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 THE WHOLESALE POWER CAPACITY PURCHASES MADE BY PETITIONER TO MEET ITS RETAIL NATIVE LOAD PEAK REQUIREMENTS; (2) AUTHORITY TO RECOVER VIA RIDER NO. 70 CERTAIN COSTS ASSOCIATED WITH PETITIONER'S POWERSHARE® PROGRAM (INCLUDING PERMANENT AUTHORITY TO IMPLEMENT AND RECOVER COSTS ASSOCIATED WITH THE POWERSHARE® PROGRAM ON A 12-MONTH BASIS) ; (3) AUTHORITY TO SHARE NON-NATIVE SALES PROFITS VIA RIDER NO. 70; AND (4) CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION RELATING TO PETITIONER'S POWER PURCHASES AND NON-NATIVE SALES	)	CAUSE NO. 43715 APPROVED: JUN 23 2010

BY THE COMMISSION:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Administrative Law Judge

On June 17, 2009, Duke Energy Indiana, Inc. ("Petitioner" or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") initiating this Cause. The Petition requested the following pursuant to the Commission's Orders in Cause Nos. 42359, 43302 and Ind. Code § 8-1-2-42, and Petitioner's Standard Contract Rider No. 70 ("Rider 70"): (1) a determination that Petitioner's forward reliability purchased power arrangements to meet native load peak requirements for summer 2009 were reasonable (including ongoing authority to purchase 8 MW of peaking capacity from the City of Logansport to meet ongoing capacity needs); (2) the recovery via Rider 70 of the retail jurisdictional costs (net of any energy components recovered via the fuel adjustment charge process) for the forward reliability power purchases; (3) a determination that Petitioner's PowerShare® Program costs for October 1, 2008 through September 30, 2009 were reasonable; (4) authorization to credit (or debit) customers via Rider 70 with the difference between its actual PowerShare® Program costs and the amounts included in the *pro* forma test period in Cause No. 42359; (5) permanent authority to implement and recover costs associated with the PowerShare® Program on a 12-month basis; (6) the authority to credit (or debit) retail customers via Rider 70 with 50% of the retail jurisdictional portion of annual (October 1, 2008 through September 30, 2009) net non-native sales profits above (or below) the amount included in the *pro* forma amounts approved in Cause No. 42359; (7) a determination that Petitioner's reconciliations of charges and credits to actual amounts are proper; and (8) a determination that certain information relating to Duke Energy Indiana's power purchases and non-native sales should be treated as confidential "trade secrets".

Pursuant to notice, and as provided for in 170 IAC § 1-1.1-15, a Prehearing Conference was held on July 30, 2009, at 9:00 A.M. in Room 224, 101 West Washington Street, Indianapolis, Indiana. On August 5, 2009, a Prehearing Conference Order was issued setting forth the procedural schedule in this Cause.

On January 19, 2010, Duke Energy Indiana prefiled testimony, exhibits, verifications and applicable work papers in support of its Petition, including the testimony and exhibits of Ms. Diane Jenner, Mr. Stephen Herrera, Mr. Pedram Mohseni, Mr. Bruce Sailers, Mr. Scott Burnside and Mr. Roger Flick. Petitioner also filed a Motion for Protection of Confidential and Proprietary Information, on this date, together with a supporting affidavit of Ms. Diane L. Jenner. On January 25, 2010, 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. On March 22, 2010, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony and exhibit of Ms. Stacie R. Gruca. On April 9, 2010, Petitioner filed the rebuttal testimony of Ms. Jenner.

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 24, 2010, at 9:30 a.m. in Room 224, National City Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the OUCC participated at the hearing. At the evidentiary hearing, Petitioner introduced into evidence its case-in-chief testimony and exhibits, the OUCC introduced into evidence its case-in-chief testimony and exhibits, and Petitioner introduced into evidence its rebuttal testimony.

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

1. <u>Statutory Notice and Commission Jurisdiction</u>. Due, legal and timely notices of the prehearing conference and evidentiary hearing 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, and is subject to the jurisdiction of the Commission, in the manner and to the extent provided by the laws of the State of Indiana. Petitioner has requested relief pursuant to Ind. Code § 8-1-2 generally and Ind. Code § 8-1-2-42 specifically. The Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. <u>Petitioner's Characteristics</u>. Petitioner 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. It 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.

3. **Relief Sought.** Petitioner requested that the Commission authorize it: (1) to recover via Rider 70 certain costs associated with capacity purchases of power made by Petitioner to meet its retail native load peak requirements for the summer of 2009; (2) to credit/ charge customers with the difference between PowerShare® Program costs actually incurred during the period October 1, 2008, through September 30, 2009, and the amount included in the *pro forma* test period in Cause No. 42359 via Rider 70; (3) to credit (or debit) retail customers with 50% of the retail jurisdictional portion of annual net off-system sales profits for the period October 1, 2008, through September 30, 2009, above (or below) the amount included in the *pro forma* test period in Cause No. 42359, via Rider 70; and (4) to include in current Rider 70 computations differences between actual amounts approved for recovery in Cause No. 43505 to amounts billed. Petitioner further requested that the Commission find certain information relating to Duke Energy Indiana's power purchases and non-native sales should be treated as confidential "trade secrets". As stated in the Direct Testimony of Ms. Diane Jenner, Petitioner's total relief requested in this proceeding totals $7,962,265 via Rider 70 over a 12 month period. The net impact would be a 0.1% monthly bill increase for a typical residential customer from comparable current billings approved in Cause No. 43505.

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-around PowerShare® Program costs on the basis of a 2-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, PowerShare® Program costs, the sharing of off-system sales profits, 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).

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

A. **2009 Reliability Power Purchases.** Mr. Pedram Mohseni, Lead Analyst, Load Forecasting Group, testified as to Petitioner's load forecast for the summer of 2009, projecting a peak demand of 6,751 MW. Mr. Mohseni also testified as to Petitioner's energy efficiency resources available to meet peak load requirements, including its traditional demand-side management programs, customer specific contract offerings and PowerShare® Program.

Ms. Jenner, Director, Regulatory Strategy, testified that altogether, the jurisdictional allocation of Rider 70 costs for Fiscal Year 2009, which includes a combination of (1) the October 1, 2008, through September 30, 2009, forward reliability purchase costs, (2) a charge for the amount of Fiscal Year PowerShare® program costs above that reflected in base rates, (3) a charge for the Fiscal Year 2009 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 (4) a charge resulting from reconciliation for Rider 70 costs approved in Cause No. 43302 to amounts collected, results in a request to recover a total of $7,962,265 via Rider 70 over a 12-month period. She indicated this amounts to an increase of 0.1% on the monthly bill for a typical residential customer.

Ms. Jenner testified the reserve margin requirements were in a state of transition during the timeframe of October 2008 through September 2009. She explained ReliabilityFirst's Resource Planning Reserve Requirement Standard requires that the Loss of Load Expectation ("LOLE") due to resource inadequacy not exceed one occurrence in ten years (0.1 occurrence per year). For the Planning Year June 1, 2008, through May 31, 2009, to satisfy the LOLE standard, the Midwest Planning Reserve Sharing Group ("PRSG") established a minimum 14.3% required reserve margin on an installed capacity ("ICAP") basis (*i.e.*, the historical method used by Duke Energy Indiana) for utilities in the region containing Indiana. Ms. Jenner testified that, beginning with the Planning Year of June 1, 2009 to May 31, 2010, the LOLE standard became enforceable under the Midwest ISO's tariff and there are financial consequences for failure to meet this standard.[1]

Ms. Jenner explained the Midwest ISO Planning Reserve Margin ("PRM") assigned to each load serving entity ("LSE") is on an unforced capacity ("UCAP") basis, such that the PRM on an ICAP basis will be translated to PRM_{UCAP} by multiplying it by 1 minus the Midwest ISO 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 $XEFOR_d$).

Ms. Jenner stated that compliance is assessed monthly by comparing the amount of Planning Resource Credits ("PRCs") designated by each LSE with its monthly forecasted load multiplied by 1 plus the PRM_{UCAP}. For the 2009/10 Planning Year, she stated that Duke Energy Indiana was required to meet a PRM_{UCAP} of 5.35%, which is essentially the equivalent of a Reserve Margin of approximately 14.3% on an ICAP basis.

[1] The deficiency charges in Planning Year 2009/10 are $80,000 per MW-month for the first month of deficiency and are expected to increase to $90,000 per MW-month in Planning Year 2010/11.

Ms. Jenner detailed Petitioner's reliability purchases for the summer of 2009. She testified that, without the forward purchases and PowerShare® impacts secured for the period of June through August 2009, Duke Energy Indiana's reserve margin on a UCAP basis heading into the summer was 1.2% for July and 1.1% for August. Thus Petitioner was required to make forward reliability purchases to supplement its other resources to be in compliance with the Midwest ISO PRM_{UCAP}.

Ms. Jenner testified Duke Energy Indiana entered into contracts for 215.2 and 219.2 PRCs for July and August 2009, respectively. She noted that PRCs are capacity products for Resource Adequacy purposes only and do not entitle the purchaser to energy at a specific, fixed price, or even to any right to purchase energy at all; rather, the purchaser of PRCs has the right to designate this capacity to meet its resource adequacy and reserve margin needs, and the seller has the obligation to "Must Offer" the units from which PRCs were converted into the Midwest ISO energy markets. The PRC purchases were made at then-prevailing market prices.

Ms. Jenner explained that Petitioner also purchased 8 MW of ICAP (6.7 MW of UCAP) each month, year-around from Logansport Municipal Utility ("Logansport") on a long-term basis. Although Duke Energy Indiana did not register the Logansport capacity with the Midwest ISO due to its location behind the Logansport meter, it was nevertheless taken into account in the determination of the number of PRCs that Petitioner needed to purchase to meet its Resource Adequacy Requirements. She testified that without this contract, Petitioner would have been required to purchase additional PRCs to meet the Midwest ISO PRM_{UCAP}.

Ms. Jenner testified that due to the volatility and newness of the Voluntary Capacity Auction ("VCA"), Duke Energy Indiana procured all PRCs needed to meet compliance prior to the VCA date. However, in any months that Petitioner had surplus PRCs, an offer was made into the VCA to attempt to sell the surplus and lower the ultimate cost to customers. She stated that Petitioner was successful in the month of July 2009 in that its offer to sell 4 surplus PRCs was cleared and Petitioner received the auction clearing price.

Ms. Jenner described Petitioner's proposed treatment of VCA revenues. 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.[2] Revenue from PRCs sold in excess of the number purchased for native load reliability or in months without PRC purchases (*i.e.*, PRCs sold due to surplus generating capacity, not surplus purchased PRCs) 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.

[2] She noted surplus PRCs may result due to the need to make block purchases larger than the actual need or due to subsequent rebalancing of the native load capacity position and that this also occurs with native load power hedging purchases, for which a similar netting approach is taken for ratemaking.

Ms. Jenner stated the surplus PRCs sold in July flowed from native load reliability PRC purchases that were required to be purchased in block sizes slightly larger than Petitioner's actual need and therefore, Petitioner netted the revenue from this sale against the cost of purchasing the July PRCs. Petitioner did not have any other PRC sales revenues during the October 2008 through September 2009 period covered by this Cause.

Ms. Jenner described how Petitioner used the Midwest ISO 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 5.35% in its determination of the number of PRCs that were necessary to purchase. However, because normally it is not possible to purchase the exact quantity of PRCs that are needed to precisely meet the reserve margin requirement, the surplus PRCs were then offered into the VCA. For July 2009, the resulting actual PRM_{UCAP} was 5.36%, and for August 2009, it was 5.37%, with surplus PRCs of 0.7 and 1.6, respectively. Ms. Jenner stated that in future years it is not likely Petitioner would come this close to meeting 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 Midwest ISO Module E PRM_{UCAP} as the appropriate minimum reserve requirement.

Ms. Jenner testified that buying forward cannot completely ensure against expensive energy arising from price spikes in the spot market during limited hours throughout the operating 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, including the PRC purchases Petitioner made, are purely capacity products to meet Midwest ISO Resource Adequacy Requirements, with compliance measured on a forward month-ahead basis.

Ms. Jenner also described the impact of New Source Review ("NSR") verdicts and remedy orders. She testified for summer 2009, there were no impacts on the amount of PRCs that Petitioner needed to purchase and Wabash River Units 2, 3, and 5 were not required to be shut down until September 30, 2009, so they were available to contribute to meeting Petitioner's PRM_{UCAP} during the summer of 2009.

She testified the future impacts of NSR on capacity purchases were unknown at the time of testimony because the remedy order requiring the Wabash River units to be shut down is under appeal at the 7th Circuit Court of Appeals. She stated Petitioner does not anticipate receiving a ruling until after Summer 2010, so additional purchases will likely be required for Summer 2010. She stated if Petitioner is required to permanently retire these units, additional PRCs will need to be purchased to replace this capacity in the summer months of 2010 and 2011, as well as possibly in the month of January in 2011 and 2012, until the Edwardsport IGCC plant goes in service. At this time, the Gallagher units are expected to remain in service.[3]

[3] Pursuant to a proposed settlement recently filed by the parties in the NSR lawsuit, Gallagher Units 1 and 3 will continue to operate until a final decision is made by Petitioner on January 1, 2012, to retire or repower units 1 and 3 with natural gas. If Petitioner decides to repower these units, the conversion, which is expected to result in a modest derate, will occur by January 1, 2013, and Petitioner would surrender SO_2 allowances during the conversion period. In addition, Petitioner is agreeing in the proposed settlement to install additional pollution controls at Gallagher Units 2 and 4, and to switch to lower sulfur coal.

Ms. Jenner testified that Duke Energy Indiana continues to be committed to a portfolio approach to meet is native load peak demand obligations. Including the purchases needed to meet the required reserve target, Ms. Jenner noted that for summer 2009, Petitioner's resource mix to meet native load customers' peak demand requirements was: 91.5% through its existing fleet of generating assets, 3.1% through net forward reliability purchases from the wholesale power market, 5.5% through a combination of traditional regulated 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.

Mr. Herrera, Director, Financial Trading, Bulk Power Marketing & Trading for Duke Energy Business Services LLC, again described the capacity purchases that were made for the summer of 2009 as identified by Ms. Jenner. Mr. Herrera testified the capacity purchases were reasonable, necessary and made in order to comply with the Midwest ISO's capacity requirement that commenced in June 2009. The PRC purchases were the result of arms' length negotiations at then-prevailing market prices. He testified the Logansport capacity purchase is in the public interest and should be recoverable because the contract provides Duke Energy Indiana with year-round capacity that will help it meet its Midwest ISO PRM requirement in the winter months as well as the summer months. Also the price paid was comparable to then-prevailing market prices, and the long-term nature of the contract provides customers and Petitioner with price certainty going forward.

Mr. Herrera further testified as to the continued volatility of the power and natural gas markets. He also sponsored a confidential exhibit that included all agreements or confirmations supporting the capacity purchases.

B. Fiscal Year 2009 PowerShare® Costs. Mr. Sailers, Manager, Retail Energy Desk, 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. Further, Mr. Sailers explained that in addition to the standard June through September program agreement, Petitioner added a winter program during the months of December through February, as approved in Cause No. 42870 and extended through May 31, 2010 in Cause No. 43302.

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 around, in accordance with the Commission's Order in Cause No. 42870.

Mr. Sailers supported Petitioner's request to offer its PowerShare® program on a year-round permanent basis, noting that Petitioner was authorized in Cause No. 42870 to implement and recover costs for its PowerShare® program on a year-round basis pursuant to a settlement agreement between Petitioner and the OUCC. The initial two year pilot was originally set to expire in June of 2008, but was extended in Cause No. 43302 for an additional two year period ending on May 31, 2010. He pointed out that Petitioner has been successful in implementing the PowerShare® program in the non-summer months with some customers and, given that emergency conditions can occur at anytime of the year and the overall benefits of this peak load management program, ongoing application of the PowerShare® program on a year-round basis is good for customers as well as Petitioner.

Mr. Sailers also discussed the settlement agreements entered into in Cause No. 43374. Mr. Sailers stated that if those settlement agreements are approved, Duke Energy Indiana plans to continue to recover PowerShare® QuoteOption costs in Rider 70 proceedings. He also explained that, through these settlement agreements, Petitioner has committed to not include CallOption costs under Revised Standard Contract Rider 66 until such time that it complies with Midwest ISO requirements. Mr. Sailers testified that current participation by large customers in CallOption will continue to be recovered under Rider 70. Finally, Mr. Sailers stated that if the settlement agreements are approved, the non-grandfathered portion of the PowerShare® Call Option program and the PowerShare® Emergency program, a new option for participation, and the associated revenue requirements will be removed from Rider 70 and incorporated into Rider EE. Mr. Sailers explained that none of these proposed changes impact the PowerShare® amounts in this filing.[4]

Mr. Sailers testified that due to economic conditions and mild temperatures during the summer and winter of 2009, there were no PowerShare® events. During the summer of 2009, there were no CallOption events. However, Petitioner entered into 48 CallOption contracts and paid premiums of $1,545,451 for 54 MW of load reduction. He also stated that Duke Energy Indiana paid no event credits for CallOption and QuoteOption net of buy-throughs. Total PowerShare® related expenditures were $1,545,451 for the 12 months ended September 2009. Mr. Sailers explained that there is an annual total amount of $1,023,000 built into Duke Energy Indiana's base rates for PowerShare® expenses. Under Rider 70, the actual PowerShare® expenses, both demand and energy payments will be compared to the base rate level of expense and only the actual expenditures will be recovered. As a result, Mr. Sailers explained that Rider 70 will reflect a total debit to customers of $522,451.

Mr. Sailers described the PowerShare® attributes for summer 2010. He expects the CallOption attributes to be approximately the same as they were last year, through either Rider 70 or Rider EE. Event options will change slightly to 5, 10, or 15 economic events versus 4, 8, or 12 in 2009. He stated this change will make these program attributes consistent with the program attributes in other Duke Energy Midwest service areas. Premium values for these options will be $15/kW-yr, $25/kW-yr and $30/kW-yr respectively. The new PowerShare®

[4] On February 10, 2010, the Commission issued an Order that approved the settlement agreement with the OUCC and Vectren, but rejected and/or modified the other then-pending settlement agreements concerning the opt-out provisions. As the parties to the settlement agreements objected to the Commission's modifications, the case has been set for hearing on June 23-25, 2010 to consider Petitioner's underlying request in that Cause.

Emergency program will have a premium of \$10/kW-yr. In addition, based on projected commodity prices, Petitioner will set the strike price at seven (7) cents per kilowatt hour for the CallOption program. Other program attributes are expected to remain approximately the same as last year.

Mr. Sailers described the PowerShare® attributes for winter 2009/2010. The CallOption winter 2010 program consists of the months December 2009, and January and February 2010. Duke Energy Indiana entered into twenty (20) CallOption contracts for winter 2009/2010 for an estimated total of 15 MW of curtailable load. The program attributes are similar to the summer 2009 program with one notable exception: the peak period is defined as 7 am to 1 pm, compared to 12 pm to 8 pm during the summer period, which better aligns the winter CallOption program with the winter peak periods.

Mr. Sailers testified that PowerShare® is registered with Midwest ISO, thereby allowing Petitioner to reduce its Midwest ISO resource adequacy requirements. Finally, Mr. Sailers addressed a commitment made by the Petitioner concerning its economic development riders, approved in Cause Nos. 42664 and 43567 that shareholders would bear any proportionate share of variable costs not covered by economic development rider customers. He explained that only one (1) customer with a total load of 2.5 MW was served under the rider during all or a portion of the summer of 2009. Given that the load for this customer was small and had no impact on purchases for the summer period, there were no incremental costs related to serving economic development customers that required consideration for this filing.

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 2008 through September 2009. She explained that Duke Energy Indiana has sold its surplus generation into the Midwest ISO markets since the advent of the Midwest ISO Day 2 energy markets, in addition to remaining a party to certain pre-Joint Generation Dispatch Agreement legacy power sales contracts.

Mr. Flick, Lead Rates Analyst for Petitioner, explained that in Duke Energy Indiana'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. Burnside, Lead Accounting Analyst for Petitioner, 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 the Midwest ISO, energy sales under the Midwest Contingency Reserve Sharing Group, energy or capacity sales to non-Midwest ISO counterparties, realized margin from non-native sales of emission allowances, pre-Joint Generation Dispatch Agreement contracts, and non-firm retail contracts with special contract customers. Mr. Burnside explained how revenues and expenses allocable to non-native sales are determined.

Mr. Herrera explained Petitioner's non-native load power hedging strategy to lock in a margin for Petitioner's forecasted excess generation not needed to serve native load. For the period at issue, this power hedging strategy resulted in a gain of approximately $2.3 million. Mr. Herrera also explained Petitioner's plans for future non-native load hedging, including using a three-year hedging horizon for power, natural gas, coal and emission allowances hedging.

Mr. Burnside stated that gross profits from non-native sales for the October 1, 2008, through September 30, 2009, total $6,342,358 before trading expense reduction or prior period adjustment amounts. Mr. Burnside explained that due to the Midwest ISO'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 $278,327. This adjustment was made to reflect the fact that during the current Rider 70 non-native power sales period (October 1, 2008 through September 30, 2009), Petitioner received updated Midwest ISO settlement statements for operating dates impacting prior Rider 70 non-native power sales periods.

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, and the sharing of non-native sales profits. He indicated that the period covered by this filing included periods ended September 30, 2009.

Mr. Flick testified that Petitioner made capacity purchases for the summer 2009 for the 12 months ended September 2009, in the amount of $949,431 on a retail jurisdictional basis. He indicated costs associated with these purchases were for capacity, were not reflected in Petitioner's FAC recoveries and, in his opinion, were appropriate for recovery via Rider 70.

Mr. Flick testified that Rider 70 provides for the tracking of actual PowerShare® CallOption premiums and CallOption and QuoteOption energy credits. He testified that Petitioner's PowerShare® costs for October 2008 through September 2009 totaled $1,545,451 or $522,451 more than the amount authorized in Cause No. 42359. As such, retail customers will be charged $522,451 in this proceeding.

Mr. Flick stated that the results of Petitioner's non-native sales for the period October 1, 2008 through September 30, 2009, totals $2,111,031 inclusive of applicable prior period adjustments and fixed trading expenses. Mr. Flick explained that amount of net non-native sales profits allocated to retail customers is $1,937,736. 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 $6,404,632.

Mr. Flick explained that Rider 70 includes a standard reconciliation provision in which Petitioner 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. 43302 was made, and Petitioner included a charge to customers of $85,751 from the reconciliation in the determination of the proposed Rider 70 billing factors in this proceeding.

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-9. Mr. Flick explained that these costs would be recovered over a one-year period, and that Petitioner's request herein would result in approximately a 0.1% increase 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 testified that the Order in Cause No. 43505 permitted cost recovery of capacity purchase amounts related to the Gibson Generating Unit 4 outage on an interim basis subject to refund pending the outcome of Cause No. 38707 FAC 76-S1. On October 21, 2009, the Commission issued its Order in Cause No. 38707 FAC 76-S1, which found, among other things, that incremental fuel cost related to the Gibson Unit 4 outage in question was not a result of imprudent or unreasonable actions with respect to inspection and maintenance of the stator bars of that unit before the failure and that no refunds are due Petitioner's retail customers and that the subdocket should be closed. Accordingly, Mr. Flick stated that Petitioner requests the Commission remove the interim recovery and subject to refund designations on certain capacity purchases established in Cause No. 43505.

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. Ms. Jenner supported Petitioner's request that certain proprietary information (such as pricing) concerning Petitioner's purchased power arrangements be treated as confidential. She explained that if such information were made public, it could be detrimental to Petitioner and its customers with regard to future power purchases and sales. Ms. Jenner also testified that Petitioner has taken reasonable steps to maintain the confidentiality of the information. Duke Energy Indiana filed a Motion for the Protection of Confidential and Proprietary Information, including the supporting Affidavit of Ms. Jenner. In such motion, Petitioner requested that the Commission find that certain power purchase arrangement information and non-native sales information are "trade secrets" and are excepted from the access to public records provisions, consistent with Ind. Code §§ 5-14-3-4(a)(4) and 24-2-3-2.

6. OUCC's Case-In-Chief. The OUCC filed the testimony of Stacie R. Gruca, a Utility Analyst in the Electric Division. Ms. Gruca testified she had no concerns with Petitioners forward reliability purchase needs for October 1, 2008, through September 30, 2009. She testified Petitioner complied with the Cause No. 43505 Order requirement of using Midwest ISO Module E reserve margin requirements and she recommended that Petitioner continue to use Module E requirements. She also had no concerns regarding Petitioner's proposed recovery of non-native sales profits or Petitioner's Power Share® Program Costs.

Ms. Gruca expressed concern with Petitioner's proposal to remove the two-year PowerShare® pilot program limitation and begin permanent implementation. She testified that the OUCC believes it would be better to extend the PowerShare® Program for another two-year term because there have been only two winter call option events over the past four years and no winter or summer events during 2009. Additionally, only two call option events occurred during the winter of 2007 and no winter events occurred during 2006. She testified that the OUCC believes a case could be made for discontinuing the PowerShare® program from Rider 70 based on the fact that the program lacks substantial data, does not seem volatile in nature, and does not prove to be outside of management's control. She testified although emergency conditions can occur at any time, the data shows little event activity has occurred over the past four years. She expressed the OUCC's support for demand response and agreement with Mr. Sailers that mild weather conditions and economic weakness may have contributed to the minimal PowerShare® event activity. She added that, as indicated by Mr. Sailers, the Midwest ISO continues to refine resource adequacy rules, in which it may be necessary for Petitioner to make further revision to the PowerShare® program in order to comply with Midwest ISO resource adequacy requirements and additional changes surrounding resource testing requirements may be required. She also added that demand response programs are currently under investigation in Cause No. 43566, and there is continued action following the Order in Cause No. 43374.

Ms. Gruca testified that although there was not a great need or benefit to customers in allowing year-round cost recovery of its PowerShare® program in its current Rider 70 filing, as PowerShare® events did not occur during the winter months, the Rider 70 filing in Cause No. 43302 did show a quantifiable benefit to customers during winter months. She testified that it seems reasonable to allow the PowerShare® program to continue on a year-round basis for another two-year pilot period, in which more substantial data may be available.

Ms. Gruca testified Petitioner provided the documentation required in the settlement agreement approved in Cause No. 42870. She testified the inclusion of hedging activity in this proceeding is consistent with prior Rider 70 filings.

Ms. Gruca also acknowledged Petitioner's offer to discuss the possibility of extending its forward hedging period and she reserved the OUCC's right to review and comment on such changes. She further acknowledged Petitioner's anticipation that additional capacity purchases will likely be required for Summer 2010 (and possibly the summer months of 2010 and 2011, as well as January 2011 and 2012), as a result of the NSR remedy order. She testified that this does not affect the current proceeding, but may impact future Rider 70 filings, and she reserved the OUCC's right to review transactions for prudency regarding additional capacity purchases in future Rider 70 filings.

Ms. Gruca testified that the OUCC recommends the Commission approve Petitioner's proposed recovery of Rider 70 reliability purchases and costs associated with such purchases, non-native sales profits, and PowerShare® program costs for the period October 1, 2008 through September 30, 2009 included in this proceeding. She also testified that the OUCC recommends the Commission approve Petitioner's proposed recovery of capacity purchase costs over the 10-year term of the Logansport contract, as the Logansport purchase negotiated contracted price was at comparable prevailing market prices and the purchase was included and needed in meeting Petitioner's Resource Adequacy Requirements. Ms. Gruca further testified that the OUCC recommends that the Commission continue to require Duke to use the Midwest ISO's new Module E reserve margin requirements as the appropriate target for future necessary capacity purchases, and provide an update on the status of the NSR as it affects capacity purchases going forward. Lastly, she testified that the OUCC recommends Duke's PowerShare® pilot program, and year-round cost recovery of this program, be extended for an additional two-years.

7. **<u>Petitioner's Rebuttal Testimony</u>.** Ms. Jenner sponsored Petitioner's Rebuttal Testimony. She testified although Petitioner would prefer to have permanent approval to offer Power Share® on a year-round basis, it is willing to agree to a two-year extension for purposes of this proceeding as suggested by Ms. Gruca. Ms. Jenner also testified the Petitioner is willing to discuss with the OUCC its thoughts on future non-native hedging, and is in the process of scheduling a meeting with the OUCC.

8. **<u>Commission Discussion and Findings</u>.** Based upon the evidence presented, we find that Petitioner has adequately demonstrated that its forward reliability purchases at issue in this proceeding were necessary and reasonable in order to reliably and efficiently meet its native load customers' projected peak demand requirements. Ms. Jenner provided supporting testimony regarding the differing reserve margin requirements for the summer of 2009, including the Midwest PRSG requirement of 14.3% effective June 1, 2008. As stated by Mr. Herrera, Petitioner's forward purchases were necessary to comply with this calculated reserve margin, taking into account known outages and derates.

Through their testimonies, Petitioner and the OUCC have agreed that the PowerShare® program should be extended for an additional two-year period on a year-round basis. Given the evidence presented in this proceeding, we find that the year-round implementation of the program and recovery of costs should be continued for an additional two years.

The Commission notes that Petitioner continues to use a diverse portfolio of options to serve its customers' capacity needs, which is an important component of resource planning. Even with alternatives to purchased power in place, such as Petitioner's demand side resources, Petitioner's purchases were necessary to obtain a reasonable level of reserve margin, in this case 14.3% after known outages and derates. Accordingly, we approve the recovery of the costs associated with such purchases via Petitioner's Standard Contract Rider No. 70 and we approve Petitioner's proposed treatment of VCA revenues from the sale of surplus PRCs.

We find that Petitioner should use the Midwest ISO Module E reserve margin requirements as the appropriate minimum for future necessary capacity purchases, with cost recovery for purchases in excess subject to a finding of reasonableness based upon adequate justification.

Duke Energy Indiana's Petition included a request for the Commission to approve recovery of the 8 MW capacity purchase from Logansport over the ten (10) year term of the contract. However, the Rider 70 proceeding was designed to review and approve the capacity related costs and credits for a particular time period (*e.g.*, summer 2009). It was not intended to be a means for obtaining approval of future long-term capacity purchases. Further, Petitioner has failed to offer sufficient evidence to support its capacity needs in each of the future years or to demonstrate that this specific capacity resource is the best alternative to meet such needs should they exist. Accordingly, we decline to provide pre-approval of this long-term capacity purchase from Logansport.

We also find that Petitioner's PowerShare® Program costs for October 1, 2008, through September 30, 2009, were reasonable, and the expenses were accurately calculated and should be approved. As we recognized 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 expenses and prior period amounts, and we authorize Petitioner to credit retail customers accordingly. We also find that Petitioner's non-native hedging strategy is reasonable and prudent.

We find that Petitioner has appropriately applied Rider 70 to the three components of cost recovery discussed herein, including the reconciliation of prior period billed amounts.

Finally, Petitioner demonstrated a need for confidential treatment of certain information associated with its purchased power contracts and non-native sales, and no party objected to the request for confidential treatment. Accordingly, pursuant to Ind. Code § 5-14-3-4(a)(4), we find that certain power purchase arrangement information and non-native sales information, as identified in Petitioner's redacted testimony and exhibits, constitute "trade secrets" and shall be afforded confidential treatment.

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

1. Petitioner is hereby authorized to recover, through Standard Contract Rider No. 70, its retail summer 2009 purchased power capacity costs consistent with Petitioner's testimony and exhibits.

2. Petitioner is hereby authorized to recover, through Standard Contract Rider No. 70, its fiscal year 2009 PowerShare® costs consistent with Petitioner's testimony and exhibits.

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

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

5. Petitioner is hereby authorized to defer, as necessary to effectuate Rider 70, its reliability purchased power capacity costs, PowerShare® costs, and net non-native sales profits (losses).

6. Petitioner is hereby authorized to continue to offer the PowerShare® program on a year round basis with continued cost recovery for an additional two years, to end May 31, 2012, with the possibility of further extension thereafter.

7. 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 on all bills rendered on and after the later of the date of such filing or the July billing period, and shall continue for a 12-month period.

8. Petitioner shall file with the Commission's Electricity Division its Standard Contract Rider No. 23, reflecting the provisions of this Order.

9. Petitioner's request for confidential treatment of its purchased power and non-native sales arrangements is hereby granted pursuant to Ind. Code § 5-14-3-4(a)(4).

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

<u>ATTERHOLT, LANDIS, MAYS AND ZIEGNER CONCUR; HARDY ABSENT:</u>

APPROVED: JUN 2 3 2010

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