ORIGINAL

JT6

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 PURCHASES MADE BY PETITIONER TO MEET ITS RETAIL NATIVE LOAD PEAK REQUIREMENTS FOR THE PERIOD JANUARY 11, 2008 THROUGH SEPTEMBER 30, 2008; (2) AUTHORITY TO RECOVER VIA RIDER NO. 70 CERTAIN COSTS ASSOCIATED WITH PETITIONER'S POWERSHARE® PROGRAM; (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. 43505 APPROVED: JUN 17 2009

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

On June 2, 2008, 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 and 43302, 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 2008 were reasonable; (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, 2007 through September 30, 2008 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) the authority to credit (or debit) retail customers via Rider 70 with 50% of the retail jurisdictional portion of annual (October 1, 2007 through September 30, 2008) net non-native sales profits above (or below) the amount included in the *pro* forma amounts approved in Cause No. 42359; (6) a determination that Petitioner's reconciliations of charges and credits to actual amounts are proper; and (7) 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 7, 2008, at 10:30 a.m. in Room 222 of the National City Center, 101 West Washington Street, Indianapolis, Indiana. On July 16, 2008, a Prehearing Conference Order was issued setting forth the procedural schedule in this Cause.

On January 20, 2009, 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 26, 2009, the Commission 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 20, 2009, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony and exhibit of Ms. Stacie R. Gruca. On April 13, 2009, 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 4, 2009, 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 and exhibits.

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

1. **Statutory Notice and Commission Jurisdiction.** 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. **Petitioner's Characteristics.** 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 2008; (2) to

credit/ charge customers with the difference between PowerShare® Program costs actually incurred during the period October 1, 2007, through September 30, 2008, 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, 2007, through September 30, 2008, 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. 43302 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 $5,516,877 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. 43302.

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.

Most recently, 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.

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

A. **2008 Reliability Power Purchases.** Mr. Pedram Mohseni, Senior Forecaster, Load Forecasting Group, testified as to Petitioner's load forecast for the summer of 2008 projecting a peak demand of 6,998 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, during the period of June 2008 through August 2008, Petitioner required 350 MW and 450 MW of capacity, respectively, to meet a minimum 14.3% reserve margin. Ms. Jenner also testified that Petitioner made forward reliability purchases of 560 MW in March 2008 and 300 MW in April 2008, as well as two daily forward reliability purchases totaling 700 MW in June 2008. She stated that the total amount of recovery sought in this proceeding is $5,516,877, which 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 2007 through September 2008. She testified that, for the period October 1, 2007, through May 31, 2008, the standard in effect required Duke Energy Indiana to offer, on a day-ahead basis, capacity-backed generation sufficient to meet its native load, plus approximately a 4% operating reserve requirement, after accounting for known outages and derates.

Ms. Jenner explained that starting June 1, 2008, Duke Energy Indiana adhered to ReliabilityFirst's Resource Planning Reserve Requirement Standard, which required that the Loss of Load Expectation ("LOLE") due to resource inadequacy cannot exceed one occurrence in ten years (0.1 occurrence per year). Because the Planning Year starting June 1, 2008, was the first year in which this standard was in effect, the day ahead 4% operating reserve requirement after outages and derates was no longer applicable for meeting Midwest ISO Module E requirements beginning June 1, 2008. Instead, the Module E requirement was to meet the applicable reserve margin under the new ReliabilityFirst standard.

Ms Jenner testified that to satisfy this new standard, the Midwest Planning Reserve Sharing Group ("PRSG") performed an LOLE study and published its report establishing a minimum 14.3% required reserve margin for utilities in the region containing Indiana for the June 1, 2008 - May 31, 2009 Planning Year. She stated that, going forward, the requirement to provide sufficient reserves to meet a LOLE of no more than one occurrence in ten years will remain in effect. However, the Midwest ISO has also made changes to its tariff including a long-term resource adequacy requirement similar to the ReliabilityFirst requirement. Therefore, beginning with the Planning Year June 1, 2009 - May 31, 2010, the LOLE standard will be enforceable under the Midwest ISO's tariff and there will be financial consequences for failure to meet this standard.

Ms. Jenner testified there are a number of differences going forward regarding reserve margin requirements. She testified that the Planning Reserve Margin ("PRM") that is assigned to each load serving entity ("LSE") will be on a UCAP *(i.e.,* unforced capacity) basis, such that the PRM on an ICAP *(i.e.,* installed capacity) 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 ("$XEFOR_d$"). Ms Jenner stated that each capacity resource will be valued at its unforced capacity rating. She stated that compliance will be assessed monthly by comparing the amount of Planning Resource Credits ("PRCs") with the monthly forecasted load multiplied by 1 plus the PRM_{UCAP}. For the 2009/10 Planning Year, Duke Energy Indiana will be required to meet a PRM_{UCAP} of 5.35%, which is essentially the equivalent of a reserve margin of approximately 12.69% on an ICAP basis, or the historical method used by Duke Energy Indiana.[1]

Ms. Jenner stated that Duke Energy Indiana entered into contracts for 350 MW of monthly capacity for June and 450 MW of monthly capacity for July and August, which contractually entitled Duke Energy Indiana to specifically-identified and sourced capacity to be offered into the Midwest ISO Day 2 markets. She explained that these purchases contractually entitled Duke Energy Indiana to designate this purchased capacity as Designated Network Resources ("DNRs") for the Midwest ISO's purposes. In addition, Petitioner purchased 560 MW of monthly forward capacity for March 2008 and 300 MW of monthly forward capacity for April 2008. Furthermore, Duke Energy Indiana made two daily forward capacity transactions for a total of 700 MW in June 2008.

Ms. Jenner testified that Petitioner had to make forward capacity and energy purchases because the wholesale market has changed over the past couple of years as a result of the Midwest ISO's physical capacity requirements. She explained that Duke Energy Indiana had purchased 5x16 power purchases and call option products in past years to meet its summer reliability requirements. However, with the Midwest ISO Day 2 markets and requirements in effect, the Midwest ISO's physical capacity requirements cannot be satisfied by a firm liquidated damages 5x16 energy product alone without capacity backing. She explained that under the new requirements, Duke Energy Indiana needs the ability to point to physically-backed capacity; the purchase of tolling agreements or regulated capacity products is now required to meet resource adequacy and reserve margin needs. Ms. Jenner explained that the regulated capacity products do not provide a price hedge; the energy is either priced at market price or is not included in the contract at all (effectively the same as market pricing). Therefore, in addition to regulated capacity, Duke Energy Indiana also needs to purchase energy products to hedge its market-price risk. Ms. Jenner testified that Duke Energy Indiana is not seeking recovery of the energy products it purchased to hedge market-price risk for Summer 2008 in this proceeding, but rather through its quarterly fuel adjustment clause proceedings for the period.

Ms. Jenner also testified regarding Duke Energy Indiana's forward reliability purchases for the period of June 2008 through August 2008. She stated that Duke Energy Indiana projected a gap between peak load and available supply and demand reduction resources and that it filled the gap with forward reliability purchases to meet the minimum target reserve margin. She stated that trading personnel regularly monitor the market price movements and get price quotes for various products that fit within the resource portfolio and that the primary capacity purchase product alternatives for the period of June 2008 through August 2008 were regulated capacity-backed products.

Ms. Jenner explained that Duke Energy Indiana viewed the ReliabilityFirst Standard of 14.3% as a minimum, not a maximum, requirement. Ms. Jenner explained that adhering to 14.3% after known outages and derates was reasonable and appropriate because the specific Duke Energy Indiana outages and derates were not known at the time of the study, so they were not taken into account. She also stated that Duke Energy Indiana was concerned that

[1] As stated in Ms. Jenner's rebuttal testimony, this translates to an applicable RM_{ICAP} of 14.3%.

some of the assumptions in the study tended to bias the results toward a lower reserve margin, given that this was the first year that a LOLE study was performed. Ms. Jenner stated that Duke Energy Indiana personnel decided that taking the known outages and derates into account was prudent for this first year under the new resource adequacy standard and that the 350 MW of capacity purchased for June and the 450 MW of capacity purchased for July and August were reasonable and necessary in order to achieve this reserve margin. Ms. Jenner explained that, without accounting for the known outages and derates, the purchases resulted in a projected reserve margin of 17.5% for June and 15.3% for July and August.

Ms. Jenner explained that Duke Energy Indiana's load forecast for Summer 2008 peak demand was 6,998 MW at the time of the summer purchases, while its projected 2008 summer net load for planning was 6,709 MW. She stated that without the forward purchases and PowerShare® impacts secured for the period of June 2008 through August 2008, Duke Energy Indiana's reserve margin heading into the summer was 7.5% for June and 6.5% for July and August.

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 a 14.3% reserve target, Ms. Jenner noted that for summer 2008, Petitioner planned to meet its anticipated native load customers' peak demand requirements as follows: 88.1% through its existing fleet of generating assets, 5.5% through forward reliability purchases from the wholesale power market, 5.7% through a combination of traditional regulated conservation and demand response products and 0.7% 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, described the capacity purchases that were made for the summer of 2008. These purchases included monthly net purchases of 350 MW of Midwest ISO DNR Capacity for June and 450 MW of DNR for July and August 2008. He explained that all of the purchases qualified as Midwest ISO DNR and therefore were in compliance with Midwest ISO Module E requirements. Mr. Herrera also testified that Petitioner made two daily capacity transactions in June totaling 700 MWs for a total net cost, before retail jurisdictional allocation, of $5,649,300 for the three months. He offered explanation for his opinion that these purchases were reasonable and necessary. Mr. Herrera further testified as to the continued volatility of the power and natural gas markets. Mr. Herrera sponsored a confidential exhibit that included all agreements or confirmations supporting the capacity purchases.

B. <u>Fiscal Year 2007 PowerShare® Costs</u>. 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, as approved in Cause No. 42870 and extended through May 31, 2010 in Cause No. 43202, during the months of December through February.

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 are paid an energy credit 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 also discussed the settlement agreements entered into and awaiting approval 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 times that it complies with Midwest ISO requirements. Mr. Sailers testified that the settlement agreements provide 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® CallOption 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.

Mr. Sailers testified that during the winter of 2008, there were no PowerShare® events. During the summer of 2008, there were two CallOption events. For summer 2008, Petitioner entered into 40 CallOption contracts and paid premiums of $1,932,426 for 81 MW of load reduction capability. He also stated that Duke Energy Indiana also paid $80,386 in event credits for CallOption and QuoteOption net of buy throughs. PowerShare® related expenditures totaled $2,012,812 for the 12 months ended September 2008. 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 $989,812.

Mr. Sailers described the PowerShare® attributes for summer 2009 and for winter 2008/2009. He explained that there are two changes to the 2008/2009 program: (1) the peak period is defined as 7 am to 1 pm, and (2) the premium for the winter period will be $9/kW verses $25/kW for the summer period. He also testified that he prepared an Activity Log as required pursuant to the Settlement Agreement in Cause No. 42870, as set forth in Petitioner's Exhibit D-1.

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 4 customers with a total load of 8.6 MW were served under the rider during all or a portion of the summer of 2008. Given that the load for these customers 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. Sharing of Non-Native Sales Profits. Ms. Jenner summarized Duke Energy Indiana non-native sales strategy for the period of October 2007 through September 2008. 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 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 Duke Energy Indiana and the $14,747,000 net profit level for non-native sales included in the determination of the 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 Duke Energy Indiana's non-native load power hedging strategy to lock in a margin for the forecasted excess generation not needed to serve native load. For the period at issue, this power hedging strategy resulted in a gain of approximately $4 million. Mr. Herrera also explained Petitioner's plans for future non-native load hedging, including consideration of 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, 2007, through September 30, 2008 total $21,234,976 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. The prior period adjustment applicable to this proceeding increased gross profits from non-native sales for the period

August 1, 2005 through September 30, 2007, by $160,710. Mr. Burnside also explained the factors that contributed to this prior period adjustment.

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, and the sharing of non-native sales profits. He indicated that the period covered by this filing included the period from January 11, 2008 through September 30, 2008 and varied by tracker component. Mr. Flick testified that Petitioner recognized two substantive changes pursuant to the Order in Cause No. 43202, including: (1) the recovery of the retail jurisdictional costs associated with necessary and reasonable capacity purchases on a year-round basis instead of only during the summer months (June through September, as previously authorized in Rider 70), for all such purchases made on or after January 11, 2008; and (2) the continuation on a pilot basis of a year-round PowerShare® program with related cost recovery through May 31, 2010.

Mr. Flick testified that Petitioner made capacity purchases for the summer 2008 in March, April, June, July, and August 2008, in the amount of $5,303,959 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 2007 through September 2008 totaled $2,012,812 or $989,812 more than the amount authorized in Cause No. 42359. As such, retail customers will be charged $989,812 in this proceeding.

Mr. Flick stated that the results of Petitioner's non-native sales for the period October 1, 2007 through September 30, 2008 totals $17,442,686 inclusive of applicable prior period adjustments and fixed trading expenses. Mr. Flick explained that starting with the revised gross non-native sales profits of $21,234,976, increasing that figure for a prior period adjustment of $160,170 and reducing gross non-native sales profits by $3,953,000 for fixed trading expenses, yields a figure of $17,442,686, before retail jurisdictional allocation. Mr. Flick further testified that the net non-native sales profits allocated to retail customers total $16,010,816. The base rates established in Cause No. 42359 included a net revenue contribution of $14,747,000, which lowered base rates. Rider 70 provides for 50/50 sharing of net profits above and below this base level amount. Therefore, reconciling the actual net non-native sales profits allocated to retail customers of $16,010,816 with the amount in base rates, results in a credit to customers of $631,908.

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. 43074 was made, and Petitioner included a credit to customers of $144,986 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).

Finally, 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. Pet. Ex. G, pp. 10-11.

E. <u>Request for Confidential Treatment</u>. Ms. Jenner supported Petitioner's request that certain proprietary information, such as pricing, concerning Petitioner's purchased power arrangements be treated as confidential. She indicated that if such information were made public, it could be detrimental to Petitioner and its customers vis-à-vis 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. <u>OUCC's Case-In-Chief</u>. The OUCC filed the testimony of Stacie R. Gruca, Utility Analyst in the Electric Division for the OUCC. Ms. Gruca testified that she did not have concerns with Petitioner's forward reliability purchase needs for the period of January 11, 2008 through May 31, 2008. However, she did express concerns with Petitioner's forward reliability purchases for the period of June 1, 2008, through September 30, 2008. Ms. Gruca testified that ReliabilityFirst adopted a resource adequacy standard to begin June 1, 2008 that required a planning reserve margin based on a one in ten year LOLE. She testified that the Midwest PRSG took on the task of performing the LOLE study and published its results on April 4, 2008. Ms. Gruca testified that based on stakeholder input and the PRSG model, Petitioner was required to carry a minimum planning reserve margin of 14.3% for the period June 1, 2008 through May 31, 2009. She testified that Petitioner determined its need for additional monthly reserves for this period by taking into account outages and derates on its installed capacity; however the PRSG study already took into account in its statistical model the effect of outages and derates in calculating a minimum 14.3% reserve margin. Ms. Gruca testified that Petitioner did not provide justification to support its decision to reflect outages and derates, in addition to what is included in the PRSG LOLE study, nor did Petitioner provide sufficient justification for its need to carry a larger reserve margin (before accounting for known outages and derates) than the minimum required through its PRSG agreement.

Ms. Gruca explained that Petitioner's participation in the PRSG provides benefits in that individual load serving entities ("LSEs") may carry smaller reserve margins, while maintaining a higher system-wide reserve margin. She testified that this leads to more efficient use of utility resources and reduces the need for LSEs, like Petitioner, to supply additional capacity. She further testified that the OUCC has supported Petitioner's and other Indiana utilities' participation in regional transmission organizations because, among other things, it brings benefits to customers through the more efficient use of utility resources. Ms. Gruca stated that the PRSG ostensibly captures some of this efficiency that should inure to the benefit of ratepayers. Ms. Gruca further stated that Petitioner testified that it was concerned about assumptions in the PRSG report, and instead used its own internal planning criteria, the imputation of outages and derates, to derive its target reserve margin. Ms. Gruca testified that Petitioner is requesting the recovery of costs from ratepayers for its decision to carry a reserve margin as much as 3.2% greater than the minimum required by the PRSG.

Ms. Gruca estimated the impact of Petitioner's higher reserve margin to be nearly $1 million and the retail jurisdictional amount to be approximately $900,000. She did not recommend that this amount be disallowed from the current proceeding. She recommended that the Commission consider whether Petitioner's approach to a reserve margin is overly conservative and fails to capture a significant benefit that ratepayers should receive from participating in the Midwest ISO.

Ms. Gruca testified that she did not have any concerns with Petitioner's calculation of proposed recovery of non-native sales profits. She testified that Petitioner achieved the net non-native sales profits embedded in base rates in the current proceeding, which in turn provided a credit to ratepayers.

Ms. Gruca testified she did not have concerns with Petitioner's PowerShare® program costs. She explained that based on Petitioner's "PowerShare® Activity Log," Petitioner's year-round cost recovery of the PowerShare® program shows a quantifiable benefit to customers who participate in the program. She further explained that although Petitioner did not incur PowerShare® events outside the summer months, the OUCC believes the 2-year extension of the PowerShare® pilot program and year-round cost recovery of the program, should continue throughout the extended 2-year pilot period, at which time Petitioner, the Commission, and the OUCC can assess the need for possible permanent year-round program and recovery, and analyze benefits to customers.

Ms Gruca also testified that Petitioner included realized gains to non-native hedging which benefited customers by adding to Petitioner's non-native sales profits. She further testified that the inclusion of hedging activity in this proceeding was consistent with Petitioner's inclusion of such activity in its previous Rider 70 filings (Cause Nos. 43074 and 43302) which were approved by the Commission.

Ms. Gruca testified that Petitioner provided documentation consistent with its obligation pursuant to the Settlement Agreement in Cause No. 42870. She testified that the OUCC recommends the Commission approve Petitioner's proposed recovery of Rider 70 non-native sales profits and PowerShare® program costs (for the period October 1, 2007 through September 30, 2008), as well as costs associated with reliability purchases (for the period January 11, 2008 through May 31, 2008) included in this proceeding. With respect to reliability purchases (for the period June 1, 2008, though September 30, 2008), Ms. Gruca testified that the OUCC recommends the Commission approve recovery of the capacity costs incurred to serve retail customers. However, the OUCC recommended that the Commission consider requiring Petitioner to use the Midwest ISO's new Module E reserve margin requirements as the appropriate target for future necessary capacity purchase in order to fully capture the benefit of participating in the Midwest ISO.

7. **Petitioner's Rebuttal Testimony.** Ms. Jenner provided context for Petitioner's 2008 spring purchasing decisions. She explained that at the time the purchases were made, Duke Energy Indiana had concerns regarding the PRSG Study and Real Time Sufficiency issues that led Petitioner to determine it was prudent to err on the side of reliability by carrying a small buffer above the required minimum 14.3% by taking into account known outages and derates.

As to the PRSG Study, Ms. Jenner testified that the PRSG group was new and this was the first year that the group has performed such a study; as such, the exact process and assumptions were developed simultaneously with the study, as opposed to through years of past experience. Ms. Jenner testified that Petitioner was specifically concerned with the treatment of generating unit forced outages. Although companies provided this information to PRSG, Petitioner was concerned that the information provided overestimated the reliability within the footprint and with the lack of checks on the veracity of the data. Ms. Jenner stated that Petitioner decided to be more conservative in accessing the appropriateness of the PRSG reserve margin requirement result. Ms. Jenner also expressed concern about whether the LOLE standard should be applied to the Midwest PRSG as a whole or to each of the three zones, the treatment of contracts for purchase of capacity with liquidated damages clauses, and the fact that the reserve margin requirement was lower than that of groups with more experience had produced in the past.

Regarding the Real Time Sufficiency issue, Ms. Jenner testified that Petitioner was concerned, in the event of a real time capacity shortage in the Midwest ISO footprint, whether load would be shed across the footprint on a *pro rata* basis or whether the LSEs that were short of capacity in real time would be required to shed load first. Since this issue was unresolved at the time of the purchases, Ms. Jenner stated that the nature of Petitioner's capacity (*i.e.,* seven large units) and the potential for river temperature derates at Wabash River Station caused Petitioner to be cautious that it could find itself in an adverse position if the known outages and derates were not taken into consideration in Petitioner's procurement decisions.

Ms. Jenner explained that Ms. Gruca's calculation of the cost of carrying a higher reserve margin was overstated because Petitioner was not able to purchase the precise amount of MWs necessary, but rather had to purchase in 50 MW blocks. Ms. Jenner also testified that Ms. Gruca should have removed later chronological purchases from her average price calculation because these purchases would not have been made had Petitioner used a smaller reserve margin.

Regarding Ms. Gruca's concern that the demand response impacts from the 2007 IRP were not fully represented, Ms. Jenner stated that those estimates were continually updated going into the summer of 2008. Ms. Jenner explained that Petitioner improved its estimating methodology to yield a much more realistic estimate of what Petitioner can expect at the time of an interruption.

Ms. Jenner testified that Petitioner intends to procure Planning Resource Credits to meet the minimum PRM requirement of 5.35% on a UCAP basis, which translates to 14.3% on an ICAP basis for Petitioner for 2009. Ms Jenner stated that Petitioner is comfortable meeting the minimum requirement in 2009 because the concerns from 2008 have been mitigated.

8. <u>Commission Discussion and Findings</u>. Based upon all of the evidence presented at the evidentiary hearing in this proceeding, we find that, except as discussed further below, the Petitioner has adequately demonstrated that its forward reliability purchases made for January 11, 2008 through September 30, 2008 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 2008, 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.

Although the OUCC did not recommend any disallowance for summer purchases, Ms. Gruca argued that Petitioner did not provide sufficient justification for its purchases above the PRSG requirement. Ms. Jenner's rebuttal testimony explained the reasons that Petitioner chose to make purchases above the PRSG reserve requirement. We find that Petitioner's deviations from the Midwest ISO requirements are within reason and were adequately justified. We agree with the OUCC 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.

We also find that Petitioner's PowerShare® Program costs for October 1, 2007, through September 30, 2008 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 power hedging strategy is reasonable and prudent.

We also 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.

The Commission notes that Mr. Herrara, in explaining the reasons for Petitioner's capacity purchases in the non-summer months, stated that, "during part of this period the Gibson Generating Unit 4 was out of service for repair." Pet. Ex. B, p. 6. A proceeding is currently pending before the Commission, in Cause No. 38707 FAC 76 S1, in which the Commission is investigating the extended outage at Gibson Generating Unit 4 and whether such outage was the result of imprudent maintenance by Petitioner. Therefore, the Commission finds that the portion of its order in this proceeding that concerns the recovery of costs associated with the extended outage at Gibson Generating Unit 4 shall be an interim order subject to refund pending the Commission's final decision in Cause No. 38707 FAC 76 S1.

Finally, Petitioner demonstrated that certain information associated with its purchased power contracts and non-native sales satisfied the criteria for confidential treatment, 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 2008 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 2008 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 Standard Contract Rider No. 70, its reliability purchased power capacity costs, PowerShare® costs, and net non-native sales profits (losses).

6. 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 date of such filing, and shall continue for a 12-month period.

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

8. 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).

9. The portion of this Order that relates to the recovery of costs associated with the extended outage at Gibson Generating Unit 4 shall be an interim order and subject to refund pending a final order in Cause No. 38707 FAC76 S1.

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

HARDY, GOLC, AND ZIEGNER CONCUR; LANDIS ABSENT:

APPROVED: JUN 17 2009

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