BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 14-1297-EL-SSO

REBUTTAL TESTIMONY OF

EILEEN M. MIKKELSEN

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

OCTOBER 19, 2015

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Eileen M. Mikkelsen. I am employed by FirstEnergy Service Company as the Director of Rates and Regulatory Affairs for the FirstEnergy Corp. Ohio utilities (Ohio Edison Company ("Ohio Edison"), The Cleveland Electric Illuminating Company ("CEI") and The Toledo Edison Company ("Toledo Edison") (collectively, the "Companies")). My business address is 76 South Main Street, Akron, Ohio 44308.

Q. ARE YOU THE SAME EILEEN MIKKELSEN WHO PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. I provided Direct Testimony on August 4, 2014, Supplemental Testimony on December 22, 2014, Second Supplemental Testimony on May 4, 2015, Third Supplemental Testimony on June 1, 2015 and Fourth Supplemental Testimony on June 4, 2015.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to:

1. the Supplemental Testimony of Dr. Kalt on behalf of P3/EPSA and the Supplemental Testimony of Mr. Comings on behalf of the Sierra Club questioning the impact of Rider RRS on retail rate volatility and Mr. Comings' concern that the Companies have not demonstrated their customers faced retail rate volatility since January 2013;
2. Dr. Choueiki's Prefiled Testimony on behalf of the PUCO Staff stating its preference for staggering and laddering only to mitigate retail price volatility and his belief that fixed rate contracts help reduce exposure to the high volatility in the day-ahead and real-time hourly markets;

3. Mr. Hecker's Prefiled Testimony on behalf of the PUCO Staff regarding concerns about the Companies' storm deferral mechanism and his recommendation not to accept the Companies' proposal to modify costs recovered in Rider NMB;

4. Ms. McCarter's Prefiled Testimony on behalf of the PUCO Staff opposing the Companies' proposal to increase the annual Rider DCR revenue caps by $30 million and proposing to exclude certain plant related costs from Rider DCR and other cost recovery related matters;

5. Mr. Scheck's Prefiled Testimony on behalf of the PUCO Staff regarding Rider ELR, Rider EDR(d), the proposed Commercial High Load Factor ("HLF") Time of Use ("TOU") rate and other provisions included in the Stipulation and Recommendation filed in this proceeding; and

6. Mr. Benedict's Prefiled Testimony on behalf of the PUCO Staff recommending the Companies file a business case for implementation of a broad spectrum of smart grid technologies.

Q. DO YOU AGREE WITH MR. COMINGS THAT THERE IS NO EVIDENCE OF RETAIL RATE INSTABILITY (VOLATILITY)?

A. No. I have seen many examples of retail rate volatility over the last few years for the Companies' retail customers. One example would be customers who take service under a variable price contract with a CRES provider based on Day-Ahead or Real Time LMPs with a retail adder. The chart below summarizes PJM hourly prices for the Companies load zone over the last four delivery years. Specifically: 1) the highest LMP's observed,

2) the lowest LMP's observed, 3) the number of hours the LMP exceeded $100/MWh, and 4) the average daily volatility for on-peak LMP's.

	Companies' Load Zone							
Planning	Highest LMP		Lowest LMP		Hours LMP Exceeds		Average on-peak Daily	
Period	Day Ahead	Real Time	Day Ahead	Real Time	Day Ahead	Real Time	Day Ahead	Real Time
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
6/11 to 5/13	$ 312.33	$ 399.84	$ 4.90	$ (119.92)	109	274	10%	20%
6/13 to 5/15	$ 904.65	$ 1,801.78	$ 4.05	$ (230.05)	505	598	16%	27%

All of the measures in the chart show a significant increase in volatility for the last two planning years compared to the first two planning years the Companies were in PJM. Customers with variable priced contracts indexed to either the Day-Ahead or Real Time hourly LMPs have seen volatility with prices varying more widely and more frequently.

The Companies' Rider ELR customers provide another example of retail rate volatility. The Rider ELR customers are subject to an Economic Buy Through ("EBT") provision. Under this provision, whenever the Day-Ahead LMP exceeds 1.5 times the average auction clearing price for the delivery year, the Rider ELR customers are notified and have the option to curtail load to their firm service level or buy through for all MWhs in excess of their firm load levels at the Day-Ahead LMP. For delivery years 2011/2012 and 2012/2013 the Rider ELR customers had 194 EBT hours. For delivery years 2013/2014 and 2014/2015 the number of EBT hours increased to 687. As a result, Rider ELR customers faced an increase in retail price volatility in recent years.

A third example is the retail rate volatility our SSO customers faced after the polar vortex. While the SSO retail prices were not immediately impacted, the effects of these higher prices were included in SSO rates that went into effect June 1, 2014 and June 1, 2015.[1]

The polar vortex resulted in retail rate volatility for shopping customers as well. The higher SSO prices discussed above, resulted in higher prices-to-compare when the new SSO rates went into effect on June 1, 2014. In many instances, the price-to-compare is the price CRES offers compete against so a higher price-to-compare could lead to higher CRES offers. More directly, CRES offers for residential shopping customers were more volatile after the polar vortex. In December 2013 the average CRES offer for a 12 month fixed price, full requirements product (excluding introductory offers or offers with a green component or monthly fee) on the Apples to Apples website was $0.060 per kWh. By March 2014 the average offer for the same product had climbed to $0.073 per kWh and by May 2014 the average offer for the same product was $0.081 per kWh. Customers shopping for generation service during that timeframe faced retail rate volatility with the average retail offer increasing by 35% in the first four full months after the polar vortex.

Q. DO YOU AGREE WITH THE CONCERN OF DR. KALT AND MR. COMINGS THAT RIDER RRS WOULD NOT MITIGATE PRICE INCREASES OR VOLATILITY?

A. No. One way to look at the mitigation value of Rider RRS is to compare the total value of Rider RRS to the estimated cost of generation or the total electric bill over the term of the Economic Stability Program. Estimated total generation charges over the 15-year

[1] *See* Company Exs. 109a through f.

period, on an illustrative basis, are approximately $71.2 billion[2]. As proposed, Rider RRS over the term of the Economic Stability Program is estimated to have a nominal benefit to customers of $2.018 billion, which equates to an approximate 3% reduction in estimated generation charges. Similarly, total retail revenue is estimated, on an illustrative basis, at $104.2 billion[3] over the term of the Economic Stability Program. As proposed, Rider RRS is projected to reduce by 2% the estimated total retail charges over the period.

Q. DO YOU AGREE WITH DR. CHOUEIKI THAT CUSTOMERS CAN HEDGE THEIR RISK BY PURCHASING FIXED RATE CONTRACTS?

A. Not entirely. While fixed price contracts do mitigate some risk associated with short term volatility, they do not function as a hedge because a hedge should move counter to market and mitigate the impact of swings in the market. A fixed price contract would likely take into account projected changes in the market and convert those projections, likely with a risk adder, into a flat price. While this may smooth out the impact of an increase, Rider RRS, on the other hand, functions as a hedge and reduces the impact of a market increase, rather than just spreading it out over a longer term.

Q. WHAT COSTS, RISKS, AND OTHER FACTORS CAN UNDERMINE THE RISK REDUCTION BENEFITS MENTIONED BY DR. CHOUEIKI REGARDING FIXED PRICE CONTRACTS?

A. The stability provided by these fixed price contracts may be accompanied by the added costs associated with risk premiums. Following the end of a fixed price contract a

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[2] Estimate calculated using illustrative estimated generation pricing for energy and capacity included in the work paper of Companies' witness Strah, applied to estimated retail sales.
[3] Estimates assume that approximately 68% of total electric charges are for generation, based on information reported to EEI for the 12 months ended December 31, 2014.

customer is typically faced with two choices: (1) select a new contract with a CRES provider; or (2) return to default service. In either case, a customer would be subject to the full impact of market prices and conditions at the time of their contract expiration. In an environment of rising market prices, customers will likely be faced with these higher prices when they are deciding whether or not to enter into a new contract after their fixed price contract ends.

Q DO YOU AGREE WITH DR. CHOUEIKI THAT STAGGERING AND LADDERING ARE A BETTER APPROACH TO MITIGATING RETAIL PRICE VOLATILITY THAN RIDER RRS?

A. No. While staggering and laddering play a role in mitigating retail rate volatility in the short run, they do not offer the same long term retail price mitigation benefits that are available to customers under Rider RRS. Rider RRS is not a substitute for staggering and laddering, or vice versa. Rather, Rider RRS complements those strategies by providing a different type of mitigation benefit to a broader group of customers. Staggering and laddering may provide some short term reduction in volatility to non-shopping customers. But the majority of the Companies' customers are shopping. The benefits of Rider RRS apply to all customers and extend over a much longer period than the proposed ESP.

Both approaches provide retail price mitigation benefits and should be used together to provide both short and longer term stability for customers. If we look at the market forwards for the AEP/Dayton Hub observed at the time of the various solicitations that produced the Companies' Rider GEN rate for the delivery period June 2013 through May 2014, their weighted average price was $37.72 per MWh[4]. While the staggering and laddering mitigated some of the volatility in the auction results for this period, which

[4] *See* rider update filing for Rider RTP, filed in Case No. 12-2977-EL-RDR on May 1, 2013.

were based in part on forwards observed at the time of the solicitations, Rider RRS would have provided an additional benefit for customers by capturing the actual value of the 2013/2014 LMPs. In comparison to the observed forwards of $37.72 per MWh, the corresponding Day-Ahead average LMP for June 2013 through May 2014 at the AEP/Dayton Hub was $44.03 per MWh and the Real Time average LMP was $42.11 per MWh. Rider RRS would have captured the value of these increasing and volatile PJM LMPs and provided additional customer value beyond the mitigation benefits associated with staggering and laddering.

Q. DO YOU AGREE WITH MR. HECKER'S RECOMMENDATION THAT LABOR RELATED PAYMENTS RECEIVED FROM OTHER UTILITIES FOR THE STRAIGHT-TIME PORTION OF THE FIRST 40 HOURS OF MUTUAL ASSISTANCE SHOULD BE AN OFFSET TO THE COMPANIES' STORM DEFERRALS?

A. No. Mr. Hecker's recommendation doesn't accurately reflect the way that mutual assistance revenues and expenses are accounted for and treated in the ratemaking process. Currently, mutual assistance revenues and reimbursements received by the Companies are used to offset costs incurred by the Companies to provide mutual assistance to non-affiliated companies. Since this mutual assistance work is being done for other entities, any associated net revenues and expenses are appropriately treated as non-regulated activity and are recorded in accounts that are non-jurisdictional for ratemaking purposes. Accordingly, there are no revenues or expenses for mutual assistance work included in the Companies' base distribution rates from their last rate case. Mr. Hecker's recommendation would result in unregulated or non-jurisdictional revenues being included in the calculation of a regulatory asset or regulatory liability, which is inappropriate and inconsistent with traditional ratemaking.

Q. ASIDE FROM THIS FUNDAMENTAL DISAGREEMENT WITH MR. HECKER'S RECOMMENDATION, DO YOU HAVE SPECIFIC CONCERNS THAT THE COMMISSION SHOULD CONSIDER?

A. Yes. Mr. Hecker's recommendation assumes that 100% of straight-time labor costs for mutual assistance are being paid for by customers through base distribution rates as an expense, and that customers do not see any offset for this labor. This is an incorrect assumption. The Companies' ability to provide mutual assistance support is dependent, at least in part, on whether there is a need to perform storm restoration work in their own service territories. If the Companies' own storm restoration activities in a given month are relatively low or not existent, this increases the likelihood that the Companies would be in position to provide mutual assistance, if needed, to other utilities. In a circumstance where the mutual assistance straight-time labor is being provided by straight-time labor that would have been recovered in the Companies' storm baseline, customers already receive the benefit of this lower straight-time storm labor through the monthly comparison of actual storm expenses to the storm baseline as part of the monthly storm deferral calculation. Inclusion of the reimbursement for the mutual assistance straight-time labor in the storm deferral calculation, as Mr. Hecker suggests, creates a situation where the customers may receive credit for the straight time labor twice, thereby creating a windfall for customers and leaving the Companies without recovery of straight time labor expenses.

Further, Mr. Hecker's recommendations overstate the amount of the mutual assistance reimbursement that would be included in the storm deferral by making the mistaken assumption that 100% of the straight-time labor costs were included in base distribution rates as an operating expense. This is also incorrect. Mr. Hecker fails to recognize that a portion of straight-time labor costs were capitalized, and therefore, not recovered as a test year operating expense through base distribution rates. While it varied by Company, the labor allocated to capital in base rates ranged from 41 - 49%. Thus, adoption of Mr. Hecker's recommendation would require the Companies to credit 100% of straight time labor for mutual assistance to the storm deferral, while only a portion of straight-time labor costs are recovered through base distribution rates as an operating expense. Again, this creates a situation where the customers receive a windfall and the Companies are left with unrecovered expenses. Consequently, it would be inappropriate to treat mutual assistance in the manner as proposed by Mr. Hecker.

Q. DO YOU AGREE WITH MR. HECKER'S RECOMMENDATION THAT THE COMPANIES USE THE "MAJOR EVENT" STANDARD ESTABLISHED IN THE OHIO ADMINISTRATIVE CODE (O.A.C.) § 4901:1-10-01(T)?

A. No. This recommendation misinterprets the intent of the storm deferral and disregards provisions of the Companies' prior Commission-approved ESPs. Mr. Hecker ignores the fact that, pursuant to the Commission-approved Stipulation in the Companies' ESP II, in April 2010, the Companies and the Commission Staff agreed that the expenses subject to the storm deferral would have the following definition: "The weather event designated as a "storm" is one in which the event (i.e. time to restore customer service due to the weather event) is anticipated to last longer than 12 hours (using local only crews) including the time required to pre-stage personnel for the event. In anticipation of the weather event the Regional Dispatch Office will hold-over or call-in crews and restoration personnel for such anticipated or actual weather events." This storm definition was developed in consultation with Commission Staff, was informed by the individual Company storm expense baselines used in the storm deferral calculation, and has continued to be used in ESP III. It would be inappropriate to change the storm event definition without also adjusting the storm baseline expense used in the deferral calculation because it would create a mismatch between the type of storms eligible for inclusion in the storm deferral and the type of storms assumed when the storm baseline was created. The Companies' storm deferral mechanism is symmetric. If actual storm expenses are less than the storm deferral baseline in a month, the over recovery in base rates is returned to customers as a regulatory liability. If the actual storm expenses are more than the storm deferral baseline in a month, a deferral of the incremental expenses is recorded. Under Mr. Hecker's recommendation, it is likely that the customers would, in many if not most months, receive a monthly credit in the storm deferral calculation simply because the definition of "storm" was narrowed while the storm baseline expense level used for calculating the storm deferral was not adjusted.[5] Therefore, Mr. Hecker's recommendation should not be adopted.

Q. DO THE COMPANIES AGREE WITH MR. HECKER'S CLAIM THAT STAFF WOULD NOT BE ABLE TO VERIFY WHETHER THE COSTS DEFERRED UNDER THE STORM DEFERRAL ARE LEGITIMATE OR PRUDENT BECAUSE THE STORM DEFINITION USED BY THE COMPANIES IS BASED UPON ANTICIPATED OUTAGE PERIODS?

A. No. Mr. Hecker suggests that the reference to events "anticipated to last longer than 12 hours" in the storm definition agreed to with Staff discussed above would somehow limit Staff's ability to review the costs included in the storm deferral calculation. This is incorrect. The agreed to definition is used to identify weather events that should be considered storms for storm deferral purposes. Once that determination is made, specific

[5] It would be impractical today to attempt to identify the storm expenses currently included in base rates associated with the Staff's newly proposed major storm definition.

storm work orders are established to capture actual costs, and only actual costs, incurred for restoration activities. The upfront establishment of unique work orders that contain actual storm related costs should facilitate, not hinder, Staff's ability to review the actual deferred costs on the basis of prudency or legitimacy, contrary to Mr. Hecker's assertions.

Q. DO YOU AGREE WITH MR. HECKER THAT IT IS SIGNIFICANT THAT THE OTHER OHIO EDUS DO NOT INCLUDE CERTAIN PJM NON-MARKET BASED COSTS IN THEIR TRANSMISSION RIDERS?

A. No. The Companies were the first EDUs in Ohio to have a rider for non-market based services. As the PJM market continues to evolve and the Companies' understanding of that market continues to evolve, the Companies will continue to seek modifications to their riders that are in the best interest of their customers. The Companies see no significance in them being the first EDU in Ohio to make this proposal.

Q. DO YOU SHARE MR. HECKER'S CONCERN THAT CERTAIN CUSTOMERS COULD PAY TWICE FOR THESE PJM NON-MARKET BASED COSTS IF THOSE CUSTOMERS ARE UNDER CONTRACT WITH A CRES PROVIDER PAST JUNE 1, 2016?

A. No. The Companies would work closely with the CRES community to implement the proposed changes in a transparent and seamless manner that would avoid the likelihood customers would pay twice for these costs.

Q. DO YOU AGREE WITH MS. MCCARTER THAT SINCE THE COMPANIES CONTINUE TO MEET THEIR RELIABILITY TARGETS, THE ANNUAL REVENUE CAP INCREASES SHOULD BE LIMITED TO $15 MILLION?

A. No, not at all. In fact, it leads me to the opposite conclusion. Over the 2010-2014 time frame, the Companies have not only met their distribution reliability standards, as stated by Ms. McCarter, but they have also consistently outperformed them. In fact, reliability performance in years in which Rider DCR has been in place has improved for all three Companies. This improving level of performance is enabled by the Companies' ability to make investments in their distribution system and timely recover the costs of these investments under Rider DCR. The customers' perception of the Companies' reliability has improved over the same timeframe, as evidenced by the results of the most recent customer perception survey. The continued opportunity to earn a return of and on reasonable distribution investments after the investments are placed in-service will continue to benefit customers and allow the Companies to maintain or improve reliability and customer perception over the ESP IV period.

Q. DO YOU AGREE WITH MS. MCCARTER THAT A SINGLE MAJOR DISTRIBUTION CAPITAL PROJECT WOULD BE NEEDED TO JUSTIFY THE PROPOSED ANNUAL INCREASE IN THE RIDER DCR REVENUE CAP?

A. No. Ms. McCarter's view that an annual revenue cap increase of $30 million per year rather than $15 million per year would need to be predicated upon projecting a major single distribution capital project is misplaced. The Companies' distribution system is comprised of many assets in service across their expansive and diverse service territories. As such, the Companies' distribution capital expenditure portfolio is naturally weighted more heavily toward smaller projects that are needed across the Companies' distribution system. The Companies' experience is that approximately 20% of the total distribution portfolio of capital work is associated with specific large projects, while the remaining 80% is comprised of smaller projects or programs.

More specifically, the entire distribution portfolio of capital work in a given year is made up of three types of projects: Programs, Blankets, and Specific Projects.

Distribution projects fall into one of the three categories based on the scope of the project, as defined by the cost and time to complete the work, and the underlying reason the work was performed. For instance, work orders that are small in scope and of a similar nature are often grouped together in the Program category (e.g. pole replacements). Work orders that are relatively small in scope and address a particular issue (e.g. equipment failures) are often grouped into the Blanket category. Specific projects represent work with a longer duration and a larger total cost (e.g. constructing a new substation). Although Specific projects are the "largest" individual projects in the distribution portfolio they typically represent a small percentage of the overall portfolio. There is no reason to conclude that Specific project work is more important to the overall operation of the distribution system and as a result should be the basis for a higher Rider DCR revenue cap.

Further, as a part of the annual Rider DCR audit process the Companies provide a list of all projects that went into service during the audit period. In the Rider DCR audits that have taken place thus far, there has been no finding as to the reasonableness of the overall project designations (large or small) that the Companies have implemented and sought recovery of through Rider DCR. There is simply no evidence that the existence of a projected single large distribution capital project is necessary or would provide any useful purpose as it relates to determining the revenue caps for Rider DCR.

Q. DO YOU AGREE WITH MS. MCCARTER'S RECOMMENDATION THAT FUTURE INCREASES TO PLANT-IN-SERVICE ASSOCIATED WITH ACCOUNTS OTHER THAN FERC ACCOUNTS 360 TO 374 AND FERC ACCOUNTS 350 TO 358 BE EXCLUDED FROM RECOVERY THROUGH RIDER DCR DURING THE ESP IV PERIOD?

A. No. Ms. McCarter's recommendation fails to recognize that assets outside FERC accounts 360 to 374 and 350 to 358 (i.e., General and Intangible plant) directly contribute to the reliability of the distribution system as well as overall customer satisfaction. Examples of such assets include but are not limited to: (1) work management mobile communication equipment installed in line trucks in order to allow direct communication with the field; (2) customer applications in the form of a mobile optimized website and smartphone applications for outage management; (3) interactive voice response related to storm restoration; (4) the Geographic Information System (GIS); and (5) the *PowerOn* outage management system. These and other such assets have been included in Rider DCR to-date. They are used and useful plant in the provision of distribution service to customers, consistent with the types of investments that Rider DCR revenue requirement is intended to include.

The Companies are industry leaders for their use of mobile website and smartphone apps to enhance customers' experiences. The new tools make it easier for customers to access important information and services related to their electric accounts. Features of the mobile website and smartphone apps include: a simple power outage reporting process and access to the Companies' 24/7 Power Center outage maps; secure and convenient account access to review and pay monthly electric bills, analyze electric usage and enroll in electronic billing; a click-to-call feature to reach customer service and links to the Companies' social media sites; and one-click access to the Companies' website from each page of the mobile site. Customers also have the option to sign up for text message alerts for Storms and Weather, Outage Updates, Bill Available, Payment Due, Payment Posted and Meter Read Reminder. The value of these investments to the

Companies' customers is underscored by the fact that in 2014, for the second year in a row, the mobile website and smartphone app have been recognized among the top performers in customer satisfaction by J.D. Power.

Moreover, it would be premature to implement a broad, all-encompassing exclusion of future changes in General and Intangible plant now without understanding what value these future expenditures might bring to the operation of the distribution system and the customers. It would be more appropriate for the Commission Staff, or its designee, to continue to review these costs for reasonableness on a work order by work order basis as part of the Rider DCR annual audit process.

Finally, Ms. McCarter's rationale regarding consistency with other Ohio EDUs is not a valid basis upon which to seek modification of the current Commission-approved methodology for the calculation of Rider DCR. If the assets assist the Companies in providing reliable service and contribute to improved customer satisfaction, those assets should be included in Rider DCR. Therefore, the Companies disagree with Ms. McCarter's recommendation to exclude General and Intangible plant on a going forward basis from the calculation of Rider DCR.

Q. DO YOU AGREE WITH MS. MCCARTER'S RECOMMENDATION THAT THE INDIVIDUAL COMPANY ANNUAL REVENUE CAPS BE CHANGED FROM THE CURRENT 70/50/30 PERCENT ALLOCATION OF THE TOTAL ANNUAL REVENUE CAP FOR CEI, OE, AND TE, RESPECTIVELY, TO A 60/55/25 PERCENT ALLOCATION OF THE TOTAL REVENUE CAP?

A. The individual Company Rider DCR revenue caps were originally established in the Companies' ESP II to provide the Companies flexibility in terms of focusing capital spending on a particular Company when needed, to the benefit of customers. Ms.

McCarter acknowledges this in her testimony. The Companies' proposed individual Company revenue caps allow for this original intent to continue to be met and therefore, no change is necessary. So while the Companies think the CEI and TE individual Company revenue caps should remain the same, the Companies would not be opposed to an increase in OE's individual Company revenue cap. Increasing OE's individual Company revenue cap would be consistent with Ms. McCarter's stated intent of better aligning the revenue caps with the underlying plant balances, while also recognizing the reliability performance of the individual Companies.

Q. DO YOU AGREE WITH MS. MCCARTER'S RECOMMENDATION THAT THE TERM OF RIDER DCR SHOULD BE CONTINGENT UPON THE COMPANIES FILING A BASE DISTRIBUTION RATE CASE?

A. No. Consistent with the Companies' ESP II and ESP III cases, Rider DCR is being proposed in ESP IV in combination with a base distribution rate freeze. As the Commission has recognized in the Companies' prior ESP cases, the base distribution rate freeze provides significant benefits to the Companies' customers in terms of rate stability, certainty, and reliability. Making Rider DCR contingent upon the filing of a base distribution rate case by May 31, 2018 would disrupt the stability that has been afforded to customers and the Companies through the successful combination of the base distribution rate freeze and Rider DCR. Acceptance of Ms. McCarter's proposal would create unnecessary uncertainty, resulting in potential rate volatility for customers and/or the Companies not having an opportunity to recover revenue requirements that they otherwise would be recovering. Accordingly, continuation of Rider DCR should not be contingent upon the filing of a base distribution rate case, and Rider DCR should remain in place as long as the rates under ESP IV are in effect, in order to continue to provide stability and certainty to customers and the Companies.

Q. WHY SHOULD THE EXPERIMENTAL HLF TOU RATE OFFERING NOT BE OPENED UP TO ALL RATE GS AND RATE GP CUSTOMERS, AS PROPOSED BY MR. SCHECK?

A. Mr. Scheck's recommendation ignores the fact that the proposed experimental HLF TOU rate was designed specifically for customers meeting the defined eligibility criteria. Specifically, the rate is targeted to high load factor customers – these customers have already demonstrated an ability to use electricity efficiently and this proposed rate gives them an opportunity to potentially save money by further improving their load shape during peak usage periods. The existing Time-of-Day Option under Rider GEN that is available to Rate GS and Rate GP customers is designed to test customer responsiveness to time differentiated energy prices. The HLF TOU rate is designed to test high load factor customers' responsiveness to time differentiated capacity prices. If the proposed rate was open to all Rate GS and Rate GP customers without restrictions, it would defeat the purpose of the rate design and could result in unintended consequences. For example, seasonal customers who naturally use little electricity during summer peak hours, would benefit from a low energy rate in all other hours without a need to modify energy consumption. Restricting participation in the rate only to customers that meet the eligibility criteria protects the integrity of the rate design.

Q. DO YOU AGREE WITH MR. SCHECK'S ASSERTION THAT CUSTOMERS PAYING THE RIDER DSE 1 CHARGES WOULD BE SUBSIDIZING CUSTOMERS WHO RECEIVE THE RIDER ELR CREDIT?

A. No. There is no subsidy associated with recovery of Rider ELR credits. All customers who pay for Rider ELR credits are benefited by more reliable service as a result of Rider ELR customers. Rider ELR customers are compensated for their willingness and ability to be interrupted, in some instances with as little as 30 minutes notice, when PJM, ATSI or one of the Companies is in a system emergency situation. The ability to interrupt the Rider ELR customers is a significant tool in the reliability toolbox and assures that Rider ELR customers will be interrupted in advance of firm service customers. If Mr. Scheck bases this subsidy claim on his belief that the $5/kW per month Rider ELR Program Credit is more than the Rider ELR customer would receive under a PJM demand response program, then he fails to recognize that PJM revenues will offset the costs through DSE1. Further, his comparison focuses solely on PJM-related compensation and does not recognize that Rider ELR customers are also subject to interruptions from ATSI and the Companies in addition to PJM.

Q. ACCORDING TO MR. SCHECK, THE RIDER EDR CREDIT FOR RIDER ELR CUSTOMERS SHOULD BE ELIMINATED. DOES RIDER ELR PROVIDE ECONOMIC BENEFITS TO THE STATE OF OHIO?

A. Yes. In addition to the demand response benefits provided by Rider ELR customers, Rider ELR provides both reliability and economic development and job retention benefits to the Companies' service area and promotes Ohio's effectiveness in the global economy, consistent with state policy. The Rider ELR and EDR provision (b) credits have been important to customers and their continued operations in the state of Ohio. The continued operations of these customers, some very large, helps economic development and job retention in the state.

In addition, all eligible customers have previously proven that they needed economic development support, as required for participation under the predecessor tariffs or special contacts in the past. The interruptible tariffs and special contracts contained economic development and/or job retention clauses. Since economic development and job retention are key goals and benefits of Rider ELR, participating customers should also receive an economic development credit associated with their Rider ELR participation.

Q. MR. SCHECK ACKNOWLEDGES THAT THERE ARE BENEFITS OF PROVIDING EMERGENCY INTERRUPTIBLE SERVICE, DOES RIDER ELR ALLOW FOR EMERGENCY CURTAILMENT EVENTS NOT INITIATED BY PJM?

A. Yes. Rider ELR provides a much wider range of benefits than simply PJM-called demand response events. For example, in addition to being subject to Emergency Curtailment Events initiated by PJM, Rider ELR customers are also subject to curtailment when the Companies or ATSI determines "in its respective sole discretion that an emergency situation exists that may jeopardize the integrity of either the distribution or transmission system in the area." Also, Emergency Curtailment Events called by the Companies or ATSI "may occur anytime during the year with no restrictions on the number of events or the duration of the event." As a result, more localized reliability issues of particular importance to Ohio customers, such as transmission or distribution constraints, can also be addressed under Rider ELR.

PJM's compensation level and the PJM settlement process do not incorporate this element of other curtailment events. In addition, the inclusion of events called by ATSI and the Companies helps improve reliability on the Companies' system. In 2011, Ohio

Edison curtailed a subset of Rider ELR customers to address a local reliability emergency. Also, during the Polar Vortex, Rider ELR customers experienced a mandatory curtailment and were additionally asked to voluntarily curtail load to maintain the reliability of the distribution system. These curtailments demonstrate that Rider ELR provides an enhanced reliability benefit, since it allows for curtailments that PJM could not or would not necessarily call in order to address local emergencies. They highlight the importance of retaining interruptible load that is under the control of the Companies, not just PJM.

Q. DO YOU AGREE WITH MR. SCHECK'S RECOMMENDATION THAT RIDER ELR CUSTOMERS SHOULD NOT BE ALLOWED TO SHOP FOR GENERATION SERVICE?

A. No. Allowing Rider ELR customers to shop is consistent with state policy and encourages the competitive retail market. The Companies procure SSO generation service through a competitive bid process which makes the Companies and the Companies' customers financially indifferent to whether or not Rider ELR customers shop. Rider ELR customers can benefit from potential savings from shopping opportunities. It is reasonable to conclude that if these customers can reduce their electric costs by shopping, all things being equal, it will increase their competiveness and make it more likely that these businesses remain or expand in Ohio.

Q. ARE REASONABLE ARRANGEMENTS AN ALTERNATIVE TO RIDER ELR?

A. No. Mr. Scheck suggests that if the Rider EDR (b) credit is eliminated and a Rider ELR customer experiences economic hardship as a result, the customer could try to avail itself to "other mechanisms." I presume that Mr. Scheck is talking about special contracts such as reasonable arrangements. While reasonable arrangements are important economic development tools, there is no reason why these types of agreements should be the exclusive vehicle for encouraging economic development. Economic development and job retention objectives can also be achieved through tariff rates such as Rider ELR when applied to a group of customers with similar capabilities and needs. The Commission has recognized this fact by approving Rider ELR as part of the Companies previous ESPs.

Q. SHOULD, AS MR. SCHECK RECOMMENDS, THE COMPANIES ACT AS A CURTAILMENT SERVICE PROVIDER ("CSP") FOR ANY CUSTOMER ABOVE 100 KW WHO WISHES TO PARTICIPATE IN A PJM DEMAND RESPONSE PROGRAM?

A. No. While the Companies currently act as the CSP for Rider ELR customers, the Companies are not interested in serving as a CSP for all customers who wish to participate in demand response programs. Customers who wish to participate in PJM demand response programs may do so by contracting with a CSP. Acting as the CSP for all customers participating in PJM Demand Response Programs would be an administrative burden on the Companies and would cause the Companies to compete with other CSPs in the marketplace. Customers qualified for Rider ELR have the choice to participate in Rider ELR or to participate directly in the PJM markets. Therefore, the Companies do not agree with the Staff's proposal to offer PJM demand response service to any customer with at least 100 kW of demand and an interval meter.

Q. GIVEN THE UNCERTAINTY REGARDING THE CONTINUATION OF PJM PROGRAMS THAT RECOGNIZE DEMAND RESPONSE AS A SUPPLY SIDE RESOURCE, SHOULD THE COMMISSION ACCEPT MR. SCHECK'S RECOMMENDATION NOT TO APPROVE RIDER ELR AS PROPOSED?

A. No. The Commission should approve Rider ELR as proposed. In fact, this uncertainty makes it even more important that Rider ELR continue. If PJM is no longer allowed to treat demand response as a supply side resource, the Companies believe demand response could and should continue to provide cost and system reliability benefits as a demand side resource. Having an approved retail interruptible tariff assures the Commission that the Companies will have interruptible load under contract for the term of ESP IV and preserve this important tool if the demand resources are precluded from participating as a supply resource in PJM.

Q. DO YOU AGREE WITH MR. SCHECK THAT RIDER EDR(d), MORE COMMONLY REFERRED TO AS THE LOAD FACTOR PROVISION, SHOULD BE PHASED OUT RATHER THAN PHASED DOWN?

A. No. A phased down approach allows for a more gradual transition to market based pricing for the Companies' largest customers. A rapid phase out of this provision would have the unfortunate consequence of rate shock for many of our largest customers while creating a windfall for others. Gradually phasing the rate down, but not eliminating it, still provides a benefit to high load factors customers. Also, with respect to economic development, the load factor provision encourages the Companies' largest customers to reduce their electric bill by improving their load factor.

Q. STAFF WITNESS BENEDICT PROPOSES THAT THE COMPANIES SHOULD FILE A BUSINESS CASE FOR FURTHER IMPLEMENTATION OF A BROAD SPECTRUM OF SMARTGRID TECHNOLOGIES. IS THIS SUGGESTION APPROPRIATE AT THIS TIME?

A. No. The Companies have committed to and are in the process of conducting a study of Distribution Automation and Volt Var controls over a period of five years, through June 1, 2019. The objective of the study is to identify improvements, if any, to CAIDI and SAIFI in the pilot area resulting from Distributions Automation and Volt Var controls. The five year study period is necessary in order to evaluate the technology under various conditions. The Companies and Staff agreed that comparing a five year period with the technology installed to a five year period prior to installation is appropriate to assess the true benefits of the technology. The Companies cannot assess the true benefits associated with the technology on its system until the conclusion of the pilot. Since this pilot is currently underway, conducting a business case now on a broad spectrum of SmartGrid technologies, including Distribution Automation and Volt Var controls would prevent the business case from being informed by the results of the pilot. Therefore, it is premature to complete a business case on a broad spectrum of technologies at this time. However, if the Companies are directed to conduct a business case as Mr. Benedict suggests, the Companies should be allowed to recover the costs incurred to conduct the mandated business case in Rider AMI.

Q. MR. SCHECK STATES THAT THE PAYMENTS INCLUDED ON PAGES 10-15 OF THE STIPULATION HAVE NO CLEAR OR SPECIFIED BENEFITS RETURNING TO ALL RATE PAYERS. DO YOU AGREE?

A. No. The parties receiving the funding are organizations that help support attainment of energy efficiency/demand response goals through their unique advocacy relationships with many of the Companies' customers. These entities have long histories representing the interests of a broad spectrum of the Companies' customers on regulatory matters and they also serve as advocates for their constituents who help to achieve the Companies' energy efficiency benchmarks. The members and constituents of these entities have been active participants in the Companies' energy efficiency activities and contributed to the Companies' benchmark attainment efforts to-date.

Q. HAVE THERE BEEN ANY BENEFITS FROM THE PROGRAMS ADMINISTERED BY THE COUNCIL OF SMALLER ENTERPRISES (COSE)?

A. Yes. The program administered by COSE has produced over 210,000 MWhs of energy efficiency savings and approximately 35 MWs of peak demand reduction savings from 2010 through August 31, 2015.

Q. HAVE THERE BEEN ANY BENEFITS FROM THE PROGRAMS ADMINISTERED BY THE ASSOCIATION OF INDEPENDENT COLLEGES AND UNIVERSITIES OF OHIO (AICUO)?

A. Yes. Projects completed by members of AICUO have over 2,700 MWhs of energy efficiency savings and nearly 0.4 MWs of peak demand reduction from 2011 through August 31, 2015.

Q. HAVE THERE BEEN ANY BENEFITS FROM THE PROGRAMS ADMINISTERED BY THE CITY OF AKRON?

A. Yes. Projects completed by the City of Akron have produced over 5,200 MWhs of energy efficiency savings and 0.7 MWs of peak demand reduction through from 2010 through August 31, 2015. Further, the City of Akron has undertaken other efficiency and sustainability initiatives.

Q. SHOULD THERE BE AN AGREEMENT BETWEEN COSE AND THE COMPANIES TO DEMONSTRATE A NEXUS BETWEEN THE ASHRAE II AUDITS AND ENERGY EFFICIENCY INVESTMENTS OR PROCESS IMPROVEMENTS AS STAFF WITNESS SCHECK RECOMMENDS?

A. No. Such an agreement is unnecessary because the program elements outlined in the Stipulation provide such a nexus. The stipulation sets forth a program combining: (1) broad customer education; (2) unique customer assessments of energy savings opportunities through the ASHRAE II audits; (3) removal of barriers to energy efficiency investment through the unrestricted “seed money” funding; and (4) financial incentives to COSE to produce energy efficiency savings. The interplay of these factors fosters an environment aligning the interest of COSE, COSE's customers, and the Companies to identify and produce energy efficiency savings applicable towards the benchmarks in ORC 4928.66.

Q. SHOULD AICUO BE REQUIRED TO MAKE A SHOWING THAT IT WILL IMPLEMENT COST EFFECTIVE ENERGY EFFICIENCY AS STAFF WITNESS SCHECK RECOMMENDS?

A. No. Savings that are identified as originating through this program will be included in the Companies' Energy Efficiency and Peak Demand Reduction Program Portfolio Status reports to the Commission and incorporated in the overall energy efficiency portfolio's cost effectiveness results.

Q. SHOULD AICUO AND COSE BE REQUIRED TO FILE AN ANNUAL REPORT ON THE BENEFITS THEIR PROGRAMS PROVIDE AS STAFF WITNESS SCHECK RECOMMENDS?

A. No. Savings that are identified as originating through this program will be included in the Companies' Energy Efficiency and Peak Demand Reduction Program Portfolio Status reports to the Commission.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes. I reserve the right to supplement my testimony.