BEFORE
THE PUBLIC UTILITY COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc. for an Increase in Electric Distribution Rates.	)))	Case No. 17-32-EL-AIR
In the Matter of the Application of Duke Energy Ohio, Inc. for Tariff Approval.	))	Case No. 17-33-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc. for Approval to Change Accounting Methods.	)))	Case No. 17-34-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Modify Rider PSR.	))	Case No. 17-872-EL-RDR
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Amend Rider PSR.	))	Case No. 17-873-EL-ATA
In the Matter of the Application of Duke Energy Ohio Inc., for Approval to Change Accounting Methods.	)))	Case No. 17-874-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to Section 4923.143, Revised Code, in the Form of an Electric Security Plan, Account Modifications, and Tariffs for Generation Service.	))))))	Case No. 17-1263-EL-SSO
In the Matter of the Application of Duke Energy Ohio, Inc. for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)))	Case No. 17-1264-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc. for Authority to Defer Vegetation Management Costs.	)))	Case No. 17-1265-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., to Establish Minimum Reliability Performance Standards Pursuant to Chapter 4901:1-10, Ohio Administrative Code.	))))	Case No. 16-1602-EL-ESS

DIRECT TESTIMONY OF J. EDWARD HESS
ON BEHALF OF
THE RETAIL ENERGY SUPPLY ASSOCIATION AND
INTERSTATE GAS SUPPLY, INC.

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q1. Please state your name and title.

A1. My name is J. Edward Hess. I am a self-employed consultant.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of Interstate Gas Supply, Inc. (IGS or IGS Energy) and the Retail Energy Supply Association (RESA).[1]

Q3. Please describe your educational background and work history.

A3. I have a Bachelor of Business Administration degree from Ohio University and completed most of Capital University's Master of Business Administration program. I am a certified public accountant (presently inactive). I was employed by the Public Utilities Commission of Ohio in 1975 as a field auditor. I resigned from the Commission in 1977 and joined the public accounting firm of John Gerlach and Company. I rejoined the Commission in July 1980. In March 2009, I retired from the Commission after over 30 years of employment. My last position with the Commission was as the Chief of the Accounting and Electricity Division of the Utilities Department. In that capacity, I was responsible for ensuring statutory compliance with state and federal statutes, rules and procedures governing utility regulation with most of that responsibility focused on the electric sector. I was also responsible for analyzing and testifying to a whole variety of financial data regarding all utilities regulated by the Commission. From October 2009

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[1] The comments expressed in this filing represent the position of the Retail Energy Supply Association (RESA) as an organization but may not represent the views of any particular member of the Association. Founded in 1990, RESA is a broad and diverse group of twenty retail energy suppliers dedicated to promoting efficient, sustainable and customer-oriented competitive retail energy markets. RESA members operate throughout the United States delivering value-added electricity and natural gas service at retail to residential, commercial and industrial energy customers. More information on RESA can be found at www.resausa.org.

through May 2015, I was employed by McNees Wallace & Nurick as a technical specialist where I provided practical insight and analytical expertise on regulatory and legislative issues to the business community. I also provided expert testimony on behalf of the firm's clients in regulatory hearings before the Commission. I have attended and completed numerous continuing education courses relevant to the regulation of public utilities and my accounting profession. I have also participated in regulatory conferences and training seminars and have served as a workshop presenter at the annual energy conference sponsored by the Manufacturers' Education Council.

Q4. Were you involved with Ohio's electric restructuring as a member of the PUCO Staff?

A4. Yes. In 1999, I began working with Chairman Glazer on the restructuring of the electric industry. The first Johnson-Mead bill had been proposed, the utilities countered with their own version and everyone involved was working on the second version of Johnson-Mead that eventually became known as Senate Bill 3 (SB 3). The bill passed in July 1999. Before the bill was passed Alan Schreiber became the chairman of the PUCO and I continued my work on the legislation with Chairman Schreiber.

After the legislation was passed, I was given the responsibility of managing the Staff's efforts to implement the bill. That included processing electric transition plans (ETP) and developing rules that were required by the legislation. At the time of the legislation there were eight electric distribution companies that were required to file transition plans per the legislation. The issues that were addressed in the ETP filings and the rules that were required are too numerous to list here. We completed the required tasks on time and we were ready for the transition on January 1, 2001.

Sometime in late 2002 and early 2003 – shortly after the California Energy Crisis and Enron's collapse -- there was a general belief that the Ohio industry was not ready for a flash cut to market-based rates on January 1, 2006. We began discussing a longer transition period with all interested parties. I was again given the responsibility of coordinating the Staff efforts. We successfully implemented rate stabilization plans for an additional three or four years with all the utility distribution companies except Monongahela Power Ohio. Monongahela Power was eventually purchased by Columbus Southern after several negotiations and litigations. Eventually, additional legislation, SB 221, was enacted. Among other things, the legislation provided the PUCO with additional flexibility to deal with actual circumstances that were different than anticipated when SB 3 was enacted.

As a Staff member, I did help with processing the first round of electric security plans for AEP and First Energy that were put into effect in 2009.

Q5. What was your involvement with Ohio's electric restructuring as a member of McNees Wallace & Nurick?

A5. I testified before the PUCO in several SSO cases that were filed in the second round of cases. I also submitted testimony in Ohio Power Company's and Columbus Southern Power Company's Distribution Rate Case and Fuel cases.

Q6. What are you recommending in this testimony?

A6. I am recommending that Duke Energy Ohio, Inc. (Duke) be required to unbundle the distribution costs required to process and administer the standard service offer (SSO) and allocate those costs to SSO customers directly rather than allocating those costs to all customers including shopping customers so the SSO rates are comparable to rates provided by other Competitive Retail Energy Service (CRES) providers.

I am also recommending that the Commission reject the portion of the settlement proposal that recommends Rider PSR become effective with energy and capacity delivered to Duke under the ICAP on and after January 1, 2018. This is a request for an equivalent transition revenue.

II. COMPARABLE SSO RATES

Q7. What are you recommending?

A7. I recommend that the Commission establish a credit rider for all customers allowing them to avoid distribution costs that support the SSO administrative and processing costs. I am also recommending that the Commission create an avoidable rider that collects these costs directly from non-shopping customers. My recommendation accounts for the fact that Duke has proposed for recovery through distribution rates capital costs and expenses that are related to the provision of the SSO and more appropriately recovered through Duke's bypassable competitive retail electric service rates and riders.

Q8. What is the impact of your recommendation?

A8. The net impact of my proposal would result in a credit rider detailed by class of customer on Exhibit JEH-1 to all customers and an avoidable rider charge also detailed by customer class on Exhibit JEH-1 to non-shopping customers. The net impact will leave Duke revenue neutral. Unbundling and reallocating these costs to the non-shopping customers and adding the cost to the advertised price-to-compare will continue the Commission's long-standing practice of appropriately allocating costs to cost causers as well as eliminating barriers for customers to leave the SSO and shop for a competitive retail supplier. This is also consistent with the State's policy to ensure the availability of unbundled and comparable retail electric service and corrects for the current problem of subsidization by the regulated utility.

Q9. What is the SSO?

A9. The SSO is a statutory requirement that the electric distribution utility must provide its customers a firm supply of electric generation service when there is a failure of a supplier to provide retail electric generation service. The service must be on a comparable and nondiscriminatory basis.

Q10. Was the SSO intended to be a competitive service?

A10. No. The SSO was intended to simply be a back-up service for customers that hadn't decided on a retail competitive offer or were between competitive service providers.

Q11. What costs does Duke incur to provide SSO service?

A11. Duke's current SSO consists of generation service for "a full requirements service of capacity, energy, ancillary service, and market-based firm transmission services."[2] Duke also incurs additional costs, such as overhead costs to process this service and provide administrative support. The administrative and processing costs are incurred by the distribution company and socialized to all distribution customers.

Q12. Did the Commission address the issue of administrative costs in its last SSO case?

A12. Yes. IGS raised the issue that Duke incurred certain SSO administration and processing costs and recommended that the Commission add them to the SSO price. The proposal by

[2] *In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, Accounting Modifications, and Tariffs for Generation Service*, Case Nos. 14-841-EL-SSO et al, Opinion and Order at 49 (Apr. 2, 2015).

the applicant in that case did not include in the SSO price the costs that are required to administer and process the SSO service.

Q13. How did the Commission decide the issue?

A13. The Commission believed that the issue was better suited for another forum, such as a distribution rate case.[3]

Q14. Does the Applicant recognize that there are currently costs in the distribution rates to provide service to the SSO customers in this case?

A14. Yes. Applicant's witness Henning discusses the costs in his testimony.[4] The witness refers to the costs as "significant" and "unavoidable."[5]

Q15. What costs do CRES providers incur to supply generation service to customers?

A15. CRES providers are required to provide a full requirements service of capacity, energy, ancillary service, and market-based firm transmission services (just like the SSO providers) and must incur administrative and processing costs (e.g., computer systems, buildings and land, labor, etc.) to comply with the Commission's requirements under Chapter 4901:1-21 of the Ohio Administrative Code (OAC). Moreover, by statute, CRES providers (like utilities) are required to pay PUCO and OCC assessments based upon their gross receipts. These are all essential components of competitive retail electric service. Compliance with these rules and statutes is costly. The non-commodity costs incurred by a CRES provider must be recovered through the price that is offered to the customer for generation service.

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[3] *Id*. at 86.
[4] Case Nos. 17-32-EL-AIR *et al*, Direct Testimony of James P. Henning, page 5.
[5] *Id.*

Q16. Will you give a specific example of the type of costs that a CRES provider is required to incur to comply with these rules?

A16. OAC Section 4901:1-21-08(B) requires CRES providers to investigate customer complaints and provide a status report within three business days following receipt of the complaint. This rule requires CRES providers to staff and educate a complaint department and be prepared to respond to any complaint that a customer initiates.

Q17. Does the electric distribution company have similar requirements?

A17. Yes. OAC Section 4901:1-10-21(C) requires each electric utility to investigate customer/consumer complaints and provide a status report within three business days of the date of receipt of the complaint.

Q18. Does the electric distribution company include these costs in the price for the SSO when it responds to a complaint about the SSO?

A18. No. These costs are accounted for in FERC account 903 and are included in this application as an electric distribution company expense.

Q19. Do shopping customers avoid any of the distribution company's non-commodity administrative and processing costs?

A19. No. As I mentioned above, these costs are not reflected in the SSO price but rather bundled into distribution rates and recovered from all distribution customers.

Q20. Generally, what other costs are required by CRES providers to provide service to shopping customers that the electric distribution utility must also provide to non-shopping customers?

A20. Other types of costs would include providing minimum standards for service quality, safety, and reliability, providing consumers with sufficient information to make informed decisions about competitive retail electric service, protect consumers against misleading, deceptive, unfair, and unconscionable acts and practices in the marketing, solicitation, and sale of CRES and in the administration of any contract for that service, establish and maintain records and data sufficient to verify its compliance with the requirements of any applicable commission rules and support any investigation of customer complaints, maintain those records for no less than two years, establish reasonable and nondiscriminatory creditworthiness standards, require a deposit or other reasonable demonstration of creditworthiness from a customer as a condition of providing service, provide reasonable access to its service representatives, a customer complaint process, environmental disclosures, timely providing to the customer up to twenty four months of the customers payment history, net-metering service and customer billing and payments. A CRES provider must be able to provide these essential components of competitive retail electric service in order to serve customers in this state.

Q21. Does Duke charge the CRES providers for services that the CRES providers must recover through their rates but that are not included in the SSO rates?

A21. CRES providers often must pay Duke additional fees, for example, switching fees, interval data fees and bill ready billing fees. During 2016, CRES suppliers and their customers paid Duke $469,335 in switching fees.[6] Customers are not required to pay switching fees to return to the SSO. Moreover, Duke charges CRES providers $32 for twelve months of electronic interval meter data per request. During 2016, CRES providers paid Duke $561,192 in interval data fees[7]. CRES providers also paid $87,470

[6] Exhibit JEH-5, Duke Response to IGS-INT-01-016, Case Nos. 17-1263-EL-SSO *et al.*
[7] *Id.* at IGS-INT-02-001.

for bill ready fees[8]. Each of the fees discussed above are separate and apart from internal costs that CRES providers must incur to make a competitive product available and must recover these costs through their rates.

Q22. The Staff Report did not recommend distribution rate recovery of costs associated with the litigation of the current ESP case because they believe that the costs are not appropriate to include for ratemaking purposes. Do you agree with the Staff on this issue?

A22. In part, yes. As I note earlier in my testimony, costs related to the SSO service are more appropriately recovered by a bypassable rate; thus, I concur with Staff's general conclusion that ESP-related expenses should not be authorized for recovery from all distribution customers. But the costs of processing and filing an ESP case are legitimate costs and should be allowed to be recovered. This is an example of the type of a cost that would justify my proposal to identify administrative and processing costs for the SSO customer and allocate those costs to bypassable rates.

Q23. What is the effect of shopping customers paying these administrative and processing costs to both Duke and their supplier?

A23. Shopping customers are subsidizing the costs of non-shopping customers.

Q24. Does the SSO rate currently reflect the full cost of SSO service?

A24. No. The SSO rate is artificially low because it only recovers commodity costs. It does not recover the additional costs necessary to process and administer SSO service.

Q25. How does an artificially low SSO rate affect competition?

[8] *Id*. at IGS-INT-01-017.

A25. Artificially low SSO rates have a negative effect on competition. The artificially low default rate makes customers less likely to shop. The SSO price is a product that all products compete against. According to the PUCO shopping statistics, 53% of residential Duke customers receive service on the utility SSO rate.[9] The SSO product has by far the largest market share for the residential customer class. To the extent that the SSO is subsidized and artificially low, it harms all other products that must compete against the SSO. Ultimately, subsidizing the SSO leads to less competition in the Duke service territory and fewer products being available to customers.

Q26. If the SSO rate is artificially low, does that mean the distribution rates are artificially high for shopping customers?

A26. Yes. As I mentioned above, all SSO administrative and processing costs are recovered through distribution rates from all customers. If the portion of administrative and processing costs attributable to SSO service were instead unbundled, allocated and recovered from SSO customers, the distribution rates for shopping customers would be lower.

Q27. How would your recommendation to unbundle the SSO administrative costs affect customers?

A27. The distribution rate would be as proposed by the Staff. I am recommending that all customers receive a credit rider to eliminate the administrative and processing SSO costs and that only SSO customers be required to pay a separate avoidable rider to recover these costs. The net impact to SSO customers is an increase and the net impact to shopping customers is a decrease.

[9] https://www.puco.ohio.gov/industry-information/statistical-reports/electric-customer-choice-switch-rates-and-aggregation-activity/electric-switch-rates-by-customer/customers-2016-pdf/.

Q28. Would unbundling tend to produce a more level playing field for customers to shop?

A28. Yes. The portion of currently unavoidable administrative costs that are included in the distribution rates would become avoidable.

Q29. Would unbundled distribution and SSO rates result in a default utility product that is more comparable to products offered by competitive suppliers?

A29. Yes. Both the utility and supplier product would better reflect the true cost of service. It would be a better apples-to-apples comparison.

Q30. Is unbundling consist with state policies reflected in R.C. 4928.02?

A30. Yes. It would ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service by prohibiting the recovery of any generation-related costs through distribution rates.

Q31. Should the Commission continue to take measures that would encourage customers to engage in Ohio's competitive retail electric markets?

A31. Yes. The Commission should adopt measures for moving Ohio's competitive retail electric markets forward in a way that encourages customer engagement. In order for customers to be more willing to adopt value-added products and services that enable them to use and consume energy more efficiently, customers must be engaged in the competitive retail electric market. Unfortunately, the current SSO service discourages customer engagement and encourages customers to view electric service as a commodity-only product. I encourage the Commission to adopt proposals that encourage customers to affirmatively choose a retail electric product based on the preferences of the customer and the true cost of the service.

Q32. Have you determined what type of costs should be unbundled?

A32. Yes. There are many costs Duke incurs through the distribution company that are required to administer and support SSO service and should be unbundled and allocated to the non-shopping customers. Those costs include but are not limited to:

- Call center infrastructure and employees to maintain appropriate customer service and customer complaints for SSO customers;
- Printing and postage to communicate with SSO customers;
- Accounting infrastructure and employees to establish and maintain records and data sufficient to verify compliance with any Commission rules for SSO customers;
- IT employees, infrastructure, and software;
- Administrative and general salaries and infrastructure to comply with the regulatory rule requirements for the SSO service and oversee minimum standards for service quality, safety and reliability;
- Outside and inside legal, regulatory, and compliance personnel to comply with the regulatory rule requirements for the SSO;
- Office space for employees to provide these services;
- The regulatory assessments for the PUCO and the OCC that are based on SSO generation revenue, but are recovered through distribution rates;
- Taxes Other than Income Taxes such as labor taxes and excise taxes associated with other costs to support SSO service.

Q33. Where does the Applicant account for these costs?

A33. According to the FERC Uniform System of Accounts, the Applicant accounts for these expenses in FERC categories Customer Accounting Expense, Customer Service and Information Expense, Sales Expense, Administrative and General Expenses and Taxes

Other than Income Taxes Expense. The plant that would support these costs would be accounted for in the Applicant's accounts for Common plant.

Q34. Is it feasible to implement unbundling and reallocation of these costs in this proceeding?

A34. Yes. Duke has both ESP and distribution case pending. This is the perfect opportunity.

Q35. Would your unbundling recommendation inhibit Duke's ability to recover its costs?

A35. No. Duke will continue to recover these costs. It will just recover them from shopping and non-shopping customers in a different proportion.

Q36. Have you calculated the level of costs that should be unbundled from distribution rates and instead recovered from non-shopping customers?

A36. Yes. A summary of my recommendation is below.

	Residential	Comercial	Street Lighting	OPA	Industrial
Credit Rate for All Customers	$ (0.002843)	$ (0.000346)	$ (0.001026)	$ (0.000087)	$ (0.000014)
Avoidable Rider to Non-Shopping Customers	$ 0.005747	$ 0.001556	$ 0.003097	$ (0.000366)	$ 0.002047

Q37. Will you explain your calculation?

A37. I reviewed the Schedule C-2.1 and have identified several accounts included in distribution expenses that would include the type of expenses I discussed earlier. These accounts are included in the FERC categories Customer Accounts Expense, Customer Service and Information Expense, Sales Expense, Administrative and General Expenses and Taxes Other Than Income Taxes. I reviewed these categories by specific FERC account to identify the accounts that would include costs that should be directly allocated to SSO customers. These accounts include costs such as PUCO and OCC assessments, legal and regulatory expenses, payroll taxes, call center costs, accounting costs, infrastructure costs, and several other categories of costs I have identified throughout my testimony. These accounts, which I have identified, contain costs that are being incurred to process or administer to the SSO. For instance, Customer Account Expense contains costs for receiving, recording, and handling of inquiries, complaints, and requests for investigations from customers, including SSO customers. Duke also recovers items such as the PUCO and OCC assessment, legal and compliance and other costs required to support the SSO service through the General and Administrative account. These are items that directly support SSO customers. The accounts that I selected are identified on Exhibit JEH-2.

Q38. How did you arrive at the allocated costs?

A38. I started with the unadjusted C-2.1 expenses and included the Staff's proposed adjustments by FERC account. I then eliminated expenses that would have been directly associated with expenses and investments outside of the four categories. For example, there are labor costs included in FERC accounts that I am not including in my analysis, so I eliminated taxes that are associated with those labor expenses. The Staff's adjusted Pension and Benefits expense is included, in total, in FERC account 926 so I eliminated the portion of those expenses that were not associated with the accounts that I am including in my analysis. I allocated Property Insurance, Property Taxes and Depreciation Expense based on the net plant investment. That brought me to the adjusted expenses.

The adjusted expenses listed in each category support both distribution service and SSO service and need to be allocated to both services. I developed an allocation factor based upon the relationship of Duke's SSO revenue to total Duke revenue (excluding transmission revenues) and an allocation factor based on a weighted customer count allocator.

Specifically, I divided Duke's SSO revenue by Duke's total revenue collected from customers to get the revenue allocation factor. For the weighted customer count allocation factor, I accounted for SSO customers as both distribution customers and generation customers and accounted for shopping customers as only distribution customers. Both allocators are calculated on my Exhibit JEH-4.

Q39. Were you able to identify rate base items that should be included in this recommendation?

A39. Yes. Most of the plant to support the SSO process would be included in the Applicant's accounts titled Common Plant. My review of those accounts was limited by the title descriptions on Staff's Schedules because I did not have a copy of the Applicant's account description. I performed a similar allocation that I did in the expense analysis and converted the allocated rate base to a revenue requirement amount. The results are included on Exhibit JEH-3.

Q40. Why did you choose SSO revenue and a weighted number of customers to calculate your allocation factors?

A40. The Customer Accounts Expenses and the Customer Service and Information Expenses and Sales Expense that I allocated are customer related expense meaning that these expenses vary by numbers of customers. I applied a weighted customer allocation ratio to these expenses consistent with that relationship. The ratio was weighed to account for the costs to support distribution service for CRES customers and distribution and generation service for SSO customers.

I chose to allocate the Administrative and General Expenses and Rate Base based on the amount of SSO revenue Duke receives from customers. A utility company's revenues provide a proxy for and generally mirror the costs that are required to provide the utility service to various customer categories.

Q41. What is the total amount you have identified that should be allocated to SSO generation service?

A41. The total amount I have identified is on schedule JEH-1.

Q42. How should the amount identified on JEH-1 be collected?

A42. The amounts that I have identified are already included in the Staff's proposed rates. The costs first need to be excluded from the Staff's proposed rates by calculating a volumetric credit rider that will be applied to all customers. The rider is calculated by customer class by dividing the total amount per class by the total sales (shopping and non-shopping customers) per class.

These same costs will then be charged to the SSO customer by creating an avoidable rider by customer class. The amount per kWh would be calculated by dividing the identified costs by the SSO sales by customer class.

The rider/credit structure provides a revenue-neutral mechanism for Duke while also allocating costs more equitably, it provides a better comparison for shopping customers furthering the Commission's desires to provide shopping incentives to customers, and it would eliminate the subsidization that the distribution company is currently providing the SSO customers.

Q43. Would the riders need to be trued-up periodically to prevent any over-or under-recovery of revenue by Duke?

A43. Yes. Under my proposal, both the credit rider and the avoidable rider would have to be adjusted periodically to reflect the changing shopping levels in the Duke service territory. The changes in shopping levels would require an update to the revenues percentage, the weighted customers percentage and the sales statistics used to calculate the volumetric rates. I do not recommend that the adjusted expense in the four categories or the rate base be adjusted.

Therefore, I recommend that every 6 months Duke re-calculate both the credit rider and the avoidable rider to ensure it is not over- or under-recovering costs.

III. TRANSITION REVENUES

Q44. Were you involved in Duke's ETP case?

A44. Yes. As described in my background, I was a member of the Commission Staff at the time of the processing of Duke's ETP application. I was responsible for the overall management of all the ETP cases. I was primarily responsible for reviewing all request for transition costs and making a Staff recommendation to the Commission. The Commission hired Resource Data International as a consultant to the Staff on this portion of the application. I assigned various Staff members to review and verify the regulatory asset portion of the request.

Q45. What is your understanding of how and when SB 3 permitted collection of transition revenue?

A45. Like many states that enacted electric restructuring legislation in the late 1990's, Ohio addressed the subject that was typically referred to as "stranded costs" for those services for which a customer could select a competitive supplier. This subject provoked most of the debate about how to move to a customer choice structure, while at the same time being fair to utilities that may have been negatively impacted if they were subjected to competition on day one of customer choice. SB 3 implemented customer choice on January 1, 2001. SB 3 also provided an opportunity for the surviving regulated entity, the EDU, to seek transition revenue associated with the prior vertically integrated electric generation function for a period of years, but not after December 31, 2010. SB 3 contains the criteria that the Commission applied to determine how much, if any, of the transition revenue claim was eligible for recovery. When the Commission approved a transition revenue claim, it also approved transition charges that the EDU could then charge shopping customers for the period specified by the Commission. For non-shopping customers, the transition charges were embedded in the default generation supply price and were equal to the portion of the applicable default generation supply price that was not avoidable by shopping customers.

Q46. Please explain the difference between transition revenue and transition costs.

A46. An allowable claim for transition revenue had to be based on the positive difference between the generation-related revenue stream for generation service based on a date certain and a capped price previously established by Ohio's cost-based regulation, and the generation-related revenue stream available from the application of market pricing to generation service supply. In some cases, the cost-based revenue stream was believed to be less than the market-based revenue stream and, in this instance, there would have been no allowable transition revenue claim and no “stranded costs” as a result of electric restructuring. A positive difference in these unbundled default generation supply prices created through implementation of SB 3 and the market-based revenue streams was referred to as a transition cost. The transition cost reflected the differences in value available to the generation business segment from two different means of establishing price. Although the use of the term “transition costs” or “stranded costs” may imply that SB 3 created a new type of generation-related cost that was accounted for as some type of transition costs or stranded costs, SB 3 did not do so.

Q47. What is your understanding of the SB 3 criteria that were applied to determine how much, if any, transition revenue could be approved by the Commission and collected through transition charges?

A47. It is my understanding that Section 4928.39, Revised Code, specified these criteria. These criteria were applied to determine the total amount of generation-related transition revenue that was eligible for collection through transition charges **if** an EDU submitted a claim for transition revenue. SB 3 did not require transition revenue to be addressed unless the EDU submitted a claim for transition revenue.

Q48. Which EDUs submitted a claim for transition revenues?

A48. All of the EDUs, including Duke, submitted a claim with their ETP applications which also contained the plans by which the formerly vertically integrated electric utility would separate, either structurally or functionally, into distribution, transmission and generation business units (or affiliates) subject to important requirements to facilitate “customer choice” and avoid differentiation or discrimination by the EDU as a consequence of a customer’s choice of a supplier of generation service.

Q49. More specifically, what is your understanding of the criteria that were used to determine how much, if any, of a transition revenue claim was eligible for collection through transition charges?

A49. It is my understanding that Section 4928.39, Revised Code, contains the criteria used to determine the total allowable transition revenue claim. A transition revenue claim was eligible for collection through transition charges if the revenue claim was limited to:

(1) Costs that were prudently incurred;

(2) Costs that were legitimate, net verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state;

(3) Costs that were unrecoverable in a competitive market; and

(4) Costs that the utility would otherwise have been entitled an opportunity to recover.

All four of the criteria had to be satisfied for the transition revenue claim to be recoverable. With these criteria and the firm service nature of the default generation supply obligation of the EDU, the Commission evaluated transition revenue claims based on a comparison of the revenue produced by the EDU's unbundled and capped default generation supply price and a revenue stream computed based on assumed market prices for the entire range of generating services and fixed and variable costs used in Ohio's prior cost-based ratemaking system. Since generation service was the only service declared to be competitive by SB 3, the transition revenue evaluation process focused exclusively on the generation function.

Q50. Was the amount of a total generation-related transition revenue claim potentially separated into different components?

A50. Yes. The total allowable amount of any generation-related transition revenue claim was separated if a portion of that total claim was based on a claim for regulatory assets. The total transition charge resulting from any allowable transition revenue claim was also separated to show a separate regulatory asset charge. It is my understanding that SB 3 limited the Commission's ability to adjust the regulatory asset portion of an allowed transition charge and also required the regulatory asset portion of a transition charge to end no later than December 31, 2010. Under SB 3, the non-regulatory asset portion of any transition charge which was associated with above-market generating plants had to end by no later than December 31, 2005, or the end of the market development period ("MDP"), whichever occurred first. Based on the advice of counsel, I also understand that Section 4928.141, Revised Code, which was added after SB 3, excluded any previously authorized allowances for transition costs, with the exclusion becoming effective on and after the date the allowance was scheduled to end under the prior rate plan. SB 3 also did not allow the Commission to authorize the receipt of transition revenues <u>or any equivalent revenues</u> by an electric utility except as expressly authorized in sections 4928.31 to 4928.40 of the Revised Code.

Q51. Generally, how was the amount of generation-related transition revenue associated with above-market generating plants measured?

A51. If an EDU wanted to make a claim for transition revenue, it had to include the claim in its proposed ETP. A proposed ETP had to be filed 90 days after the effective date of SB 3. The statutory criteria discussed above were then used to determine how much of the generation-related transition revenue claim was eligible for collection through transition charges. For the generation plant-related portion of the transition revenue claim, the

Commission's Staff used the net book value of generating assets at December 31, 2000, as the baseline to determine how much, if any, of the net, verifiable, prudently incurred book value of the generation assets (including generation-related regulatory assets) would not be recoverable in the market. In this context, the market included the entire market, including the wholesale and retail segments

Q52. Did Duke file an ETP case and request transition cost recovery?

A52. Yes. The case was filed on December 28, 1999, in case number 99-1658-EL-ETP.

Q53. Please generally describe the transition revenue claim made by Duke in its proposed ETP.

A53. Duke[10] presented several witnesses to value its request for transition costs. The company requested that $364 million of generation related regulatory assets be recovered with a regulatory transition charge (RTC) and $563 million for the excess of jurisdictional net book value for the Zimmer and Woodsdale generating stations be recovered with a generation transition charge (GTC). Both the RTC and GTC would be unbundled from the current bundled rate.[11]

Q54. Will you generally describe how the company valued its request for the regulatory asset portion of its request for transition cost?

A54. Duke listed its request for the generation regulatory assets on its balance sheet as of December 31, 2000. The balances were projected from actual balances as of December 31, 1999. Duke provided descriptions and support for each of these assets.[12]

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[10] The request was prior to the merger with Duke Energy Corporation. Duke was known as Cincinnati Gas and Electric Company (CG&E).
[11] Direct Testimony of CG&E witness Leigh J. Pefley, Case No. 99-1658-EL-ETP.
[12] Direct Testimony of CG&E witness John P. Steffen, Case No. 99-1658-EL-ETP.

Q55. Will you generally describe how the company valued its request for the generation plant portion of its request for transition cost?

A55. Duke's witness Pifer determined a market value for Duke's generation units by projecting market revenues for each generation unit from January 1, 2001 forward. The gross market revenue per unit was netted with operating costs and other costs such as capital additions, working capital and income taxes to estimate each unit's market based, after tax, operating cash flows. He then calculated the present value of the annual, after tax operating cash flow from 2001 forward to estimate the then current market value of each generating unit as of December 31, 2000. The projected December 31, 2000 net book value of each unit was compared to the estimated unit market value to determine if there were transition costs (market value less than net book value) or negative transition costs (market value more than net book value). Duke's $563 million request was based on a positive transition costs calculation for Zimmer Unit No. 1 and Woodsdale Units Nos. 2-6.

Q56. How were Duke's transition costs resolved?

A56. The issues were resolved through a stipulation that was ultimately accepted by the Commission. The stipulation recommended an implied RTC recovery mechanism (unbundled generation charge less the shopping credit provided to customers) that would be paid by all customers whether they shopped or did not shop. Duke's request for GTC was withdrawn.

Q57. Will you explain your understanding of Duke's request for a price stabilization rider (Rider PSR)?

A57. The PSR relates to Duke's legacy interest in the Ohio Valley Electric Corporation (OVEC). As a sponsoring company of OVEC, Duke pays a cost-based Power Purchase Agreement rate to OVEC. As Duke notes in its testimony, these rates are set "in the same manner as cost recovery of a traditional rate base power plant."[13] Duke is requesting recovery of the "net costs" which it defines as the revenues received by the Company in liquidating its output in the applicable wholesale markets less all costs incurred under the OVEC Inter-Company Power Agreement (ICAP), where such amounts may be either positive or negative.[14] Duke has previously stated that it would make a quarterly filing that will include a projection of the revenue expected from selling its share of the output from OVEC into the PJM markets and the expenses it expects to be billed from OVEC. The difference between the expected revenue and expected cost for that upcoming quarter will be divided by the projected kWh sales for the same quarter to calculate a "$/kWh" rate applicable to all customers except that customers taking service above distribution voltage levels will have slightly lower prices to account for the lower line losses at their service level. They further stated that as actual data is available, the rider would be trued up to ensure that there is no over-or under-recovery.[15] Duke describes the PSR as a hedge against the volatility of future market prices for its customers. The rider was approved by the PUCO in Duke's SSO application in case 14-0841-EL-SSO on April 2, 2015, although the Commission did not permit Duke to recover any OVEC-related costs through the rider on the basis that the PSR would not provide customers with sufficient benefit.[16]

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[13] Supplemental Testimony of Judah Rose at 16.
[14] Direct testimony of Duke witness William Don Wathen Jr., Case No. 17-872-EL-RDR.
[15] Direct testimony of Duke witness William Don Wathen Jr., Case No. 14-841-EL-SSO.
[16] Case Nos. 14-841-EL-SSO, *et al.*, Opinion and Order at 46.

Q58. Will you briefly describe OVEC?

A58. OVEC and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC) were organized on October 1, 1952. The Companies were formed by investor-owned utilities furnishing electric service in the Ohio River Valley area and their parent holding companies to provide the large electric power requirements projected for the uranium enrichment facilities then under construction by the Atomic Energy Commission near Portsmouth Ohio. On October 15, 1952, OVEC and Atomic Energy Commission executed a 25-year agreement, which was later extended through December 31, 2005 under a Department of Energy (DOE) Power Agreement. On September 29, 2000, the DOE gave OVEC notice of cancellation of the DOE Power Agreement. On April 30, 2003, the DOE Power Agreement terminate. The power is provided by OVEC's Kyger Creek Plant at Cheshire, Ohio, and IKEC's Clifty Creek Plant at Madison, Indiana.

i. OVEC, AEC and OVEC's owners or their utility company affiliates (called Sponsoring Companies) entered into power agreements to ensure the availability of the AEC's substantial power requirements OVEC and the Sponsoring Companies signed an Inter-Company Power Agreement (ICPA) on July 10, 1953, to support the DOE Power Agreement and provide for excess energy sales to the Sponsoring Companies of power not utilized by the DOE or its predecessors. Since the termination of the DOE Power Agreement on April 30, 2003, OVEC's entire generating capacity has been available to the Sponsoring Companies under the terms of the ICPA. It is my understanding that existing unamortized investment in OVEC occurred following restructuring under SB 3 and the notification from the DOE that it would terminate its obligation to purchase from OVEC. The Sponsoring Companies and OVEC entered an Amended and Restated ICPA, effective as of August 11, 2011, which extends its term to June 30, 2040. Duke's ownership share and power participation benefits and requirements is 9%.[17]

Q59. Have any events occurred since the PUCO approved the rider on April 2, 2015, that should have an impact on its decision?

A59. Yes. There are two Supreme Court of Ohio (Court) decisions that the Commission should consider. On April 21, 2016, the Court issued a decision stating that the Commission had erred when it found that AEP was not recovering transition revenue or its equivalent through the RSR.[18] The Court found that the Commission erred in focusing solely on whether AEP had expressly sought to receive transition revenues rather than looking at the nature of the costs recovered. The Court found that Ohio Revised Code 4928.38 bars the "the receipt of transition revenues or *any equivalent revenues* by an electric utility." *In re Application of Columbus S. Power Co.*, 147 Ohio St. 3d 439, 445 (2016). "By inserting the phrase 'any equivalent revenues,' the General Assembly has demonstrated its intention to bar not only transition revenue associated with costs that were stranded during the transition to market following S.B. 3 but also any revenue that amounts to transition revenue by another name." *Id.; see also In re Application of Dayton Power and Light Company*, 147 Ohio St.3d 166 (2016).

Q60. Is the PSR request like the GTC portion of transition costs recovery request?

A60. Yes. Both the PSR and the GTC are requests to recover the difference between market revenues minus generation costs. The PSR proposal nets market revenues with generation costs annually to create either a positive contribution (equal to negative transition

[17] OVEC and subsidiary IKEC 2016 Annual Report.
[18] *In re Application of Columbus Southern Power Co.*, 147 Ohio St.3d 439, 2016-Ohio-1608, Appeal and Cross-Appeal from the Public Utilities Commission, Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM.

revenues) or a negative contribution (equal to transition revenues). The GTC proposal netted market revenue with generation costs and compared it to the December 31, 2000 net book value to determine if there were transition costs (recoverable with transition revenues) or negative transition costs (offsets to other transition costs). The recovery mechanisms for the PSR is an annual recovery of the value where the GTC would have been valued at a point in time and recovered over five years. The PSR is an unavoidable rider by both shopping customers and non-shopping customers as the GTC would have been an unavoidable rider by both shopping customers and non-shopping customers.

Q61. Have you reviewed company witness Rose's testimony on this issue?

A61. Yes. Company witness Rose provided economic forecasts for OVEC's two coal-fired power plants, Clifty Creek and Kyger Creek, related to the request of Duke Energy Ohio to adjust Rider PSR in this case. Mr. Rose concluded in his base case that the present value of the company's request will cost customers approximately $77 million dollars under his base scenario or approximately $66 million in his other scenario that he describes as AEO 2018 Reference Case.

I am also aware that Mr. Rose was retained by FirstEnergy Solutions Corp. (FirstEnergy) in April of 2017 to calculate the losses of the intercompany power purchase agreement with OVEC in FirstEnergy's bankruptcy case. Mr. Rose calculated that FirstEnergy would lose $268 million on an undiscounted basis through 2040.[19] FirstEnergy's ownership share and power participation benefits and requirements is 4.85%.[20]

[19] Affidavit of Kevin Warvell and Judah L. Rose in Case No. 18-50758; United States Bankruptcy Court for the Northern District of Ohio, Akron Division Hon. Judge Alan M. Koschik.
[20] OVEC and subsidiary IKEC 2016 Annual Report.

Q62. Is the PSR a request for the equivalent of transition revenues?

A62. Yes. The valuation of the costs that the PSR is recovering reimburses Duke for generation costs that are unrecoverable in a market just like the costs that were proposed to be recovered by the GTC were generation costs that were unrecoverable in a market. This rider provides Duke with financial stability by not forcing it to absorb these costs and shifting the risks of the market to the customers without the customers able to choose whether they want to absorb that market risk. The rider is completely inconsistent with the customer's right to choose its generation supplier and provides Duke with recovery of above market costs. It is contrary to policies against subsidization of competitive services and it would frustrate the cornerstone principle that customers may select the competitive products and services they desire. Customers would become involuntary investors in OVEC regardless of their decision to take default service or embrace the options available in the competitive market.

I also believe that this rider will be very confusing to customers and undermine the ability of competitive suppliers to provide rate certainty and understanding to customers. It is unclear whether the rider will be shown separately on the bill or whether it will be netted as part of the distribution charges or the energy charge. A customer may see value in entering into a fixed-rate contract with a supplier with the belief that they can control the generation portion of their electric price and not understand why they are also being charged an additional generation charge. The confusion will increase the costs to administer and process generation service which will be passed on to customers. The customer will have to account for an unknown generation-related cost or credit in their monthly bill.

Q63. Should the Commission authorize recovery of the PSR?

A63. No. The purpose of SB 3 was to allow the utilities to have a glide path to participating in a competitive market. Following the market development period, the utilities had to live or die by their market-based revenues. Providing guaranteed cost recovery through a non-by passable charge for generation-related costs—effectively, insulating the utility from the risk associated with the competitive market—would violate the prohibition against transition revenue recovery.

Q64. Does this conclude your testimony?

A64. Yes, it does. However, I reserve the right to further supplement my testimony.

CERTIFICATE OF SERVICE

I hereby certify that a copy the foregoing Direct Testimony of J. Edward Hess was served by electronic mail this 25th day of June, 2018 to the following:

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/s/ Rebekah J. Glover
One of the Attorneys for the Retail Energy Supply Association

From JEH 2	$ 21,740,264
From JEH 3	$ 1,403,679
	$ 23,143,943

Calculation of the Credit Rate to All Customers (By Sales)

Allocation to Customer Class (By Number of Total Customers)

	Residential	Comercial	Street Lighting	OPA	Industrial	Total
Total Customers	632,214	69,658	2,833	3,421	2,137	710,263
% to the Total	89.011%	9.807%	0.399%	0.482%	0.301%	100.000%
	$ 20,600,714	$ 2,269,808	$ 92,313	$ 111,473	$ 69,634	$ 23,143,943
	Residential	**Comercial**	**Street Lighting**	**OPA**	**Industrial**	**Total**
Total KWH Sales	7,247,656,859	6,567,276,667	89,952,871	1,279,119,574	5,134,392,213	20,318,398,184
	$ (0.0028424)	$ (0.0003456)	$ (0.0010262)	$ (0.0000871)	$ (0.0000136)	

Calculation of the Avoidable Rider to Non-Shoppers (By Sales)

Allocation to Customer Class (By Number of Non- Shopping Customers)

	Residential	Comercial	Street Lighting	OPA	Industrial	Total
Non-Shopping Customers	333,174	27,006	1,045	525	590	362,340
% to the Total	91.951%	7.453%	0.288%	0.145%	0.163%	100.000%
	$ 21,281,007	$ 1,724,969	$ 66,748	$ 33,534	$ 37,685	$ 23,143,943
	Residential	**Comercial**	**Street Lighting**	**OPA**	**Industrial**	**Total**
Non-Shopping KWH Sales	3,702,892,296	1,108,764,596	21,556,771	-91,742,620	18,409,314	4,759,880,357
	$ 0.005747	$ 0.001556	$ 0.003096	$ (0.000366)	$ 0.002047	

Acct. No.	Account Title	Unadjusted Distribution	Staff's Adjustments	Staff's Adjusted		Adjusted Expenses	SSO Allocationed Expenses	Alloc. Method
	Customer Accounts Expense	(A)	(B)	(C)		(D)	(E)	
	Operation							
901	Supervision and Engineering	343,246		343,246	100.000%	343,246	115,953	CUST
902	Meter Reading Expense	1,027,336		1,027,336		-		
903	Customer Records and Collections	20,496,516	(111)	20,496,405	100.000%	20,496,405	6,923,967	CUST
903250	Customer Billing-Common	(1,075,007)		(1,075,007)		-		
904	Uncollectible Accounts	(121,520)	(1,866,649)	(1,988,169)		-		
426	Sale of Accounts Receivable Fees - Elec.	5,988,148		5,988,148		-		
905	Miscellaneous Customer Accounts	1,825	556,071	557,896	100.000%	557,896	188,465	CUST
	Total Customer Accounts Expense	26,660,544	(1,310,689)	25,349,855				
	Customer Service and Information Expense							
	Operation							
908	Customer Assistance Expenses	7,318		7,318	100.000%	7,318	2,472	CUST
909	Information and Instructional Advertising	25,755	1,204	26,959	100.000%	26,959	9,107	CUST
910	Misc. Customer Service and Information Expense	4,012,778	(331)	4,012,447	100.000%	4,012,447	1,355,460	CUST
	Total Customer Service and Information Expense	4,045,851	873	4,046,724				
	Sales Expense							
	Operation							
912	Demonstrating & Selling	2,708,432	7,625	2,716,057	100.000%	2,716,057	917,521	CUST
913	Advertising	154,183	(154,183)	-	100.000%	-	-	CUST
	Total Sales Expense	2,862,615	(146,558)	2,716,057				
	Administrative and General Expenses							
	Operation							
920	Administrative & General Salaries	10,912,223	(6,352,305)	4,559,918	100.000%	4,559,918	1,539,495	REV
921	Office Supplies & Expenses	6,972,617	(427,986)	6,544,631	100.000%	6,544,631	2,209,563	REV
922	Administrative Expenses Transferred - Credit	2,933		2,933	100.000%	2,933	990	REV
923	Outside Services Employed	6,102,738	(692,870)	5,409,868	100.000%	5,409,868	1,826,450	REV
924	Property Insurance	575,901		575,901		-	5,552	Net Plant
925	Injuries & Damages	2,220,406	(1,571)	2,218,835	52.211%	1,158,476	391,118	REV
926	Employee Pension & Benefits	10,841,656	(75,055)	10,766,601	52.211%	5,621,348	1,897,849	REV
928	Regulatory Commission Expenses	93	85,310	85,403	100.000%	85,403	28,833	REV
928006	State Regulatory Commission Expense	1,626,923	(52,981)	1,573,942	100.000%	1,573,942	531,386	REV
929	Duplicate Charges-Credit	(1,418,555)		(1,418,555)	100.000%	(1,418,555)	(478,925)	REV
930.1	General Advertising Expenses	56,908	(56,908)	-	100.000%	-	-	REV
930.2	Miscellaneous General Expenses	1,831,344	(2,169)	1,829,175	100.000%	1,829,175	617,556	REV
931	Rents	3,122,884	8,717	3,131,601	100.000%	3,131,601	1,057,274	REV
	Total Operation	42,848,071	(7,567,818)	35,280,253				
	Maintenance							
935	Maintenance of Equipment	960,932	30	960,962		-		
	Total Administrative and General Expense	43,809,003	(7,567,788)	36,241,215				
	Taxes Other Than Income Taxes							
	Other Federal							
408152	Employer FICA Tax	1,278,344		1,278,344	52.211%	667,436	225,336	REV
408700	Fed Social Security Tax-Elec	(20,400)		(20,400)	52.211%	(10,651)	(3,596)	REV
408151	Federal Unemployment Tax	(2,012)		(2,012)	52.211%	(1,050)	(355)	REV
408800	Federal Highway Use Tax-Elec	1,483		1,483	52.211%	774	261	REV
408960	Allocated Payroll Taxes	2,479,422	(154,496)	2,324,926	52.211%	1,213,867	409,819	REV
	Total Other Federal	3,736,837	(154,496)	3,582,341				
	Other State and Local							
408100	Franchise Tax - Electric	1,184,164		1,184,164		-		
408101	Ohio Kilowatt Tax	69,698,967	(69,698,967)	-		-		
408121	Taxes Property-Operating	85,492,339	7,410,307	92,902,646			895,663	Net Plant
408150	State Unemployment Tax	1,176		1,176	52.211%	614	207	REV
408191	Commercial Activity Tax	1,524,415	(78,558)	1,445,857		-		
408205	Highway Use Tax	3,130		3,130		-		
408470	Franchise Tax	67,635		67,635		-		
408851	Sales & Use Tax Exp	(226)		(226)		-		
				-		-		
	Total Other State and Local	157,971,600	(62,367,218)	95,604,382				
	Total Taxes Other Than Income Taxes	161,708,437	(62,521,714)	99,186,723				
	Depreciation Expense					3,177,708	1,072,841	REV
			Total				21,740,264	

Customer Allicator 33.7814%
Revenue Allocator 33.7615%

Line No.	FERC Acct. No.	Company Acct. No.	Account Title	Juris PIS	Jurs Reserve	Net Plant		Adjusted Rate Base	SSO Allocationed Rate Base	Depreciation Expense
								(D)	(E)	
									33.7615%	
			Common Plant							
1		1030	Miscellaneous Intangible Plant	27,051,437	26,805,547	245,890		-	-	
2		1701	Common AMI Meters	5,095,274	1,010,789	4,084,485		-	-	
3		1701	Common AMI Meters - Smart Grid	6,962,488	2,186,660	4,775,828		-	-	
4		1890	Land and Land Rights	217,802	6,889	210,913		-	-	
5		1890	Land and Land Rights	712,330	42,482	669,848		-	-	
6		1890	Land and Land Rights	156,856	3,938	152,918		-	-	
7		1891	Rights of Way	0	0	0		-	-	
8		1900	Structures & Improvements - Clopay 3rd Floor	0	0	0	100%	-	-	
9		1900	Structures & Improvements - Clopay 4th/5th/6th Floor	0	0	0	100%	-	-	
10		1900	Structures & Improvements -Clopay Bldg & Access Ramp	0	0	0	100%	-	-	
11		1900	Structures & Improvements - 4th & Main	56,982,154	15,417,216	41,564,938	100%	41,564,938	14,032,929	1,874,713
12		1900	Structures & Improvements - Micro	57,954	11,924	46,030		-	-	
13		1900	Structures & Improvements	81,024	18,935	62,089		-	-	
14		1900	Structures & Improvements	25,077,634	2,113,420	22,964,214		-	-	
15		1900	Structures & Improvements - Holiday Park	0	0	0		-	-	
16		1910	Office Furniture & Equipment	3,708,247	1,243,694	2,464,553	100%	2,464,553	832,069	185,412
17		1911	Electronic Data Processing	1,071,488	658,960	412,528	100%	412,528	139,275	214,298
18		1911	Electronic Data Processing - Smart Grid	39,140	65,972	(26,832)		-	-	
19		1920	Transportation Equipment	46,486	46,486	0		-	-	
20		1921	Trailers	258,430	181,706	76,724		-	-	
21		1930	Stores Equipment	255,995	65,582	190,413		-	-	
22		1940	Tools, Shop & Garage Equipment	1,326,322	502,209	824,113		-	-	
23		1950	Laboratory Equipment	0	0	0		-	-	
24		1960	Power Operated Equipment	83,859	48,588	35,271		-	-	
25		1970	Communication Equipment	13,542,510	7,147,979	6,394,531	100%	6,394,531	2,158,887	903,285
26		1970	Communication Equipment - Micro	2,777,983	941,770	1,836,213		-	-	
27		1970	Communication Equipment - Node	5,305,215	0	5,305,215		-	-	
28		1970	Communication Equipment - Node - Smart Grid	0	0	0		-	-	
29		1970	Communication Equipment - Nodes being replaced	33,334,129	10,102,753	23,231,376		-	-	
30		1980	Miscellaneous Equipment	243,548	106,248	137,300		-	-	
31		1990, 1991	ARO Common General Plant	0	0	0		-	-	
					(409,601)	409,601		-	-	
32			Total Common Plant	184,388,305	68,320,146	116,068,159		50,836,550	17,163,161	3,177,708
			Customer Service Deposits			(18,535,684)		0.964088%	(178,700)	
			Unclaimed Funds			(322,353)		0.964088%	(3,108)	
			Postretirement Benefits			8,387,395	52.211%	4,379,142	1,478,462	
			Investment Tax Credits			0		0	-	
			Deferred Income Taxes			(499,759,260)		0.964088%	(4,818,117)	
			Smart Grid Post In Service Carrying Costs			32,446,159	0.000%	0	-	
						Total			13,641,698	
						Staff's midpoint (net of tax)			6.59%	
						Staff's GRCF			1.5613731	
						Revenue Requirement Impact			1,403,679	

SSO Plant Allocated to Rate Base	17,163,161
Staff's Adjusted Net Plant	1,780,249,041
Ratio	0.964088%

Exhibit JEH-4

Revenue Allocation Factor

Billed Revenue By Function 2016

	Distribution	Other Riders	Transmission	Generation	Total Billed
Non-Shopping	$ 147,824,823	$ 86,660,991		$ 308,480,915	$ 542,966,729
Shopping	$ 251,524,839	$ 119,215,751			$ 370,740,591
	$ 399,349,662	$ 205,876,742	$ -	$ 308,480,915	$ 913,707,320

Revenue Allocation Factor	33.76146%

Customer Count as of December 2017

	Distribution	Generation	Total
Non-Shopping	362,340	362,340	724,680
Shopping	347,923		347,923
	710,263	362,340	1,072,603

Weighted Customer Allocation Factor	33.78137%

Duke Energy Ohio
Case No. 17-1263-EL-SSO
IGS First Set Interrogatories
Date Received: August 29, 2017

IGS-INT-01-016

REQUEST:

Supplier Tariff page 52.4 lists a Customer Enrollment/Switching Fee of $5.00/switch charged to the supplier. Regarding this provision:

a. Are customers required to pay this fee when returning to SSO service?
b. What is the total amount in switching fees that Duke collected in 2016?

RESPONSE:

a. No.
b. $469,335

PERSON RESPONSIBLE: Scott Nicholson

Duke Energy Ohio
Case No. 17-1263-EL-SSO
IGS First Set Interrogatories
Date Received: August 29, 2017

IGS-INT-01-017

REQUEST:

Supplier Tariff page 52.4 lists a Bill Ready Fee of $0.056 per residential bill and $0.268 per commercial bill. Regarding this provision:

a. What is the total amount in bill ready billing fees that Duke collected in 2016 for all accounts and by customer class.

RESPONSE:

The total amount is $87,470.02 and the amounts by class are: Industrial $13,940.15, Commercial $24,696.23, OPA $3,722.88, Residential $45,012.76.

PERSON RESPONSIBLE: Scott Nicholson

Duke Energy Ohio
Case No. 17-0032-EL-AIR
IGS Second Set of Interrogatories
Date Received: October 5, 2017

IGS-INT-02-001

REQUEST:

Duke Energy Ohio's Supplier Tariff's Rate CS, Certified Supplier Charges, sheet No. 52.4 identifies a charge of $32 for 12 months of electronic interval meter data, per account. Regarding the charge identified above:

a. Describe and provide calculations demonstrating how the charge of $32 was derived.
b. Identify all costs being recovered through the $32 charge. Including but not limited to labor, software expenses, IT equipment, etc.
c. Identify the origin or basis of this $32 charge.
d. Describe the entire process used to deliver the applicable data to parties who pay the $32 under the current structure by which the data is delivered
e. Is the data provided to suppliers through an EDI transaction?
f. How much labor is required to provide each data request on a monthly basis?
g. How often and with what delay is interval data delivered to suppliers who pay the $32 charge under the current system?
h. Identify the amount of interval data charges collected by Duke in 2016.
i. Identify the amount of interval data charges collected by Duke during the test year.

RESPONSE:

a. These charges were agreed to through a stipulated settlement in ESPII, Case No.14-841-EL-SSO, *et al.*
b. See response to a.
c. See response to a.
d. Interval meter data is available either throught the Secured Certified Supplier Information (Portal) or through EDI transactions. Data deliveried via the Portal is provided after an account is entered into the Portal, and in the case of a residential customers an Authorization is required to be uploaded. After that, the interval data is provided within a few moments. Data deliveried via EDI is provided after a Supplier requests the interval data through an EDI 814HI or thru an enrollment 814E (secondary request). Then the interval data is sent through and EDI 867HI the next day.
e. See response to d.
f. A study of this is not available.
g. See response to d.
h. $556,560

i. $561,192

PERSON RESPONSIBLE: Scott Nicholson