ORIGINAL

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; AND (3) CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION RELATING TO PETITIONER'S POWER PURCHASES AND SALES AND NON-NATIVE SALES	CAUSE NO. 44214 APPROVED: JUN 19 2013

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Gregory Ellis, Administrative Law Judge

On June 8, 2012, Duke Energy Indiana, Inc. ("Petitioner", "the Company", or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") initiating this Cause. Pursuant to notice and as provided for in 170 IAC 1-1.1-15, a Prehearing Conference in this Cause was held at 1:30 p.m. on July 10, 2012 in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana.

On January 24, 2013, 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, Ms. Yuan Niu, 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 4, 2013, 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, 2013. On April 4, 2013, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony and exhibit of Ms. Stacie R. Gruca. Petitioner did not file rebuttal testimony.

Pursuant to notice given and published as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, a public evidentiary hearing was held in this Cause at 9:30 a.m. on May 1, 2013, in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Duke Energy Indiana and the OUCC were present and participated. The case-in-chief testimony and exhibits of Duke Energy Indiana and the OUCC were introduced into evidence at the evidentiary hearing. 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 notice of the prehearing conference and evidentiary hearing in this Cause was 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 Commissions' 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 E. 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 service to the public. Duke Energy Indiana directly supplies electric energy to over 790,000 customers located in 69 counties in the central, north central, and southern parts of Indiana.

3. **Relief Sought.** Petitioner requested the Commission authorize it to: (1) recover PowerShare® and special contract demand response program costs for the period October 1, 2011 through September 30, 2012; (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, 2011, through September 30, 2012, 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; and (4) approve recovery of applicable reconciliation amounts. Petitioner further requested 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. As stated in the Direct Testimony of Ms. Jenner, Petitioner's relief requested in this proceeding totals $13,113,880 before adjustment for Utility Receipts Tax via Rider 70 over a twelve-month period. The net impact would be a $0.18 monthly bill increase for a typical residential customer from comparable current billings approved in Cause No. 44035.

[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.

4. **Prior Applicable Commission Orders**. On May 18, 2004, in Cause No. 42359, Petitioner's 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® 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 final 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 8 MW capacity purchase from Logansport, for the summer of 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 approved in Cause No. 43505 and made that recovery final.

Most recently, on May 30, 2012, in Cause No. 44035, the Commission approved Petitioner's purchased power capacity costs, including an 8 MW capacity purchase from Logansport for the month of June, and sales revenues for the summer of 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.

5. **Petitioner's Case-in-Chief.**

A. **Reliability Planning, Sales and Purchases.** Ms. Yuan Niu, Forecaster in the Load Forecasting group of Duke Energy Business Services LLC, testified as to Petitioner's March 2012 load forecast for the summer of 2012, projecting a peak demand of 6,576 MW. Ms. Niu also testified that customers who were served under Duke Energy Indiana's economic development riders totaled 2.5 MWs of incremental load. The incremental load is very small and as such this type of load growth is already captured in the peak summer load forecast *(i.e.,* the forecast would not have been reduced if a customer with 2.5 MW of load shut down). Therefore, there are no material incremental costs related to serving economic development customers that required consideration for this filing.

Mr. Bruce L. Sailers, Manager, Demand Response Analytics with Duke Energy Business Services LLC, 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. Dianne L. Jenner, Director, Regulatory Strategy with Duke Energy Business Services LLC, testified that the Company continues to rely on a portfolio resource 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. Duke Energy Indiana did not purchase any PRCs *(i.e.,* capacity on an unforced capacity ("UCAP") basis)[2], to meet the Midcontinent Independent System Operator, Inc. ("MISO") Planning Reserve Margin Requirement on a UCAP basis during the period that is the subject of this filing. She testified that the Company had purchased 8 MW of installed capacity ("ICAP") from Logansport under a long-term contract signed in 2009, but the unit became unavailable in summer 2011 and has not been repaired; therefore, no capacity payments were made to Logansport under that contract between October 2011 and September 2012.

Ms. Jenner testified that as a result of the return to service of Wabash River Units 2, 3 and 5, no PRC purchases were ultimately necessary for the summer of 2012. Duke Energy

[2] One PRC is equal to one MW-month of qualified UCAP capacity.

Indiana's capacity position was adequate to meet the minimum required reserve margin for the summer of 2012 and as a result, the Company made forward capacity sales of 301 PRCs for both July and August and 98 PRCs for September.

Without certain special contracts, and the PowerShare® impacts, Petitioner's reserve margin on a UCAP basis, as required by MISO requirement, was 4.6% for July and 4.9% for August. Ms. Jenner testified, altogether, the jurisdictional allocation of Rider 70 costs for Fiscal Year 2012 results in a request to recover a total of $13,113,880 before adjustment for Utility Receipts Tax via Rider 70 over a 12-month period, which amounts to an increase of $0.18 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 1 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 1 minus the unit-specific $XEFOR_d$).

For purposes of this filing, there were two different MISO Planning Years. For the 2011/2012 Planning Year (October 2011 through May 2012), to satisfy the LOLE requirement, MISO established a minimum 3.81% required reserve margin on an UCAP basis. For the 2012/2013 Planning Year (June 2012 through September 2012), Duke Energy Indiana was required to meet a PRM_{UCAP} of 3.79%.

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 but one month and typically at low prices. She provided details of sales and clearing prices for the months of October 2011 through September 2012. 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 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 3.79% in its assessment of its Supply vs. Demand position. As previously stated, the surplus PRCs were sold forward and/or offered into the VCA, and that for summer 2012, the resulting actual PRM_{UCAP} was 3.79% for July and 5.4% for August. 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 PRCs that are purchased, the block sizes available for purchase, and the marketability of any surplus in the VCA. Nevertheless, Petitioner will continue to target the MISO Module E PRM_{UCAP} as the appropriate minimum reserve requirement.

Ms. Jenner explained that although the Company's reserve margin was above the summer 2012 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 true 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 are purely capacity products to meet MISO Resource Adequacy Requirements, with compliance measured on a forward month-ahead basis.

Ms. Jenner testified that Duke Energy Indiana continues to be committed to a portfolio approach to meet is native load peak demand obligations. Ms. Jenner noted that for summer 2012, Petitioner met native load customers' peak demand requirements through a resource mix consisting of 89.9% through its existing fleet of generating assets, 9.3% through a combination of traditional regulated conservation and demand response products, and 0.8% 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 ("Module E-1") beginning with Planning Year 2013/14. She explained that although the changes to the construct will involve changes to the Company's processes, she does not anticipate any changes to the basic philosophy with regard to meeting Resource Adequacy requirements. The Company will continue to use the MISO reserve requirement as the minimum reserve margin and pursue a balanced portfolio approach through its own generation, renewables, demand response, EE, and reliability purchases. She also testified that it is likely any surplus capacity above the MISO requirement will be offered into the Planning Resource Auction ("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} will be applied will result 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 beginning with Planning Year 2013/14 a change would be warranted and that the Company's next Rider 70 filing will be a combination of the old monthly construct for the period October 2012 – May 2013, and the new annual construct for the period June 2013 – September 2013. Although the new construct is annual, MISO will calculate settlements on a daily basis to accommodate retail switching in retail choice states, which could facilitate a resolution.

Mr. Wenbin Chen, Manager, Portfolio Optimization with Duke Energy Business Services LLC, explained that there weren't any capacity purchases made for the summer of 2012 and described the capacity sales that were made for the 12 months ended September 30, 2012. Mr. Chen testified that there were capacity sales in 5 contracts with 4 counterparties with total sale proceeds of $67,014. He further testified that in his belief the capacity sales were reasonable and only made after it was determined that the Company had surplus capacity after complying with MISO's Resource Adequacy requirement. He stated the sales of the Aggregate PRC ("APRC") were the result of arms' length negotiations at then-prevailing market prices. Mr. Chen indicated that the Company contracted with Logansport Municipal Utilities 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 also sponsored Petitioner's Confidential Exhibit B-1 that included all agreements or confirmations supporting the capacity sales. He indicated these documents and the commercial terms therein should be treated as confidential.

B. __PowerShare® and Customer-Specific Peak Load Management Programs.__ 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 winter of 2011/2012, there were no PowerShare® events. During the summer of 2012, there were 7 PowerShare® CallOption economic events and 3 PowerShare® QuoteOption events due to hot weather conditions. For summer 2012, Petitioner entered into ninety-eight CallOption contracts.

Mr. Sailers described the PowerShare® attributes for the June 2013 through May 2014 planning year. He explained that Duke Energy Indiana implemented changes to the current program in anticipation of requirements from MISO for the new annual Resource Adequacy framework, with the most significant change being earlier registration guidelines. For the 2013/2014 program, event durations will be 6 hours instead of 8 hours. Mr. Sailers 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 changed substantively 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 12:00 p.m. to 8:00 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 Steel Dynamics, Inc.

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 North American Electric Reliability Corporation Energy Emergency Alert Level 2 or higher. 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 unlike past treatment of EE resources wherein they were incorporated into the load forecast, MISO has filed new requirements with the Federal Energy Regulatory Commission for most incremental EE resources installed starting June 1, 2012 to be excluded from the load forecast and to be registered with MISO similar to demand response resources.

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 2011 through September 2012. 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, as previously discussed.

Mr. Roger A. Flick, Lead Rates Analyst with Duke Energy Business Services LLC, 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. Burnside 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 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 excess 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 $5,440.

Mr. Burnside stated that gross profits from Duke Energy Indiana's non-native sales for the period October 1, 2011, through September 30, 2012, totals a loss of $5,517,389 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 $33,477. This adjustment was made to reflect the fact that during the current Rider 70 non-native power sales period (October 1, 2011, through September 30, 2012), 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, the demand (load) with available supply resources (generation or purchases) and allocates those production costs for serving native load and non-native sales. Referring to the testimony of Mr. John Swez in the Company's FAC proceedings, Mr. Burnside testified that there are new developments affecting the dispatch of the Company's units, including unforeseeably low natural gas prices, extremely mild winter weather, increased wind generation, and other factors ultimately causing the Company's coal generating facilities to experience lower dispatch levels and some periods of economic shutdown, leading to increased 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. Rider 70 Calculation and Rate Impact. 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, 2012.

Mr. Flick testified that there were not any capacity purchases during the 12-months ended September 30, 2012, but that there were capacity sales totaling $67,014. 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 2011 through September 2012 totaled $6,608,738, which is more than the $1,023,000 authorized in Cause No. 42359. As such, retail customers will be charged $5,585,738 in this proceeding.

Mr. Flick stated the results of Petitioner's non-native sales for the period October 1, 2011, through September 30, 2012, totals a $5,517,389 loss before applicable prior period adjustments and fixed trading expenses or a $9,503,866 net non-native sales loss after the adjustments. Mr. Flick explained the amount of net non-native sales loss allocated to retail customers is $8,723,694. 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 $7,373,500 charge to customers.

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. 43906 was made, and the reconciliation results in a $154,642 under-billing, which has been included as a charge to customers.

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 $0.18 or 0.2% 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. <u>Request for Confidential Treatment</u>. 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 Steel Dynamics, Inc. 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 R. 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 she had no concerns with Petitioner's forward reliability purchase needs for October 1, 2011 through September 30, 2012 and that Duke Energy Indiana did not make any forward reliability purchases during this period due to their capacity position being adequate to meet the minimum required reserve margin. She next explained that Duke Energy Indiana had provided an update regarding the status of its contract with Logansport with no capacity payments being made to Logansport for summer 2012, and that this capacity was not included in Duke Energy Indiana's supply vs. demand balance to meet its resource adequacy requirements. She further stated that the OUCC recommends 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 testified that her calculations of the jurisdictional allocation of Rider 70 costs for the period October 1, 2011 through September 30, 2012 match the amount that Petitioner is requesting to recover and recommends the Commission approve recovery of such costs. She also discussed the capacity sales made during October 2011 and September 2012 and that the Company's treatment of its capacity sales is consistent with the Commission's Order in Cause No. 43906.

Ms. Gruca testified that Duke Energy Indiana complied with the Commission's Order in Cause No. 43505 by using the required PRM_{UCAP} of 3.79% and that Duke Energy Indiana's capacity position was adequate to meet the minimum required reserve margin for summer 2012 and no forward capacity purchases were necessary. She testified that Duke Energy Indiana's actual summer 2012 PRM_{UCAP} was 3.79% for July 2012 and 5.4% for August 2012. She further stated that the OUCC continues to recommend that the Company utilize the Module E reserve margin requirements as the target for future necessary capacity purchases to fully capture the benefit of participating in the MISO.

Ms. Gruca explained Duke Energy Indiana's continued use of special contracts and PowerShare® resources when it had already exceeded the MISO reserve margin requirements and that the OUCC agreed with Ms. Jenner's testimony that 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 next testified regarding the modification of the MISO Resource Adequacy construct from a monthly basis to an annual basis and recommends the Commission require Duke Energy Indiana to update the Commission on any additional changes to the MISO Resource Adequacy construct. She further testified that the OUCC welcomes a discussion with Duke Energy Indiana regarding modification of the MISO Resource Adequacy construct prior to the Company making its proposal in next year's filing.

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 described her concerns with Duke Energy Indiana's use of a coal price decrement. She stated that the approach seems like a short-term solution and not a long-term response to market competition. She therefore recommended that Duke Energy Indiana continue to update the Commission on its coal inventory, including the development of alternatives to its decrement pricing. The OUCC also reserved all of its rights in future FAC proceedings, Rider 70 proceedings, or other proceedings to address the 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 $5,440 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 which requires them to meet annually to discuss the matter.

Finally, Ms. Gruca 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. **Commission Discussion and Findings.** Based upon the evidence presented in this Cause, the Commission finds that Petitioner continues to use a portfolio of diverse options to serve its customers' capacity needs. We also find that Petitioner's PowerShare® Program and customer specific peak load management costs for October 1, 2011, through September 30, 2012, were reasonable, and the expenses were accurately calculated and should be approved. As we previously stated in the final Order in Cause No. 43074, the PowerShare® program is an important component in Petitioner's summer preparedness.

The 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. In addition, we find that Petitioner's non-native hedging strategy is reasonable and that Petitioner's recovery of its calculated reconciliation amount is appropriate.

The Commission further finds that Duke Energy Indiana has adequately explained the proposed Rider No. 70 adjustment factors. Accordingly, we hereby approve such adjustment factors and direct Duke Energy Indiana to include such adjustment factors in the Rider No. 70 filed with this Commission in compliance with this Order.

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 §§ 8-1-2-29 and 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.

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 defer, as necessary to effectuate Rider 70, its reliability purchased power capacity costs, PowerShare® and other peak load management costs, and net non-native sales profits (losses).

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 2013 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. This Order shall be effective on and after the date of its approval.

ATTERHOLT, MAYS AND ZIEGNER CONCUR; BENNETT AND LANDIS ABSENT:

APPROVED: JUN 19 2013

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