that the fuel costs used in PACE are undecremented, which prevents decremented units with high actual fuel costs from displacing undecremented units with a low fuel cost in the native stack, and that all of the Company's resources are included as available resources in this process.

D. <u>Rider 70 Calculation and Rate Impact</u>. Mr. Flick explained that Rider 70 was designed to recover the demand or capacity component of summer reliability purchased power costs, the reconciliation of actual and authorized PowerShare® costs, the sharing of non-native sales profits, and the recognition of a standard reconciliation process. He indicated that the period covered by this filing included the 12 months ended September 30, 2013.

Mr. Flick testified that $787,982 in capacity purchases were made in the PRA for native load for June through September 2013; however, they were offset by revenues received for Company generating capacity offered into the PRA, resulting in no net capacity purchases during the 12-months ended September 30, 2013. The net capacity sales were $356,886. Mr. Flick also explained Duke Energy Indiana's treatment of capacity sales included in this filing. He stated that sales of surplus capacity are from the Company's generating capacity or prior capacity purchases, and that capacity sales occurring in periods without capacity purchases or in excess of capacity purchase values, such amounts were included in the non-native load sharing mechanism.

Mr. Flick testified that Rider 70 provides for the tracking of actual PowerShare® CallOption premiums and CallOption and QuoteOption energy credits and for costs associated with a customer-specific peak-load management contract with SDI. He testified that Petitioner's total peak-load management costs included in Rider 70 for October 2012 through September 2013 totaled $8,033,294, which is more than the amount authorized in Cause No. 42359. As such, retail customers will be charged $7,010,294 in this proceeding.

Mr. Flick stated the results of Petitioner's non-native sales for the period October 1, 2012 through September 30, 2013, totals a gain of $113,512 before applicable prior period adjustments and fixed trading expenses, or a $3,898,026 net non-native sales loss after the adjustments. Mr. Flick explained the amount of net non-native sales loss allocated to retail customers is $3,578,037. He explained that, when this is compared to the net non-native sales profits currently in base rates, the authorized 50/50 sharing results in a charge to customers of $7,373,500.

Mr. Flick explained that Rider 70 includes a standard reconciliation provision in which Duke Energy Indiana determines the difference between Rider 70 amounts approved for recovery and Rider 70 amounts actually billed to customers. Accordingly, a reconciliation of billed Rider 70 amounts corresponding to those authorized for recovery in Cause No. 44035 was made, and the reconciliation results in a $13,855 under-collection, which has been included as a charge to customers.

Mr. Flick testified that updated allocation rates are being proposed in this filing for the LLF and HLF rate classes due to the migration of customers and their corresponding sales between the rate classes. Since 2008 the number of Rate HLF customers and sales has declined while the number of RATE LLF customers and sales has increased. This change will better align Rider 70 costs with current customer loads. Mr. Flick testified that the result is a reduction in the Rate HLF share and an increase in the Rate LLF share of the kW system peak of approximately 50 MWs. This results in a change in the allocation percentages of approximately 1%.

In total, the amount to be recovered via Rider 70, including purchased power demand costs, PowerShare® costs, non-native sales profits sharing, and reconciliation is set forth in Petitioner's Exhibit F-2. Mr. Flick explained that these costs would be recovered over a one-year period, and that Petitioner's request herein would result in approximately an increase of $0.03 in the base bill of a typical residential customer compared to what such customer is paying today (excluding various tracking mechanisms and sales tax).

Mr. Flick explained that in order to effectuate Rider 70, Petitioner would defer the jurisdictional component of its purchased power costs until such time as the net purchased power costs are recovered through Rider 70, and that Petitioner would record either a regulatory asset or liability related to the true-up of PowerShare® costs in relation to the give back of PowerShare® costs, the reconciliation of actual Rider 70 billing amounts to amounts approved for recovery, and non-native sales profits subject to sharing.

E. Request for Confidential Treatment. In addition to the Affidavits of Ms. Jenner and Mr. Bailey filed in support of Duke Energy Indiana's Motion for the Protection of Confidential and Proprietary Information, Ms. Jenner provided additional testimony explaining that certain pricing and vendor information pertaining to sales, power sale contracts, GADS data relating to statistical generation operating data, and the customer-specific peak load management contract with SDI are "trade secrets" and excepted from the access to public records provisions, consistent with Ind. Code §§ 5-14-3-4(a)(4) and 24-2-3-2.

6. <u>OUCC's Case-In-Chief</u>. Ms. Stacie Gruca, Senior Utility Analyst in the Electric Division of the OUCC, testified concerning the OUCC's review of Petitioner's requested relief.

Ms. Gruca testified that her calculations of the jurisdictional allocation of Rider 70 costs for the period October 1, 2012 through September 30, 2013 match the amount that Petitioner is requesting to recover and recommends the Commission approve recovery of such costs.

Ms. Gruca testified that Duke Energy Indiana complied with the Commission's Order in Cause No. 43505 by using the required PRM_{UCAP} of 6.2% and that Duke Energy Indiana's capacity position was adequate to meet the minimum required reserve margin for summer 2013 and no forward capacity purchases were necessary. She testified that Duke Energy Indiana's actual summer 2013 PRM_{UCAP} was 6.2%. She further stated that the OUCC continues to recommend that the Company utilize the Module E-1 reserve margin requirements as the target for future necessary capacity purchases to fully capture the benefit of participating in MISO.

Ms. Gruca testified that Duke Energy Indiana explained its continued use of special contracts and PowerShare® resources when it had already exceeded the MISO reserve margin requirements and that the OUCC agreed it is appropriate to take a longer-term view by considering future compliance needs that may impact resource planning. She testified that it seems reasonable to continue the use of special contracts and PowerShare® resources until it is known how retirement of Duke Energy Indiana's units and the addition of the Edwardsport capacity will affect capacity conditions and capacity needs.

Ms. Gruca testified that the OUCC participated in a conference call with Duke Energy Indiana in advance of its current Rider 70 filing to discuss modifications to MISO's Resource Adequacy construct from a monthly construct to an annual construct, as well as Duke Energy Indiana's proposed treatment of purchases and sales under the new Module E-1 annual construct.

Ms. Gruca testified she had no concerns regarding whether Petitioner's evidence supports its forward reliability purchase needs for October 1, 2012 through May 31, 2013, during which MISO's Module E monthly Resource Adequacy construct was in place, and that Duke Energy Indiana did not make any forward reliability purchases during this period. Ms. Gruca further testified that she had no concerns regarding whether Petitioner's evidence supports its forward reliability purchase needs for June 1, 2013 through September 30, 2013, during which MISO's Module E-1 annual Resource Adequacy construct was in place, and that Duke Energy Indiana did not make any forward reliability purchases during this period. She testified that since Petitioner was able to perform a generator test and register a portion of the Edwardsport capacity with MISO prior to it officially going into service, Duke Energy Indiana's capacity position was adequate to meet the minimum required reserve margin for the summer of 2013. She also explained that Duke Energy Indiana provided an update regarding the status of its contract with Logansport with no capacity payments being made to Logansport for summer 2013, and that this capacity was not included in Duke Energy Indiana's supply versus demand balance to meet its Resource Adequacy requirements. She recommended that Duke Energy Indiana continue to keep the Commission informed of the status of the Logansport contract and unit in future Rider 70 proceedings.

Ms. Gruca discussed the capacity sales made during the October 2012 through May 2013 period when MISO's Module E monthly Resource Adequacy construct was in place, and indicated that the Company's treatment of its capacity sales during this period is consistent with the Commission's Order in Cause No. 43906. Ms. Gruca also discussed the capacity sales made during the June 2013 through September 2013 period, during which MISO's Module E-1 annual Resource Adequacy construct was in place. She testified that the OUCC does not entirely agree with Duke Energy Indiana's proposed netting of purchases and sales under the new MISO Module E-1 annual Resource Adequacy construct. The OUCC believes for ratemaking purposes and in order to follow the new MISO annual Resource Adequacy construct and ZRC annual product, it would be more appropriate to net the daily net revenues for the Planning Year against the daily net charges for the Planning Year, with any excess annual net revenues included in the 50/50 non-native sales profit sharing.

Ms. Gruca stated that the OUCC agrees with the Company's proposal to net revenues from daily ZRC sales against total daily purchases up to the cost of the daily ZRCs purchased. However, the OUCC disagrees with Petitioner regarding the next step of how excess charges and revenues are treated. The Company is proposing that on days where there is a net charge, customers recover 100% of the daily charges associated with capacity purchases and on days where there are net revenues, then customers share the profits 50/50 of capacity sales. She testified that the OUCC's proposal allows customers that are paying 100% of the capacity purchases and associated charges to first be made whole by revenues received from capacity sales, and then any excess revenues are shared 50/50 between customers and shareholders. She stated that this treatment continues to provide an incentive to Duke Energy Indiana through the non-native sales profit sharing computation.

Ms. Gruca testified that modifications to MISO's Resource Adequacy construct included a change from a monthly VCA to an annual PRA. Ms. Gruca explained that compliance under MISO's previous Module E Resource Adequacy construct was measured on a monthly basis through the monthly VCA and compliance under the new MISO Module E-1 Resource Adequacy construct is measured on an annual basis through the annual PRA. Daily netting of sales and purchases is consistent with the resulting daily settlements and should not distort the economic value of the ZRC transactions. In addition, the annual netting of daily settlements is consistent with the annual compliance under Module E-1 and the annual nature of the PRA. Ms. Gruca testified that Ms. Jenner's rebuttal testimony in Cause No. 43906 explained MISO's proposal to move to an annual, rather than a monthly, Resource Adequacy construct and indicated that the new product (ZRC) would be an annual product, so annual netting clearly would be appropriate at that time. Ms. Gruca further testified that annual netting of daily charges/revenues is also consistent with Duke Energy Indiana's recovery of retail jurisdictional costs associated with reliability power purchases on a year-round basis under Rider 70. Ms. Gruca provided hypothetical examples of the results of Duke Energy Indiana's proposal versus the OUCC's proposal.

Ms. Gruca testified that the OUCC proposes three options to account for the fact that the Rider 70 period and MISO Planning Year period are not the same: (1) net the June through September amounts from the Planning Year in the initial filing and then true up the amounts in the subsequent Rider 70 filing at the time the October through May amounts from the Planning

Year are available and the entire twelve months of the Planning Year is able to be netted annually; (2) compute the annual netting in every other Rider 70 filing; or (3) modify the Rider 70 period to match the Planning Year period. Ms. Gruca testified that the OUCC is open to other recommendations by the Commission or the Company that would allow for the annual netting of daily net charge/revenue amounts.

Ms. Gruca also explained that if the Commission were to approve the OUCC's proposed annual netting of charges and revenues, there are resulting capacity sales revenues included in the non-native sales profit sharing computation that may require an adjustment in Petitioner's subsequent Rider 70 filing or removal in the current filing to be recovered in Petitioner's subsequent Rider 70 filing, unless Duke Energy Indiana opts to modify its Rider 70 recovery period. Ms. Gruca further explained that should there be daily net purchases/charges during the remainder of the Planning Year, which will be recovered as part of Duke Energy Indiana's subsequent Rider 70 filing, then revenues should be netted against any charges before any sharing occurs between ratepayers and shareholders. Ms. Gruca testified that if capacity sales revenues were removed from the current filing (and recovered in Petitioner's subsequent Rider 70 filing), there would be no effect on the monthly bill of a typical residential customer and Reliability Adjustment factors proposed in this proceeding would remain unchanged.

Ms. Gruca testified that her audit corroborates Duke Energy Indiana's calculation of off-system sales profits and that the Company's requested recovery seems reasonable.

Ms. Gruca recommended that Duke Energy Indiana continue to update the Commission in future Rider 70 proceedings regarding its coal inventory, including the development of alternatives to its decrement pricing. She further indicated that the OUCC reserves all of its rights in future FAC proceedings, Rider 70 proceedings, or other proceedings to address this below-cost bidding strategy, and its impact on customers.

Ms. Gruca testified she had no concerns regarding Petitioner's proposed recovery of PowerShare® Program costs or customer-specific peak load management costs. She testified that Petitioner's PowerShare® Activity Log shows a quantified benefit to customers who participate in the programs.

Ms. Gruca stated that Petitioner's realized gains related to non-native hedging in the amount of $580,513 benefited customers by adding to Petitioner's non-native sales profits. With respect to Petitioner's hedging philosophy, Ms. Gruca testified that Petitioner indicated in testimony that Duke Energy Indiana and the OUCC have entered into a settlement agreement to meet annually to discuss the matter.

Ms. Gruca also testified that Duke Energy Indiana provided documentation consistent with its obligation pursuant to the Settlement Agreement approved in Cause No. 42870 and modified as agreed to by the OUCC in Cause No. 43906.

7. **<u>Petitioner's Rebuttal</u>.** Ms. Jenner provided rebuttal testimony stating that the OUCC's proposal regarding the treatment of purchases and sales under the new MISO Module E-1 Resource Adequacy construct and the options for dealing with the mismatch between the

Rider 70 period and the MISO Planning Year unnecessarily complicate the Rider 70 filings. She testified that adopting the OUCC's proposal to utilize annual netting of charges and revenues will require additional reconciliations, increase the regulatory lag to recover costs/share revenues, or change the timing of reconciliation periods and/or of the annual filings because of the time periods at issue. Ms. Jenner testified that the Company's current practice is administratively simpler. She explained that it has the flexibility to deal with the alignment issue as well as any changes MISO might make to its Resource Adequacy construct in the future. Daily netting also aligns better with the Day Ahead and Real Time hourly nature of the energy markets. She stated that the different methodologies proposed by the OUCC and the Company do not produce different results in this Rider 70 or the next Rider 70.

Ms. Jenner testified that the OUCC's first option, as noted above, would always result in true-ups in subsequent filings. As to the second option, Ms. Jenner testified that waiting until all 12 months of Planning Year information is available would result in a mismatch with the timing of all of the other Rider 70 components and cause an even longer lag in time for cost recovery/revenue sharing than already exists. It would add another 12 months to the current lag time of 12-21 months. She testified that the third proposal by the OUCC, to modify the Rider 70 reconciliation period to match the MISO Planning Year, is the only way that netting the charges and revenues for a Planning Year on an annual basis rather than daily bases could work reasonably. However, she stated that this would entail shifting all of the reconciliation calculations to a different date within the year and developing a methodology to deal with the transition to the "new" Rider 70 period.

Ms. Jenner proposed that the Commission not adopt the OUCC's proposal to use annual aggregation to determine whether the result is a net charge or net revenue in this Rider 70, especially because there would be no difference in results. The Company also proposed that the OUCC and Company meet prior to filing testimony in the next Rider 70 to discuss a way to harmonize the Rider 70 period with the MISO Planning Year and develop an acceptable methodology for the transition. She testified that there will be no impact to customers in the current Rider 70 or even in the next Rider 70 if the Commission does not adopt the OUCC's proposal in this Rider 70.

8. Commission Discussion and Findings.

A. Petitioner's Requested Relief. Based upon the evidence presented, we find Petitioner continues to use a portfolio of diverse options to serve its customers' capacity needs. The Commission finds that Petitioner should continue to use the MISO Module E-1 reserve margin requirements as the appropriate target for future necessary capacity purchases and update the Commission on any additional changes to MISO's Resource Adequacy construct. We further find that Petitioner should keep the Commission informed of the status of the Logansport contract and unit in future Rider 70 proceedings.

We also find that Petitioner's PowerShare® Program and customer specific peak load management costs for October 1, 2012, through September 30, 2013 were reasonable, and the expenses were accurately calculated and should be approved. As we stated in the final Order in

Cause No. 43074, the PowerShare® program is an important component in Petitioner's summer preparedness.

We further find that Petitioner has accurately calculated the amount of non-native sales profits that should be shared with customers under Rider 70, as approved by the Commission in Cause No. 42359. Mr. Burnside explained how Petitioner calculated its non-native sales amount, including adjustments for expense reduction and prior period amounts. Additionally, we find that Petitioner should continue to update the Commission on its coal inventory, including the development of alternatives to its decrement pricing.

We also find that the calculations of the Rider 70 billing factors as outlined in the exhibits and testimony of Mr. Flick are accurate and appropriate and are hereby approved, including the adjustments made to the allocations for the industrial class rate migrations. We direct Duke Energy Indiana to include such adjustment factors in the Rider 70 filed with this Commission in compliance with this Order.

As to netting of capacity purchases and sales under the new MISO Module E-1 construct, we find that Petitioner and the OUCC should discuss the various issues inherent in synchronizing Petitioner's Rider 70 period with the MISO planning year and propose a netting methodology in Petitioner's next Rider 70 filing. Because the methodology recommended by the OUCC does not yield a different outcome than the methodology proposed by Duke Energy Indiana for this filing, we will approve Petitioner's proposed treatment of Module E and Module E-1 capacity revenues for this filing. We will revisit the treatment of capacity purchases and sales after the OUCC and Petitioner have the opportunity to collaborate on a possible netting methodology to be addressed in Petitioner's subsequent Rider 70 proceeding.

Finally, Petitioner demonstrated a need for confidential treatment of certain information associated with its pricing and vendor information pertaining to sales made by the Company for native load purposes, power sales contracts, GADS data relating to statistical generation operating data, and the customer-specific peak load management contract with SDI and no party objected to the request for confidential treatment. Accordingly, pursuant to Ind. Code § 5-14-3-4(a)(4), we find that this information, as identified in Duke Energy Indiana's redacted testimony and exhibits, constitutes "trade secrets" and shall continue to be held as confidential.

B. <u>Other Matters</u>. In accordance with the Commission's May 31, 2000 Order in Cause No. 41448, Duke Energy Indiana initiates this tracker proceeding approximately a year in advance of the proposed implementation of the requested Rider 70 adjustment factor to allow for an opportunity to scrutinize the reasonableness of contracts for the upcoming peak period. However, experience with this mechanism shows that this provision is not functionally significant and Duke Energy Indiana does not file its evidence until January of the following year in which the petition was filed. Accordingly, we question the necessity for the continued early filing of these proceedings. Therefore, unless any of the parties notifies the Commission within 10 days of this Order of its objection, the Commission finds that Duke Energy Indiana shall initiate its next Rider 70 proceeding by filing its petition and supporting evidence no later than January 30, 2015.

In addition, for purposes of administrative efficiency and ease of reference, the Commission finds that future Rider 70 proceedings shall be filed under this Cause using a standard docketing convention of "SRA X." Accordingly, Duke Energy Indiana shall file its next Rider 70 filing under Cause No. 44348 SRA 1.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Petitioner is authorized to recover, through Standard Contract Rider No. 70, its PowerShare® and customer-specific peak load management program costs consistent with Petitioner's testimony and exhibits.

2. Petitioner is authorized to recover, through Standard Contract Rider No. 70, its non-native sale sharing costs consistent with Petitioner's testimony and exhibits.

3. Petitioner is authorized to recover, through Standard Contract Rider No. 70, its calculated reconciliation amounts.

4. Petitioner is authorized to recover its MISO Module E and E-1 costs consistent with Petitioner's testimony and exhibits.

5. Petitioner shall file with the Commission's Electricity Division its Standard Contract Rider No. 70, with the rates therein reflecting the provisions of this Order. Rider 70 shall be effective for all bills rendered on and after the first billing cycle of July 2014 or the date of such filing, if later, and shall continue for a 12-month period.

6. Petitioner's confidential information identified herein shall continue to be held as confidential pursuant to Ind. Code §§ 8-1-2-29 and 5-14-3-4(a)(4).

7. Petitioner shall file its next proceeding in accordance with Finding Paragraph 8.B. above.

8. This Order shall be effective on and after the date of its approval.

<u>STEPHAN, MAYS, WEBER, AND ZIEGNER CONCUR</u>:

APPROVED: MAY 28 2014

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe,
Secretary to the Commission