CAC-INCAA Exhibit 2

STATE OF INDIANA

BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS	)	**CAUSE NO. 45235**

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA, INC.

AND

INDIANA COMMUNITY ACTION ASSOCIATION

Resource Insight, Inc.

AUGUST 20, 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: Please summarize your professional experience.

A: I have worked as a consultant to the electric power industry since 1981. From 1981 to 1986, I was a Research Associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a Senior Analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since 1990.

Over the past four decades, I have advised and testified on behalf of clients on a wide range of economic, planning, and policy issues relating to the regulation of electric utilities, including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market-price forecasting; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and mitigation; integrated resource planning; mergers and acquisitions; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Attachment JFW-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have sponsored expert testimony in more than 90 state, provincial, and federal proceedings in the U.S. and Canada, including before the Indiana Utility Regulatory Commission ("the Commission") in Cause Nos. 44967, 45029, and 45159. I include a detailed list of my previous testimony in Attachment JFW-1.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Citizens Action Coalition of Indiana, Inc. ("CAC") and Indiana Community Action Association ("INCAA").

Q: Are you sponsoring any attachments?

A: Yes. I am sponsoring the following attachments:

- Attachment JFW-1: Resume of Jonathan Wallach, Resource Insight, Inc.
- Attachment JFW-2: Citations to Marginal-Price Elasticity Studies
- Attachment JFW-3: I&M Supplemental Response to CAC Data Request 5-2
- Attachment JFW-4: I&M Response and Attachment to South Bend Data Request 4-6
- Attachment JFW-5: I&M Response to CAC Data Request 5-3
- Attachment JFW-6: National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, 38-39 (January, 1992)
- Attachment JFW-7: I&M Supplemental Response and Attachment to CAC Data Request 3-4
- Attachment JFW-8: I&M 2018-2019 Integrated Resource Plan, 105 (July 1, 2019)
- Attachment JFW-9: Cause No. 44967, Direct Testimony of Mr. Matthew W. Nollenberger, 12-13 (July 26, 2017)
- Attachment JFW-10: National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016)
- Attachment JFW-11: James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 334 (1961)
- Attachment JFW-12: Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988)

- Attachment JFW-13: Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964)
- Attachment JFW-14: I&M Response to CAC Data Request 6-2
- Attachment JFW-15: I&M Response to CAC Data Request 4-10

Q: What is the purpose of your testimony?

A: On May 14, 2019, Indiana Michigan Power Company ("I&M" or "the Company") filed a petition (including supporting direct testimony) with the Commission for authority to increase electric rates. My testimony addresses the Company's proposals to:

- Invest in advanced metering infrastructure ("AMI") and recover such investments through base rates, as discussed in direct testimony by I&M witnesses Toby L. Thomas and Andrew J. Williamson.
- Allocate among the various customer classes the forecasted revenue deficiency for the 2020 test year, as discussed in direct testimony by I&M witness Matthew W. Nollenberger, on the basis of the results of a class cost-of-service study (CCOSS), as discussed in direct testimony by I&M witness Michael M. Spaeth.
- Increase the monthly service charge and introduce a declining-block volumetric energy rate for residential customers, as described by Mr. Nollenberger.[1]
- Pilot a voluntary demand-metered tariff for residential customers, as described by I&M witnesses Kurt C. Cooper and Nollenberger.

[1] By "residential", I mean in the context of rate design those customers taking service under Tariff RS (Residential Electric Service). I do not address the Company's proposals regarding the monthly service charge or energy rates for customers taking service under Tariff RS-TOD (Residential Time-of-Day Service) or Tariff RS-TOD2 (Experimental Residential Time-of-Day Service).

Q: Please summarize your findings and conclusions with regard to the Company's proposed AMI deployment plan.

A: The Company seeks pre-approval of its proposal to invest in advanced metering infrastructure and associated customer-engagement software. The Company further requests base-rate recovery of AMI revenue requirements in the 2020 test year. The Commission should deny both of these requests because I&M has failed to show that the proposed AMI investments could reasonably be expected to be economically used and useful. Instead, the Commission should docket a separate proceeding to consider the Company's AMI proposal and direct I&M to file a cost-effectiveness analysis of its AMI proposal in that proceeding.

Q: Please summarize your findings and conclusions with regard to I&M's proposal for allocating the requested revenue increase.

A: The Commission should reject the Company's proposal for allocating the requested revenue deficiency because it relies solely on the results of a class cost-of-service study that does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. Instead, based on the range of results from the Company's CCOSS and from a CCOSS that corrects the misallocations in the Company's CCOSS, a fair and reasonable approach would be to: (1) maintain base revenues at current levels (i.e., no increase or decrease) for those classes where the class cost of service studies show a revenue decrease at an equalized rate of return; and (2) increase base revenues for all other classes by the same percentage in order to recover any authorized revenue deficiency.

Q: Please summarize your findings and recommendations with regard to I&M's proposal to increase the residential service charge.

A: The Company's proposal runs contrary to long-standing principles for designing cost-based rates since it would inappropriately shift recovery of demand-related costs from the volumetric energy rate to the fixed service charge. As explained in more detail below, the Company's proposal to recover demand-related costs through the residential service charge would:

- Lead to subsidization of high-usage residential customers' costs by low-usage customers, and thereby inequitably increase bills for the Company's low-usage residential customers.
- Dampen price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

Consequently, the Commission should reject the Company's proposal to increase the residential monthly service charge.

Instead, I recommend that the residential service charge be set at $10.12 per residential customer per month. Consistent with long-standing cost-causation and rate-design principles, a monthly service charge of $10.12 per customer would provide for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer.

Q: Please summarize your findings and recommendations with regard to the design of volumetric energy rates for residential customers.

A: The Company lacks a reasonable basis for its proposal to implement a declining-block structure for residential volumetric energy rates. The Company's proposal to recover demand-related costs at a higher rate in the first energy block than in the second block would further dampen energy price signals and promote inefficient customer behavior. Accordingly, the Commission should reject the Company's request to implement a declining-block rate structure for residential volumetric energy rates. Instead, I&M should be directed to: (1) maintain the current flat-rate structure for residential energy rates; and (2) set the residential energy rate at a level that, in combination with a $10.12 fixed service charge, recovers the Commission-authorized allocation of base revenues to the residential class.

Q: Please summarize your findings and recommendations with regard to the Company's proposal for a residential demand-rate pilot.

A: A residential demand charge such as the Company proposes for the pilot will dampen price signals for conservation, encourage inefficient customer behavior, and undermine customers' ability to control electricity costs. All of which begs the question as to why a utility seeking to invest more than $90 million in state-of-the-art advanced metering infrastructure would propose to use that sophisticated technology to support an antiquated and economically inefficient rate structure for residential customers.

Given these concerns, if the Commission chooses to approve the Company's request, I&M should be directed to file a detailed implementation plan in advance of the roll-out of the pilot. This implementation plan should include, at a minimum, detailed plans for customer education, for ongoing communications with participants regarding usage patterns and bill savings, and for monitoring and evaluation of program performance. Any such implementation plan should clearly state the objectives of the pilot and the criteria by which regulators and the public should determine whether the pilot was a success.

Q: How is the rest of your testimony organized?

A: In Section II, I explain why the Company's request for pre-approval of proposed spending on advanced metering infrastructure should be denied at this time. In Section III, I describe how the Company's proposal for allocating the test-year revenue deficiency relies on a CCOSS that misallocates production plant costs and propose an alternative approach for allocating test-year revenues to correct for the flaws in the Company's CCOSS. In Section IV, I explain how I&M's proposal to increase the residential service charge violates long-standing principles of cost-based rate design, would give rise to unreasonable cost subsidization within the residential class, and would dampen energy price signals. In Section V, I explain how the Company's proposal to implement a declining-block structure for residential volumetric energy rates would further dampen energy price signals. In Section VI, I discuss I&M's proposal to pilot a demand charge for residential customers. Finally, I provide my conclusions and recommendations in Section VII.

II. Advanced Metering Infrastructure

Q: Please summarize the Company's request with regard to the deployment of advanced metering infrastructure.

A: The Company requests Commission pre-approval of its plan to invest about $94 million in advanced metering infrastructure and associated customer-engagement software over three years starting in 2020.[2] The Company further seeks to recover through base rates estimated AMI capital investments

[2] *Pre-Filed Verified Direct Testimony of Toby L. Thomas*, Cause No. 45235, 19 (May 14, 2019).

and O&M expenses for the 2020 test year.[3] Finally, I&M requests Commission approval of a new rider that would allow the Company to track and eventually recover actual AMI expenditures in excess of estimated costs recovered through base rates.[4]

Q: Why does I&M seek pre-approval of its AMI deployment plan?

A: According to I&M witness Andrew J. Williamson, the Company seeks pre-approval in order to "avoid potential disputes over the used and usefulness of this investment once it has been placed in service."[5] Mr. Williamson further suggests that "much like a large investment in a generation resource", the costs and benefits – and thus the economic used and usefulness – of the proposed investment in AMI should be assessed over the life of the investment.[6]

Q: Does it make sense to try and reduce the likelihood of after-the-fact disputes over used and usefulness?

A: It does. However, if I&M wishes to avoid disputes over used and usefulness *after* the investment is placed in service, then it should at least show that there is a reasonable expectation that the investment will be used and useful *before* it is placed in service. In other words, the Commission should withhold approval of the planned investment until such time that I&M can show that investment is reasonably expected to be cost-effective over its useful life.

[3] I&M Supplemental Response to CAC Data Request 5-2 (Attachment JFW-3).

[4] *Pre-Filed Verified Direct Testimony of Andrew J. Williamson*, Cause No. 45235, 34 (May 14, 2019).

[5] *Id.*, 35.

[6] *Id.*

Q: Has I&M provided any evidence in this Cause that the proposed AMI investments are expected to be cost-effective over the life of the investments?

A: No. To the contrary, an analysis by I&M in 2016 of AMI cost-effectiveness showed that, on a discounted basis over 15 years, AMI costs were expected to be more than double AMI benefits (for a benefit-cost ratio of 0.45).[7]

According to the Company's response to discovery, I&M management did not rely on this analysis because it did not model the Company's specific proposal for AMI deployment in this Cause.[8] However, I&M never undertook any further studies to assess whether the proposed AMI deployment plan would be expected to be economically used and useful.[9]

Q: Should the Commission grant the Company's request for pre-approval of its proposed AMI deployment plan?

A: Not at this time. As discussed above, I&M has not shown that the proposed AMI deployment plan could reasonably be expected to be cost-effective. Nor has the Company shown whether there might be sufficient non-monetizable benefits to reasonably justify an uneconomic investment. I therefore recommend that the Commission deny the Company's requests for pre-approval and for base-rate recovery of 2020 test-year AMI revenue requirements.

Instead, the Commission should docket a separate proceeding to consider the Company's request for pre-approval and direct I&M to file a

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[7] Provided in I&M Response and Attachment to South Bend Data Request 4-6 (Attachment JFW-4).

[8] I&M Response and Attachment to South Bend Data Request 4-6 (Attachment JFW-4).

[9] I&M Response to CAC Data Request 5-3 (Attachment JFW-5).

cost-effectiveness analysis of its proposed AMI deployment plan as part of its petition in that proceeding. If the Commission approves the Company's AMI deployment plan in this separate proceeding, it can provide for full recovery of actual AMI costs (net of reductions in AMR base revenue requirements) through the proposed AMI rider.

III. Revenue Allocation

Q: Please describe the Company's requested revenue increase.

A: The Company is requesting that electric base rates be increased on average by 14.3% in order to recover an expected revenue deficiency of about $164.6 million in the 2020 test year.[10] Of the total $164.6 million requested base revenue increase, I&M proposes to allocate about $78.9 million to residential customers. This amount represents a 15.8% increase over residential test-year revenues under current rates.[11]

Q: What is the basis for the Company's proposed allocation of the requested base revenue increase to the residential class?

A: According to I&M witness Matthew W. Nollenberger, the Company's CCOSS served as the basis for its revenue allocation proposal. Specifically, the Company's CCOSS indicates that residential base revenues would have to be increased by about $84.7 million, or about 16.9%, to achieve the requested rate of return.[12] Of that total increase, the Company's CCOSS

[10] *Pre-Filed Verified Direct Testimony of Matthew W. Nollenberger*, Cause No. 45235, Attachment MWN-2, 3 (May 14, 2019) [Hereinafter "Nollenberger Direct"].

[11] *Id.*, Attachment MWN-2, 4.

[12] *Id.*, Attachment MWN-2, 3.

indicates that about $7.5 million represents the increase required to achieve the system average rate of return under current rates.[13] In other words, the Company's CCOSS indicates that the residential class is currently under-earning relative to the system average achieved rate of return and that the current "subsidy" amounts to $7.5 million. According to Mr. Nollenberger, I&M proposes to increase residential base revenues to eliminate 25% of this current subsidy.[14]

Q: What is the purpose of a class cost of service study?

A: The primary purpose of a class cost of service study is to allocate a utility's total revenue requirements to individual customer classes in a manner that reasonably reflects each class's responsibility for such revenue requirements. In other words, the primary purpose of a class cost of service study is to attribute costs to customer classes based on how those classes cause such costs to be incurred.

Q: Please describe how the Company's CCOSS allocates total-system revenue requirements to customer classes.

A: In order to allocate costs to customer classes, the CCOSS first separates total costs into production, transmission, distribution, and customer functions. Costs in each function are then classified as energy-, demand-, or customer-related based on whether costs are considered to be "caused" by energy sales, peak demand, or the number of customers, respectively. Finally, costs classified as either energy-, demand-, or customer-related are allocated to

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[13] *Id.*, Attachment MWN-2, 2.

[14] *Id.*, 7-8.

customer classes in proportion to each class's contribution to total-system energy sales, peak demand, or number of customers, respectively.[15]

Q: Does the Company's CCOSS reasonably allocate test-year revenue requirements?

A: No. The Company's CCOSS does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. In particular, the CCOSS allocates more production plant costs to customer classes with low load factors than is appropriate.[16]

Q: How does the Company's CCOSS over-allocate production plant costs to the customer classes with low load factors?

A: The Company's CCOSS inappropriately classifies all production plant costs as demand-related, as if such costs were incurred solely for the purposes of meeting system reliability requirements, and not at all for the purposes of minimizing the cost of meeting energy requirements. This classification approach is inconsistent with investment decision-making under typical generation expansion planning practices, where plant investment choices are driven by both reliability and energy requirements. As explained in NARUC's *Electric Utility Cost Allocation Manual*:

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[15] *Pre-Filed Verified Direct Testimony of Michael M. Spaeth*, Cause No. 45235, 9-10 (May 14, 2019).

[16] Load factor is defined as the ratio of average demand to peak demand, where average demand is annual energy requirements divided by 8760 (i.e., the number of hours in a year).

> Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability, loss of load hours, reserve margin, or expected unserved energy; and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.[17]

From a cost-causation perspective, investments in peaking plant are appropriately classified as demand-related, since peaking units typically would be the least-cost generation option for meeting an increase in peak demand and planning reserve requirements. On the other hand, baseload or intermediate plant costs *in excess of peaking plant costs* (so-called "capitalized energy" costs) should be classified as energy-related, since these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements.

The Company's CCOSS misclassifies these capitalized energy costs as demand-related. As a result, the Company's CCOSS over-allocates capitalized energy costs to the residential class and under-allocates such costs to the industrial classes since the residential class has a lower load factor than the industrial classes.[18]

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[17] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, 38-39 (January, 1992) (Attachment JFW-6).

[18] A customer class with a low load factor (relative to other classes) will be allocated a greater percentage of demand-related costs than that of energy-related costs because that class's percentage contribution to total system demand is larger than its contribution to total system energy requirement.

Q: Are there other classification methods that would classify the Company's production plant costs in a manner that reasonably reflects cost causation?

A: Yes. For example, the Equivalent Peaker classification method classifies production plant costs in a manner that reasonably reflects investment decision-making under typical generation expansion planning practices, as described above. According to the *Electric Utility Cost Allocation Manual*:

> Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the <u>need</u> for additional generating capacity and the most cost-effective <u>type</u> of capacity to be added….
>
> The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.[19]

Q: Have you reclassified the Company's production plant costs using the Equivalent Peaker method?

A: Yes. For this analysis, I estimated the demand- and energy-related portions of the Company's production plant costs based on data regarding: (1) the Company's generation portfolio provided in response to discovery;[20] and (2)

[19] *Electric Utility Cost Allocation Manual*, 52-53 (Attachment JFW-6).

[20] I&M Supplemental Response and Attachment to CAC Data Request 3-4 (Attachment JFW-7).

the cost and capacity of gas turbines installed in Indiana and Michigan provided in utility FERC Form 1 reports for 2018.[21] I calculated the demand-related portion of total plant costs for the Company's generation portfolio as the product of: (1) total plant capacity of the Company's generation portfolio; and (2) the average plant cost per kilowatt of plant capacity for gas turbines installed in Indiana and Michigan between 1967 and 2002.[22] In other words, the demand-related portion of total plant costs is what plant costs would have amounted to if the Company's generation capacity were priced at the average cost per kilowatt for gas turbines in Indiana and Michigan. The energy-related (or capitalized energy) portion is then the excess of total plant costs over the demand-related portion of total plant costs. Using this approach, I estimate that 31% of the Company's production plant costs are demand-related and about 69% are energy-related.

Q: How would this reclassification affect the allocation of the requested revenue increase to customer classes?

A: I modified the Company's CCOSS to reflect my estimate of a 31%/69% demand/energy split under an Equivalent Peaker classification ("Modified CCOSS").[23] As indicated in Table 1, such a reclassification would yield

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[21] I relied on gas-turbine data from other utilities in Indiana and Michigan because I&M does not own any gas turbines.

[22] This calculation overstates the demand-related portion of plant costs, especially for the Company's solar plant, because it assumes that 100% of a plant's installed capacity contributes to meeting peak demand. In fact, I&M assumes for planning purposes that each megawatt of solar installed capacity contributes about 0.51 megawatts toward meeting the Company's capacity requirements. See, I&M's 2018-19 Integrated Resource Plan, p. 105 (July 1, 2019) (Attachment JFW-8).

[23] More precisely, I modified the electronic spreadsheet version of the Company's CCOSS (45235_IndMich_WP IM IN JCOSS CCOS COMBINED TYE 123120 051419.xlsx), provided

dramatically different results for the residential class. Specifically, whereas the Company's CCOSS indicates that the residential class is currently under-earning relative to the system average rate of return ("ROR"), the Modified CCOSS shows that the residential class is actually currently over-earning and subsidizing other rate classes. Moreover, under the Modified CCOSS, the revenue increase for the residential class at an equalized ROR would be less than the system-average increase.

Table 1: Results of Company's and Modified Class Cost of Service Studies

	Revenue Increase at Equalized ROR		**Current ROR**	
	Company's CCOSS	**Modified CCOSS**	**Company's CCOSS**	**Modified CCOSS**
RS	16.92%	13.38%	3.18%	3.63%
GS	8.28%	4.73%	4.38%	4.97%
LGS	13.47%	15.85%	3.48%	3.16%
IP	15.54%	21.76%	2.93%	2.13%
MS	13.36%	11.23%	3.55%	3.85%
WSS	9.93%	18.85%	4.01%	2.79%
IS	-25.55%	-22.00%	11.38%	10.32%
EHG	2.56%	0.17%	5.38%	5.83%
OL	-16.23%	-4.91%	8.53%	6.56%
SL	-29.20%	-8.72%	11.27%	7.08%
Total System	14.33%	14.33%	3.41%	3.41%

with the Company's workpapers. The modified version will be included in my workpaper submission.

Q: How should any base revenue increase authorized by the Commission be allocated to customer classes?

A: Given the range of results between the Company's and my Modified CCOSS, a reasonable and fair approach would be to: (1) maintain base revenues at current levels (i.e., no increase or decrease) for those classes where the class cost of service studies show a revenue decrease at an equalized ROR; and (2) increase base revenues for all other classes by the same percentage in order to recover any authorized revenue deficiency.

IV. Residential Service Charge

A. I&M's Proposal to Increase the Residential Service Charge

Q: What is a service charge?

A: A service charge is a fixed fee charged to each customer on their monthly bill regardless of the customer's energy usage during that month.

Q: What is the Company's proposal with respect to the monthly fixed service charge for residential customers?

A: The Company proposes to increase the fixed service charge from $10.50 to $15.00 per customer per month.[24] The proposed $4.50 increase represents a 43% increase over the current service charge.

Q: What is the Company's rationale for increasing the residential service charge?

A: Company witness Nollenberger contends that "ideally" costs classified in the CCOSS as customer-related, demand-related, or energy-related would be

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[24] Nollenberger Direct, 15.

recovered through a service charge, demand rate, or energy rate, respectively.[25] However, because residential customers are not currently demand-metered, I&M proposes instead to recover a portion of demand-related secondary distribution costs through the fixed service charge.[26] Mr. Nollenberger further contends that the Company's proposal to recover demand-related costs through the service charge would yield residential rates that more-closely align with cost causation and therefore would provide appropriate price signals.[27]

Q: Do you agree that the "ideal" rate design would recover costs classified as demand-related through a residential demand rate?

A: No. To the contrary, residential rates designed to formulaically reflect cost classifications in the CCOSS would neither reflect cost causation nor provide appropriate price signals. In particular, recovery of demand-related costs through a residential demand charge would dampen price signals for conservation, promote inefficient customer behavior, and undermine customers' ability to control electricity costs.

Demand charges on a monthly bill are typically determined based on the customer's maximum demand, whenever that maximum occurs during the month. In order to control monthly demand costs, customers would therefore need to have detailed information regarding their load profiles for each day of the month as well as an in-depth understanding of which combination of appliance- or equipment-usage gives rise to monthly maximum demands.

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[25] *Id.*, 13.

[26] As discussed below in Section V, I&M also proposes to recover the remaining portion of demand-related secondary distribution costs through a first block volumetric energy rate.

[27] Nollenberger Direct, 20.

Even with such information and knowledge, it would be difficult for a residential customer to reduce demand charges, since even a single failure to control load during the month would result in the same demand charge as if the customer had not attempted to control load at all.

A demand charge would also provide little or no incentive for residential customers to take actions that reduce distribution-system costs. Distribution equipment costs typically are driven by the coincident peak load for all customers sharing the equipment. An individual customer is unlikely to reach her maximum demand at the same time as when the coincident peak on the distribution system occurs. Thus, a demand charge will provide an incentive to a residential customer to control load at the time that customer reaches her *individual* maximum demand, which does not necessarily correspond to the time of peak load on the distribution system. In fact, some customers might respond to a demand charge by shifting loads from their own peak to the peak hour on the local distribution system, thereby increasing their contribution to maximum or critical loads on the local distribution system and further stressing the system during peak periods.

Finally, shifting recovery of demand-related costs from the energy rate to a demand charge would send the wrong energy price signal. Shifting demand-related costs to a demand charge would lower the energy rate and thereby perversely encourage *increased* energy consumption, some of which might occur at times of peak load on the distribution system – when energy conservation is most needed. Shifting costs from the energy rate to a demand charge could therefore increase distribution system costs and offset any (limited) benefits from a residential demand charge.

Severin Borenstein aptly summed up the shortcomings (and the antiquated nature) of demand charges when he wrote: "It is unclear why demand charges still exist."[28]

Q: Given that a demand rate is not currently an option for residential customers, what is the Company's rationale for recovering demand-related costs through the fixed service charge rather through the volumetric energy rate?

A: In simplest terms, the Company's position is that demand-related costs do not vary with energy because such costs are not classified as energy-related in the CCOSS. And since in the Company's view demand-related costs are "fixed" in relation to energy usage, I&M contends that such costs are more appropriately recovered through a fixed service charge than through a volumetric energy rate.

Q: Do you agree that demand-related costs are fixed for rate-design purposes?

A: No. The Company's position that costs not classified as energy-related in the CCOSS are necessarily fixed reflects a failure to recognize that there are different objectives when developing a cost of service study than when designing rates. The purpose of a cost of service study is to allocate the total amount of costs incurred in the past to the various customer classes in a manner that reasonably approximates the extent to which each class "caused" the utility to incur those costs. In contrast, the primary challenge of rate

[28] Severin Borenstein, "The Economics of Fixed Cost Recovery by Utilities", in *Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives*, Lawrence Berkeley National Laboratory, 60 (2016). Available at http://eta-publications.lbl.gov/sites/default/files/lbnl-1005742.pdf.

design is to recover the costs allocated to a customer class in a manner that not only allows for an equitable sharing of allocated costs among the customers within the class, but also provides reasonable price signals to customers in that class regarding the impact of their electricity usage on future utility costs. From the long-run perspective of price efficiency, costs which are classified as demand-related in the CCOSS are in fact not fixed but variable with respect to customer usage.

Q: In its previous rate case in Cause No. 44967, did I&M propose recovering demand-related costs through the fixed service charge?

A: No. In fact, in Cause No. 44967, I&M proposed recovering only the marginal cost to connect a residential customer – i.e., the cost of meters, service drops, and customer services – in the fixed service charge. Testifying in support of that proposal, Mr. Nollenberger stated that:

> The goal is to institute a service charge for residential customers that more accurately reflects the Company's customer costs – i.e., the actual cost of connecting a customer to the Company's system…. I&M incurs these customer connection costs for each customer regardless of the amount of energy the customer uses, or how much demand the customer places on the system…. The proposed increase in the residential service charge also brings I&M's rates more in line with principles of cost causation….[29]

In his direct testimony in this Cause, Mr. Nollenberger does not explain why two years later he now believes that a fixed service charge must recover not just customer connection costs but also demand-related costs in order to be "in line with principles of cost causation."

[29] *Pre-Filed Verified Direct Testimony of Matthew W. Nollenberger*, Cause No. 44967, 12-13 (July 26, 2017) (excerpt included as Attachment JFW-9).

Q: What portion of demand-related secondary distribution costs does I&M propose to recover through the fixed service charge?

A: As indicated in Table 2 below, the $15 fixed service charge proposed by I&M would effectively recover 46% of the demand-related secondary distribution costs allocated to the residential class in the Company's CCOSS.[30] As discussed below in Section V, I&M proposes to recover the remaining 54% of demand-related secondary distribution costs through a first-block volumetric energy rate.

Table 2: Costs Recovered through I&M Proposed Residential Service Charge

	Residential Revenue Requirements	Residential Bills	% Recovered through Service Charge	Cost per Bill Recovered through Service Charge
Customer-Related	$47,020,444	4,648,110	100%	$10.12
Demand-Related Secondary	$49,306,781	4,648,110	46%	$4.88
Total	$96,327,225			$15.00

[30] Calculated based on data provided in the 'RS' tab of Petitioner's confidential workpaper labeled as '45235_IndMich_CONFIDENTIAL WP-MWN-4 Rate Design CONFIDENTIAL WP_051419.xls'. The Company has agreed to make public the 'RS' tab of this confidential workpaper.

B. *I&M's Proposal for the Residential Service Charge Violates Principles of Cost-Based Rate Design*

Q: What are the relevant considerations in designing cost-based rates for residential customers?

A: As the Commission recognized in Cause No. 44576, the primary challenge in rate design is to reflect the costs that customers impose on the system, both to encourage them to use utility resources responsibly and to share costs fairly:

> Cost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided.[31]

Accordingly, fixed service charges should reflect the fact that each customer contributes equally to certain types of costs (e.g., meter costs) regardless of that customer's energy usage. Volumetric energy rates, on the other hand, recognize that customers of different sizes and load profiles contribute to other types of costs (e.g., generation plant costs) at different levels. If usage-driven costs are inappropriately collected through fixed service charges, then customers will have reduced incentives to control their bills through conservation or investments in energy efficiency or distributed renewable generation.[32]

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[31] IURC Final Order, Cause No. 44576, 72.

[32] National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016), available at https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0 (excerpt included as Attachment JFW-10).

Q: Given these considerations, what categories of costs are appropriately recovered through the volumetric energy rate?

A: In order to provide efficient price signals, volumetric energy rates should be set at levels that recover those categories of costs that tend to increase with customer usage over the long run, including plant, fuel, and O&M costs for the production, transmission, and distribution functions. In other words, volumetric energy rates should reflect long-run marginal costs.

As James Bonbright explains in his seminal text *Principles of Public Utility Rates*:

> In view of the above-noted importance attached to existing utility rates as indicators of rates to be charged over a somewhat extended period in the future, one may argue with much force that the cost relationships to which rates should be adjusted are not those highly volatile relationships reflected by short-run marginal costs but rather those relatively stable relationships represented by long-run marginal costs. The advantages of the relatively stable and predictable rates in permitting consumers to make more rational long-run provisions for the use of utility services may well more than offset the admitted advantages of the more flexible rates that would be required in order to promote the best available use of the existing capacity of a utility plant.[33]

> I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or “capacity costs” as variable costs.[34]

Almost three decades later, Alfred Kahn affirmed Bonbright’s opinion in his *The Economics of Regulation*:

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[33] James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 334 (1961), available at media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf (excerpt included as Attachment JFW-11).

[34] *Id.*, 336.

> … the practically achievable benchmark for efficient pricing is more likely to be a type of average long-run incremental cost, computed for a large, expected incremental block of sales, instead of SRMC [short-run marginal cost] ….[35]

Q: Which costs are appropriately recovered through the fixed service charge?

A: In contrast to the volumetric energy rate, the fixed service charge is intended to reflect the cost to connect a customer who uses very little or zero energy to the distribution system. Such "minimum connection costs" are generally limited to plant and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer-service expenses. As Bonbright explains:

> But this twofold distinction [between demand and energy in rate design] overlooks the fact that a material part of the operating and capital costs of utility business is more directly and more closely related to the number of customers than to energy consumption on the one hand or maximum kilowatt demand on the other hand. The most obvious examples of these so-called customer costs are the expenses associated with metering and billing.[36]

In their *Public Utility Economics*, economists Paul Garfield and Wallace Lovejoy also describe which costs are truly customer-related and therefore appropriately recovered through the fixed service charge:

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[35] Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988) (excerpt included as Attachment JFW-12).

[36] Bonbright, *op. cit.*, 311 (excerpt included as Attachment JFW-11).

> The purpose of both the service charge and the minimum charge is to cover at least some of the costs incurred by the utility whether or not the customer uses energy in a particular month. For small customers under the block meter-rate schedule, a charge of this kind is intended to cover the expenses relating to meter service and maintenance, meter reading, accounting and collecting, return on the investment in meters and the service lines connecting the customer's premises to the distribution system, and others. Such expenses as these represent as a minimum the "readiness-to-serve" expenses incurred by the utility on behalf of each customer.[37]

More recently, Severin Borenstein restated these principles for designing cost-based fixed service charges as follows:

> When having one more customer on the system raises the utility's costs regardless of how much the customer uses – for instance, for metering, billing, and maintaining the line from the distribution system to the house – then a fixed charge to reflect that additional fixed cost the customer imposes on the system makes perfect economic sense. The idea that each household has to cover its customer-specific fixed costs also has obvious appeal on ground of fairness or equity.[38]

Q: Is the Company's proposal for the residential service charge consistent with these long-standing principles of cost-based rate design?

A: No. Contrary to these principles, I&M proposes to recover through the residential fixed service charge not just minimum connection costs – i.e., the costs for meters, service drops, and customer services – but also a portion of the costs allocated to the residential class under the CCOSS for secondary poles, wires, transformers. As discussed above, the $15 residential service charge proposed by I&M would recover 100% of the minimum connection

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[37] Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964) (excerpt included as Attachment JFW-13).

[38] Severin Borenstein, "What's So Great About Fixed Charges?" (2014), available at https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/.

cost per residential customer and 46% of the demand-related secondary distribution cost per residential customer.

Q: Is it reasonable to recover demand-related costs through the fixed service charge, as the Company proposes?

A: No. As discussed in detail below, the Company's proposal to recover more than minimum connection cost through the residential service charge would give rise to cost subsidization within the residential class and would dampen energy price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

Q: What would be an appropriate rate for I&M's residential service charge in order to recover its minimum cost to connect a residential customer?

A: As shown in Table 2 above, customer-related costs amount to $10.12 per residential bill. Thus, consistent with long-standing rate design principles, a residential service charge of $10.12 would appropriately recover only minimum connection costs, i.e., the costs of meters, service drops, and customer services.

Q: What accounts for the $4.88 difference between your recommended $10.12 fixed service charge and the $15 fixed service charge proposed by I&M?

A: The $4.88 difference between my recommended $10.12 residential service charge and the $15 service charge proposed by I&M represents demand-related secondary distribution costs that would be inappropriately recovered through the fixed service charge under the Company's proposal. As discussed below, this shift in recovery of demand-related costs from the volumetric energy rate to the fixed service charge would give rise to cost subsidization within the residential class and would dampen energy price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

C. I&M's Proposal for the Residential Service Charge Would Lead to Intra-Class Cost Subsidization

Q: How would the Company's proposal to increase the residential service charge cause intra-class subsidization?

A: As discussed above, I&M's proposal to increase the residential service charge would shift recovery of demand-related costs from the volumetric energy rate to the fixed service charge. Such demand-related costs are driven by residential load and are therefore appropriately recovered from residential customers in proportion to their contribution to total load. To the extent that demand-related costs are recovered at a fixed rate through the residential service charge rather than at a volumetric rate through the energy charge, residential customers with below-average usage would bear a disproportionate share of demand-related costs and consequently subsidize customers with above-average usage. In this case, a residential customer with below-average usage will pay more, and a residential customer with above average-usage will pay less, than their fair share of such costs.

Q: What is the extent of the intra-class subsidization under the Company's proposal for the residential fixed service charge?

A: As explained above, the $4.88 difference between the minimum connection cost of $10.12 and the $15 residential service charge proposed by I&M represents demand-related secondary distribution costs that would be inappropriately recovered from each residential customer every month through a fixed charge on the customer's bill. The Company estimates about 4.6 million residential bills in the test year.[39] This means that $22.7 million of demand-related costs would be recovered annually through the residential fixed service charge under the Company's proposal.[40]

If the demand-related costs recovered through the residential fixed service charge under the Company's proposal were instead recovered through the volumetric energy rate (as I propose), each residential customer would contribute to recovery of these costs in proportion to their usage. The Company estimates residential sales in the test year of about 4.1 million megawatt-hours.[41] Therefore, if the $22.7 million of demand-related costs continued to be recovered through the volumetric energy rate rather than through the fixed service charge, they would be charged at a rate of 0.55 cents per kilowatt-hour ("¢/kWh").[42] In this case, a residential customer with below-average monthly usage of 450 kWh would contribute about $30 per year toward recovery of the $22.7 million of demand-related costs while a

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[39] The number of residential bills in the test year is provided in the 'RS' tab of 45235_IndMich_CONFIDENTIAL WP-MWN-4 Rate Design CONFIDENTIAL WP_051419.xls. The Company has agreed to make public the 'RS' tab of this confidential workpaper.

[40] The $22.7 million result is derived by taking the product of the annual number of residential bills (4.6 million) and the amount of the proposed residential service charge in excess of minimum connection cost ($4.88 per bill).

[41] Residential sales for the test year are provided in the 'RS' tab of 45235_IndMich_CONFIDENTIAL WP-MWN-4 Rate Design CONFIDENTIAL WP_051419.xls. The Company has agreed to make public the 'RS' tab of this confidential workpaper.

[42] The 0.55¢/kWh result is derived by dividing $22.7 million by residential sales of 4.1 million megawatt-hours.

customer with above-average monthly usage of 1,350 kWh would contribute about $89 per year.[43] Thus, under my proposal, the 1,350 kWh customer would contribute three times more than the 450 kWh customer, in direct proportion to their usage and consistent with accepted principles of cost-causation.

In contrast, under the Company's proposal to recover $22.7 million of demand-related costs through the fixed service charge, each residential customer would contribute about $59 per year toward recovery of such costs regardless of that customer's usage. A below-average 450 kWh customer would therefore pay about double their fair share of these demand-related costs under the Company's proposal while an above-average 1,350 kWh customer would pay only two-thirds of their fair share.

D. I&M's Proposal for the Residential Service Charge Would Dampen Energy Price Signals

Q: Would the Company's proposal to increase the residential service charge send appropriate price signals?

A: No. As discussed above, I&M proposes to set the residential service charge at a rate that greatly exceeds the minimum cost to connect a residential customer. The amount in excess of minimum connection costs represents usage-related costs that are more appropriately recovered in the volumetric energy rate. However, under the Company's proposal, this excess over the

[43] Based on data provided in the 'RS' tab of 45235_IndMich_CONFIDENTIAL WP-MWN-4 Rate Design CONFIDENTIAL WP_051419.xls], I estimate monthly usage of about 890 kWh for an average residential customer. The Company has agreed to make public the 'RS' tab of this confidential workpaper.

minimum connection costs would instead be inappropriately recovered through the fixed service charge. This shift in the recovery of usage-related costs from the volumetric energy rate to the fixed service charge would dampen price signals and discourage economically efficient behavior by residential customers.

Q: To what extent would the Company's proposal to increase the residential fixed service charge dampen price signals provided by the residential volumetric energy rate?

A: With a fixed amount of revenue requirements to be recovered from the residential class, the higher the residential fixed service charge, the lower the volumetric energy rate, and vice versa. With the residential fixed service charge set at $15, I&M proposes an average volumetric energy rate (average across the two proposed energy blocks) of 12.32¢/kWh in order to recover the proposed allocation of test year revenue requirements to residential customers.[44] If, instead, the fixed service charge were set at the cost-based rate of $10.12, I estimate that the average volumetric energy rate would have to be increased to 12.87¢/kWh to recover the same allocated revenue requirement.

In other words, I&M is proposing an average residential energy rate that is 0.55¢/kWh, or about 4%, less than what the volumetric rate would be if the residential fixed service charge were set at the cost-based rate of $10.12. Thus, the Company's proposal for the residential service charge would

[44] Calculated based on data provided in the 'RS' tab of 45235_IndMich_CONFIDENTIAL WP-MWN-4 Rate Design CONFIDENTIAL WP_051419.xls. The Company has agreed to make public the 'RS' tab of this confidential workpaper.

dampen the price signal provided by the volumetric energy rate by about 4%.[45]

Q: How would residential customers likely respond to the reduction in the energy price signal resulting from the Company's proposal for the residential service charge?

A: Since the volumetric energy rate under the Company's proposal for the residential service charge would be lower than the volumetric energy rate with a cost-based fixed service charge of $10.12, we would expect residential customers to consume more energy with the Company's proposed service charge than they would with a cost-based service charge. The magnitude of the increase in energy consumption would depend on: (1) the extent to which the volumetric energy rate with the Company's proposed residential service charge is lower than the volumetric energy rate with a cost-based service charge; and (2) the price elasticity of electricity demand.

Q: What is the price elasticity of electricity demand?

A: Residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, i.e., the ratio of the percentage change in consumption to the percentage change in price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term. For example, a review by Espey and Espey (2004) of 36 articles on residential electricity demand

[45] To be precise, the Company's proposal for the residential service charge would dampen price signals by about 4% if I&M were proposing a flat energy rate. As discussed in Section V below, the Company's proposal to introduce a declining-block energy rate would further dampen price signals.

published between 1971 and 2000 reports short-run elasticity estimates of about −0.35 on average across studies and long-run elasticity estimates of about −0.85 on average across studies.[46] In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in price.

Studies of electric price response typically examine the change in usage as a function of changes in the marginal rate paid by the customer.[47] Table 3 below lists the results of seven studies of marginal-price elasticity over the last forty years.[48]

Table 3: Summary of Marginal-Price Elasticities

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 without electric space heat and −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	–0.27 to –0.30
Reiss and White	2005	−0.39
Xcel Energy Colorado	2012	–0.3 (at years 2 and 3)
Orans et al, on BC Hydro inclining-block rate	2014	–0.13 in 3rd year of phased-in rate

Q: What would be a reasonable estimate of the marginal-price elasticity for changes in the residential volumetric energy rate?

A: From Table 3, it appears that –0.3 would be a reasonable mid-range estimate of the impact over a few years.

[46] The citation for this study is provided in Attachment JFW-2.

[47] For residential customers, that would be the energy rate.

[48] The citations for these studies are provided in Attachment JFW-2.

Q: What would be a reasonable estimate of the effect on energy use from the Company's proposal for the residential fixed service charge?

A: As discussed above, if the residential service charge were increased as proposed by I&M, the volumetric energy rate would be about 4% less than what the volumetric rate would be if the residential service charge were set at the cost-based rate of $10.12. Assuming an elasticity of –0.3, this 4% reduction in the volumetric energy rate would result in an increase in energy consumption of about 1.2% for the average residential customer. This means that all else equal, residential load after a few years with a residential service charge as proposed by I&M would be expected to be about 1.2% higher than it would have been if the residential service charge had been set at the cost-based rate of $10.12.

V. Residential Energy Rates

A. I&M's Proposal for Residential Volumetric Energy Rates

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

A: The Company proposes to implement a "declining-block" rate structure for its residential volumetric energy rates. Under the current rate structure, residential customers pay the same ("flat") energy rate regardless of the amount of monthly usage. In contrast, under the Company's proposal, a residential customer would pay 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. Thus, with the declining-block rate structure proposed by I&M, a residential customer would pay a higher volumetric rate for that portion of her monthly usage that falls within the first energy block and a lower volumetric rate for the remaining portion of her usage in excess of her first-block usage.

Specifically, I&M proposes two energy blocks: (1) for monthly usage up to 900 kWh; and (2) for monthly usage in excess of 900 kWh. Table 4 shows the current flat energy rate and the declining-block energy rates proposed by I&M for residential customers.[49]

Table 4: Current and I&M Proposed Residential Energy Rates

	Current	I&M Proposed	Rate Increase	% Increase
First 900 kWh	10.46	12.58	2.13	20.3%
Over 900 kWh	10.46	11.67	1.21	11.6%
Average	10.46	12.32	1.86	17.8%

Q: How did I&M derive its proposed volumetric rate for each energy block?

A: As discussed above in Section IV, I&M proposes to recover 46% of demand-related secondary distribution costs through the fixed service charge. According to I&M witness Nollenberger, the Company further proposes to recover the remaining 54% of demand-related secondary distribution costs through the first block energy rate.[50] Finally, I&M proposes to recover all

[49] Current flat and proposed declining-block energy rates shown in Table 4 are from Petitioner's workpaper labeled as '45235_IndMich_WP Attachment MWN4 Typical Bills 051419.xlsx'. The average of the Company's proposed declining-block energy rates was derived based on data provided in the 'RS' tab of 45235_IndMich_CONFIDENTIAL WP-MWN-4 Rate Design CONFIDENTIAL WP_051419.xls. The Company has agreed to make public the 'RS' tab of this confidential workpaper.

[50] Nollenberger Direct, 17.

other demand-related and energy-related costs allocated to the residential class at a uniform volumetric rate in both energy blocks.

As indicated in Table 4 above, I&M proposes a volumetric rate for the first energy block that is 0.91¢/kWh higher than the rate for the second block. This 0.91¢/kWh difference between the first and second block rates proposed by I&M is due solely to the Company's decision to recover all of the remaining 54% of demand-related secondary distribution costs through the first energy block and none of those remaining costs through the second energy block. In other words, I&M is proposing declining-block rate recovery of demand-related secondary distribution costs.

B. I&M's Proposal for Declining-Block Energy Rates Would Further Dampen Energy Price Signals

Q: Why is I&M proposing declining-block rate recovery of demand-related secondary distribution costs?

A: The Company proposes recovering demand-related secondary distribution costs in the first energy block for the same reason that it proposes recovering those costs through the fixed service charge: in the Company's opinion, declining-block rate recovery is the third best option (after demand-charge and service-charge recovery) for recovering these allegedly "fixed" costs. By the Company's reasoning, to the extent not recovered through a demand charge or the fixed service charge, such "fixed" costs should be recovered through a first block energy rate so that the second block rate more closely reflects "variable" costs (i.e., those costs classified as energy-related in the Company's CCOSS).

Q: Do you agree with the Company's contention that demand-related costs are appropriately recovered through declining-block energy rates?

A: No. As discussed in Section IV, from a long-run price-efficiency perspective, these demand-related costs vary with customer usage and therefore are appropriately recovered from customers in proportion to their usage. Consequently, such costs should be recovered through a uniform rate so that all customers pay volumetric energy rates that reasonably reflect long-run marginal costs.

Conversely, the Company's proposal to recover demand-related costs through declining-block volumetric energy rates would drive second-block energy rates below long-run marginal costs and thereby dampen energy price signals for most customers.

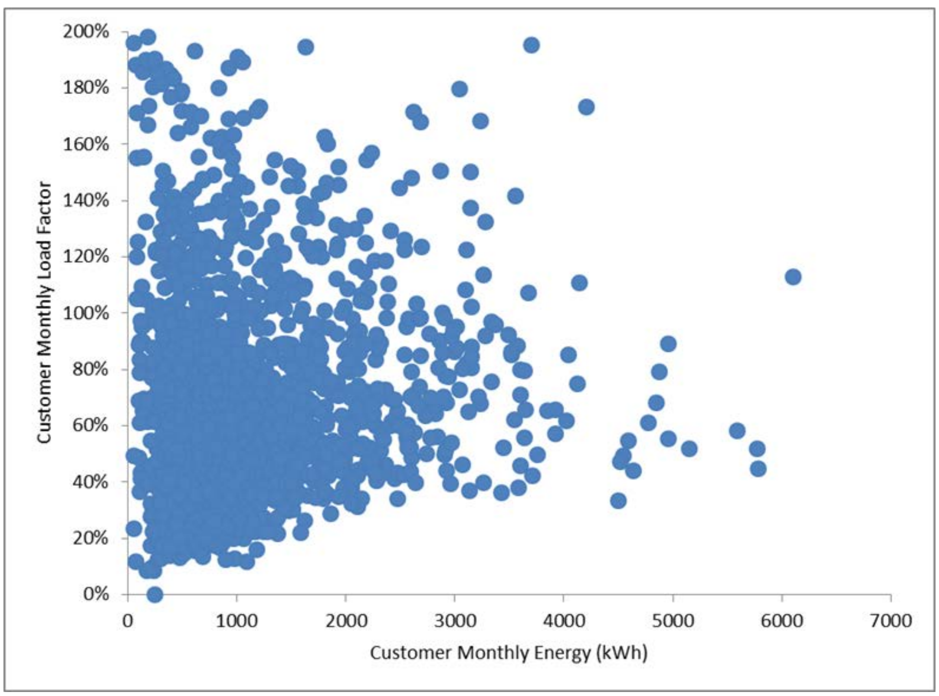
Even from a short-run cost-causation perspective, it would not be reasonable to recover demand-related costs through declining energy rates. Declining-block rate recovery of demand-related costs might be appropriate in the case where low-usage customers' hourly loads were "peakier" than high-usage customers' hourly loads, i.e, in the case where customer load factors were lower for low-usage customers than for high-usage customers.[51] If customer load factors generally increased with customer usage, then a customer's contribution to demand-related costs per kilowatt-hour of usage would be greater for a low-usage customer than for a high-usage customer. In

[51] Customer load factor is the ratio of average hourly usage to hourly usage at the time of system or class peak. A customer who used the same amount of energy every hour of every day of the month would have a load factor of 1 since average hourly usage during the month would be equal to usage in the peak hour. In contrast, a customer who used the same amount of energy every hour except for the peak hour, where he used double the amount of energy, would have a load factor of about 0.5.

which case, a high-usage customer would pay more than their fair share of demand-related costs if such costs were recovered through a uniform volumetric energy rate.

However, load-research data collected by the Company indicates that this is not the case for the Company's residential customers and thus that declining-block energy rates are not appropriate.[52] As illustrated in Figure 1 below, load factors do not appear to increase with customer usage. This means that residential customers contribute to demand-related costs in the same proportion to energy usage regardless of customer size. Thus, the residential class' demand-related costs are effectively driven by energy usage and therefore appropriately recovered through a uniform volumetric energy rate.

Figure 1: Residential Load Factor vs. Energy Usage



[52] The Company provided load-research data in I&M Response to CAC Data Request 6-2 (Attachment JFW-14). Please see my associated workpaper for the Excel spreadsheet attachment to CAC Data Request 6-2.

Q: What do you recommend with regard to the Company's proposal to implement declining-block energy rates?

A: I recommend that the Commission reject the Company's request to implement a declining-block rate structure for residential volumetric energy rates. Instead, I&M should be directed to:

- Maintain the current flat rate structure for residential energy rates.
- Set the residential energy rate to recover an amount equal to: (1) the Commission-authorized allocation of base revenues to the residential class; less (2) revenues recovered through a $10.12 fixed service charge.

VI. Residential Demand-Rate Pilot

Q: Please describe the Company's proposal for a pilot residential demand-metered tariff.

A: The Company proposes to implement a new residential tariff with a monthly service charge, demand charge, and flat volumetric energy rate. This new tariff would be offered on a voluntary, opt-in basis and would be limited to the first 4,000 residential eligible customers.[53] The proposed demand charge is designed to recover almost all secondary distribution and 25% of primary distribution costs allocated to the residential class.[54]

Each month, the demand charge will be assessed against the single highest 15-minute load recorded during the "on-peak" period, defined as weekdays between the hours of 7am and 9pm.[55] If the Company's AMI

[53] *Pre-Filed Verified Direct Testimony of Kurt C. Cooper*, Cause No. 45235, 15 (May 14, 2019) [Hereinafter "Cooper Direct"].

[54] Nollenberger Direct, 27.

[55] I&M Response to CAC Data Request 4-10 (Attachment JFW-15).

deployment plan is approved, I&M will install AMI meters at pilot participants' premises. If not, I&M will install the same type of time-of-day meters used by Tariff RS-TOD customers.[56]

Q: Why is I&M proposing to offer a demand-rate option to residential customers?

A: According to Company witness Kurt C. Cooper, I&M is offering the demand-rate option to provide residential customers, particularly high-load-factor customers, the opportunity to lower their bills by shifting usage and flattening their load profiles during the on-peak period. In addition, the proposed demand-rate option offers I&M the opportunity "to gain experience with a residential tariff with demand components".[57]

Q: Do you have any concerns regarding the Company's proposal to offer a demand-rate option?

A: Yes. As discussed above in Section IV, a demand charge such as the Company proposes for this pilot will dampen price signals for conservation, encourage inefficient customer behavior, and undermine customers' ability to control electricity costs. In order to overcome these perverse incentives, I&M will need to provide extensive education to eligible customers regarding strategies for effectively and efficiently controlling their billing demand. In addition, the Company will need to carefully monitor individual participants' usage patterns and provide feedback on monthly bills regarding whether participants are benefitting from participation (relative to taking service under Tariff RS). Finally, I&M will need to carefully and thoroughly evaluate

[56] *Id.*

[57] Cooper Direct, 15.

program performance – particularly with respect to program participation rates, the impact of participation on participant load profiles and overall usage, the impact on utility costs from changes in participants' load profiles and overall usage, and bill savings achieved by program participants – in order to inform the Commission's consideration of any proposal to implement the tariff at full scale.

Q: What do you recommend with respect to the Company's proposal for a residential demand-rate pilot?

A: If the Commission chooses to approve the Company's request, I&M should be directed to file a detailed implementation plan in advance of the roll-out of the pilot. This implementation plan should include, at a minimum, detailed plans for customer education, for ongoing communications with participants regarding usage patterns and bill savings, and for monitoring and evaluation of program performance. Any such implementation plan should clearly state the objectives of the pilot and the criteria by which regulators and the public should determine whether the pilot was a success.

VII. Conclusions and Recommendations

Q: What do you conclude with regard to the Company's proposal to deploy advanced metering infrastructure?

A: The Company seeks pre-approval of its proposal to invest in advanced metering infrastructure and associated customer-engagement software. The Company further requests base-rate recovery of AMI revenue requirements in the 2020 test year. The Commission should deny both of these requests because I&M has failed to show that the proposed AMI investments are likely to be cost-effective. Instead, the Commission should docket a separate proceeding to consider the Company's AMI proposal and direct I&M to file a cost-effectiveness analysis of its AMI proposal in that proceeding.

Q: What do you conclude with regard to I&M's proposal for allocating the 2020 test-year revenue deficiency?

A: The Company's proposal for allocating the requested revenue deficiency relies solely on the results of a class cost-of-service study that does not allocate production plant costs in a manner that reasonably reflects each class's responsibility for such costs. Correcting for this misallocation yields dramatically different results for the residential class. Specifically, whereas the Company's CCOSS indicates that the residential class is currently under-earning relative to the system average ROR, the Modified CCOSS shows that the residential class is currently over-earning and subsidizing other rate classes. Moreover, under the Modified CCOSS, the revenue increase for the residential class at an equalized ROR would be less than the system-average increase.

Given the range of results from the Company's CCOSS and from a CCOSS that corrects the misallocations in the Company's CCOSS, a fair and reasonable approach would be to: (1) maintain base revenues at current levels (i.e., no increase or decrease) for those rate classes where the cost of service studies show a revenue decrease at an equalized ROR; and (2) increase base revenues for all other classes by the same percentage in order to recover any authorized revenue deficiency.

Q: What do you conclude with respect to the Company's proposal to increase the residential fixed service charge?

A: The Company's proposal would inappropriately shift load-related costs from the volumetric energy rate to the fixed service charge, dampen price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, and result in subsidization of larger residential customers' costs by customers with below-average usage. Accordingly, the Commission should reject the Company's proposal to increase the monthly fixed service charge for residential customers. Instead, consistent with long-standing cost-causation and rate-design principles, I recommend that the residential fixed service charge be set at a cost-based rate of $10.12 per residential customer per month.

Q: What do you conclude with respect to I&M's proposal to implement a declining-block structure for residential volumetric energy rates?

A: The Company lacks a reasonable basis for its proposal to implement a declining-block structure for residential volumetric energy rates. The Company's proposal to recover demand-related costs at a higher rate in the first energy block than in the second block would further dampen energy price signals and promote inefficient customer behavior. Accordingly, the Commission should reject the Company's request to implement a declining-block rate structure for residential volumetric energy rates. Instead, I&M should be directed to:

- Maintain the current flat-rate structure for residential energy rates.
- Set the residential energy rate to recover an amount equal to: (1) the Commission-authorized allocation of base revenues to the residential class; less (2) revenues recovered through a $10.12 fixed service charge.

Q: What do you conclude with regard to the Company's proposal to pilot a demand-metered tariff for residential customers?

A: A residential demand charge as the Company proposes will dampen price signals for conservation, encourage inefficient customer behavior, and undermine customers' ability to control electricity costs. Given these concerns, if the Commission chooses to approve the Company's request, I&M should be directed to file a detailed implementation plan in advance of the roll-out of the pilot. This implementation plan should include, at a minimum, detailed plans for customer education, for ongoing communications with participants regarding usage patterns and bill savings, and for monitoring and evaluation of program performance.

Q: Does this conclude your direct testimony?

A: Yes.

VERIFICATION

I, Jonathan Wallach, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Jonathan Wallach

August 20, 2019
Date

ATTACHMENT JFW-1

Qualifications of

JONATHAN F. WALLACH

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

“The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets” (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

“The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities” (with Paul Chernick), *1996 Summer Study on Energy Efficiency in Buildings* 7(7.47–7.55). Washington: American Council for an Energy-Efficient Economy, 1996.

“Retrofit Economics 201: Correcting Common Errors in Demand-Side-Management Cost-Benefit Analysis” (with John Plunkett and Rachael Brailove). In proceedings of “Energy Modeling: Adapting to the New Competitive Operating Environment,” conference sponsored by the Institute for Gas Technology in Atlanta in April of 1995. Des Plaines, Ill.: IGT, 1995.

“The Transfer Loss is All Transfer, No Loss” (with Paul Chernick), *Electricity Journal* 6:6 (July, 1993).

“Benefit-Cost Ratios Ignore Interclass Equity” (with Paul Chernick et al.), *DSM Quarterly*, Spring 1992.

“Consider Plant Heat Rate Fluctuations,” *Independent Energy*, July/August 1991.

“Demand-Side Bidding: A Viable Least-Cost Resource Strategy” (with Paul Chernick and John Plunkett), *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“New Tools on the Block: Evaluating Non-Utility Supply Opportunities With *The Power Analyst*, (with John Plunkett), *Proceedings of the Fourth National Conference on Micro-computer Applications in Energy*, April 1990.

REPORTS

“Economic Benefits from Early Retirement of Reid Gardner” (with Paul Chernick) prepared for and filed by the Sierra Club in PUC of Nevada Docket No. 11-08019.

“Green Resource Portfolios: Development, Integration, and Evaluation” (with Paul Chernick and Richard Mazzini) report to the Green Energy Coalition presented as evidence in Ontario EB 2007-0707.

“Risk Analysis of Procurement Strategies for Residential Standard Offer Service” (with Paul Chernick, David White, and Rick Hornby) report to Maryland Office of People’s Counsel. 2008. Baltimore: Maryland Office of People’s Counsel.

“Integrated Portfolio Management in a Restructured Supply Market” (with Paul Chernick, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers’ Counsel.

“First Year of SOS Procurement.” 2004. Prepared for the Maryland Office of People’s Counsel.

"Energy Plan for the City of New York" (with Paul Chernick, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

"Peak-Shaving–Demand-Response Analysis: Load Shifting by Residential Customers" (with Brian Tracey). 2003. Barnstable, Mass.: Cape Light Compact.

"Electricity Market Design: Incentives for Efficient Bidding; Opportunities for Gaming." 2002. Silver Spring, Maryland: National Association of State Consumer Advocates.

"Best Practices in Market Monitoring: A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets" (with Paul Peterson, Bruce Biewald, Lucy Johnston, and Etienne Gonin). 2001. Prepared for the Maryland Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Delaware Division of the Public Advocate, New Jersey Division of the Ratepayer Advocate, Office of the People's Counsel of the District of Columbia.

"Comments Regarding Retail Electricity Competition." 2001. Filed by the Maryland Office of People's Counsel in U.S. FTC Docket No. V010003.

"Final Comments of the City of New York on Con Edison's Generation Divestiture Plans and Petition." 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

"Response Comments of the City of New York on Vertical Market Power." 1998. Filed by the City of New York in PSC Case Nos. 96-E-0900, 96-E-0098, 96-E-0099, 96-E-0891, 96-E-0897, 96-E-0909, and 96-E-0898.

"Preliminary Comments of the City of New York on Con Edison's Generation Divestiture Plan and Petition." 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

"Maryland Office of People's Counsel's Comments in Response to the Applicants' June 5, 1998 Letter." 1998. Filed by the Maryland Office of People's Counsel in PSC Docket No. EC97-46-000.

"Economic Feasibility Analysis and Preliminary Business Plan for a Pennsylvania Consumer's Energy Cooperative" (with John Plunkett et al.). 1997. 3 vols. Philadelphia, Penn.: Energy Coordinating Agency of Philadelphia.

"Good Money After Bad" (with Charles Komanoff and Rachel Brailove). 1997. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

"Maryland Office of People's Counsel's Comments on Staff Restructuring Report: Case No. 8738." 1997. Filed by the Maryland Office of People's Counsel in PSC Case No. 8738.

"Protest and Request for Hearing of Maryland Office of People's Counsel." 1997. Filed by the Maryland Office of People's Counsel in PSC Docket Nos. EC97-46-000, ER97-4050-000, and ER97-4051-000.

"Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests" (with Paul Chernick, Susan Geller, John Plunkett, Roger Colton, Peter Bradford,

Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People's Counsel.

"Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric-Utility Industry" (with Bruce Biewald and Paul Chernick). 1996. Concord, N.H.: NH OCA.

"Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities" (with Paul Chernick, Susan Geller, Rachel Brailove, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

"Report on Entergy's 1995 Integrated Resource Plan." 1996. On behalf of the Alliance for Affordable Energy (New Orleans).

"Preliminary Review of Entergy's 1995 Integrated Resource Plan." 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

"Comments on NOPSI and LP&L's Motion to Modify Certain DSM Programs." 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

"Demand-Side Management Technical Market Potential Progress Report." 1993. On behalf of the Legal Environmental Assistance Foundation (Tallahassee)

"Technical Information." 1993. Appendix to "Energy Efficiency Down to Details: A Response to the Director General of Electricity Supply's Request for Comments on Energy Efficiency Performance Standards" (UK). On behalf of the Foundation for International Environmental Law and Development and the Conservation Law Foundation (Boston).

"Integrating Demand Management into Utility Resource Planning: An Overview." 1993. Vol. 1 of "From Here to Efficiency: Securing Demand-Management Resources" (with Paul Chernick and John Plunkett). Harrisburg, Pa.:Pennsylvania Energy Office

"Making Efficient Markets." 1993. Vol. 2 of "From Here to Efficiency: Securing Demand-Management Resources" (with Paul Chernick and John Plunkett). Harrisburg, Pa.: Pennsylvania Energy Office.

"Analysis Findings, Conclusions, and Recommendations." 1992. Vol. 1 of "Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro" (with Paul Chernick and John Plunkett).

"Demand-Management Programs: Targets and Strategies." 1992. Vol. 1 of "Building Ontario Hydro's Conservation Power Plant" (with John Plunkett, James Peters, and Blair Hamilton).

"Review of the Elizabethtown Gas Company's 1992 DSM Plan and the Demand-Side Management Rules" (with Paul Chernick, John Plunkett, James Peters, Susan Geller, Blair Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

"Comments of Public Interest Intervenors on the 1993–1994 Annual and Long-Range Demand-Side Management and Integrated Resource Plans of New York Electric Utilities" (with Ken Keating et al.) 1992.

"Review of Jersey Central Power & Light's 1992 DSM Plan and the Demand-Side Management Rules" (with Paul Chernick et al.). 1992. Report to the New Jersey Department of Public Advocate.

"Review of Rockland Electric Company's 1992 DSM Plan and the Demand-Side Management Rules" (with Paul Chernick et al.). 1992.

"Initial Review of Ontario Hydro's Demand-Supply Plan Update" (with David Argue et al.). 1992.

"Comments on the Utility Responses to Commission's November 27, 1990 Order and Proposed Revisions to the 1991–1992 Annual and Long Range Demand Side Management Plans" (with John Plunkett et al.). 1991.

"Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities" (with John Plunkett et al.). Filed in NY PSC Case No. 28223 in re New York utilities' DSM plans. 1990.

"Profitability Assessment of Packaged Cogeneration Systems in the New York City Area." 1989. Principal investigator.

"Statistical Analysis of U.S. Nuclear Plant Capacity Factors, Operation and Maintenance Costs, and Capital Additions." 1989.

"The Economics of Completing and Operating the Vogtle Generating Facility." 1985. ESRG Study No. 85-51A.

"Generating Plant Operating Performance Standards Report No. 2: Review of Nuclear Plant Capacity Factor Performance and Projections for the Palo Verde Nuclear Generating Facility." 1985. ESRG Study No. 85-22/2.

"Cost-Benefit Analysis of the Cancellation of Commonwealth Edison Company's Braidwood Nuclear Generating Station." 1984. ESRG Study No. 83-87.

"The Economics of Seabrook 1 from the Perspective of the Three Maine Co-owners." 1984. ESRG Study No. 84-38.

"An Evaluation of the Testimony and Exhibit (RCB-2) of Dr. Robert C. Bushnell Concerning the Capital Cost of Fermi 2." 1984. ESRG Study No. 84-30.

"Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant." 1984. ESRG Study No. 83-81.

"Power Planning in Kentucky: Assessing Issues and Choices—Project Summary Report to the Public Service Commission." 1984. ESRG Study No. 83-51.

"Electric Rate Consequences of Retiring the Robinson 2 Nuclear Plant." 1984. ESRG Study No. 83-10.

"Power Planning in Kentucky: Assessing Issues and Choices—Conservation as a Planning Option." 1983. ESRG Study No. 83-51/TR III.

“Electricity and Gas Savings from Expanded Public Service Electric and Gas Company Conservation Programs.” 1983. ESRG Study No. 82-43/2.

“Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Summary of Findings.” 1983. ESRG Study No. 83-14S.

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“Customer Programs to Moderate Demand Growth on the Arizona Public Service Company System: Identifying Additional Cost-Effective Program Options.” 1982. ESRG Study No. 82-14C.

“The Economics of Alternative Space and Water Heating Systems in New Construction in the Jersey Central Power and Light Service Area, A Report to the Public Advocate.” 1982. ESRG Study No. 82-31.

“Review of the Kentucky-American Water Company Capacity Expansion Program, A Report to the Kentucky Public Service Commission.” 1982. ESRG Study No. 82-45.

“Long Range Forecast of Sierra Pacific Power Company Electric Energy Requirements and Peak Demands, A Report to the Public Service Commission of Nevada.” 1982. ESRG Study No. 81-42B.

“Utility Promotion of Residential Customer Conservation, A Report to Massachusetts Public Interest Research Group.” 1981. ESRG Study No. 81-47

PRESENTATIONS

“Office of People’s Counsel Case No. 9117” (with William Fields). Presentation to the Maryland Public Utilities Commission in Case No. 9117, December 2008.

“Electricity Market Design: Incentives for Efficient Bidding, Opportunities for Gaming.” NASUCA Northeast Market Seminar, Albany, N.Y., February 2001.

“Direct Access Implementation: The California Experience.” Presentation to the Maryland Restructuring Technical Implementation Group on behalf of the Maryland Office of People’s Counsel. June 1998.

“Reflecting Market Expectations in Estimates of Stranded Costs,” speaker, and workshop moderator of “Effectively Valuing Assets and Calculating Stranded Costs.” Conference sponsored by International Business Communications, Washington, D.C., June 1997.

EXPERT TESTIMONY

1989 **Mass. DPU** on behalf of the Massachusetts Executive Office of Energy Resources. Docket No. 89-100. Joint testimony with Paul Chernick relating to statistical analysis of U.S. nuclear-plant capacity factors, operation and maintenance costs, and capital additions; and to projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

1994 **NY PSC** on behalf of the Pace Energy Project, Natural Resources Defense Council, and Citizen's Advisory Panel. Case No. 93-E-1123. Joint testimony with John Plunkett critiques proposed modifications to Long Island Lighting Company's DSM programs from the perspective of least-cost-planning principles.

Vt. PSB on behalf of the Vermont Department of Public Service. Docket No. 5270-CV-1 and 5270-CV-3. Testimony and rebuttal testimony discusses rate and bill effects from DSM spending and sponsors load shapes for measure- and program-screening analyses.

1996 **New Orleans City Council** on behalf of the Alliance for Affordable Energy. Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.

New Orleans City Council Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.; Alliance for Affordable Energy. April, 1996.

Prudence of utilities' IRP decisions; costs of utilities' failure to follow City Council directives; possible cost disallowances and penalties; survey of penalties for similar failures in other jurisdictions.

1998 **Massachusetts Department of Telecommunications and Energy** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Paul Chernick, January, 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

Massachusetts Department of Telecommunications and Energy Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Paul Chernick, October, 1998. Joint surrebuttal with Paul Chernick, January, 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

1999 **Maryland PSC** Case No. 8795, Delmarva Power & Light comprehensive restructuring agreement, Maryland Office of People's Counsel. July 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case Nos. 8794 and 8808, Baltimore Gas & Electric Company comprehensive restructuring agreement, Maryland Office of People's Counsel. Initial Testimony July 1999; Reply Testimony August 1999; Surrebuttal Testimony August 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case No. 8797, comprehensive restructuring agreement for Potomac Edison Company, Maryland Office of People's Counsel. October 1999.

Support of proposed comprehensive restructuring settlement agreement

Connecticut DPUC Docket No. 99-03-35, United Illuminating standard offer, Connecticut Office of Consumer Counsel. November 1999.

Reasonableness of proposed revisions to standard-offer-supply energy costs. Implications of revisions for other elements of proposed settlement.

2000 **U.S. FERC** Docket No. RT01-02-000, Order No. 2000 compliance filing, Joint Consumer Advocates intervenors. Affidavit, November 2000.

Evaluation of innovative rate proposal by PJM transmission owners.

2001 **Maryland PSC** Case No. 8852, Charges for electricity-supplier services for Potomac Electric Power Company, Maryland Office of People's Counsel. March 2001.

Reasonableness of proposed fees for electricity-supplier services.

Maryland PSC Case No. 8890, Merger of Potomac Electric Power Company and Delmarva Power and Light Company, Maryland Office of People's Counsel. September 2001; surrebuttal, October 2001. In support of settlement: Supplemental, December 2001; rejoinder, January 2002.

Costs and benefits to ratepayers. Assessment of public interest.

Maryland PSC Case No. 8796, Potomac Electric Power Company stranded costs and rates, Maryland Office of People's Counsel. December 2001; surrebuttal, February 2002.

Allocation of benefits from sale of generation assets and power-purchase contracts.

2002 **Maryland PSC** Case No. 8908, Maryland electric utilities' standard offer and supply procurement, Maryland Office of People's Counsel. Direct, November 2002; Rebuttal December 2002.

Benefits of proposed settlement to ratepayers. Standard-offer service. Procurement of supply.

2003 **Maryland PSC** Case No. 8980, adequacy of capacity in restructured electricity markets; Maryland Office of People's Counsel. Direct, December 2003; Reply December 2003.

Purpose of capacity-adequacy requirements. PJM capacity rules and practices. Implications of various restructuring proposals for system reliability.

2004 **Maryland PSC** Case No. 8995, Potomac Electric Power Company recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental March 2004, Surrebuttal April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8994, Delmarva Power & Light recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8985, Southern Maryland Electric Coop standard-offer service; Maryland Office of People's Counsel. Direct, July 2004.

Reasonableness and risks of resource-procurement plan.

2005 **FERC** Docket No. ER05-428-000, revisions to ICAP demand curves; City of New York. Statement, March 2005.

Net-revenue offset to cost of new capacity. Winter-summer adjustment factor. Market power and in-City ICAP price trends.

FERC Docket No. PL05-7-000, capacity markets in PJM; Maryland Office of People's Counsel. Statement, June 2005.

Inefficiencies and risks associated with use of administratively determined demand curve. Incompatibility of four-year procurement plan with Maryland standard-offer service.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Coalition of Consumers for Reliability, Affidavit October 2005, Supplemental Affidavit October 2006.

Inefficiencies and risks associated with use of administratively determined demand curve. Effect of proposed reliability-pricing model on capacity costs.

2006 **Maryland PSC** Case No. 9052, Baltimore Gas & Electric rates and market-transition plan; Maryland Office of People's Counsel, February 2006.

Transition to market-based residential rates. Price volatility, bill complexity, and cost-deferral mechanisms.

Maryland PSC Case No. 9056, default service for commercial and industrial customers; Maryland Office of People's Counsel, April 2006.

Assessment of proposals to modify default service for commercial and industrial customers.

Maryland PSC Case No. 9054, merger of Constellation Energy Group and FPL Group; Maryland Office of People's Counsel, June 2006.

Assessment of effects and risks of proposed merger on ratepayers.

Illinois Commerce Commission Docket No. 06-0411, Commonwealth Edison Company residential rate plan; Citizens Utility Board, Cook County State's Attorney's Office, and City of Chicago, Direct July 2006, Reply August 2006.

Transition to market-based rates. Securitization of power costs. Rate of return on deferred assets.

Maryland PSC Case No. 9064, default service for residential and small commercial customers; Maryland Office of People's Counsel, Rebuttal Testimony, September 2006.

Procurement of standard-offer power. Structure and format of bidding. Risk and cost recovery.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Maryland Office of the People's Counsel, Supplemental Affidavit October 2006.

Distorting effects of proposed reliability-pricing model on clearing prices. Economically efficient alternative treatment.

Maryland PSC Case No. 9063, optimal structure of electric industry; Maryland Office of People's Counsel, Direct Testimony, October 2006; Rebuttal November 2006; surrebuttal November 2006.

Procurement of standard-offer power. Risk and gas-price volatility, and their effect on prices and market performance. Alternative procurement strategies.

Maryland PSC Case No. 9073, stranded costs from electric-industry restructuring; Maryland Office of People's Counsel, Direct Testimony, December 2006.

Review of estimates of stranded costs for Baltimore Gas & Electric.

2007 **Maryland PSC** Case No. 9091, rate-stabilization and market-transition plan for the Potomac Edison Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Rate-stabilization plan.

Maryland PSC Case No. 9092, rates and rate mechanisms for the Potomac Electric Power Company; Maryland Office of People’s Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9093, rates and rate mechanisms for Delmarva Power & Light; Maryland Office of People’s Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9099, rate-stabilization plan for Baltimore Gas & Electric; Maryland Office of People’s Counsel, Direct, March 2007; Surrebuttal April 2007.

Review of standard-offer-service-procurement plan. Rate stabilization plan.

Connecticut DPUC Docket No. 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts.

Maryland PSC Case No. 9117, residential and small-commercial standard-offer service; Maryland Office of People’s Counsel. Direct and Reply, September 2007; Supplemental Reply, November 2007; Additional Reply, December 2007; presentation, December 2008.

Benefits of long-term planning and procurement. Proposed aggregation of customers.

Maryland PSC Case No. 9117, Phase II, residential and small-commercial standard-offer service; Maryland Office of People’s Counsel. Direct, October 2007.

Energy efficiency as part of standard-offer-service planning and procurement. Procurement of generation or long-term contracts to meet reliability needs.

2008 **Connecticut DPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Paul Chernick), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

Ontario EB-2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Paul Chernick and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

2009 **Maryland PSC** Case No. 9192, Delmarva Power & Lights rates; Maryland Office of People's Counsel. Direct, August 2009; Rebuttal, Surrebuttal, September 2009.

Cost allocation and rate design.

Wisconsin PSC Docket No. 6630-CE-302, Glacier Hills Wind Park certificate; Citizens Utility Board of Wisconsin. Direct and Surrebuttal, October 2009.

Reasonableness of proposed wind facility.

PUC of Ohio Case No 09-906-EL-SSO, standard-service-offer bidding for three Ohio electric companies; Office of the Ohio Consumers' Counsel. Direct, December 2009.

Design of auctions for SSO power supply. Implications of migration of First-Energy from MISO to PJM.

2010 **PUC of Ohio** Case No 10-388-EL-SSO, standard-service offer for three Ohio electric companies; Office of the Ohio Consumers' Counsel. Direct, July 2010.

Design of auctions for SSO power supply.

Maryland PSC Case No. 9232, Potomac Electric Power Co. administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, Rebuttal, August 2010.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Maryland PSC Case No. 9226, Delmarva Power & Light administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, Rebuttal, August 2010.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Maryland PSC Case No. 9221, Baltimore Gas & Electric cost recovery; Maryland Office of People's Counsel. Reply, August 2010; Rebuttal, September 2010; Surrebuttal, November 2010

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Wisconsin PSC Docket No. 3270-UR-117, Madison Gas & Electric gas and electric rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, September 2010.

Standby rate design. Treatment of uneconomic dispatch costs.

Nova Scotia UARB Case No. NSUARB P-887(2), fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Direct, September 2010.

Effectiveness of fuel-adjustment incentive mechanism.

Manitoba PUB, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystems. Direct, December 2010.

Assessment of drought-related financial risk.

2011 **Mass. DPU 10-170,** NStar–Northeast Utilities merger; Cape Light Compact. Direct, May 2011.

Merger and competitive markets. Competitively neutral recovery of utility investments in new generation.

Mass. DPU 11-5, -6, -7, NStar wind contracts; Cape Light Compact. Direct, May 2011.

Assessment of utility proposal for recovery of contract costs.

Wisc. PSC Docket No. 4220-UR-117, electric and gas rates of Northern States Power: Citizens Utility Board of Wisconsin. Direct, Rebuttals (2) October 2011; Surrebuttal, Oral Sur-Surrebutal November 2011;

Cost allocation and rate design. Allocation of DOE settlement payment.

Wisc. PSC Docket No. 6680-FR-104, fuel-cost-related rate adjustments for Wisconsin Power and Light Company: Citizens Utility Board of Wisconsin. Direct, October 2011; Rebuttal, Surrebuttal, November 2011

Costs to comply with Cross State Air Pollution Rule.

2012 **Maryland PSC** Case No. 9149, Maryland IOUs' development of RFPs for new generation; Maryland Office of People's Counsel. March 2012.

Failure of demand-response provider to perform per contract. Estimation of cost to ratepayers.

PUCO Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, 11-350-EL-AAM, transition to competitive markets for Columbus Southern Power Company and Ohio Power Company; Ohio Consumers' Counsel. May 2012

Structure of auctions, credits, and capacity pricing as part of transition to competitive electricity markets.

Wisconsin PSC Docket No. 3270-UR-118, Madison Gas & Electric rates, Wisconsin Citizens Utility Board. Direct, August 2012; Rebuttal, September 2012.

Cost allocation and rate design (electric).

Wisconsin PSC Docket No. 05-UR-106, We Energies rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, September 2012.

Cost allocation and rate design (electric).

Wisconsin PSC Docket No. 4220-UR-118, Northern States Power rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, October 2012; Surrebuttal, November 2012.

Recovery of environmental remediation costs at a manufactured gas plant. Cost allocation and rate design.

2013 **Corporation Commission of Oklahoma** Cause No. PUD 201200054, Public Service Company of Oklahoma environmental compliance and cost recovery, Sierra Club. Direct, January 2013; rebuttal, February 2013; surrebuttal, March 2013.

Economic evaluation of alternative environmental-compliance plans. Effects of energy efficiency and renewable resources on cost and risk.

Maryland PSC Case No. 9324, Starion Energy marketing, Maryland Office of People's Counsel. September 2013.

Estimation of retail costs of electricity supply.

Wisconsin PSC Docket No. 6690-UR-122, Wisconsin Public Service Corporation gas and electric rates, Wisconsin Citizens Utility Board. Direct, August 2013; Rebuttal, Surrebuttal September 2013.

Cost allocation and rate design; rate-stabilization mechanism.

Wisconsin PSC Docket No. 4220-UR-119, Northern States Power Company gas and electric rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, Surrebuttal, October 2013.

Cost allocation and rate design.

Michigan PSC Case No. U-17429, Consumers Energy Company approval for new gas plant, Natural Resources Defense Council. Corrected Direct, October 2013.

Need for new capacity. Economic assessment of alternative resource options.

2014 **Maryland PSC** Case Nos. 9226 & 9232, administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, April 2014; surrebuttal, May 2014.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Conn. PURA Docket No. 13-07-18, rules for retail electricity markets; Office of Consumer Counsel. Direct, April 2014.

Estimation of retail costs of power supply for residential standard-offer service.

PUC Ohio Case Nos. 13-2385-EL-SSO, 13-2386-EL-AAM; Ohio Power Company standard-offer service; Office of the Ohio Consumers' Counsel. Direct, May 2014.

Allocation of distribution-rider costs.

Wisc. PSC Docket No. 6690-UR-123, Wisconsin Public Service Corporation electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, August 2014; Surrebuttal, September 2014.

Cost allocation and rate design.

Wisc. PSC Docket No. 05-UR-107, We Energy biennial review of electric and gas costs and rates; Citizens Utility Board of Wisconsin. Direct, August 2014; Rebuttal, Surrebuttal September 2014.

Cost allocation and rate design.

Wisc. PSC Docket No. 3270-UR-120, Madison Gas and Electric Co. electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, September 2014.

Cost allocation and rate design.

Nova Scotia UARB Case No. NSUARB P-887(6), Nova Scotia Power fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Evidence, December 2014.

Allocation of fuel-adjustment costs.

2015 **Maryland PSC** Case No. 9221, Baltimore Gas & Electric cost recovery; Maryland Office of People's Counsel. Second Reply, June 2015; Second Rebuttal, July 2015.

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Cost allocation and rate design.

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Cost basis for residential customer charges.

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Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 44967, Indiana Michigan Power Company electric rates; Citizens Action Coalition of Indiana, Indiana Coalition for Human Services, Indiana Community Action Association, and Sierra Club. Direct, November 2017.

Cost basis for residential customer charges.

2018 **North Carolina NCUC** Docket No. E-7, Sub 1146, Duke Energy Carolinas electric rates; North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy. Direct, January 2018.

Cost basis for residential customer charges.

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ATTACHMENT JFW-2

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ATTACHMENT JFW-3

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	**CAUSE NO. 45235**

INDIANA MICHIGAN POWER COMPANY'S OBJECTIONS AND FIRST SUPPLEMENTAL RESPONSE TO
CITIZEN ACTION COALITION OF INDIANA, INC.'S
FIFTH SET OF DISCOVERY REQUESTS

Indiana Michigan Power Company (I&M), pursuant to 170 IAC 1.1-16 and the discovery provisions of Rules 26 through 37 of the Indiana Rules of Trial Procedure, by its counsel, hereby submits the following Objections and Supplemental Responses to the Citizens Action Coalition of Indiana, Inc.'s Fifth Set of Discovery Requests to Indiana Michigan Power Company.

Note and General Objections

The general objections provided in I&M's previous responses are hereby incorporated by reference in this response as if each had been restated here.

Without waiving these objections, Petitioner supplements its response to the Requests in the manner set forth below.

As to Objections,

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INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. CAC DR 5
IURC CAUSE NO. 45235

DATA REQUEST NO CAC 5-02

REQUEST

Please reference I&M Witness Williamson Direct Testimony, Figures AJW-2 and AJW-3. Please explain in detail the Company’s proposal for recovering AMI capital and O&M expenditures incurred in the 2020 test year. Specifically, is I&M proposing to recover estimated amounts through base rates, with reconciliation to actual expenditures recovered or credited through the proposed AMI rider? Or is the Company proposing to recover all actual expenditures in the 2020 test year through the proposed AMI rider?

RESPONSE

See I&M’s response to OUCC DR 5-1. The AMI related investment and O&M for the 2020 test year, represented in Figures AJW-2 and AJW-3, are included in the Company's proposed base rates in this Cause. Please refer to Company witness Williamson's direct testimony, page 37. I&M is proposing the AMI Rider track pre-tax return on net plant in-service investment, depreciation and amortization expense, property tax expense, O&M expense, and Gross Revenue Conversion Factor (GRCF) costs, that are incremental to the level included in base rates in this Cause.

SUPPLEMENTAL RESPONSE

See I&M’s response to OUCC DR 5-1. $9,059,861 of the Test Year AMI Meters & Communication equipment and all of the Test Year AMI Software/Technology investment for the 2020 test year, represented in Figure AJW-2, is included in the Company's proposed base rates in this Cause. The remaining amount of Test Year AMI Meters & Communication equipment is in CWIP at December 31, 2020 and therefore not included in the Company's proposed base rates in this Cause. The AMI O&M for the 2020 test year, represented in Figure AJW-3, is included in the Company's proposed base rates in this Cause. Please refer to Company witness Williamson's direct testimony, page 37. I&M is proposing the AMI Rider track pre-tax return on net plant in-service investment, depreciation and amortization expense, property tax expense, O&M expense, and Gross Revenue Conversion Factor (GRCF) costs, that are incremental to the level included in base rates in this Cause.

ATTACHMENT JFW-4

INDIANA MICHIGAN POWER COMPANY
CITY OF SOUTH BEND
DATA REQUEST SET NO. SB DR 4
IURC CAUSE NO. 45235

DATA REQUEST NO SB 4-06

REQUEST

Provide all cost benefit analyses performed by or on behalf of or reviewed by I&M to evaluate the effectiveness of installing AMI meters.

RESPONSE

A generic discussion draft analysis was prepared by an I&M operations employee using a generic AEP template and inputs. Neither the inputs nor the analysis were completed. The template was not focused on the transition from AMR to AMI via a planned deployment versus a reactive deployment, which is the technology issue here. As a result the draft analysis was not used by I&M management. See “SB 4-06 AMI Draft.pdf.”

gridSMART

I&M AMI Full Deployment Benefits / Cost Analysis

May 2016

DRAFT

Attachment JFW-4

Summary – Major Assumptions

- Business Case reflects company spend and customer cost/benefit perspective
- Full Service Territory (IN & MI figures shared as well)
- 3 Year Deployment of Meters
- Net MRO FTE reduction of 3 FTEs (12 reduced / 9 new positions)
- 5 Year Ramp Up of Consumer Programs including Prepaid Metering, Direct Load Control (DLC), TOU and TOU w/ CPP, and energy usage through web portal
- Remote disconnect functionality included and fully operational
- Prepay is deployed

Summary – Full Deployment

- Full AMI deployment – install additional 608,000 meters over 3 years
  - $82 million capital investment (3 years)
  - $6.0 million O&M (3 years) – Security and ITRON Cost (License, SaaS, Maint)
  - $3 - $4M post-deployment O&M increase can be offset by labor reductions ($0.75 - $1.0M) and credit/collection savings ($4 - $5M)
  - ~$56M in stranded meter assets (AMR depreciated over 25 years)
    - 41,333,420 (Indiana)
    - 14,786,436 (Michigan)
  - Other non-financial benefits include customer experience benefits from AMI-enabled consumer programs, data analytics, and CO2 reduction
- Consumer Program assumptions
  - $2 million capital investment for Prepay / Consumer program IT enhancements (first 3 years)
  - $16.5 million O&M (first 5 years) and $1.8M ongoing (potentially recoverable through EE riders) – Not sure where the O&M is coming from. Assumption is I&M will continue to use current portal. Capital projects for TOU and other tariff offerings but should not have additional O&M tail. O&M Removed from totals but kept benefits
  - Spend more than offset by energy/demand reductions in long-term
- Customer rate impact TBD (will engage Regulatory when appropriate)

Attachment JFW-4

I&M gridSMART/ Benefit Analysis (15 year view)

15 Year Benefits:	$78,600,150.66
15 Year Costs:	($110,519,812.57)
Benefit / Cost Ratio:	0.71
15 Year NPV Benefits:	40,745,740
15 Year NPV Costs:	(90,021,811)
NPV Benefit / Cost Ratio:	0.45

- Compares unfavorably to other internal and external business cases given full deployment of AMR

Attachment JFW-4

Combined benefit / cost ratio of 0.71. Regulatory business case would be built around customer experience including enablement of programs / technologies and application of analytics

Other Options to Consider

- Broader gridSMART deployment including Volt Var Optimization (VVO) and DACR (Distribution Automation – Circuit Reconfiguration) to strengthen overall business case
  - VVO – Energy, peak load reduction savings
  - DACR – SAIDI / Customer Outages Avoided savings
- Phased AMI deployment (e.g., urban settings first like AEP-OH)
- Targeted AMI deployment (e.g., Micro AP for credit/collections benefits)

Appendix

Attachment JFW-4

Financial Benefits - AMI

- "Hard" Field loaded labor net reductions – $0.8M annually
  - Meter Reading - $0.6M annually
  - Limited savings by full deployment of
- "Medium" Credit / Collections / Revenue Enhancements - $4-5M annually
  - *Assumes remote disconnect*
  - Reduced delinquency / bad debt
  - Reduction in theft
  - Lower consumption on inactive meters
  - Benchmarked to ensure in reasonable range of peer business cases

Attachment JFW-4

Financial Benefits - AMI

- Other “soft” O&M / Capital benefits – $500K annually
  - Billing/call center inflow reduction – $100K annually
  - Obsolete meter avoidance - $1.8M over 3-year installation
  - Capacity planning efficiency - $200K annually
- Peak load reduction savings (Programs) - $5-7M annually
- Energy reduction savings (Prepay) - $3-4M annually – Removed
- Reduction bad debt (Prepay) - $81K annually

Attachment JFW-4

Non-Financial Benefits – AMI

- Enables implementation of consumer programs (e.g., Direct Load Control, TOU) and new technologies (e.g., Powerley)
  - o Significant energy / peak load reduction serves to offset the customer costs of AMI investment
- Enables prepaid metering that has proven customer satisfaction benefits (e.g., Salt River Project, Oklahoma Electric Cooperative and Arizona Public Service)
- Creates opportunity for increased customer flexibility / satisfaction through billing accuracy / better usage data (MDM, web portal)

Attachment JFW-4

Non-Financial Benefits – AMI

- Provides platform for proactive data analysis
  - Quicker identification of reliability / power quality issues
  - Decrease outage restoration times (CAIDI)
  - "Pinging" meters to confirm outages can reduce truck rolls and decrease CAIDI
  - Automation of outage orders (work in progress) could further reduce CAIDI
  - Load data ensures more precise capacity planning
  - Timely and accurate identification of theft / consumption on inactive meters
  - Improved mapping of transformer ties – improved outage prediction and quality of mobile alerts
  - Supports fuller view of 360 view of the customer
- Reduction of CO_2 from energy reduction (Prepay) and truck roll avoidance (will be quantified if we move forward)

I&M gridSMART Fundamental Assumptions

- Model includes components for AMI and Consumer Programs
  - Cost / benefit analyses were done on stand-alone basis
  - Program management expenses were included in AMI analysis
- 15-year project life
- AMI capital depreciated over 15 years; IT capital depreciated over 30 years
- Weighted Average Cost of Capital – 7.02%
- Customer growth rate – 0.5%
- PJM Energy and estimated Capacity pricing from CP&B
- AMI Deployment
  - 613,607 total meters – 585,929 single phase, 26,678 poly-phase, 1000 MicroAP
  - Financial benefits driven largely by credit / collections benefit requiring approval of remote disconnect; labor savings relatively small given AMR technology deployment
  - Average Meter Cost – $91 per meter – single phase, $188 per meter – poly-phase
  - Blended installation cost of network and meter at $20 device
  - Replacement Rate for Meter-Related Capital – 1% Years 1 – 20

Attachment JFW-4

I&M gridSMART Fundamental Assumptions (continued)

Consumer Programs

- Costs based largely on PSO experience (e.g., Prepay)
- Prepaid Metering assumes 8% penetration rate, 10% energy reduction
- Other programs ramp up to max participation over 5 years (Years 2 through 6)
- No assumed participation in Year 1
- Participation/penetration rates:
  - Direct Load Control – 7%
  - TOU – 5%
  - TOU w/ CPP – 0.6%
  - Web Portal – 5%
- Peak load reduction %s:
  - Direct Load Control – 35%
  - TOU – 10%
  - TOU w/ CPP – 10%
  - Web Portal – 1%

ATTACHMENT JFW-5

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 5
IURC CAUSE NO. 45235

DATA REQUEST NO CAC 5-03

REQUEST

Please reference I&M Witness Isaacson Direct Testimony, pp. 29-31.

a) Please provide the Company's current estimate of the annual revenue requirement savings associated with each of the operational benefits described by Mr. Isaacson.

i) Please provide copies of all workpapers, including all electronic spreadsheets with cell formulas and file linkages intact, relied on by the Company to estimate annual revenue requirement savings associated with each of the operational benefits described by Mr. Isaacson.

b) Please provide complete documentation of any and all studies conducted by I&M or its consultants of the cost-effectiveness of the Company's proposed AMI deployment plan.

RESPONSE

I&M objects to this Request on the grounds and to the extent it mischaracterizes Mr. Isaacson's testimony and the reasons why the AMI investment is being made at this time. I&M further objects to this Request to the extent it seeks an analysis, calculation, or compilation which has not already been performed and which I&M objects to performing. I&M further objects to the request on the grounds and to the extent the request is overly broad and unduly burdensome, particularly to the extent the request seeks copies of "all workpapers" and "any and all studies". I&M also objects to the request on the grounds and to the extent it is vague and ambiguous, particularly with respect to the meaning of the term "cost-effectiveness" in this context. Subject to and without waiver of the foregoing objections, I&M provides the following response.

a)-b) As explained by Mr. Thomas on pages 22-23 of his testimony, I&M's AMR meters are at the point where they are in need of replacing. Given the age of the existing meters, I&M considered whether to continue to replace failing meters with AMR or move to the next generation of technology. In making its decision, the Company recognized that over the past decade AMI technology has matured, its pricing has stabilized and its importance to system reliability has increased. As further explained by Mr. Isaacson, 35% of the AMR meters deployed in I&M's Indiana service territory will reach the end of their design life by the start of the proposed AMI deployment. Rather than a patchwork AMI deployment to replace AMR meters as they reach the end of their design lives, it is prudent to build out the entire AMI system in a single deployment. This approach is the most efficient and effective way to gain the most benefits from the AMI technology. For example, if AMI were deployed in pockets across I&M's Indiana service territory, the cost of deployment would increase; areas without AMI would not benefit from visibility into system conditions and outage restoration time would be higher; and customers without AMI would have fewer

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 5
IURC CAUSE NO. 45235

options to understand their electric usage. Given this focus, I&M has not calculated a specific number reflecting annual revenue requirement savings associated with the benefits described by Mr. Isaacson, many of which are difficult to quantify by their nature. See also I&M's response to OUCC DR 2-17.

ATTACHMENT JFW-6

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

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$25.00

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Exhibit 4-1
(Continued)

FERC Uniform System of Account	Description	Demand Related	Energy Related
	CLASSIFICATION OF EXPENSES[1]		
	Other Power Generation Operation		
546, 548-554	All Accounts	x	-
547	Fuel	-	x
	Other Power Supply Expenses		
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH), reserve margin, or expected unserved energy (EUE); and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.

IV. METHODS FOR CLASSIFYING AND ALLOCATING PRODUCTION PLANT COSTS

In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important for planning. Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it became apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods. The Federal Energy Regulatory Commission began encouraging the use of a method based on the 12 monthly peak demands, and many utilities accordingly adopted this approach for allocating costs within their retail jurisdictions as well as their resale markets.

This section is divided into three parts. The first two contain a discussion of peak demand and energy weighted cost allocation methods. The third part covers time-differentiated cost of service methods for allocating production plant costs. Tables 4-1 through 4-4 contain illustrative load data supplied by the Southern California Edison Company for monthly peak demands, summer and winter peak demands, class noncoincident peak demands, on-peak and off-peak energy use. These data are used to illustrate the derivation of various demand and energy allocation factors throughout this Section as well as Section III.

The common objective of the methods reviewed in the following two parts is to allocate production plant costs to customer classes consistent with the cost impact that the class loads impose on the utility system. If the utility plans its generating capacity additions to serve its demand in the peak hour of the year, then the demand of each class in the peak hour is regarded as an appropriate basis for allocating demand-related production costs.

If the utility bases its generation expansion planning on reliability criteria -- such as loss of load probability or expected unserved energy -- that have significant values in a number of hours, then the classes' demands in hours other than the single peak hour may also provide an appropriate basis for allocating demand-related production costs. Use of multiple-hour methods also greatly reduces the possibility of atypical conditions influencing the load data used in the cost allocation.

ATTACHMENT JFW-7

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	**CAUSE NO. 45235**

INDIANA MICHIGAN POWER COMPANY'S OBJECTIONS AND FIRST SUPPLEMENTAL RESPONSE TO
CITIZEN ACTION COALITION OF INDIANA, INC.'S
THIRD SET OF DISCOVERY REQUESTS

Indiana Michigan Power Company (I&M), pursuant to 170 IAC 1.1-16 and the discovery provisions of Rules 26 through 37 of the Indiana Rules of Trial Procedure, by its counsel, hereby submits the following Objections and Supplemental Responses to the Citizens Action Coalition of Indiana, Inc.'s Third Set of Discovery Requests to Indiana Michigan Power Company.

Note and General Objections

The general objections provided in I&M's previous responses are hereby incorporated by reference in this response as if each had been restated here.

Without waiving these objections, Petitioner supplements its response to the Requests in the manner set forth below.

As to Objections,

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INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. CAC DR 3
IURC CAUSE NO. 45235

DATA REQUEST NO CAC 3-04

REQUEST

Please reference Attachment DEH-1, p. 1. Please provide in an electronic spreadsheet the following data for the Company's ownership share of each I&M generating plant:
a) Plant in Service for the 2020 test year.
b) Non-fuel fixed operations and maintenance expense for the 2020 test year.
c) Installed capacity rating.
d) Book life.
e) Primary fuel type.

RESPONSE

I&M objects to this request the grounds and to the extent the request is vague and ambiguous with respect to the reference to Attachment DEH-1, p. 1 in the context of I&M generating plant information requested, and with respect to the meaning of the term "non-fuel fixed" in the context of operations and maintenance expense requested. Without waiving this objection;
a) Please see CAC 3-04 Attachment_1.pdf
b) Please see CAC 3-04 Attachment_1.pdf
c) Please see CAC 3-04 Attachment_1.pdf
d) Please refer to pages 23 to 25 of 34 of Attachment JAC-1: Depreciation Study Report in the direct testimony of Company Witness Cash for the average remaining lives of the Company's production plant. Please refer to page 34 of 34 of Attachment JAC-1: Depreciation Study Report in the direct testimony of Company Witness Cash for the estimated year of retirement for each plant.
e) Please see CAC 3-04 Attachment_1.pdf

SUPPLEMENTAL RESPONSE

a) Please see CAC 3-04 Supplemental Attachment 1.pdf.

Indiana Michigan Power Company
Total Company Amounts in ($000)

	Adjusted Gross Plant in Service for 2020 [b]	Unadjusted Non-Fuel O&M Test Year [d]	O&M Adjustments [e]	Adjusted Non-Fuel O&M Test Year	Total Plant Capacity Rating	Fuel type
Rockport Unit 0 (Common)		23,622	599	24,221		Coal
Rockport Unit 1 [a][c]	939,554	8,037	4,040	12,077	1320 MW	Coal
Rockport Unit 2 [a]	241,979	75,764	4,135	79,899	1300 MW	Coal
Cook Unit 0 (Common)		188,679	11,131	199,811		Nuclear
Cook Unit 1	1,439,475	33,526		33,526	1084 MW	Nuclear
Cook Unit 2 [c]	2,162,923	30,937		30,937	1194 MW	Nuclear
Watervliet	11,816	53		53	4.6 MW	Solar
Olive	12,046	53		53	5.0 MW	Solar
Deer Creek	6,132	53		53	2.5 MW	Solar
Twin Branch	6,955	53		53	2.6 MW	Solar
South Bend Solar	29,303			-	20.0 MW	Solar
Berrien Springs	16,445	104		104	7.2 MW	Hydro
Buchanan	8,714	153		153	4.1 MW	Hydro
Constantine	5,525	507		507	1.2 MW	Hydro
Elkhart	9,343	68		68	3.4 MW	Hydro
Mottville	4,654	88		88	1.7 MW	Hydro
Twin Branch	14,930	313		313	4.8 MW	Hydro
I&M Hydro	542	2,320		2,320		Hydro
I&M Generation	1,597	4,414		4,414		All

[a] I&M has a 50% direct ownership share of Rockport Unit 1, and Rockport Unit 2 is operated under a lease agreement. I&M is directly entitled to 50% of the output of both Units; in addition, I&M affiliate AEP Generating Company is entitled to 50% of the output of both Units, and I&M purchases 70% of AEG's entitlement under a Unit Power Agreement (UPA) between I&M and AEG. Therefore, I&M is entitled to 85% of the total output of the Rockport Plant.

Notes

[b] End of Test Year 2020 Gross Plant In Service Balance which includes Rate Base adjustments from Exhibit A-6
Projected Retirements were not available by Unit or Facility, so were allocated based upon balances

[c] Rockport common items are included with Unit 1 (longer depreciable life)
Cook common items are included with Unit 2 (longer depreciable life)

[d] O&M is taken from Attachment DAL-1 Steam, Hydro, Nuclear and Other Generation Categories
Consumables and allowances are taken from Attachment NAH-3
Non-Fuel O&M excludes FERC accounts 501 and 518

[e] O&M adjustments from Exhibit A-5

ATTACHMENT JFW-8

INDIANA MICHIGAN POWER

An AEP Company

INTEGRATED RESOURCE PLANNING REPORT

TO THE

INDIANA UTILITY REGULATORY COMMISSION

Submitted Pursuant to

Commission Rule 170 IAC 4-7

July 1, 2019

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19. The purpose of adding this resource was to allow the model an option to include a short-term capacity commitment as opposed to building a long-term capacity resource.

4.7.6 Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). In the past, on a national level development of these resources has been driven primarily as the result of renewable portfolio requirements. That is not universally true now as advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs.

At this time within the industry, renewable energy resources, because of their intermittent nature, provide more energy value than capacity value. For this IRP, the overall threshold for intermittent resource additions are 30% of I&M's energy demand for wind and 15% for solar. This assumes that the RTO and other key stakeholders will advance the understanding, forecasting and management of intermittent resources, ultimately supporting a higher penetration level and capacity planning values.

4.7.6.1 Solar

4.7.6.1.1 Large-Scale Solar

Solar power comes in two forms to produce electricity: concentrating and photovoltaics. Concentrating solar — which heats a working fluid to temperatures sufficient to generate steam to power a turbine — produces electricity on a large scale and is similar to traditional centralized supply assets in that respect. Photovoltaics can more easily be distributed throughout the grid and are a scalable resource that, for example, can be as small as a few kilowatts or as large as 500MW. This IRP assumes its solar resources will be photovoltaic.

The cost of large-, or utility-scale, solar projects has declined in recent years and is expected to continue to decline through 2023 (see Figure 25). This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy in Europe, Japan, and California. With the trend firmly established, forecasts generally foresee declining nominal prices in the next decade as well, notwithstanding solar panel tariffs which from an IRP perspective are regarded as a short-term impact.

Large-scale solar plants require less lead time to build than fossil plants. There is no defined limit for how much utility solar can be built in a given time. However, in practice, solar facilities are not added without considering the timing impacts of obtaining siting and regulatory approval, for example.

Solar resources were made available in the *Plexos* model with some limits on the rate with which they could be chosen. In the IRP modeling, the assumption was made that large-scale solar resources were available in yearly quantities up to 300MWac[16] of nameplate capacity starting in 2022. A limit on solar capacity additions is needed because as solar costs continue to decrease relative to the market price of energy, there will come a point where the optimization model will theoretically pick an unlimited amount of solar resources, a nonsensical result. Additionally, this 300MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified, permitted, constructed, and interconnected by I&M in a given year. For example, the land requirement to develop a 1MW solar plant is estimated to be 7 acres, implying that 700 acres of land would be required to develop 100MW of solar annually. Over the planning period the maximum threshold for solar resource additions was limited to approximately 15% of I&M's load obligation or 1,700MW. Certainly, as I&M gains experience with solar installations, this limit would likely be modified (for example, it may be lower earlier and greater later).

Solar resources were available in two tiers. Tier 2 as referred to in this IRP, is the overall pricing trend over the planning period based on the BNEF utility scale solar pricing forecast. An additional pricing tier was developed, tier 1, which is 10% lower than the base BNEF forecast. The tier 1 pricing is considered a "Best-In-Class" solar resource. The 10% discount from the tier 2 product is based on the concept that during an RFP process the "Best Bids" would be approximately 10% less than the average bids. Both tiers of solar resources were available in

[16] Manufacturers usually quote system performance in DC watts; however electric service from the utility is supplied in AC watts. An inverter converts the DC electrical current into AC electrical current. Depending on the inverter efficiency, the AC wattage may be anywhere from 80 to 95 percent of the DC wattage.

blocks of 150MW, which is comprised of three 50MW installations and totals 300MW annually. Additionally, both tiers of solar resources were modeled with capacity factors of approximately 24.4%, which is representative of a tracking solar resource located in Ft. Wayne, Indiana.

Figure 25 illustrates the projected large-scale solar pricing included in the IRP model. Both tiers account for Federal ITCs. The large-scale solar pricing used in this IRP reflects a normalized treatment of the ITC, as well as a four-year safe harbor factor in ITC pricing. This safe harbor factor allows projects to lock in ITC benefits four years prior to commercial operation, as long as construction has been commenced. The ITC benefit is included through 2030. After 2030, the 10% ITC benefit would become indiscernible from potential variations in forecasted prices. Solar resources are modeled with a 51.1% capacity credit, which is based on PJM's expected long-term performance of the resource.

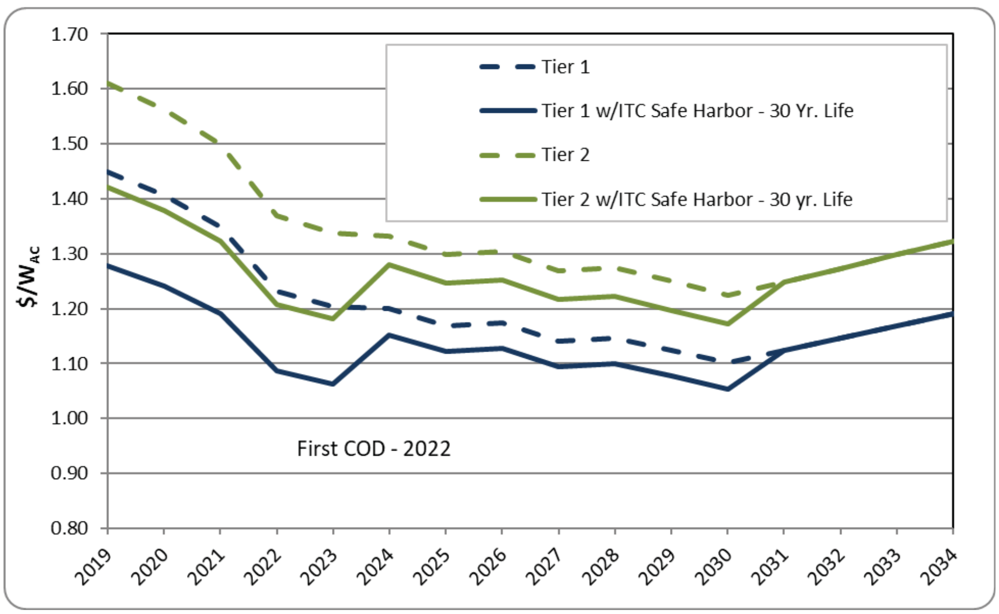

Figure 25. Large-Scale Solar Pricing Tiers

4.7.6.1.2 Trends in Solar Energy Pricing

As mentioned above, solar energy prices have declined significantly in recent years as shown below in Figure 26. From 2010 to 2018 installation costs have declined by more than 60% for residential, commercial, and large-scale solar. Further, large-scale solar has been, and is projected to be, substantially lower in cost compared to other sectors, with large-scale

ATTACHMENT JFW-9

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

FILED
July 26, 2017
INDIANA UTILITY
REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; (2) APPROVAL OF: REVISED DEPRECIATION RATES; ACCOUNTING RELIEF; INCLUSION IN BASIC RATES AND CHARGES OF QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN ENERGY PROJECTS AND COST OF BRINGING I&M'S SYSTEM TO ITS PRESENT STATE OF EFFICIENCY; RATE ADJUSTMENT MECHANISM PROPOSALS; COST DEFERRALS; MAJOR STORM DAMAGE RESTORATION RESERVE AND DISTRIBUTION VEGETATION MANAGEMENT PROGRAM RESERVE; AND AMORTIZATIONS; AND (3) FOR APPROVAL OF NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	CAUSE NO. 44967-NONE

SUBMISSION OF DIRECT TESTIMONY OF MATTHEW W. NOLLENBERGER

Petitioner, Indiana Michigan Power Company (I&M), by counsel, respectfully submits the direct testimony and attachments of Matthew W. Nollenberger in this Cause.

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The undersigned certifies that the foregoing was served upon the following via electronic email, hand delivery or First Class, or United States Mail, postage prepaid this 26th day of July, 2017 to:

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DMS 10265866v1

I&M Exhibit: _____

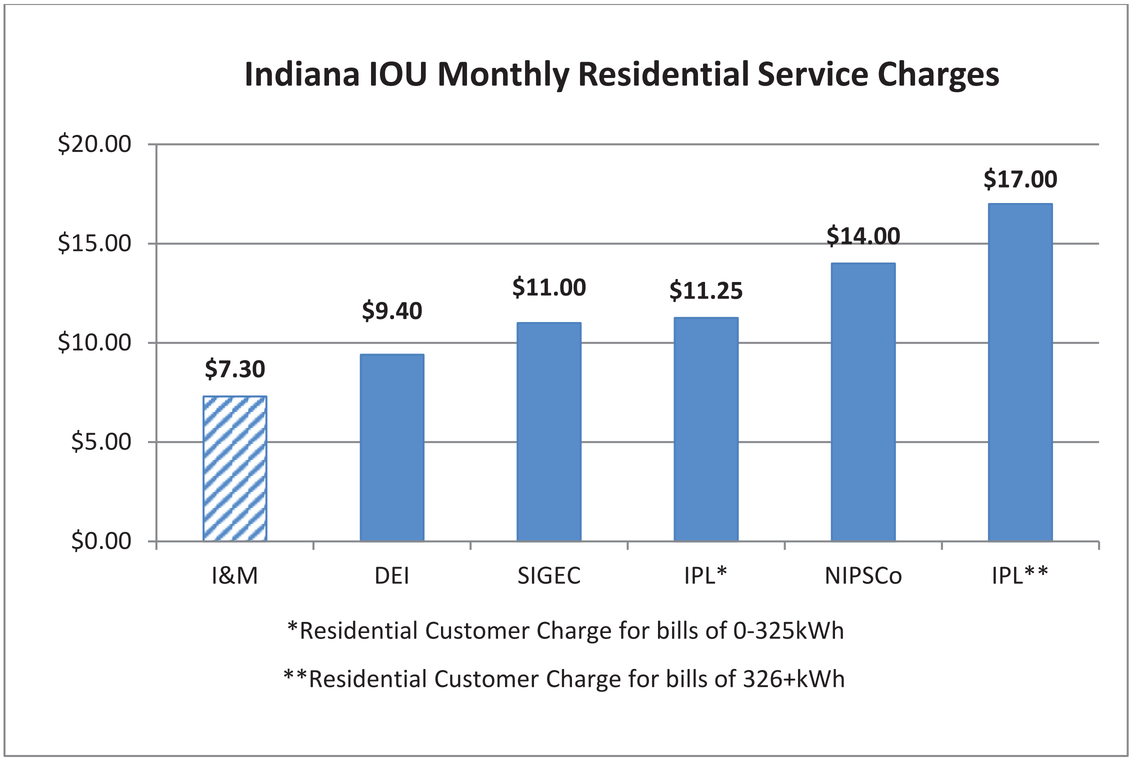
INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

MATTHEW W. NOLLENBERGER

Figure MWN-1
Indiana IOU Monthly Residential Service Charges



Q. What is the rationale for increasing the residential service charge?

A. The goal is to institute a service charge for residential customers that more accurately reflects the Company's customer costs – i.e., the actual cost of connecting a customer to the Company's system. As shown on Attachment MWN-3, connecting each residential customer to I&M's system causes the Company to incur costs to install the service drop and meter ($1,651.02 per service drop and $112.74 per meter, or $15.80 per customer per month), and to maintain and read the meter and engage in other customer-related tasks such as customer service ($22.2M per year, or $4.66 per customer, per month). I&M incurs these customer connection costs for each customer regardless of the amount of energy the customer uses, or how much demand the customer places on the system. I&M's proposed increase in the residential service charge better reflects the fixed, customer-specific nature of these customer costs and provides increased customer rate stability. The proposed increase in the residential service charge also brings I&M's rates more in line with principles of cost causation, thereby eliminating subsidies within the residential class.

Q. How does the proposed service charge increase bring I&M's rates more in line with principles of cost causation?

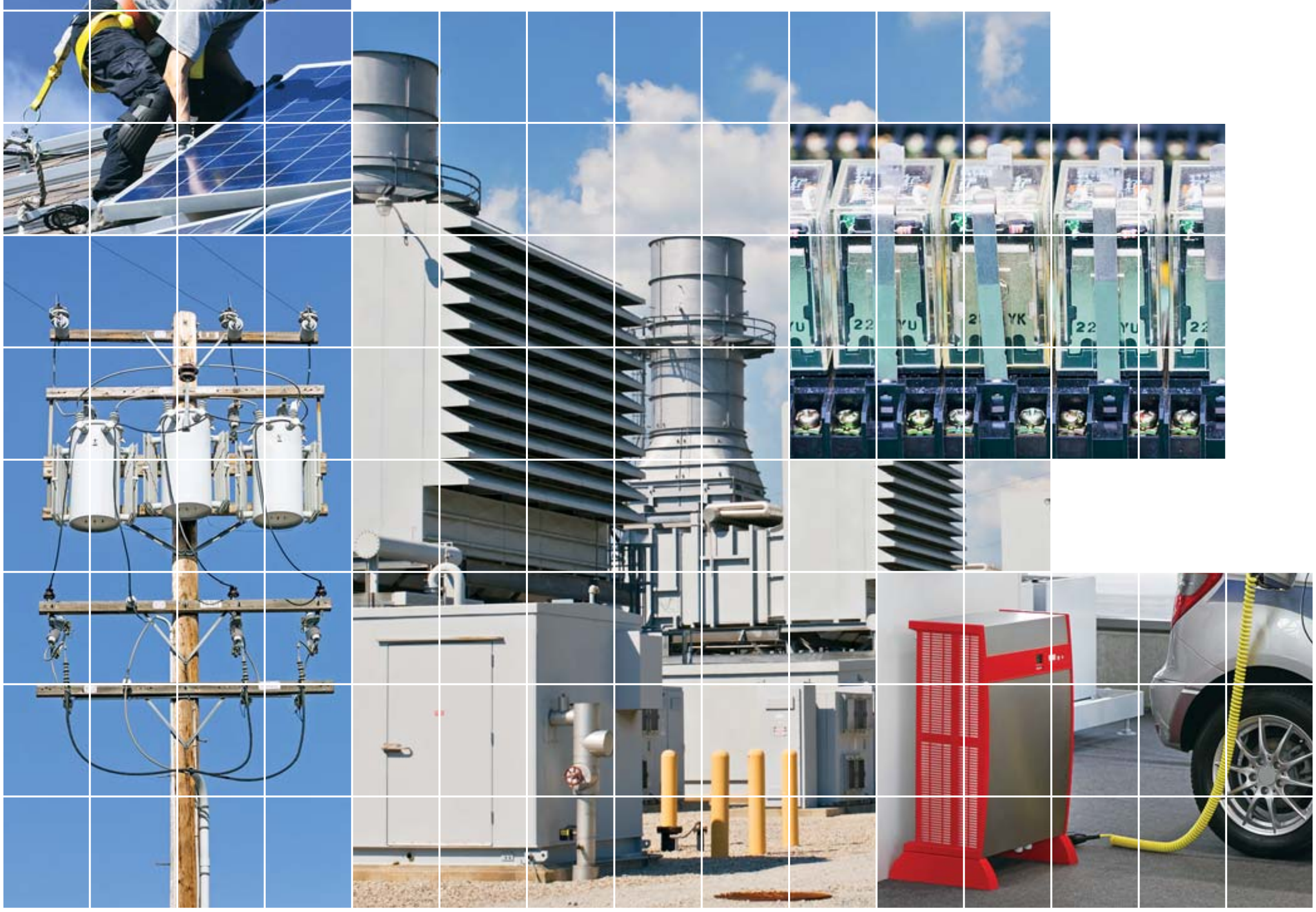
A. I&M's current residential service charge of $7.30 per customer per month recovers less than half of I&M's marginal cost of connection of $20.46 per customer per month as shown on Attachment MWN-3. The remaining customer costs are being recovered through I&M's volumetric energy charges. This means that low-usage customers are paying far less than their share of the Company's marginal costs of service drops, meters, and other customer costs. It also means that high-usage customers are paying far more than their share of these customer costs. The current residential service charge causes high-usage customers to subsidize low-usage customers, and the proposed residential service charge will substantially reduce this subsidy.

Q. How does the proposed service charge provide increased customer rate stability?

A. By recovering more of I&M's customer costs through the fixed residential service charge, a residential customer's bill will vary less from month to month as the

ATTACHMENT JFW-10

DISTRIBUTED ENERGY RESOURCES RATE DESIGN AND COMPENSATION



A Manual Prepared by the NARUC Staff Subcommittee on Rate Design

November 2016

most parties agree any roll out of demand charges should be based on a full and detailed understanding of the implications for that jurisdiction's customers, accompanied by mechanisms such as pilots or shadow billing over a multi-year period.

At the time of writing this Manual, empirical data for demand-based rate designs that are being implemented on a mandatory basis for large investor-owned utilities are limited.[170] Thus, regulators should be wary of counting on unsupported, promised benefits and cautious when plausible harm may represent itself. It may be that pilots that hold their customer's harmless could be the best way forward. Regardless, more data should be available in the future, as several utilities have submitted proposals to regulators and legislators. Whatever the implications of these newer rates may be, a regulator must be comfortable with how the new rates will affect the jurisdiction before implementing them.

2. Fixed Charges and Minimum Bills

Fixed charges (also called customer charges, facilities charges, and grid access charges) are rates that do not vary by any measure of use of the system. Fixed charges have a long history of use across the United States, and are a fixture of many bills. Fixed charges have been used by utilities to recover a base amount of revenue from customers for connection to the grid. Some argue that, as the majority of a utility's costs are fixed (at least in the short run), fixed charges should reflect this reality and collect more (if not all) of such fixed costs. Others argue that higher fixed charges dilute the conservation incentive, fail to reflect the appropriate costs as fixed (long term rather than short term), or should be set to recover only the direct costs of attaching to the utility's system.[171] This disagreement has been a part of utility rate cases for a century. Those who argue that the majority of costs are fixed are using the potential

170 Rocky Mountain Institute, "Review of Alternative Rate Designs," 76.

171 See the bibliography for more references on fixed charge rationale.

increasing cost shift of what they view as fixed costs from DER customers to other customers as an extension of previous justifications for fixed-charge increases.[172]

Higher fixed charges accomplish the goal of revenue stability for the utility and, depending on the degree to which one agrees that utility costs are fixed, match costs to causation. However, the interplay between collecting more costs through a fixed charge and the volumetric rate may result in uneconomic or inefficient price signals. Indeed, an increase in fixed charges should come with an associated reduction in the volumetric rate. Lowering the volumetric charge changes the price signal sent to a customer, and may result in more usage than is efficient. This increased usage can lead to additional investments by the utility, compounding the issue.[173]

This potentiality also highlights the disconnect between costs and their causation that a higher fixed charge may have. If higher usage leads to increased investment, then it may be appropriate for the volumetric rate to reflect the costs that will be necessary to serve it, which would point toward the appropriateness of a lower fixed charge. In other words, it may be more reasonable to lower the fixed costs and increase the volumetric rate, which would send a more efficient price signal.

A related movement is the adoption of a minimum bill component. California, which does not have a fixed charge component for residential customer bills, adopted a minimum bill component to offset concerns raised by its regulated utilities regarding the under-collection of revenue due to customers avoiding the costs of their entire electric bill and not having a balance owed to the utility at the end of the month.[174] In other words, some NEM customers in

---

172 For details on fixed charge proposals and decisions across the country, *see* NC Clean Energy Technology Center's *The 50 States of Solar Report* (https://nccleantech.ncsu.edu/?s=50+states+of+solar&x=0&y=0), which is updated quarterly.

173 Synapse Energy Economics Inc., "Caught in a Fix: The Problem with Fixed Charges for Electricity" (Synapse Energy Economics Inc., Cambridge, MA, February 9, 2016), 18.

174 *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations,* "Decision on Residential

California were able to zero out the entirety of their bill, and avoid paying the distribution utility any grid costs.[175] In a decision revamping its rate design, the California Public Utilities Commission (PUC) adopted a minimum bill component, which ensures that all customers pay some amount to the utility for service. The California PUC set a minimum bill amount at $10, which is collected from customers that have bills under $10. In April 2016, Massachusetts passed the Solar Energy Act (MA Solar Act).[176] The MA Solar Act allows distribution companies to submit to the DPU proposals for a monthly minimum reliability contribution to be included on electric bills for distribution utility accounts that receive net metering credits. Proposals shall be filed in a base rate case or a revenue-neutral rate design filing and supported by cost of service data. On the other hand, minimum bills eliminate the conservation signal by encouraging consumption up to the minimum bill amount.[177]

In either event, distribution utilities often dispute which components are fixed and should be recovered from customers in a fixed charge or minimum bill. As discussed previously, there is a great deal of disagreement as to what constitutes a fixed cost. Are overhead costs fixed? What portion of the distribution system is fixed?[178] Understanding and identifying fixed costs is a key component to determining compensation to DER, revenue recovery for the utility, and how to best balance utility financial health and the growth of DER.

Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates," D.15-07-001, California Public Utilities Commission (July 13, 2015).

175 Due to the structure of NEM at the time, those customers also avoided paying "non-bypassable charges," which included components like nuclear decommissioning costs and public purpose charges, which are used to fund energy efficiency programs in California. Subsequent changes to the NEM program have changed this situation.

176 Act Relative to Solar Energy. (2016, April 11). 2016 Mass. Acts, Chapter 75.

177 Lazar and Gonzalez, "Smart Rate Design." *See also* Lisa Wood et al., *Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives*, Future Electric Utility Regulation, Report No. 5 (Berkeley, CA: Lawrence Berkeley National Laboratory, June 2016), 58–59; Borenstein, "Economics of Fixed Cost Recovery," 14–15.

178 *See, e.g.*, the discussion of the minimum system and zero-intercept methods of cost allocation in NARUC, *Electric Utility Cost Allocation Manual*, 136–42.

ATTACHMENT JFW-11

POWELL GOLDSTEIN LLP

Principles of Public Utiliity Rates by James C. Bonbright

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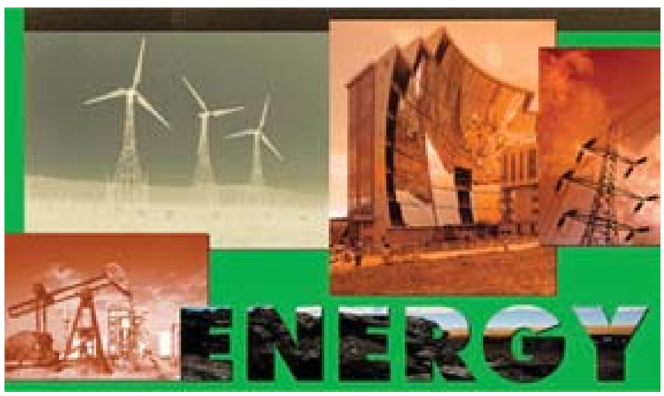

the rates for any given class of service (passenger versus freight, residential versus commercial, etc.) should cover the costs of supplying that class, and so the rates charged to any single customer within that class should cover the costs of supplying this one customer. Under this assumption, the theory of rate structures would be reduced to a mere theory of cost determination through the aid of modern techniques of cost accounting and cost analysis.

Unfortunately, however, no such simple identification of "reasonable" rates with rates measured by costs of service is attainable; and this for several reasons, three of which will now be distinguished. The first of these reasons may be called "practical," whereas the other two are theoretical and are based on the nonadditive character of the costs attributable to specific classes and units of service.

Excessive complexity of cost relationships. The "practical" reasons lie in the extreme difficulties of cost-of-service measurement together with the fact that, even if all specific costs could be measured, they would be found too complex for incorporation in rate schedules. Most public utility companies supply many different kinds of service even when they confine their activities to nothing but electricity, or gas, or telephone service, etc. In a very real sense, moreover, the supply of any one type of service to thousands of customers at different locations constitutes the supply of a different product to each customer. Equally truly, service rendered at any one time is not the same product as is otherwise comparable service rendered at another time.

But these millions of different service deliveries by a single public utility company are produced in combination and at total costs, most of which are joint or common either to the entire business or else to some major branch of the business. Under these circumstances, the attempt to estimate what part of the total cost of operating a utility business constitutes the cost of serving each individual consumer or class of consumers would involve a hopelessly elaborate and expensive type of cost analysis.[7] For this reason

[7] John Alden Bliss has sent me a quotation from a report by Alex Dow, former chairman of the Detroit Edison Company, to the effect that his company had been obliged to reply on the one hand to the customer who thinks that rates should be uniform per kilowatt-hour and on the other hand to the man "who wants us to determine so exactly the cost of service to each customer that our power plants and distribution systems would become merely unavoidable preliminaries to the operation of a meter department." The TNEC Monograph No.

alone, the most that can be hoped for is the development of techniques of cost allocation that reflect only the major, more stable, and more predictable cost relationships.

But even if, through the miracles of electronic computers and of modern techniques of mathematical analysis, all significant cost differentials could be measured without inordinate expense, they would then be found far too numerous, too complex, and too volatile to be embodied in rate differentials. Stability and predictability of the charges for public utility services are desirable attributes; and up to a certain point—or rather, up to an indeterminate point—they are worth attaining even at the sacrifice of nice attempts to bring rates into accord with current production costs. Indeed, unless rate-making policies are sufficiently stable to permit a consumer to predict with some confidence what his charges will be *if he decides* to equip his home or his factory to take the contemplated service and then to buy the service, a cost-price system of rate making will be self-defeating when viewed as a means of securing a rational control of demand.

These practical considerations leading to the design of rate structures that ignore many cost differentials are illustrated by the general uniformity of rates for gas, electricity, telephone service, and water supply throughout an entire city, despite distances from source of supply, differences in density of population, and other differences that may have a material bearing on relative costs of service. Indeed, in some parts of the country, the rates of large electric power systems are uniform, or almost uniform, throughout the state, no distinction being made between urban and rural areas. Critics of this "blanket rate" policy may well be right in insisting that it carries the principle of uniformity too far.[8] But the criticism is leveled merely against an *excessive* disregard of cost differentials in rate making.

Failure of the sum of differential costs to equate with total costs.

32, cited in footnote 4, *supra*, quotes at page 41 from an opinion by Chairman Maltbie of the New York Public Service Commission reading in part: "In every business, there is always a large percentage of customers, who are served at less than cost, for the reason that it has been found impracticable to devise and apply a system of cost accounting and computation which would carry out the principle literally; and if it were done, it would result in such an elaborate and complicated schedule of rates that the public could not understand it and few could apply it."

[8] See Chap. VII, pp. 112–113, *supra*.

We come now to a further limitation of the cost-of-service principle of rate structures—this one of critical concern when the rates must be made to yield a fair over-all return. It lies in the nonadditive character of the costs allocable, on a cost responsibility basis, to specific classes and quantities of utility service. In view of this failure of "the sum of the parts to equal the whole," the requirement that rates as a whole shall equal costs as a whole cannot be reconciled with a requirement that each consumer shall pay only the costs for which he, and no one else, is causally responsible; nor can it be reconciled with a requirement that each major class of consumers shall pay rates designed to cover the costs of serving that class, no more and no less. In consequence, save under circumstances that could occur only by rare coincidence, one of the two cost principles—the total-cost principle or the specific-cost principle—must give way. And, under the assumption of this chapter, the principle that must yield is that of service at cost as a measure of particular rates and rate relationships.

In stressing this probable conflict between the over-all-cost standard of entire rate levels and the specific-cost standard of the rate structure, the literature on rate theory has attributed it primarily to the distinction between average cost and incremental or marginal cost—a distinction familiar to the economic textbooks on the theory of price determination. This distinction will now be noted, although a second distinction will receive attention later. The point is that, when multiple products, or even multiple units of the same product, are produced jointly or in common, by an organically whole productive process, the only costs allocable solely to any given product or amount of product are *differential* costs. They are measured by a comparison between the total costs of the entire operation with the given output included, and the total costs with that output excluded.[9]

The most familiar and most significant form of a differential cost is incremental cost—the increment in total cost that will result from superimposing the production of the particular amount and type of product under inquiry on the other production. A special

[9] Under limited conditions, however, it is permissible to regard the net cost of one product, among a complex of jointly produced products, as measured by the total cost of producing the whole complex minus the proceeds of the sale of all the other products. These other products are then treated as by-products in the strictest sense of this term.

type of incremental cost, important for the theory of public utility rates, is marginal cost—a concept subject to various definitions but here best defined in a loose way, as the incremental cost, per unit, of producing a relatively small increment of a given product.[10] But these differential or incremental or marginal costs are nonadditive except under special conditions. For the determination of the cost of any particular type and amount of output assumes the continued production of the rest of the output, an assumption which is shifted when the costs of other types and amounts of output are under inquiry.

What has just been said as to the nonadditive nature of differential or incremental costs applies to all public utility companies which produce services of different kinds for many different people and in many different amounts. With an electric utility company, for example, the only cost specifically allocable to the residential service, *and not* to any other service, is the excess in total cost over what would be the cost of supplying all services other than residential. And the same statement would apply to an attempt to measure the cost that a company has actually incurred, or would incur in the future, in supplying a particular amount of service to any single consumer. The usual assumption is that, if the incremental costs of all services, separately measured, were added together, they would fall materially short of covering total costs—an assumption based on the belief that most public utility enterprises operate under conditions of decreasing costs with increasing output. When this assumption is valid, it implies that a public utility company cannot cover its total revenue requirements without charging *more* than incremental costs for at least some of its services.

The nonadditive character of the costs specifically allocable, on a cost-responsibility basis, to the different classes and amounts of public utility services has often been disguised by the acceptance of elaborate full-cost apportionments which begin with total costs and apportion these costs among the various classes of service as one might divide a pie among the members of a dinner party, leaving no residue for the kitchen. These "fully-distributed-cost" apportionments are especially familiar in the railroad field, where

[10] Marginal cost is sometimes defined as the increase in total cost resulting from the production of one additional unit of the product. But a one-unit margin is too narrow for most rate-making purposes.

they have been made under formulas developed by experts in the Interstate Commerce Commission. One such apportionment seems to indicate that the railroads of the United States, taken altogether, have been suffering annual losses of many millions of dollars per year on their passenger business. The usefulness of these apportionments is a debatable subject, which will be discussed in Chapter XVIII. But, in any case, their merits must rest on a claim that they represent, not a finding of the costs definitely occasioned by this class of service rather than that, but rather a *fair* or *equitable* division of total costs or else a statement of relative, not absolute costs. Even the cost analysts who make these full-cost apportionments recognize this fact implicitly when they concede, as they usually do, that a company may find it profitable to sell some classes of service at less than their imputed costs.[11]

The "cost" used as a measure of total revenue requirements is not the same kind of cost as the "cost" most clearly relevant to the design of the rate structure. The source of the previously discussed discrepancy between the total costs of an entire utility business and the sum of the costs causally allocable to the particular amounts and types of service lies in the distinction between *average total* costs and *incremental* or *marginal* costs. Whenever this discrepancy prevails, which it will do if the public utility company is operating under conditions of decreasing unit cost with increasing rates of output, rates set at incremental cost would tend to fall short of total costs. But we must now note another reason why the sum of the costs attributable to the specific services of a public utility company may fail to reflect the total costs of running the entire business.

[11] Public utility companies have sometimes invoked a marginal or incremental cost principle in defense of special rate concessions to very large customers, the defense resting on the contention that the revenues from this favored service will cover, or more than cover, all *additional* costs of its production. The weakness of this defense lies not, as sometimes asserted, in the invalidity of the incremental cost principle, but rather in a company's unsymmetrical proposal to base the preferential rate on incremental cost while basing the other rates on residual cost. Even this latter proposal may be justified in special cases; but the practice constitutes a form of rate discrimination, not a form of cost pricing. Its reasoning has been rejected as a defense against the charge of unlawful discrimination under the provisions of the Robinson-Patman Act. See Herbert F. Taggart, *Cost Justification*, Michigan Business Studies, Vol. 14, No. 3 (Ann Arbor, 1959), pp. 538–539: "The differential cost approach to cost justification is totally unacceptable. This means that a cost cannot be ignored *merely* because a given cost category would not be changed by the acquisition or loss of a certain customer or order or quantum of production." See also Frederick M. Rowe, "Cost Justification of Price Differentials under the Robinson-Patman Act," 59 *Columbia Law Review* 584–617 at 594 (1959).

This reason lies in the important distinction between historical or "sunk" costs and anticipated or "escapable" costs. A company's total revenue requirements, as measured under a fair-return standard, depend on liabilities and quasi liabilities for the payment of operating expenses and capital costs already partly predetermined by earlier transactions, including earlier purchases of plant, land, and other resources. On the other hand, the costs most clearly relevant to the determination of specific rates, at least under an optimum-utilization objective of rate-making policy, are those anticipated costs that can still be escaped or minimized by a control of output. This important distinction between the two types of cost is drawn most sharply when the revenue requirements are determined under an original-cost rule of rate making.[12] But the distinction remains, though in a blurred status, even under a so-called "fair-value" rule as actually applied by courts and commissions.

In short, then, there are two quite different sources of possible conflict between a cost-price system of reasonable rate levels and a cost-price system of specific rates and rate relationships. But, if the revenue requirements of the company are lower than would be the requirements of a new company, as they are likely to be during a period of rising construction costs and rising site values, the two sources of conflict may result in a partial offset. It is with this possibility in mind that some economists, who view with regret the necessity of charging public utility rates in excess of marginal costs, have tended to favor an original-cost type of rate base during a period of price inflation.

THREE WAYS BY WHICH TO RECONCILE THE COST-OF-SERVICE PRINCIPLE OF INDIVIDUAL RATES WITH THE MANDATE OF A FAIR OVER-ALL RETURN

For the reasons just suggested, rates based merely on specific or incremental or marginal costs might well suffice, on occasion, to yield adequate, or even more than adequate, total revenues under a fair-return standard. But the general principles of public utility rates dare not rely on such a convenient harmony. Instead, they

[12] See pp. 75–77, *supra*. In Chap. I of his *Economics of Sellers' Competition* (Baltimore, 1952), Professor Fritz Machlup stresses the impossibility of a rational allocation of the historical costs of standard accounting when the assumed objective is to determine the specific costs of producing any given product among a complex of products.

ATTACHMENT JFW-12

The Economics of Regulation
Principles and Institutions

Volume I Economic Principles
Volume II Institutional Issues

Alfred E. Kahn

The MIT Press
Cambridge, Massachusetts
London, England

Second Printing, 1989

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permitting prices to fluctuate widely along the SRMC function, depending on the immediate relation of demand to capacity,[49] the practically achievable benchmark for efficient pricing is more likely to be a type of average long-run incremental cost, computed for a large, expected incremental block of sales, instead of SRMC, estimated for a single additional sale. This long-run incremental cost (which we shall loosely refer to as long-run marginal cost as well) would be based on (1) the average incremental variable costs of those added sales and (2) estimated additional capital costs per unit, for the additional capacity that will have to be constructed if sales at that price are expected to continue over time or to grow.[50] Both of these components would be estimated as averages over some period of years extending into the future.

5. The prevalence of common costs has similar implications. Service A bears a causal responsibility for a share of common costs only if there is an economically realistic alternative use of the capacity now used to provide it, or if production of A requires the building of additional capacity. The marginal opportunity cost of serving A depends on how much the alternative users would be willing to pay for devoting the capacity to serving them instead. The sum of the separable marginal costs will therefore cover the common costs only if at separate prices less than this the claims on the capacity exceed the available supply.[51]

6. Long-run marginal costs are likely to be the preferred criterion also in competitive situations. Permitting rate reductions to a lower level of SRMC, which would prove to be unremunerative if the business thus attracted were to continue over time, might constitute predatory competition—driving out of business rivals whose *long-run* costs of production might well be lower than those of the price-cutter.

SRMC on the average equal to its composite ATC—running far above ATC when operations exceeded the 80% level and correspondingly below at other times. See pp. 94–97, Chapter 4, below.

[49] If SRMC pricing did not cover ATC over time, capital would eventually be withdrawn and new capital, needed to meet the rising demand, repelled, until a recovering demand, moving up along a steeply rising MC curve, pushed prices up high enough and held them there long enough to attract new capital into the industry—with the possibility of a return of depressed prices with any temporary reemergence of excess capacity. In the case of the partly-empty airplane (see pp. 75–76), the "efficient price" would be zero as long as the response of travelers remained insufficient to fill the plane; then it would have to jump the moment the empty spaces fell one short of demand, possibly to the full cost of an added flight but in any case to whatever level necessary to equate the number of available seats with the number of would-be passengers. On each flight, the available seats would have to be auctioned, with the uniform price settling at the point required to clear the market.

[50] See W. Arthur Lewis, *Overhead Costs* (New York: Rinehart, 1949), 15–20; Marcel Boiteux, "Peak-Load Pricing" in James R. Nelson, *Marginal Cost Pricing in Practice* (Englewood Cliffs: Prentice-Hall, 1964), 70–72.

[51] As we have just seen in another connection (pp. 82–83), the marginal opportunity cost of providing a cubic foot of warehouse space to any particular user, A, is the most valuable alternative use of that space excluded by serving A—what the most insistent excluded customer would have been willing to pay for it. If at any price per foot less than the proportionate share of the common costs (that is, less than ATC) of the warehouse, there are or would be unsatisfied customers—that is, more cubic feet demanded than were available—then clearly the marginal opportunity cost of each cubic foot would be at least equal to average total costs, and prices correctly set at SRMC would cover total costs. If, instead, at a price equal to ATC there is excess capacity, this demonstrates that price exceeds marginal opportunity costs: serving A is not preventing anyone else willing to pay that much from getting all the space he wants. In this circumstance, prices set lower, at true SRMC, would not provide enough revenue to cover total costs.

ATTACHMENT JFW-13

PUBLIC UTILITY ECONOMICS

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eased use. Flat rates
phone companies for

local exchange service and by urban transit utilities. Their services are supplied under circumstances which make this the most feasible form of pricing.

(2) *Straight-Line Meter-Rate Schedules.* Straight-line meter-rate schedules provide service at a constant charge per metered unit of energy, regardless of the quantity of energy used. For example, the rate schedule might provide for a charge of 4 cents per kilowatt-hour. Under this type of rate schedule, the average rate per kilowatt-hour remains the same regardless of the amount consumed, but the customer's bill increases proportionately with the increase in energy used. This type of rate schedule is used in some cases for off-peak water heating and special services; however, it has been largely abandoned for general use. The advantage of this type of rate schedule is its simplicity. The principal weakness is that it does not provide any rate reduction or incentive for larger volume use.

(3) *Block Meter-Rate Schedules.* The block meter-rate schedule is now the type most widely used for residential and other small-volume consumers. This type of rate schedule offers a decreasing price per unit of energy for successive blocks (quantities) of consumption. More specifically, this type of rate schedule offers successively lower rates per kilowatt-hour for all or part of each block of energy consumed. The customer's bill is calculated by cumulating the charges incurred for each successive block of energy taken or fraction thereof. This example illustrates a block meter-rate schedule for monthly billing; the minimum charge is $1.05.

First 10 Kwh or less	$1.05
Next 30 Kwh	4.5 cents per Kwh
Next 60 Kwh	3.9 cents per Kwh
Next 100 Kwh	2.7 cents per Kwh
201 Kwh or more	2.0 cents per Kwh
Minimum charge, $1.05 per month	

The block meter-rate schedule is simple and easily understood by consumers. The average over-all rate charged per kilowatt-hour declines with increased use, thus promoting sales. The bill increases more or less proportionately to energy used within each block but less than proportionately when all consumption beyond the first block is considered.

The block meter-rate schedule, and others, may include either a "service charge" or a "minimum charge." There is an important difference between the two. The *service charge* is a fixed amount per month, say 75 cents, that a customer must pay, regardless of the consumption of energy, and for which he can use no energy. The *minimum charge,* on the other hand, is based upon a minimum amount of consumption which the customer will have to pay for—whether or not that amount is actually used. Thus, the minimum charge permits the utility to collect some amount from the convenience user without increasing the bill of the average customer. In the above illustration of a block meter-rate schedule, for example, a minimum charge of $1.05 per month is related to the first block of 10 kilowatt-hours. Any monthly total consumption of less than that amount would be billed at $1.05 nonetheless. In summary: (a) the service charge is a fixed monthly sum that is unrelated to any specified quantity of consumption; while (b) the minimum charge is a fixed monthly sum that is related to a specified minimum monthly consumption of energy which the customer must pay for whether it is used or not. Where the rate schedule calls for a service charge, the block charges are ordinarily lower than in rate schedules providing a minimum charge.

The purpose of both the service charge and the minimum charge is to cover at least some of the costs incurred by the utility whether or not the customer uses energy in a particular month. For small customers under the block meter-rate schedule, a charge of this kind is intended to cover the expenses relating to meter service and maintenance, meter reading, accounting and collecting, return on the investment in meters and the service lines connecting the customer's premises to the distribution system, and others. Such expenses as these represent as a minimum the "readiness-to-serve" expenses incurred by the utility on behalf of each customer. In the absence of a service charge or minimum charge, these expenses would be avoided by the convenience user and transferred unfairly to those consuming service.

In some states there has been public protest against the service charge, largely on the ground that it permitted the utility to receive "something for nothing." This type of public opinion has arisen because no energy use is related to the service charge. Accordingly, some state commissions have prohibited the service charge in favor of the minimum charge. The New York commission, for example, has recognized that the basis of the public opposition to the service charge ". . . is not so much economic or accounting as it is psychological." A different attitude was found to exist with respect to the minimum charge.[35]

A predecessor of the block meter-rate schedule, called the *step meter-rate schedule,* is now almost never used. Under this type of rate schedule one price was charged per unit of energy for the entire amount of service consumed. That unit price was determined by the price attaching to the particular block in which the total consumption happened to fall; prices decreased with each successive block. Because of this feature it was sometimes possible to reduce the over-all bill by wasting service so as to cause total consumption to come within the next, lower-priced energy block. The block meter-rate schedule, which cumulates block charges, was a substantial improvement.

(4) *Hopkinson Demand Rate Schedules.* The Hopkinson-type rate schedule is widely used for medium and large commercial and industrial customers. It was devised by Dr. John Hopkinson in 1892. The Hopkinson rate schedule provides for a two-part rate, consisting of separate charges for maximum demand and energy consumption. The customer's bill under this type of rate schedule, therefore, is the sum of the two components—the demand charge and the energy charge. As the Hopkinson-type rate schedule has been adapted for present-day use, either the demand charge or the energy charge or both may be graduated by blocks so as to provide lower charges for larger volumes of consumption. The Hopkinson-type rate schedule requires a measurement of kilowatts of demand and kilowatt-hours of energy. The rate schedule may provide that the customer's maximum demand be either measured or estimated. For larger customers, the maximum demand for billing purposes is generally obtained through measurement by use of a demand meter or demand indicator. The billing demand may be the maximum 15-minute or 30-minute demand measured in kilowatts as recorded in the billing month, or some similar measure of demand. The following is an illustration of a Hopkinson rate schedule for monthly billing.

Demand Charge:

$2.25 per Kw	....	first 2 Kw of demand
$2.00 per Kw	....	next 18 Kw of demand
$1.50 per Kw	....	next 80 Kw of demand
$1.25 per Kw	....	all over 100 Kw of demand

[35] *Re Rates and Rate Schedules of Corporations Supplying Electricity,* PUR 1931 C, 337, 347.

ATTACHMENT JFW-14

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 6
IURC CAUSE NO. 45235

DATA REQUEST NO CAC 6-02

REQUEST

Please reference the electronic spreadsheet 'CAC 4-11c.xlsm', which was an attachment to I&M Response to CAC Data Request 4-11. In an electronic spreadsheet, please provide separately for each residential customer included in the Load Research data the following monthly data for the Sample Year 2018:

a) Monthly kWh energy usage for each month of 2018.

b) Hourly kW demand at the time of system peak for each month of 2018.

c) Hourly kW demand at the time of the residential class peak for each month of 2018.

d) Maximum hourly kW demand for each month of 2018.

RESPONSE

Please see "CAC 6-02 Final.xls."

ATTACHMENT JFW-15

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 4
IURC CAUSE NO. 45235

DATA REQUEST NO CAC 4-10

REQUEST

Please reference I&M Witness Nollenberger Direct Testimony, p. 25, line 6 through p. 26, line 36.

a) Please provide copies of all e-mail communications, meeting presentations or notes, memoranda, reports, or other documentation of the Company's consideration of alternative designs for the proposed pilot and of the decision to adopt the proposed design.

b) Will the on-peak kW demand charge be applied to the average or the maximum of the pilot participant's kW billing demand during the on-peak billing period? Please explain.

c) What type of meter will be installed on pilot participants' premises? Will I&M install TOD or demand meters? Please explain.

RESPONSE

I&M objects to the request on the grounds and to the extent the request is overly broad and unduly burdensome, particularly to the extent the request seeks "all e-mail communications, meeting presentations or notes, memoranda, reports, or other documentation". The preparation of a general rate case generates thousands of "e-mail communications, meeting presentations or notes, memoranda, reports, or other documentation". Requiring I&M to review and produce "all e-mail communications, meeting presentations or notes, memoranda, reports, or other documentation" as requested is oppressive and calculated to take I&M and their staff away from normal work activities, and require them to expend significant resources to provide complete and accurate answers to the CAC's request, which are only of marginal value, if any, to the CAC. See Ind. Tr. Rule 26(B)(1).

I&M further objects to the request to the extent the request seeks information that is outside the scope of this proceeding and is not reasonably calculated to lead to the discovery of admissible evidence. More specifically, the request seeks information related to I&M's consideration of alternative proposals that may or may not exist, are not proposed in this case, and which are not the subject of this proceeding. In support of this objection, I&M states that I&M's proposals and relief requested in this proceeding are set forth in I&M's petition, case-in-chief, and I&M's other supporting evidence.

I&M further objects to the request on the grounds and to the extent that the request seeks the legal reasoning and theories behind the proposals presented by I&M in this proceeding. In support of this objection, I&M states that it is under no obligation to conduct legal research on behalf of other parties through discovery. Moreover, disclosure of the requested information would disrupt the integrity of the adversarial process by requiring I&M to divulge strategies and positions considered by I&M in preparing for this litigation.

Ind. Tr. Rule 26(B)(5) provides that when a party withholds information "otherwise discoverable" under the Indiana Trial Rules by claiming that it is privileged or subject to protection as trial preparation material, the party "shall make the claim expressly and shall describe the nature of the documents, communications, or things not produced or disclosed in a manner that, without revealing information itself privileged or protected, will enable other parties to assess the applicability of the privilege or protection." As explained above, the requested information is not "otherwise discoverable" under the Indiana Trial Rules, and thus no privilege log is required. Notwithstanding the fact that the requested information is not "otherwise discoverable", I&M further objects to the request on the grounds and to the extent the request seeks information that is subject to the attorney-client privilege and/or attorney work product doctrine.

In support of this objection, I&M notes that the request on its face seeks "all e-mail communications, meeting presentations or notes, memoranda, reports, or other documentation" directly related to the subject matter of this litigation and that were prepared in anticipation of this litigation. Further, any responsive documents would "relate[] to the preparation, strategy, and appraisal of the strengths and weaknesses of an action, or to the activities of the attorneys involved" and thus constitute work product that is protected from disclosure. *See Duke Energy Indiana, Inc.*, Cause No. 44526, Docket Entry dated December 16, 2014, at 4 (denying motion to compel production of documents created in preparation of case) (quoting *Ind. State Bd. of Pub. Welfare v. Tioga Pines Living Ctr., Inc.*, 592 N.E.2d 1274, 1277 (Ind. Ct. App. 1992)).

Subject to and without waiver of the foregoing objections, I&M provides the following response.

a. See objection.

b. Billing demand in kW shall be taken each month as the single highest 15-minute peak in kilowatts as registered during the month during the stated on-peak time periods.

c. A meter programmed to record time-of-day demand.