JI Exhibit 5

STATE OF INDIANA

BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

CROSS-ANSWERING TESTIMONY OF JONATHAN WALLACH

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA, INC.,

INDIANA COMMUNITY ACTION ASSOCIATION,

AND

ENVIRONMENTAL WORKING GROUP

Resource Insight, Inc.

DECEMBER 4, 2019

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I. Introduction and Summary

Q: Please state your name, occupation, and business address.

A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Are you the same Jonathan F. Wallach who filed direct testimony in this proceeding?

A: Yes.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Citizens Action Coalition of Indiana, Inc. ("CAC"), Indiana Community Action Association ("INCAA"), and Environmental Working Group ("EWG") (collectively, "Joint Intervenors" or "JI").

Q: Are you sponsoring any attachments?

A: Yes. I am sponsoring the following attachments:

- Attachment JFW-1: DEI Response to CAC Data Request 21.1 and Attachment 21.1-A
- Attachment JFW-2: DEI Response to CAC Data Request 12.8 (Attachment 12.8-A will be provided in my workpapers)
- Attachment JFW-3: DEI Response to CAC Data Request 12.13 and Attachment CAC 12.13-A
- Attachment JFW-4: DEI Response to CAC Data Request 12.16
- Attachment JFW-5: DEI Response to CAC Data Request 12.15 and Attachment 12.15-B
- Attachment JFW-6: DEI Response to CAC Data Request 16.12(c)

Q: What is the purpose of your cross-answering testimony?

A: My cross-answering testimony responds to direct testimony by:

- Nicholas Phillips, Jr., on behalf of the Duke Industrial Group ("DIG"), regarding the allocation of production and distribution plant costs in Duke Energy Indiana's ("DEI" or "the Company") cost of service study ("COSS").
- Glenn A. Watkins, on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC"), regarding the design of residential volumetric energy rates.
- David E. Dismukes, PhD, on behalf of OUCC, regarding the Company's proposal to implement a Revenue Decoupling Mechanism ("RDM").

Q: Please summarize your response to DIG witness Phillips.

A: The Indiana Utility Regulatory Commission ("IURC" or "the Commission") should reject Mr. Phillips' recommendation that production plant costs be allocated in the Company's COSS using the 4CP allocator. As I discussed in my direct testimony, and as long held by the Commission, the 4CP allocator does not reasonably reflect the fact that system peak demands in all months of the year contribute to the Company's reserve requirements and need for reserve capacity.

Moreover, the Commission should reject Mr. Phillips' recommendation that DEI employ minimum-system methods to classify distribution-grid costs in its COSS. As discussed in detail below, minimum-system methods result in classifications and allocations of distribution-grid costs which are contrary to cost-causation principles.

Q: Please summarize your response to OUCC witness Watkins.

A: As noted by Mr. Watkins, the Company proposes two different declining-block rate structures for residential energy rates depending on whether the Commission approves the proposed Revenue Decoupling Mechanism. I agree with Mr. Watkins' conclusion that the proposed without-RDM rate structure is unreasonable since by the Company's own admission this rate structure is not cost-based.

However, I disagree with Mr. Watkin's recommendation that the Commission accept the proposed rate structure for the with-RDM scenario. The declining-block rate structures proposed by DEI in either the with-RDM or without-RDM scenarios would inappropriately recover more costs in the first energy block (and less costs in the second and third blocks) than is justified either on a long-run marginal or short-run average embedded cost basis, and thereby would dampen energy price signals and promote inefficient customer behavior.

As DEI acknowledges, the residential energy rate structure must be substantially modified to bring it in line with the Company's cost structure. The Company's proposal for the with-RDM declining-block rate structure represents a move in the right direction. However, it doesn't go far enough. Accordingly, the Commission should reject both the with-RDM and without-RDM rate structures proposed by DEI regardless of whether the proposed RDM is approved.

Instead, the Company should aim to eliminate the declining-block rate structure in order to more reasonably reflect long-run marginal costs and to remove incentives for increased usage.[1] However, in the interests of gradualism, I recommend for this proceeding that DEI set the block energy rates at a level that, in combination with the $9.01 fixed connection charge that I recommended in my direct testimony: (1) recovers the Commission-authorized allocation of base revenues to the residential class; and (2) provides no more than a 15% price discount from the first block to the third block energy rate.

Q: Please summarize your response to OUCC witness Dismukes.

A: As discussed by Dr. Dismukes, DEI lacks a reasonable basis for its proposal to implement a revenue per customer decoupling mechanism for residential and small-commercial customers. According to Dr. Dismukes, DEI has failed to show that it would suffer financial harm if the Commission were to reject the Company's proposal or that customers would benefit from more stable bills if the Commission were to approve the Company's proposal.

I would add that residential customers would likely suffer economic harm if the Company's proposal is approved. Over the proposed five-year RDM implementation period, residential customers would be expected to pay more for electric service with than without the RDM. In other words, the proposed RDM would be expected to not only stabilize, but also *enhance* revenue recovery for DEI and its shareholders between rate cases. Yet, the proposed RDM would offer no tangible economic benefits to residential or small-commercial customers in return, such as a reduction in the Company's cost of equity or a commitment to fund additional energy-efficiency efforts. I therefore concur with Dr. Dismuke's recommendation that the Commission reject the

[1] The Company should also consider offering time-of-use rates to electric vehicle owners in order to promote efficient charging practices by these higher-usage customers.

Company's proposal to implement a Revenue Decoupling Mechanism as contrary to the public interest.

II. Response to DIG Witness Phillips

A. Allocation of Demand-Related Production Plant Costs

Q: Please summarize DIG witness Phillips' direct testimony regarding the allocation of demand-related production plant costs.

A: As he argued in Cause No. 42359, Mr. Phillips asserts in his direct testimony in this proceeding that it is no longer appropriate to allocate demand-related production plant costs using the 12CP allocator because the Company's capacity investments are driven by the Company's peak demands in the four summer months.[2] Consequently, Mr. Phillips recommends allocation of demand-related production plant costs using the 4CP allocator proposed by DEI.[3]

Q: Did DEI derive the proposed 4CP allocator based on peak demands for the four summer months?

A: No. As I discussed in my direct testimony, the 4CP allocator in the Company's COSS allocates demand-related production plant costs in proportion to each class's contribution to system peak demand in one winter month (January) and

[2] Cause No. 42359 was the Company's (as Public Service of Indiana) last rate case prior to this one.

[3] *Verified Direct Testimony and Attachments of Nicholas Phillips, Jr. on behalf of the Duke Industrial Group*, Cause No. 45253, 13 (October 30, 2019) [Hereinafter "Phillips Direct"].

three summer months (June, August, and September).[4] It would appear, therefore, that Mr. Phillips' recommendation to use the Company's 4CP allocator is based on a misunderstanding of how that allocator is derived.

Q: How did the Commission respond to Mr. Phillips' recommendation to rely on a 4CP allocator in Cause No. 42359?

A: In Cause No. 42359, the Commission explicitly rejected Mr. Phillips' recommendation to allocate demand-related production plant costs with a 4CP allocator rather than with the 12CP allocator proposed by Public Service of Indiana. In so doing, the Commission noted its long-standing finding that "the 12-CP method is often utilized to reflect the full range of operating realities throughout the year including system demand, scheduled maintenance, and reserve requirements".[5]

Q: Given the Commission's long-standing support of the 12CP allocator, why is Mr. Phillips now recommending use of a 4CP allocator?

A: Mr. Phillips contends that there has been a material change in circumstances since Cause No. 42359 was decided which renders the 12CP allocator inadequate as a measure of cost-causation. Specifically, Mr. Phillips notes that, unlike at the time of Cause No. 42359, the Company's reserve requirements and thus need for investments in reserve capacity are now determined by the Midcontinent Independent System Operator ("MISO"). Mr. Phillips further

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[4] *See* Petitioner's Workpaper 3-JRB and Petitioner's Workpaper 4-JRB for the Company's derivation of the "4 MAX MONTHS AVERAGE" demand for each customer class. The Company developed its proposed 4CP allocator based on this measure of class demand at time of system peak.

[5] *In re PSI Energy, Inc.*, IURC Cause No. 42359 Final Order, 102 (May 18, 2004) (citing *In re Indiana Michigan Power Company,* IURC Cause No. 39314 Final Order, 171 (Oct. 15, 1997)).

contends the MISO determines reserve requirements (and thus the need for DEI investments in reserve capacity) based on peak demands in the summer months. Consequently, Mr. Phillips concludes that a 4CP allocator more-reasonably measures the contribution of each class to the need for new reserve capacity than a 12CP allocator.

Q: How do you respond to Mr. Phillips' claims regarding the reasonableness of a 4CP allocator?

A: I agree with Mr. Phillips that MISO is responsible for determining the Company's reserve requirements. However, Mr. Phillips is incorrect in his assertion that those requirements are driven solely by the Company's contribution to MISO peak demands in the summer months. To the contrary, as I discussed in my direct testimony, MISO's loss of load probability analysis determines the Company's annual reserve requirements based on demand throughout the year, not just on peak demand in the four summer months.[6]

Thus, the Company's investments in capacity to meet reserve requirements are driven by demand in every month, not just by the demands in the summer months as Mr. Phillips contends. Accordingly, the Commission should reject Mr. Phillips' recommendation to allocate demand-related production plant costs using the Company's 4CP allocator.

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[6] Although MISO determines the amount of capacity required for planning reserve based on demand throughout the year, it expresses the Company's reserve requirement as the percentage margin of required capacity over summer peak demand.

B. Classification of Distribution Costs

Q: How are distribution costs classified in the Company's cost of service study?

A: The Company's long-standing practice has been to classify distribution costs using what is commonly referred to as the "Basic Customer" classification method. Under the Basic Customer method, the costs incurred for meters, service drops, and customer services ("distribution-connection costs") are classified as customer-related and all other distribution costs ("distribution-grid costs") are classified as demand-related.

Q: Does the Basic Customer method classify distribution costs consistently with cost-causation principles?

A: Yes. As the Commission found in Cause No. 44075 for the Indiana Michigan Power Company ("I&M"), the Basic Customer method reasonably reflects the fact that investments in distribution-grid costs (as recorded in FERC accounts 364 through 368) are driven by demand and thus appropriately classified as demand-related:

> The Company's classification of distribution plant accounts 364-368 is consistent with the NARUC Manual and is based on principles of cost causation. Accordingly, we are persuaded that distribution plant costs included in accounts 364-368 are incurred based on peak demand and should be classified as demand-related and allocated using the Company's demand allocation factors. I&M's proposed classification and allocation of distribution plant continues to be an appropriate method due to its foundation in cost-causation.[7]

Q: What does DIG witness Phillips recommend with regard to the classification of distribution costs?

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[7] *In re Indiana Michigan Power Company*, IURC Cause No. 44075 Final Order at 117 (Feb. 13, 2013).

A: Mr. Phillips recommends that DEI switch from the Basic Customer method to a minimum-system approach for classifying distribution-grid costs.

Q: Please describe the minimum-system classification approach.

A: Minimum-system classification methods attempt to estimate the cost to install the same amount of poles, conductors, conduit, and line transformers as are currently on a utility's distribution system, assuming that each piece of distribution equipment is sized to meet minimal or zero load. In other words, minimum-system methods attempt to estimate the cost to replicate the configuration of an existing distribution grid assuming that grid was built to serve minimal or zero load.

There are two approaches for estimating the cost of this hypothetical minimum distribution grid. The "minimum-size" approach attempts to estimate the cost to replicate the configuration of the existing distribution system using the smallest-size equipment currently used on the system.

Alternatively, the "minimum-intercept" approach attempts to estimate the cost to replicate the existing distribution grid using hypothetical equipment sized to meet zero load. The minimum-intercept approach estimates the cost of this hypothetical zero-load equipment by deriving a functional relationship between equipment cost and equipment size based on the current system, and then extrapolating that cost function to estimate the cost of equipment that carries zero load (e.g., 0-kVA transformers), the smallest units legally allowed (e.g., 25-foot poles), or the smallest units physically feasible (e.g., the thinnest conductors that will support their own weight in overhead spans).

Under either approach, the cost of the hypothetical minimum distribution grid (along with distribution-connection costs) would be classified as customer-related, and the difference between the total cost of the distribution grid and the estimated cost of the hypothetical minimum distribution grid would be classified as demand-related.

Q: How do you respond to Mr. Phillips' recommendation that DEI adopt the minimum-system method for classifying distribution-grid costs?

A: The minimum-system method suffers from a number of conceptual and structural flaws which result in misclassifications of distribution-grid costs. These misclassifications, in turn, lead to allocations of distribution-grid costs which are contrary to cost-causation principles. Specifically, minimum-system classifications will result in an over-allocation of distribution-grid costs to the residential class. Accordingly, the Commission should reject any such recommendation.

Q: Has the Commission previously rejected recommendations for an Indiana utility to adopt minimum-system methods for classifying distribution-grid costs?

A: Yes. In its order in Cause No. 44075 for I&M, the Commission explicitly rejected recommendations by the City of Fort Wayne and by the I&M Industrial Group to switch to a minimum-system classification of distribution-grid costs.[8]

Q: Why do minimum-system methods produce cost classifications that are inconsistent with cost-causation principles?

A: Minimum-system methods are premised on the false notion that utilities incur a "minimum" amount of distribution-grid costs to serve customers at zero load and then incur additional costs to meet the total load of those customers. In reality, utilities typically size their distribution systems, and incur the costs to

[8] *Id.*

build those systems, based on an expectation regarding the total demand of all customers connected to the grid. In other words, distribution-grid costs are typically driven by customer load, not by the number of customers.

Contrary to typical engineering and investment practice, minimum-system methods posit an imaginary world where some portion of the Company's distribution-grid costs were incurred regardless of customer demand. Consequently, applying minimum-system methods to the Company's distribution-grid costs would yield classifications that are inconsistent with cost-causation.

Q: Are there other aspects of minimum-system approaches to cost classification that are inconsistent with cost-causation principles?

A: Yes. Even if one accepts the false premise of a minimum distribution system, minimum-system approaches suffer from a number of structural defects which lead to classifications and allocations of distribution-grid costs that are contrary to cost-causation principles.

For one, both the minimum-size and minimum-system approaches erroneously assume that the minimum system would consist of the same amount of equipment (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the amount of equipment, as well as their size. Minimum-system analyses ignore the effect of loads on the amount or type of equipment installed, classifying some costs as customer-related even though they are really driven by demand.

This problem is particularly acute for the minimum-intercept method since this approach relies on an extrapolation from the current system to estimate the cost of a system that serves zero load. A system designed to connect customers but serve zero load would likely look very different from the existing system. For example, a zero-capacity electric system would not use the overlapping primary and secondary systems and line transformers that a real system uses. Without the need for high voltages to carry power, poles could be shorter and cross-arms would be unnecessary; with no transformers or cross-arms, and lighter conductors, poles could be thinner as well. The labor and equipment costs of setting those short, light poles would be much lower than the costs of real utility poles of any size. It is therefore unlikely that a cost estimate based on an extrapolation from the current system would reasonably reflect the cost of an actual zero-load system.[9] If so, then the minimum-intercept approach would misclassify demand-related costs as customer-related and thereby over-allocate distribution-grid costs to the residential class.

Finally, the minimum-size method fails to account for the fact that even the minimum-size equipment currently installed on the system has some amount of load-carrying capability. Consequently, some portion of the cost for this minimum-size equipment should be classified as demand-related. However, under the minimum-size method, that demand-related portion of the cost of the minimum-sized equipment instead would be misclassified as customer-related.

Q: What do you conclude with regard to the classification of distribution-grid costs?

A: The Commission should reject the recommendation by DIG witness Phillips that DEI employ minimum-system methods to classify distribution-grid costs. As discussed above, minimum-system methods result in classifications and allocations of distribution-grid costs which are contrary to cost-causation

[9] Indeed, it could be reasonably argued that the true cost of a zero-load system is zero since no equipment or labor is required where there is no load to be carried.

principles. Instead, the Commission should approve the Company's continued use of the Basic Customer method for classifying distribution-grid costs.

III. Response to OUCC Witness Watkins

Q: Please describe the current structure of the Company's volumetric energy rates for residential customers.

A: The Company's residential energy rates currently employ a "declining-block" rate structure. Under a declining-block rate structure, a customer pays a higher volumetric rate for usage up to a certain threshold amount (i.e., a "block" of usage) than for usage that exceeds that threshold. The Company's current residential energy rate uses three energy blocks: (1) for monthly usage up to 300 kWh; (2) for monthly usage between 301 and 1,000 kWh; and (3) for monthly usage in excess of 1,000 kWh. Residential customers currently pay a rate of: (1) 8.91¢/kWh for monthly usage up to 300 kWh; (2) 5.19¢/kWh (a 42% discount from the first-block rate) for monthly usage in excess of 300kWh but up to 1,000 kWh; and (3) 4.26¢/kWh (an 18% discount from the second-block rate and a 52% discount from the first-block rate) for monthly usage in excess of 1,000 kWh.[10]

Q: Please describe the Company's proposal with regard to the design of volumetric energy rates for residential customers.

A: As indicated in Table 1, the Company proposes two different declining-block rate structures for residential energy rates depending on whether the Commission approves the proposed Revenue Decoupling Mechanism

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[10] For residential customers taking service under Contract Rider No. 6.3 (Optional High Efficiency Residential Service), the third-block rate of 4.26¢/kWh applies solely in the months July through October. For all other months, the third-block rate is 3.62¢/kWh.

("RDM"). In both cases, DEI proposes to continue employing three energy blocks. For the without-RDM block energy rates, DEI proposes to reduce the discounts between the first and second block rates and between the second and third block rates compared to the current block rate discounts. For the with-RDM block energy rates, the Company proposes to narrow the spread between block rates even further.

Table 1: Current and DEI Proposed Residential Energy Rates

	Current (¢/kWh)	Discount from First Block	Proposed without RDM (¢/kWh)	Discount from First Block	Proposed with RDM (¢/kWh)	Discount from First Block
Up to 300 kWh	8.91		16.09		15.09	
301-1,000 kWh	5.19	41.7%	11.71	27.2%	12.23	18.9%
Over 1,000 kWh	4.26	52.2%	10.61	34.0%	11.03	26.9%

Q: Why is DEI proposing to alter the current design for residential energy rates?

A: According to DEI witness Jeffrey R. Bailey, the Company is proposing a major revision to the current rate design because the current design no longer reflects the Company's cost structure:

> The current structure of Rate RS includes a significant declining block structure that by itself would be difficult to justify today.[11]

Q: What is the basis for the Company's proposed block discounts for the with-RDM and without-RDM residential energy rates?

A: According to Mr. Bailey, the block rate structure proposed for the with-RDM scenario was designed to reflect the Company's average embedded cost curves.

[11] *Revised Direct Testimony of Jeffrey R. Bailey*, Cause No. 45253, 4 (September 9, 2019) [Hereinafter "Revised Bailey Direct"].

Specifically, the proposed block discounts for the with-RDM energy rates are set to mimic the Company's estimate of the decline in residential non-customer-related test-year revenue requirement per kWh as usage increases.[12]

In contrast, DEI did not design the proposed without-RDM block rate structure based on its average embedded cost curves. Instead, the without-RDM block rate structure was designed to provide a "modest reduction in risk to the Company" relative to the proposed with-RDM block rate structure.[13]

Q: What does OUCC witness Watkins recommend with regard to the Company's proposals for the design of residential energy rates?

A: Regardless of whether the Commission approves the Company's RDM proposal, Mr. Watkins recommends rejection of the proposed without-RDM rate structure since DEI lacks a valid rationale for its proposal to deviate from cost in the design of residential energy rates.[14] Instead, Mr. Watkins recommends approval of the Company's proposed with-RDM rate structure for residential energy rates.[15]

Q: How do you respond to Mr. Watkins' recommendations regarding the Company's proposals for the design of residential energy rates?

A: I agree with Mr. Watkins that the Commission should reject the Company's proposal for without-RDM rates. Regardless of whether the Commission approves the Company's RDM proposal, it would not be appropriate to deviate

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[12] *Id.*, 4-5.

[13] *Id.*, 5.

[14] *Verified Direct Testimony of Glenn A. Watkins on behalf of the Indiana Office of Utility Consumer Counsel*, Cause No. 45253, 29 (October 30, 2019).

[15] *Id.*, 3.

from cost in the design of residential energy rates solely for the purpose of providing a "modest reduction in risk to the Company".[16]

On the other hand, I disagree with Mr. Watkins' recommendation that the Commission approve the Company's proposed with-RDM rate structure for residential energy rates. Whether viewed from a long-run price efficiency perspective or short-run cost-causation price perspective, the Company's proposed with-RDM rate structure is not cost-based. As I discussed in my direct testimony, from a long-run price efficiency perspective, the with-RDM rate structure should be designed to reflect marginal, not average, embedded costs. A marginal cost design would likely support a flat, if not inclining, rate structure for the Company's residential energy rates.

Even from a short-run cost-causation perspective, the proposed with-RDM rate structure is not cost-based because the Company's average embedded cost curves which serve as the basis for the proposed rate structure are derived from a flawed cost of service study that misallocates costs to the residential class.[17]

Q: Have you adjusted the Company's average cost curves to correct for these flaws in the Company's COSS?

A: Yes. As I discussed in my direct testimony, DEI modified its cost of service study to correct for the misallocations I had identified. I then used the results of this corrected COSS to re-estimate the Company's average cost curves.[18]

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[16] Revised Bailey Direct, 5.

[17] I describe in detail the flaws in the Company's COSS in my direct testimony.

[18] The results of the corrected COSS were provided in DEI Response to CAC Data Request 21.1 and corresponding Attachment 21.1-A (Attachment JFW-1). I re-estimated the Company's average cost curves by modifying the spreadsheet relied on by DEI to develop its average cost curves, as provided in DEI Response to CAC Data Request 12.8 (Attachment JFW-2). DEI's

Q: Have you developed an average cost-based block rate structure for residential energy rates based on your re-estimation of the Company's average cost curves?

A: Yes. Using my re-estimation of the Company's average cost curves, I mimicked the Company's procedures for developing a block rate structure based on the average cost curves.[19] As indicated in Table 2, an average cost-based block rate structure is substantially flatter than that proposed by DEI for the with-RDM scenario.

Table 2: DEI Proposed and Average Cost-Based Block Rate Structure

	Discount From First Block	
	DEI Proposed	**Average Cost-Based**
Second Block	18.9%	6.7%
Third Block	26.9%	9.9%

Q: What do you conclude with regard to OUCC witness Watkins's recommendations for the design of residential energy rates?

A: The declining-block rate structures proposed by DEI in either the with-RDM or without-RDM scenarios would inappropriately recover more costs in the first energy block (and less costs in the second and third blocks) than is cost-

corresponding Attachment 12.8-A and the workpaper for my re-estimation of the Company's average cost curves will be provided to the Commission in my workpaper submission.

[19] I developed an average cost-based rate structure by modifying the spreadsheet relied on by DEI to develop its proposed with-RDM rate structure, as provided in DEI Response to CAC Data Request 12.13 and corresponding Attachment CAC 12.13-A (Attachment JFW-3). The workpaper for my development of an average cost-based block rate structure will be provided to the Commission in my workpaper submission.

justified, and thereby would dampen energy price signals and promote inefficient customer behavior.

Consequently, I agree with Mr. Watkins's recommendation to reject the Company's proposed block rate structure for the without-RDM scenario. On the other hand, I disagree with his recommendation that the Commission approve the Company's proposed with-RDM rate structure. As DEI acknowledges, the current residential energy rate structure must be substantially modified to bring it in line with the Company's cost structure. The Company's proposal for the with-RDM declining-block rate structure represents a move in the right direction. However, it doesn't go far enough. Accordingly, the Commission should reject both the with-RDM and without-RDM rate structures proposed by DEI regardless of whether the proposed RDM is approved.

Instead, the Company should aim to eliminate the declining-block rate structure in order to more reasonably reflect long-run marginal costs and remove incentives for increased usage. However, in the interest of gradualism, I recommend for this proceeding that DEI set the block energy rates at a level that, in combination with the $9.01 fixed connection charge that I recommended in my direct testimony: (1) recovers the Commission-authorized allocation of base revenues to the residential class; and (2) provides no more than a 15% price discount from the first block to the third block energy rate.

IV. Response to OUCC Witness Dismukes

Q: Please describe the Company's proposal for a Revenue Decoupling Mechanism.

A: As it applies to the residential class, the proposed RDM would allow for recovery of the difference between an "allowed" amount of demand-related revenues (so-called "fixed" revenues) and the actual amount of demand-related revenues. Any positive or negative difference between allowed and actual fixed revenues in the year would be deferred and recovered from or credited to residential customers, respectively, in the following year.

In each year of the proposed five-year implementation period, the *allowed* amount of fixed revenues would be calculated as the product of: (1) actual number of residential customers; and (2) allowed fixed revenue per customer ("FRC"). The allowed FRC would be derived as the ratio of: (1) 2020 test-year demand-related costs allocated to the residential class; and (2) 2020 test-year number of customers. While the allowed FRC would remain constant over the five-year implementation period, the allowed amount of fixed revenues would vary with the actual number of customers.

Under the proposed RDM, the *actual* amount of fixed revenues in each year would be calculated as the product of: (1) actual residential sales; and (2) the Fixed Energy Charge ("FEC"). The FEC would be derived as the ratio of: (1) 2020 test-year demand-related costs allocated to the residential class; and (2) 2020 test-year residential sales. The FEC therefore represents the per-kWh rate at which residential demand-related costs are recovered through volumetric energy charges. As with the calculation of allowed fixed revenues, while the FEC would remain constant over the five-year implementation period, the actual amount of fixed revenues would vary with actual sales.[20]

Thus, DEI is proposing the RDM as a way to "decouple" recovery of fixed revenues from residential sales. In the absence of decoupling, the amount of fixed revenues recovered from residential customers would be determined by the volume of residential sales (i.e., by the product of the FEC and residential sales). In contrast, with the proposed RDM, the amount of fixed revenues recovered from residential customers would effectively be set at the product of the FRC and the number of residential customers, regardless of residential sales volumes.[21]

Q: Why is the Company proposing to decouple fixed revenue recovery from residential sales through the RDM?

A: According to Company witness Brian P. Davey, the Company is primarily concerned that, because of declining customer usage and resulting slow sales growth, residential fixed revenues currently recovered through energy rates will not keep pace with the escalation in fixed costs incurred by DEI over time.[22] Mr. Davey further asserts that this growing gap between fixed costs and

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[20] The Company illustrates the mechanics of the proposed RDM in Petitioner's Exhibit 7-H (MTD).

[21] With the proposed RDM, the actual amount of fixed revenues recovered from residential customers in any year will still be determined by the product of the FEC and residential sales in that year. However, any differences between actual fixed revenue recovery through energy rates (as driven by actual sales volume) and allowed fixed revenue recovery (as driven by actual number of customers in that year) will be reconciled in the following year.

[22] *Revised Direct Testimony of Brian P. Davey*, Cause No. 45253, 26-27 (September 9, 2019) [Hereinafter "Revised Davey Direct"]. These concerns are echoed by Company witness Jeffrey R. Bailey. *See* Revised Bailey Direct, 24-25.

fixed revenues, and the resulting erosion in shareholder earnings, would necessitate "more frequent base rate cases".[23]

In contrast, as Mr. Davey sees it, the proposed RDM would allow residential fixed revenues to keep pace with fixed-cost escalation by growing allowed fixed revenues with growth in the number of residential customers. According to Mr. Davey, by allowing fixed revenues to increase with customer growth, the proposed RDM would reduce the frequency of base rate cases.[24] In addition, Mr. Davey notes that residential fixed revenues would be less volatile if such revenues were driven by customer growth (per the proposed RDM) than by sales growth (as is currently the case).[25]

Q: Has DEI offered any evidence regarding the expected growth in fixed costs or the extent to which residential fixed revenues would fall short of fixed costs if such revenues continued to grow with residential sales?

A: Not that I am aware of.

Q: Has the Company estimated the likely frequency of base rate cases for the with-RDM or without-RDM scenarios?

A: No.[26]

Q: Please summarize OUCC witness Dismukes' findings and conclusions regarding the Company's proposal to implement a Revenue Decoupling Mechanism.

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[23] *Id.*, 26.

[24] DEI Response to CAC Data Request 12.16(a) (Attachment JFW-4).

[25] Revised Davey Direct, 27.

[26] DEI Response to CAC Data Request 12.16(c), (d), and (e) (Attachment JFW-4).

A: Dr. Dismukes finds that DEI lacks a reasonable basis for its proposal to implement a revenue per customer decoupling mechanism for residential and small-commercial customers. According to Dr. Dismukes, DEI has failed to show that it would suffer financial harm if the Commission were to reject the Company's proposal or that customers would benefit from more stable bills if the Commission were to approve the Company's proposal. Accordingly, Dr. Dismukes recommends that the Commission reject the Company's request to implement the proposed RDM.[27]

Q: How do you respond to Dr. Dismukes' findings and conclusions regarding the Company's proposal to implement a Revenue Decoupling Mechanism?

A: While the Company's shareholders may not suffer harm if the proposed RDM is rejected by the Commission, the same cannot be said for the Company's residential customers if the proposed RDM is approved. To the contrary, residential customers would be expected to pay more for electric service with than without the proposed RDM without receiving any tangible economic benefit in return.

Q: Why is it that residential customers are expected to pay more for electric service under the proposed RDM?

A: As discussed above, fixed revenues recovered from residential customers would increase over time with growth in customer count under the proposed RDM rather than with growth in energy sales under current ratemaking practice. The Company currently forecasts residential customer count to grow at a faster pace than residential energy sales over the proposed five-year RDM

[27] *Testimony of OUCC Witness David E. Dismukes, PhD*, Cause No. 45253, 25 and 31-32 (October 30, 2019) [Hereinafter "Dismukes Direct"].

implementation period. Consequently, fixed revenue recovery under the proposed RDM is expected to exceed that under current ratemaking practice over the five-year implementation period. In other words, the proposed RDM would be expected to not only ensure, but also enhance revenue recovery for DEI and its shareholders between rate cases.

Specifically, over the proposed five-year RDM implementation period, DEI currently forecasts an average annual growth rate of 0.85% for number of residential customers and 0.11% for residential energy sales.[28] Based on those growth rates, I estimate that residential fixed revenue recovery under the proposed RDM would exceed that under current ratemaking practice by about $56 million over the five-year implementation period.[29]

Q: Are residential customers likely to receive any tangible economic benefits in return for higher bills under the proposed RDM?

A: No. As Dr. Dismukes notes, the proposed RDM would benefit the Company's shareholders with revenue stability, but not the Company's customers with bill stability. Likewise, according to Company witness Robert B. Hevert, while the proposed RDM offers shareholders reduced earnings risk, it would not offer customers the benefit of a reduction in the Company's cost of equity.[30]

And although the proposed RDM would eliminate revenue erosion between rate cases resulting from a decline in residential usage, according to Dr. Dismukes, the Company has not committed to increase its spending on

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[28] Growth rates calculated based on data provided in DEI Response to CAC Data Request 12.15 and corresponding Attachment 12.15-B (Attachment JFW-5).

[29] The workpaper for my estimate of excess residential fixed revenue recovery under the proposed RDM will be provided to the Commission in my workpaper submission.

[30] DEI Response to CAC Data Request 16.12(c) (Attachment JFW-6).

energy efficiency programs.[31] Nor has DEI committed to a specific length of time before filing its next base rate case, despite the Company's claim that the proposed RDM would reduce the frequency of such filings.[32]

Q: What do you conclude with regard to OUCC witness Dismukes' recommendation that the Commission reject the Company's RDM proposal?

A: Given the potential harm to residential customers from implementation of the proposed RDM, I concur with Dr. Dismukes' recommendation that the Commission reject the Company's request to implement the proposed RDM.

Q: Does this conclude your cross-answering testimony?

A: Yes.

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[31] Dismukes Direct, 29-30.

[32] DEI Response to CAC Data Request 12.16(b) (Attachment JFW-4). On the other hand, in retrospect, residential customers may not have benefitted from the extended duration between the previous and current rate cases given OUCC witness Lane Kollen's finding that DEI is currently over-earning. *See Verified Direct Testimony of Lane Kollen on behalf of the Indiana Office of Utility Consumer Counsel*, Cause No. 45253, 3-4 (October 30, 2019).