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INDIANA UTILITY
REGULATORY COMMISSION

TESTIMONY OF JOHN D. SWEZ
DIRECTOR, GENERATION DISPATCH AND OPERATIONS
DUKE ENERGY CAROLINAS, LLC
ON BEHALF OF DUKE ENERGY INDIANA, LLC
CAUSE NO. 38707-FAC110 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Swez, and my business address is 526 South Church Street, Charlotte, NC 28202.

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

A. I am employed by Duke Energy Carolinas, LLC ("Duke Energy Carolinas") as Director, Generation Dispatch and Operations.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science degree in Mechanical Engineering from Purdue University in 1992. I received a Masters of Business Administration degree from the University of Indianapolis in 1995. I joined PSI Energy, Inc. in 1992 and have held various engineering positions with the Company or its affiliates in the Power Services, Power Trading, and Fuels and Systems Optimization departments. Though my title has changed in recent years, I assumed my current role on January 1, 2006.

Q. ARE YOU A REGISTERED PROFESSIONAL ENGINEER LICENSED IN THE STATE OF INDIANA?

A. Yes, I am.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS DIRECTOR, GENERATION DISPATCH AND OPERATIONS, AS THEY RELATE TO DUKE ENERGY INDIANA, LLC ("DUKE ENERGY INDIANA" OR "COMPANY").

A. I am responsible for the Company's: (i) generating dispatch; (ii) unit commitment; (iii) 24-hour real-time operations; and (iv) short-term generating maintenance. I am also responsible for the submission of the Company's supply offers to the Midcontinent Independent System Operator, Inc. ("MISO") for MISO's day-ahead and real-time electric energy markets ("Energy Markets") and MISO's day-ahead and real-time ancillary services markets ("ASM") in the MISO region (the Energy Markets and ASM collectively referred to as the "MISO Markets"), as well as managing the Company's short term supply position to ensure that the Company has adequate resources committed to serve its retail customers' electricity needs. These markets are often referred to as the "Energy and Operating Reserve Markets."

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. First, I discuss economic dispatch in the context of the MISO Markets and how it affects the supply resources that are used to serve Duke Energy Indiana's retail customers' electricity needs. In the course of that discussion, I will describe the actions Duke Energy Indiana takes, subject to operating constraints, to generate or purchase power or both to serve its retail customers at the lowest fuel cost reasonably possible. In addition, I generally describe the MISO Markets' charges and credits that are included in the instant fuel cost adjustment filing. I provide an update on the coal price decrement initiated by the Company in February 2012, an update on recent emissions developments and the impact on generating units, a summary of outages experienced during the review period, an update on Wabash River 6 and 7, an update to the power purchased from Benton County Wind Farm, and an update on the Edwardsport IGCC generating station.

II. OVERVIEW OF MISO'S ENERGY MARKETS

Q. MR. SWEZ, ARE YOU FAMILIAR WITH MISO'S ENERGY MARKETS?

A. Yes. As mentioned above, I manage the team that is responsible for participating in those markets, as well as ASM, on behalf of the Company.

Q. PLEASE GENERALLY DESCRIBE MISO'S ENERGY MARKETS.

A. Beginning April 1, 2005, MISO began independently administering both day-ahead and real-time markets for electric energy pursuant to its Open Access Transmission, Energy Markets Tariff (now known as the Open Access Transmission, Energy and Operating Reserve Markets Tariff or hereinafter "MISO Tariff"), on file with the Federal Energy Regulatory Commission ("FERC"). The real-time energy market functions as a real-time balancing market for electricity. Through the day-ahead energy market, market participants can mitigate their exposure to price risk in the real-time energy market. Demand bids and supply offers for power are submitted to MISO by market participants, including both generator owners (as sellers) and load serving entities (as buyers).

Thus, the Company functions as both a seller and buyer in the Energy Markets to serve its retail electric customers in Indiana. Additionally, Duke Energy Indiana has the ability to self-schedule certain generating resources in the Energy Markets to ensure that those resources are committed and dispatched.

MISO uses the offers and bids it receives for the sale and purchase of power from market participants to arrange a security-constrained, economic commitment and dispatch for the entire MISO region for each dispatch interval. The dispatch interval for the day-ahead energy market is hourly; for the real-time energy market, the dispatch interval is every five minutes. Once MISO defines a security-constrained economic dispatch solution for a given dispatch interval, it determines market clearing prices in each energy market using the principles of locational marginal pricing. Finally, MISO administers a system of financial transmission rights ("FTRs") based upon the use of locational marginal pricing for pricing energy to allow parties to hedge their exposure to day-ahead congestion costs.

Q. PLEASE EXPLAIN THE MEANING OF THE TERM "ECONOMIC DISPATCH."

A. Economic dispatch is an operating procedure used by utilities to supply electricity to their customers generally using the most cost efficient resources available, recognizing and subject to any operational limits and environmental considerations affecting the generation and transmission facilities available to supply that electricity.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY SELF-SCHEDULING.

A. Self-scheduling has become a common phrase for a number of ways that a generation owner can ensure that a specific unit or units will either be committed or operate at or above a specific energy output level in the Energy Markets. There are a variety of valid reasons for a generation owner to "self-schedule" a unit. If testing of a unit is necessary, the generation owner would designate the unit as "must-run," usually designating a specific hourly output for the generating unit. Similarly, the Company may frequently designate the commitment status of our most economic coal-fired generating units and our economic coal-fired generating units with long start up times as "must-run." MISO, utilizing all self-scheduled generator information as offered, will then perform an incremental dispatch to meet the remaining demand requirements taking into consideration reliability concerns. All of these activities described above are generally referred to as self-scheduling. It should be noted that there is no "one size fits all" approach in submitting a generating unit's day-ahead or real-time energy offer to MISO. In making the decision regarding an individual unit's offer status, the Company considers various factors such as forecasted locational marginal prices ("LMP"), unit generation production cost, MISO cost impact (revenue sufficiency guarantee make-whole payments, real-time price volatility make whole payment amount, real-time revenue sufficiency guarantee first pass distribution, etc.), and the capability and economic impact from cycling the generating unit off-line and/or on-line. Before making any generation unit offer, Company personnel engage in a planning process designed to minimize the total customer cost by maximizing each unit's economic value.

Q. PLEASE EXPLAIN LOCATIONAL MARGINAL PRICING.

A. Locational marginal pricing defines the marginal cost of energy serving the next increment (*i.e.*, 1 megawatt) of load at each location, based on generation dispatch, transmission constraints, and the offers and bids of sellers and buyers participating in the Energy Markets. Because the locational marginal price is based on the marginal cost of energy to serve the next increment of load, the energy component of the locational marginal price clearing price is the same at each location supplying energy to or withdrawing energy from the market for a given market interval. Additionally, the locational marginal price includes costs for congestion in any market interval when the transmission system is constrained and the lowest price generator available cannot serve the next increment of load at that load zone because of such congestion. The locational marginal price also includes a component to reflect the marginal losses incurred to deliver the energy to the load zone.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY CONGESTION.

A. All energy activities on the transmission system can potentially result in congestion—that is, for a period of time transmission facilities may not be adequate to deliver the least-cost available energy to load in a transmission-constrained area. Congestion can either be managed through methodologies, such as the North American Electric Reliability Corporation's ("NERC") Transmission

Loading Relief ("TLR") procedures, or through market-based mechanisms, such as the use of locational marginal pricing and FTRs.

Q. WHAT ARE FINANCIAL TRANSMISSION RIGHTS, OR FTRS?

A. FTRs are financial instruments that provide market participants a means to manage the risk of congestion costs they may incur as a result of scheduling energy transactions in the day-ahead energy market. Market participants who own FTRs are provided revenues or allocated costs as an offset to congestion for scheduling injections (*e.g.*, generation, bilateral sales, etc.) at one location, and withdrawals (*e.g.*, load, bilateral purchases) at a different location in the day-ahead energy market. FTR holders are entitled to revenues or costs based on the hourly Day-Ahead congestion price difference across the path. FTRs do not protect market participants from congestion costs that result from scheduling power in the real-time energy market or from deviations between transactions scheduled in the day-ahead energy market and real-time operations.

III. <u>ECONOMIC DISPATCH IN THE ENERGY MARKETS</u>

Q. HOW HAS MISO'S IMPLEMENTATION OF ITS ENERGY MARKETS AFFECTED THE COMPANY'S ECONOMIC DISPATCH?

A. The fundamentals of economic dispatch and hedging price risk have not changed. Duke Energy Indiana's retail customers continue to enjoy the benefits of its low cost generation as the Company participates in the Energy Markets. Participation in those markets, however, involves a number of considerations that affect the resources used and the costs incurred to serve retail customers. Those considerations include certain actions within Duke Energy Indiana's control, including decisions regarding self-scheduling of resources, the preparation and submission of generator offer curves in the day-ahead and real-time markets, the amount of retail load bid into the day-ahead market and the acquisition of FTRs, and certain factors outside of the Company's control, such as the actions of other market participants and decisions made by MISO to enhance reliability as well as administer the energy and ancillary services markets.

Q. HOW ARE THE RESPONSIBILITIES FOR DISPATCH IN THE ENERGY MARKETS DIVIDED BETWEEN MISO AND LOAD SERVING ENTITIES, SUCH AS THE COMPANY?

A. MISO directs the dispatch of all generation connected to the transmission system under its functional control. The Company submits offers for its generation resources, which define the offer prices for a range of outputs, taking into account physical limits. As described above, the Company may also choose to operate a unit at a selected output or higher level by self-scheduling. There are a variety of reasons that Duke Energy Indiana will either offer a generating resource as must-run or self-schedule a unit to ensure the unit is operated as cost efficiently as possible. Although designating the Company's lowest cost units as must-run generally results in the lowest overall fuel costs, this may not be the case for generating units in a middle or lower range of dispatch costs. Again, this depends on the circumstances. For example, if "mid-merit" units are forecast to be on-line for several days in a row but are "sandwiched" by a day in which they are only marginal or slightly uneconomic, it may be prudent to designate such units with a day-ahead offer status of must-run to avoid cycling the unit. Cycling a unit off-line and then back on-line can sometimes result in higher costs during the cycling period and overall.

In the real-time energy market, MISO sends an instruction every five-minutes, called a set point, to each generating unit connected to the transmission system under its functional control with updates to this instruction occurring every few seconds as ancillary services are deployed on generating units that cleared these same reserves. Under the ASM, Duke Energy Indiana sells regulation and contingency reserve services to MISO as well as purchases these ancillary services from MISO.

Q. DOES THE MISO TARIFF ENCOURAGE PARTICIPATION IN THE DAY-AHEAD ENERGY MARKET?

A. Yes. The MISO Tariff encourages the Company (and other market participants) to participate in the day-ahead energy market in a number of ways. First, congestion costs can only be hedged in the day-ahead market. FTRs are not available to offset congestion costs incurred in the real-time market. Moreover, as described below, Duke Energy Indiana is obligated to offer its generation resources in the day-ahead market. Finally, virtual offers and bids can only be submitted in the day-ahead market as a means of hedging certain real-time operations risks.

Q. DOES DUKE ENERGY INDIANA UTILIZE MISO'S DAY-AHEAD ENERGY MARKET TO MITIGATE ITS RETAIL CUSTOMERS' EXPOSURE TO REAL-TIME PRICES AND OBTAIN THE BENEFIT OF FTRS?

A. Yes. The Company submits demand bids in the day-ahead market based on its day-ahead load forecasts. Additionally, Duke Energy Indiana offers all available generation resources in the day-ahead market through the submission of unit offers.

Q. DOES PARTICIPATION IN THE DAY-AHEAD ENERGY MARKET CREATE FINANCIALLY BINDING OBLIGATIONS?

A. Absolutely. Transactions that are scheduled in the day-ahead energy market, including offers to supply generation and bids to purchase energy that are cleared by MISO, create financially binding obligations to sell or purchase energy at the day-ahead locational marginal prices. So, for example, when a utility bids its load forecast in the day-ahead market (a demand bid), the price paid to serve that load will be the day-ahead locational marginal price at the utility's load zone. If the real-time load exceeds the amount of load that was bid in the day-ahead market, the amount underbid will pay real-time locational marginal prices. Conversely, if the real-time load is less than the amount of load that was bid in the day-ahead market, the amount overbid will be sold back to the real-time market at real-time locational marginal prices. Prices paid to suppliers in the real-time market are handled similarly. In other words, only deviations from day-ahead schedules (injections or withdrawals) are exposed to real-time locational marginal prices.

Q. IS THE COMPANY REQUIRED TO OFFER ITS GENERATING RESOURCES IN THE ENERGY MARKETS?

A. Generally, yes. Under the MISO Tariff, Duke Energy Indiana is required to submit offers for Network Resources in the day-ahead energy market to meet its next day forecasted load plus an operating reserve requirement. Additionally, both before and after the day-ahead energy market clears, MISO employs a series of reliability assessment commitment ("RAC") processes to ensure sufficient resources are committed to serve the real-time regional load forecast and to commit units needed to resolve transmission and other operational constraints in real-time. Duke Energy Indiana's Network Resources must also be made available during these RAC processes. All of the generation resources owned by Duke Energy Indiana and used to serve its retail customers are Network Resources. Consequently, Duke Energy Indiana is required to submit offers for all of its generation resources for consideration in the day-ahead market and the RAC processes.

Q. MR. SWEZ, ARE YOU GENERALLY FAMILIAR WITH THIS COMMISSION'S JUNE 1, 2005, ORDER IN CAUSE NO. 42685 ("JUNE 1 ORDER")?

A. Yes. I am generally familiar with that Order. In that Order, the Commission, among other matters, approved the Company's, Indianapolis Power & Light

Company's, Vectren Energy Delivery of Indiana, Inc.'s and Northern Indiana Public Service Company's (collectively, the "Joint Petitioners") participation in the Energy Markets. Specifically, the Commission stated:

> Based on the evidence presented, we find that Joint Petitioners should be granted authority to participate in the Midwest ISO Day 2 directed dispatch and Day 2 energy markets as described in their testimony. We find that Joint Petitioners' description of the considerations they will take into account with respect to decisions involving self-scheduling, generation offer curves, demand bidding and the acquisition of FTRs is reasonable.

June 1 Order at page 13.

Q. DO YOU BELIEVE THE COMPANY'S PARTICIPATION IN THE MISO-DIRECTED DISPATCH DURING THE PERIOD AT ISSUE IN THIS PROCEEDING WAS CONSISTENT WITH THE TESTIMONY PRESENTED BY THE JOINT PETITIONERS IN CAUSE NO. 42685?

A. Yes, I do.

Q. DO YOU BELIEVE THE COMPANY'S PARTICIPATION IN THE MISO-DIRECTED DISPATCH DURING THE PERIOD AT ISSUE IN THIS PROCEEDING CONSTITUTED REASONABLE EFFORTS TO GENERATE OR PURCHASE POWER OR BOTH TO SERVE ITS RETAIL CUSTOMERS AT THE LOWEST FUEL COST REASONABLY POSSIBLE?

A. Yes, I do.

IV. ASSIGNMENT OF GENERATION RESOURCES

Q. MR. SWEZ, EARLIER YOU DESCRIBED HOW THE MISO TARIFF ENCOURAGES DUKE ENERGY INDIANA TO PARTICIPATE IN THE DAY-AHEAD ENERGY MARKET. IN YOUR VIEW, DOES THAT AFFECT THE MANNER IN WHICH GENERATING RESOURCES SHOULD BE ASSIGNED?

A. Yes. The fact that participation in the day-ahead energy market is encouraged under the MISO Tariff supports Duke Energy Indiana's proposal to treat the markets as separate and distinct, which they are. In addition, there are a number of other considerations that support Duke Energy Indiana's methodology for assigning generating resources subject to the Energy Markets. Those considerations include:

- because the day-ahead and real-time Energy Markets are separate and distinct markets, participation in the day-ahead energy market creates separate and distinct financially binding obligations;
- day-ahead energy supply offers and demand bids will rarely perfectly match real-time conditions; and
- Duke Energy Indiana retail customers share in the net profits from the Company's non-native sales.

Q. HOW DOES THE COMPANY ASSIGN GENERATION RESOURCES IN LIGHT OF ITS PARTICIPATION IN THE DAY-AHEAD ENERGY MARKET?

A. The Company observes the following general rules to govern assignment of its generation resources in the Energy Markets:

<u>Day-ahead energy market</u>

- all expected load will be bid in the day-ahead energy market;
- all available generation will be made available (offered or self-scheduled) in the day-ahead energy market;
- native load customers get first call on all available Company generation in the day-ahead energy market; and
- commitments on generation that clear the day-ahead market in excess of cleared demand bids for native load will be honored in real-time and will be treated as non-native sales, the net profits of which will be shared with retail customers pursuant to Standard Contract Rider No. 70.

<u>Real-time energy market</u>

- native load customers get first call on needed available generation that did not clear the day-ahead energy market;
- real-time generation in excess of real-time native load will be treated as non-native sales, the net profits of which will be shared with retail customers pursuant to Standard Contract Rider No. 70;
- native load customers will pay actual fuel costs for Company generation that is assigned to serve them in real-time, including all generating units subject to unit testing, inspections or similar operational reasons related to reliability, plus other applicable charges and credits imposed under the MISO Tariff; and

- non-native sales will pay actual fuel costs for generation that is assigned to non-native sales plus other applicable charges and credits imposed under the MISO Tariff.

Q. PLEASE DESCRIBE THE RAC PROCESSES IN MORE DETAIL.

A. As the name implies, the RAC processes are intended to enhance reliability. There are three separate RAC processes that MISO may utilize to commit and schedule a unit for purposes of reliability: (1) prior to the submission of day-ahead energy offers, if MISO believes a unit will be required for reliability purposes; (2) after the day-ahead energy market clears, if MISO believes sufficient capacity has not been committed to meet its load forecast, taking operational limitations of the transmission system into account; and (3) during real-time energy operations, if MISO believes a unit is required for reliability purposes. MISO's RAC processes employ a security-constrained unit commitment algorithm intended to minimize the cost of committing the required capacity, including start-up, no-load and cost to operate at dispatch minimum. MISO guarantees that units committed during the RAC processes will receive at least their start-up, no-load and incremental costs (based on their offers).

Q. HOW ARE THE COSTS FOR UNITS COMMITTED AS A RESULT OF THE RAC PROCESSES ALLOCATED FOR PURPOSES OF FAC PROCEEDINGS?

A. The Company proposed to economically stack units selected as a part of the RAC processes in Cause No. 38707-FAC69 S1, with the Make Whole payments associated with the units following the allocation of the units. We implemented that proposal in Cause No. 38707-FAC70 and this revised cost allocation procedure is ongoing.

V. UNIT OPERATING ISSUES

Q. ARE THERE ANY NEW DEVELOPMENTS THAT ARE AFFECTING THE DISPATCH OF THE COMPANY'S UNITS?

A. Yes. Starting in late February 2012, the Company started applying a coal price decrement to the dispatch costs of Gibson 1-5, Wabash River 2-6, and Cayuga 1-2 generating units to correctly reflect the economics of additional costs associated with avoiding or reducing surplus coal inventories. To the extent that the price decrement results in units being dispatched that otherwise would not be, coal coming into the station is consumed, other potential costs are avoided, and customers ultimately benefit because higher cost alternatives to manage the inventory are avoided. With the price decrement in place, the Company initially saw a significant increase in generation output from these units. As the level of the coal price decrement has decreased over time, the impact of the decrement has lessened. In short, the price decrement is working as designed. It should be noted that on specific hours and days, the price decrement will have no impact on the commitment and dispatch of the Company's generating units because the unit in question was already economic without application of the price decrement. In other words, the price decrement does not make a difference under certain circumstances.

Q. IN THE COMMISSION'S OCTOBER 30, 2013 ORDER IN CAUSE NO. 38707 FAC 96, THE COMMISSION ORDERED DUKE ENERGY INDIANA TO PRESENT THE INPUTS TO ITS CALCULATION OF THE COAL PRICE DECREMENT APPLICABLE TO EACH FAC FILING AS SUPPORT FOR THE REASONABLENESS OF ITS PRICING. ARE YOU PROVIDING THESE INPUTS WITH YOUR TESTIMONY?

A. Yes. Petitioner's Confidential Exhibit 6-A provides the coal stacks for the time period June through August 2016.

Q. DOES THE COMPANY PLAN TO KEEP THE COAL PRICE DECREMENT PROCESS IN PLACE THROUGH THE END OF 2016?

A. Yes. The Company continues to forecast its coal inventory position as part of the normal course of business.

Q. ARE THERE ANY OTHER DEVELOPMENTS THAT COULD AFFECT THE DISPATCH OF THE COMPANY'S UNITS?

A. On September 7, 2016, the EPA finalized an update to the Cross-State Air Pollution Rule (CSAPR) as it relates to the 2017 and forward Ozone Seasons. Ozone season emissions are measured from May 1 through September 30 of every year. The update rule substantially reduced Seasonal NOX allowance allocations for the Company as compared to 2016 allocations and reduced other affected states allocations similarly. These allocation reductions may strengthen wholesale market prices for allowances and consequently increase the dispatch costs of many of Duke Energy Indiana's generating units. This update rule may also cause other changes to the Company's generating units, including exploring methods to further reduce NOx emissions as well as operational changes.

On June 29, 2015, the United States Supreme Court remanded, without vacatur, the Environmental Protection Agency's ("EPA") Mercury and Air Toxics Standards ("MATS") back to the D. C. Circuit Court. The D.C. Circuit Court ordered on December 15, 2015 that the MATS rules will remain in effect while the EPA works on a final cost finding. The court noted in the order that the EPA "has represented that it is on track to issue a final finding" to address the Supreme Court's concern that cost was a necessary consideration when deciding to regulate mercury emissions from power plants. The EPA's final supplemental finding was delivered to the D. C. Circuit court on April 15, 2016 and then published in the Federal Register on April 25, 2016. A coal mining company sued the EPA after the supplemental finding was published on April 25. The courts have yet to rule on the lawsuit. Emission allowance prices have not changed materially and continue to constitute a relatively small portion of the overall variable cost of a fossil generation unit.

Q. IN THE COMMISSION'S DECEMBER 28, 2011 ORDER IN CAUSE NO. 38707 FAC90, THE COMMISSION ORDERED DUKE ENERGY INDIANA TO DISCUSS IN FUTURE FAC PROCEEDINGS MAJOR FORCED OUTAGES OF UNITS OF 100 MW OR MORE LASTING MORE THAN 100 HOURS. WERE THERE ANY SUCH OUTAGES

OCCURRING DURING THIS REPORTING PERIOD, JUNE THROUGH AUGUST 2016?

A. Yes. An outage occurred with Gibson 5 starting at 18:36 on August 25, 2016 and ending at 14:00 on September 2, 2016. During the unit shutdown, generator bus ground alarms occurred. Once the outage work began, the generator was tested and no issues were found. However, a standoff insulator on the isolated phase bus was found faulty after additional testing and was replaced. The unit then returned to an available status on September 2.

Finally, Cayuga 1 was forced off-line at 20:52 on August 30, 2016. Although this outage is greater than 100 hours in length, it occurred primarily after the end of the June to August reporting period so it will be discussed in the next scheduled fuel adjustment clause proceeding.

Q. PLEASE PROVIDE AN UPDATE REGARDING WABASH RIVER STATION UNITS 6 AND 7.

A. As previously discussed, Wabash River Unit 6 had a one-year MATS rule extension until April 15, 2016, after which time the unit suspended operation. As the Commission is aware, Duke Energy Indiana had been evaluating the potential to convert Wabash River 6 to natural gas fuel. The Company decided not to pursue this, and on June 7, 2016, Duke Energy Indiana submitted an Attachment Y notification to MISO requesting a decommissioning and retirement date of December 7, 2016 for Wabash River 6 (318 MW) as well as the Wabash River 7 (8 MW) diesel units. MISO studied the decommissioning request and on

September 12, 2016 approved the requested date for Wabash River 6 and also determined that MISO approval was not needed for Wabash River 7 due to the fact that it is a behind the meter resource. Both units are planned to retire on December 7, 2016.

Q. IN THE COMMISSION'S SEPTEMBER 26, 2012 ORDER IN CAUSE NO. 38707 FAC93, THE COMMISSION ORDERED DUKE ENERGY INDIANA TO PROVIDE AN UPDATE IN THIS PROCEEDING ON THE NEGATIVE LMP SITUATION WITH BENTON COUNTY WIND FARM. WILL YOU PLEASE DESCRIBE THIS SITUATION AND PROVIDE THE REQUESTED UPDATE?

A. Starting in 2012, during various times primarily in the spring, fall, and winter seasons, Benton County Wind Farm ("BCWF") received persistent negative day-ahead and real-time LMP's at the generator node. During this time, BCWF was registered at MISO as an Intermittent Resource, which means it had no ability to be committed or decommitted by, or follow the setpoint instructions of, MISO during normal energy market operations. MISO did have the ability to curtail the output of the units, however, through manual curtailment. Due to the nature of the contractual arrangement between the Company and BCWF and the way MISO treated offers from Intermittent Resources, the offer made by the Company to MISO for this generator was equal to the day-ahead forecast of the anticipated energy from the facility. The Company set the unit minimum and maximum loading equal to the forecasted generation amount, and, in addition, used a commitment status of must-run, meaning that MISO cleared the generator at any LMP, positive or negative, in the day-ahead market. As a result, negative revenue (meaning that payments must be made to send the power into the MISO system) was sometimes received by this generator in the day-ahead markets. Because the unit was an intermittent unit, the unit had no ability to be dispatched up or down and, as a result, no offer was made in the real-time market. Thus, it was possible to receive negative revenue in the real-time market as well if generation from the unit was greater than the day-ahead award and real-time LMPs were negative.

MISO's creation of the Dispatchable Intermittent Resource ("DIR") construct was designed to allow MISO to better manage the output of intermittent resources, thereby allowing for better management of congestion in certain areas, such as where Benton County Wind Farm is located. On March 1, 2013, Benton County Wind Farm began operation as a DIR, as required by MISO. Although it appears that the DIR construct is giving MISO additional tools to manage congestion at Benton County Wind Farm, negative LMPs at times do continue to be observed.

On June 17, 2013, the Company received an invoice for payment from Benton County Wind Farm for March, April, and May 2013 liquidated damages for production that was not generated. The Company disputed this invoice and, as a result, did not issue payment or include the invoice in any FAC proceeding. In accordance with provisions of the contract, the Company and Benton County Wind Farm had negotiations regarding this invoice and other issues pertaining to operation under the MISO DIR. On December 16, 2013, Benton County Wind Farm filed a lawsuit against Duke Energy Indiana in United States District Court for the Southern District of Indiana, alleging that Duke Energy Indiana breached its contract with the wind farm (Case No. 113CV1984SEBTAB). A trial was scheduled for August 2015, however, in early July the court entered summary judgment on behalf of Duke Energy Indiana in the case, meaning that the Court found the PPA was not a take or pay contract and that the Company's supply offer was found to be reasonable. Because the Court entered judgment in the Company's favor on all remaining claims, no payment is owed to Benton County Wind Farm for power not actually generated and delivered. As a result, the Company is not required to nor has plans to pay the invoice (discussed above) from Benton County Wind Farm for March, April, and May 2013 liquidated damages for production that was not generated. On July 30, 2015, Benton County Wind Farm filed a notice of appeal. As required in the appeal process, both parties participated in a court-ordered settlement conference. No settlement was reached as a result of this effort. The appeal was then fully briefed and oral argument was heard in the 7th Circuit Court on February 26, 2016. No decision has been issued at this time.

Q. PLEASE PROVIDE AN UPDATE ON THE EDWARDSPORT IGCC GENERATING STATION.

A. The station experienced strong generation performance this summer. In particular, during June 2016, the station produced the 5th most generation and during August 2016, the station produced the most generation in any month since commercial operation began.

Q. PLEASE DESCRIBE THE OFFER THAT IS BEING MADE FOR EDWARDSPORT IGCC.

A. When the unit's gasifiers are available or operating, Edwardsport is being offered with a commitment status of must-run with the unit's parameters outlined for MISO, as is typically the case with other Duke Energy Indiana large coal generating units. Edwardsport has followed MISO's dispatch direction between the minimum and maximum capability of the unit during this time. In addition, during times when syngas is not available and the station is available on natural gas operation, the unit will typically be offered to MISO with a commitment status of economic and can be committed and dispatched at MISO's discretion.

VI. ENERGY AND ANCILLARY SERVICES MARKETS CHARGES AND CREDITS

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE JUNE 1 ORDER AS IT RELATES TO THE CHARGES AND CREDITS OF THE ENERGY MARKETS THAT CAN BE INCLUDED IN FUEL COST ADJUSTMENT PROCEEDINGS.

A. On page 34 of the June 1 Order, the Commission found that costs incurred as a result of participating in the Energy Markets, including charges and credits imposed under the MISO Tariff, fall into two broad categories: fuel costs and non-fuel costs. With respect to fuel costs, the Commission stated on page 36, "[t]he charges and credits assigned to the Joint Petitioners in the Midwest ISO Day-ahead and Real-time markets are in essence the cost of power to reliably meet the needs of their loads." On page 37 of the June 1 Order, the Commission further delineated certain Energy Markets charges and credits imposed under the MISO Tariff that should be included in the cost of fuel in quarterly fuel cost proceedings as follows:

- FTR congestion costs;
- FTR congestion credits;
- FTR auction settlements;
- virtual bids and offers in the day-ahead market which are used for hedging jurisdictional load;
- day-ahead recovery of unit commitment costs;
- excess congestion charge fund credit;
- real-time marginal losses surplus credit;
- RAC recovery of unit commitment costs;
- marginal losses surplus credit; and
- inadvertent energy charge or credit.

Q. WHAT ENERGY MARKETS CHARGES AND CREDITS HAS THE COMPANY INCLUDED IN ITS CURRENT FUEL COST ADJUSTMENT FILING?

A. Consistent with the June 1 Order, Duke Energy Indiana has included in this filing the Energy Markets charges and credits that are incurred as a cost of reliably meeting the power needs of Duke Energy Indiana's load, including: (1) Energy Markets charges and credits associated with Duke Energy Indiana's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full LMP at Duke Energy Indiana's load zone; (3) other Energy Markets charges and credits included in the list on page 37 of the June 1 Order; and (4) credits and charges related to auction revenue rights ("ARRs") and Schedule 27 and 27-A.

Q. IN THE COMPANY'S PRIOR FAC PROCEEDINGS YOU DISCUSSED THE NEW AND MODIFIED CHARGE TYPES UNDER ASM. ARE ASM CHARGES OR CREDITS INCLUDED IN THIS PROCEEDING?

A. Yes. The Commission authorized the Company and the other Joint Petitioners in its Phase II Order issued on June 30, 2009 in Cause No. 43426 to recover its costs and credit revenues related to ASM. Accordingly, the Company has included various ASM charges and credits in this proceeding, consistent with that order, as well as appropriate period adjustments.

VII. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

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

Signed: ______________________ Dated: 10/28/16
John D. Swez

PETITIONER’S EXHIBIT 6-A IS CONFIDENTIAL