JI Exhibit 2

STATE OF INDIANA

BEFORE THE 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**

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA, INC., INDIANA COALITION FOR HUMAN SERVICES, INDIANA COMMUNITY ACTION ASSOCIATION, AND SIERRA CLUB

Resource Insight, Inc.

NOVEMBER 7, 2017

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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 80 state, provincial, and federal proceedings in the U.S. and Canada. 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"), Indiana Coalition for Human Services ("ICHS"), Indiana Community Action Association ("INCAA"), and Sierra Club (collectively, "Joint Intervenors" or "JI").

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: Residential Cost of Connection
- Attachment JFW-3: Citations to Marginal-Price Elasticity Studies
- Attachment JFW-4: Indiana Michigan Power Company ("I&M" or "the Company") Response to Data Request No. OUCC 25-01
- Attachment JFW-5: I&M Response to Data Request No. OUCC 25-03
- Attachment JFW-6: Excerpted Pages 297-301 from James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press (1961)
- Attachment JFW-7: Excerpted Pages 117-119 of National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation* (November 2016)
- Attachment JFW-8: Attachment JCW-2 to Direct Testimony by I&M Witness Jon C. Walter in Cause No. 44841
- Attachment JFW-9: I&M's Attachment to CAC Data Request No. 4-05

Q: What is the purpose of your testimony?

A: On July 26, 2017, I&M filed a petition (including supporting direct testimony) with the Indiana Utility Regulatory Commission ("the Commission") for authority to increase electric rates. My testimony responds

to supporting testimony by I&M witness Matthew W. Nollenberger regarding the Company's proposal to increase the monthly service charge for residential customers to $18.00 per customer.[1] My response to Mr. Nollenberger relies on data and documents provided through discovery, and on information provided in supporting direct testimony by I&M witness Daniel E. High regarding the Company's class cost of service study ("CCOSS") and by I&M witness Chad M. Burnett regarding the Company's forecast of energy sales.

Q: Please summarize your findings and recommendations.

A: The Company has not justified its proposal to increase the residential service charge. As explained in more detail below, the proposed increase would:

- Inappropriately shift recovery of load-related costs to the residential service charge.
- Lead to subsidization of high-usage residential customers' costs by low-usage customers, and thereby inequitably increase bills for the Company's smallest residential customers.
- Dampen price signals to consumers for investing in energy efficiency or distributed renewable generation.

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

[1] The Company proposes to increase the monthly service charge to $18.00 for residential customers taking service under either Tariff RS or Tariff RS-TOD. In addition, I&M proposes to charge Tariff RS-TOD customers an additional monthly fixed charge to cover the incremental cost of time-of-day meters. I do not address the Company's proposal with regard to the additional charge for time-of-day meters.

Q: How is the rest of your testimony organized?

A: In Section II, I describe the Company's proposal for increasing the residential service charge. In Section III, I discuss how the Company's proposal would result in a residential service charge that exceeds the actual cost to connect residential customers and thereby lead to cross-subsidization within the residential class. In Section IV, I explain how the residential service charge proposed by I&M would inappropriately shift recovery of load-related costs from the volumetric energy rate to the service charge and thereby dampen energy price signals. Finally, Section V summarizes my conclusions and recommendations.

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

Q: What is the monthly service charge?

A: The monthly 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 service charge for residential customers?

A: For residential customers taking standard service under Tariff RS, I&M proposes to increase the service charge from $7.30 to $18.00 per customer per month.[2] The proposed $10.70 increase represents a 147% increase over the current service charge.

For residential customers taking time-of-day ("TOD") service under Tariff R-TOD, I&M proposes to increase the service charge from $8.50 to

[2] *Pre-Filed Verified Direct Testimony of Matthew W. Nollenberger*, Cause No. 44967, 10 (July 26, 2017) [hereinafter "Nollenberger Direct"].

$18.00 per customer per month and then impose an additional fixed monthly charge of $1.90 to cover the incremental cost of a TOD meter.[3] The total increase of $11.40 proposed by I&M represents a 134% increase over the current service charge for Tariff R-TOD customers.

Q: What is the Company's rationale for increasing the service charge for residential customers to $18.00 per customer per month?

A: Company witness Nollenberger contends that the Company's proposal would result in a residential service charge that better reflects his estimate of $20.46 per customer per month for the marginal cost to connect a residential customer:

> 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.[4]

> While the Company's analysis shown on Attachment MWN-3 would support an increase in the customer charge of $13.16 per customer per month, the Company is proposing a smaller increase of $10.70. By deviating from strict adherence to the principle of cost causation in this way, the Company was cognizant of the effect that recovering the full $20.46 per month would have on low-usage customers.[5]

Q: Please describe how Mr. Nollenberger estimates the marginal connection cost for residential customers.

A: Mr. Nollenberger derives a marginal connection cost by estimating the additional cost that I&M would be expected to incur in the future to connect a new customer to the Company's distribution system. As indicated in Attachment MWN-3, Mr. Nollenberger's estimate includes the equipment

[3] Workpaper WP-MWN-2, 5.

[4] Nollenberger Direct, 12.

[5] *Id.*, 14.

and installation cost for a new meter and service drop, along with the cost to maintain and read the meter and to provide other customer services.

As shown in Attachment MWN-3, Mr. Nollenberger estimates a marginal cost per customer per month of $15.80 for meter and service drop costs and $4.66 for operations and maintenance ("O&M") and customer-service expenses, for a total of $20.46 per customer per month.

Q: Why does I&M want to move the residential service charge closer to Mr. Nollenberger's estimate of the marginal cost of connection?

A: The Company offers three justifications for this proposal. First, Mr. Nollenberger asserts that increasing the service charge would reflect cost-causation and thereby mitigate purported subsidization of low-usage customers' connection costs by larger residential customers.[6] Second, Mr. Nollenberger claims that increasing the residential customer charge to better reflect marginal connection costs would provide "appropriate price signals".[7] I address each of these justifications in the following two sections.

Third and finally, Mr. Nollenberger contends that increasing the residential service charge would reduce spikes in monthly bills.[8] However, customer concerns regarding monthly bill volatility could be addressed simply by encouraging those customers to sign up for budget billing under the Company's Average Monthly Payment Plan and by offering cost-effective energy efficiency programs targeting weather-related loads.[9] In any event,

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[6] *Id.*, 13.

[7] I&M response to Data Request No. OUCC 25-01(d) (Attachment JFW-4).

[8] Nollenberger Direct, 13-14.

[9] Mr. Nollenberger offers no evidence or documentation of customer concerns regarding monthly bill volatility. Moreover, I&M did not ask its customers whether they would prefer bill

customers experiencing financial hardship from periodically high bills—who tend to be lower-income consumers—would not likely find reprieve in an overall rate hike that smooths out billing periods by way of raising each of their monthly bills to varying degrees. In other words, consistently higher monthly bills are not made more palatable to vulnerable households simply because those bills are more uniform in their costliness.

III. I&M's Proposal to Increase the Residential Service Charge Would Cause Intra-Class Cost Subsidization

Q: What is the basis for Mr. Nollenberger's assertion that increasing the residential service charge would reflect cost-causation?

A: Mr. Nollenberger relies on his estimate of the marginal cost of connection to support this claim. Specifically, Mr. Nollenberger reports in his direct testimony that the current residential service charge recovers $7.30 of his $20.46 estimate of marginal connection cost, which means that the remaining $13.16 is currently being recovered through residential volumetric energy rates. Mr. Nollenberger asserts that this $13.16 of marginal connection costs currently being recovered through the volumetric energy rate represents a subsidy payment from customers with above-average usage to those with below-average usage since customers with above-average usage would pay more than $13.16 per month toward recovery of marginal connection costs through the energy rate, while customers with below-average usage would pay less than $13.16 per month. Thus, under Mr. Nollenberger's rationale, the

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stability over maintaining the service charge at a lower level. *See* I&M response to Data Request No. OUCC 25-03 (Attachment JFW-5).

Company's proposal to increase the residential service charge from $7.30 to $18.00 would reduce the amount of marginal connection costs recovered through the energy rate and thereby reduce the alleged subsidy payment from customers with above-average usage to those with below-average usage.

Q: Do you agree with Mr. Nollenberger's claim that increasing the monthly service charge would reflect cost-causation?

A: No. To the contrary, the results of the Company's CCOSS indicate that the Company's proposal to recover more than actual connection costs through the residential service charge would in fact create rather than alleviate intra-class subsidization – and thereby disproportionately and inequitably increase bills for low-usage customers – by shifting load-related costs inappropriately from high-usage to low-usage customers.

Q: What do you mean by "actual connection costs" for residential customers?

A: Actual connection costs for residential customers are the sum of test-year revenue requirements for the residential allocation of embedded: (1) meter plant costs; (2) service drop plant costs; and (3) meter O&M and customer service expenses.[10] Actual connection costs differ from Mr. Nollenberger's definition of marginal connection costs in that the former is derived based on meter and service costs actually incurred by I&M to connect all residential customers, whereas the latter is derived based on an estimate of meter and

[10] The term "embedded costs" refers to the accounting costs on the Company's books in the test year. Since the Company's CCOSS is based on embedded costs for a future test year (2018), connection costs are "actual" in the sense that they are based on costs actually incurred through 2016 and on costs expected to be incurred in 2017 and 2018.

service costs that might be incurred in the future to connect a new residential customer.

Q: Why do you rely on the results of the Company's CCOSS to assess whether the Company's proposal reflects cost-causation?

A: According to I&M witness Daniel E. High, the results of the Company's CCOSS reflect causation of actual costs incurred by I&M to connect residential customers:

> The cost allocation methodology used in the class cost-of-service study assigns costs among the customer classes in a fair and equitable manner based on principles of cost causation. Customers who cause costs to be incurred are allocated such costs in the Company's class cost-of-service study.[11]

In other words, the embedded connection costs directly assigned or allocated to the residential class in the Company's CCOSS reasonably reflect those costs actually incurred to connect all residential customers to the distribution system. Thus, the results of the Company's CCOSS provide a reasonable measure of each customer's fair share of actual connection costs incurred by I&M regardless of the customer's usage.

Despite this assertion by I&M witness High, the Company proposes to set the residential service charge based on Mr. Nollenberger's estimate of marginal connection cost rather than on actual residential connection costs as determined by the Company's CCOSS. To the extent that Mr. Nollenberger's estimate of marginal connection cost exceeds actual connection costs incurred by I&M, a service charge based on his estimate would recover not just actual connection costs but also a portion of the load-related distribution

[11] *Pre-Filed Verified Direct Testimony of Daniel E. High*, Cause No. 44967, 2-3 (July 26, 2017).

costs allocated to the residential class in the Company's CCOSS. This means that a residential customer would be charged not just for their fair share of connection costs, but also for a fixed portion of load-related costs regardless of usage. In this case, low-usage customers would pay more than their fair share of load-related costs, while high-usage customers would pay less than their fair share.

Q: Have you estimated the actual cost to connect a residential customer based on the results of the Company's CCOSS?

A: Yes. However, I could not derive my estimate directly from the Company's CCOSS because the Company's CCOSS does not report test-year residential revenue requirements separately for meters and service drops. Instead, as indicated in Attachment JFW-2, I estimated meter and service drop revenue requirements by modifying the analysis shown in Attachment MWN-3 based on the results of the Company's CCOSS. Specifically, in place of Mr. Nollenberger's estimates of marginal investment costs for residential meters and service drops, I used embedded gross plant-in-service costs for residential meters and services as reported in the Company's CCOSS. As in Mr. Nollenberger's analysis, I apply the Company's estimate of levelized carrying charges to plant-in-service costs to derive annualized plant costs for meters and service drops.[12]

As shown in Attachment JFW-2, I estimate a residential cost of connection of $8.76 per customer per month.

[12] My analysis overstates annualized plant cost, and therefore overstates the residential cost of connection, because I apply the return component of the levelized carrying charge to gross rather than net plant in service. I was unable to apply the return component correctly because the Company's CCOSS does not report net plant in service separately for residential meters and service drops.

Q: What does this result tell us about the effect of an $18.00 residential service charge on cost subsidization within the residential class?

A: The $9.24 difference between the $18.00 residential service charge proposed by I&M and actual connection cost of $8.76 represents load-related distribution costs that would be recovered through the residential service charge under the Company's proposal to increase the service charge to $18.00. Such load-related costs are driven by residential load and are therefore appropriately recovered from residential customers in proportion to their contribution to total load. However, under the Company's proposal to recover load-related costs 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 load-related costs and consequently subsidize larger customers. In this case, a residential customer with below-average usage would pay more, and a residential customer with above average-usage would pay less, than their fair share of such costs.

Q: What is the extent of the intra-class subsidization under the Company's proposal to increase the residential service charge to $18.00?

A: As explained above, the $9.24 difference between the $18.00 residential service charge proposed by I&M and actual connection cost of $8.76 represents load-related distribution costs that would be recovered from each residential customer every month through a fixed charge on the customer's bill. As indicated in Attachment MWN-3, the Company's CCOSS assumes about 4.9 million residential bills in the test year, which means that $45.0 million of load-related distribution plant costs would be recovered annually through the residential service charge under the Company's proposal to set

the residential service charge at a rate that exceeds actual connection cost by $9.24 per customer per month.[13]

If the additional load-related costs recovered through the residential service charge under the Company's proposal were instead recovered through the volumetric energy rate, each residential customer would contribute to recovery of these costs in proportion to their usage. The Company forecasts residential energy sales for the test year of about 4.1 million megawatt-hours, which means that the $45.0 million of load-related costs that would be recovered through the residential service charge under the Company's proposal would be charged at a rate of 1.1¢/kWh if such costs instead continued to be recovered through the energy rate.[14] In that case, a residential customer with monthly usage of 500 kWh would contribute about $65 per year toward recovery of such costs while a customer with monthly usage of 1,000 kWh would contribute about $130 per year. Thus, the 1,000 kWh customer would contribute two times more than the 500 kWh customer, in direct proportion to their usage.

In contrast, under the Company's proposal to recover $45.0 million of load-related costs through the residential service charge, each residential customer would contribute about $111 per year toward recovery of such costs regardless of that customer's usage. A 500 kWh customer would therefore pay 70% more than their fair share of these load-related costs under the

[13] The $45.0 million result is derived by taking the product of the annual number of residential bills (4.9 million) and the amount of the proposed monthly service charge in excess of actual connection cost ($9.24 per bill).

[14] The Company's forecast of residential energy sales for the test year is provided in Attachment CMB-1.

Company's proposal while a 1,000 kWh customer would pay 15% less than their fair share.

IV. I&M's Proposal to Increase 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", as Mr. Nollenberger contends?

A: No. As discussed below, I&M proposes to set the residential service charge at a rate that exceeds the minimum cost to connect a residential customer. The Company's proposal would shift recovery of costs which are appropriately recovered through volumetric energy rates to the service charge, resulting in an energy rate that understates the extent to which the Company's costs are driven by customer usage. Thus, contrary to Mr. Nollenberger's assertion, the Company's proposal would dampen energy price signals and discourage investments in energy efficiency and distributed renewable generation.

Q: How should residential service and energy charges be designed in order to provide appropriate price signals for conservation?

A: The primary challenge in cost-based ratemaking is to design rates that allow for full recovery of embedded costs allocated to a rate class while providing appropriate price signals regarding the costs imposed by customers in order to encourage responsible use of utility resources.[15] Fixed service charges are intended to recognize that customers contribute equally to certain distribution

[15] For a discussion of the trade-offs between revenue adequacy and price efficiency in rate design, *see* James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 297-301 (1961), available at media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf (excerpt included as Attachment JFW-6).

costs regardless of each customer's energy usage, whereas volumetric energy rates recognize that customers of different sizes and load profiles contribute to other distribution, transmission, and generation costs at different levels. If usage-driven costs are inappropriately collected through fixed service charges, then customers will have reduced incentives to invest in energy efficiency or distributed renewable generation.[16]

Accordingly, volumetric energy rates should be set at levels that recover costs that tend to increase with customer usage. Energy rates should include costs directly driven by customer usage, such as plant, fuel, and operation and maintenance costs. They should also include costs that tend to rise indirectly with customer usage levels, such as collection costs, uncollectible costs, and some other customer-service costs.

In contrast, the customer charge is intended to reflect the cost to connect to the distribution system a customer who uses very little or zero energy.[17] 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.[18]

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[16] National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016), available at http://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0 (excerpt included as Attachment JFW-7).

[17] *See, e.g.,* Jim Lazar & Wilson Gonzalez, *Smart Rate Design for a Smart Future*, Regulatory Assistance Project, 36 (July 2015), available at http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[18] A very small customer in multi-family housing might not require their own service drop. If so, the cost to connect such a customer would not include the cost of a service drop.

Q: What is the minimum cost to connect a residential customer in the Company's service territory?

A: As discussed in Section III, I estimate a minimum connection cost for residential customers – the embedded cost per residential customer for meters, service drops, and customer services – of $8.76 per month. This estimate represents an average of all residential customers, whether they have a dedicated or a shared service drop. For a residential customer that does not require a dedicated service drop, such as a low-usage customer in multi-family housing, I estimate a minimum connection cost of $5.62 per month.[19]

Q: How do the current and the Company's proposed residential service charges compare to the minimum connection cost for a residential customer?

A: The current residential service charge of $7.30 falls within the range of minimum connection costs. In contrast, the $18.00 residential service charge proposed by I&M overstates estimated minimum connection cost by two to three times. The amount in excess of minimum connection cost represents usage-related costs that are appropriately recovered in the volumetric energy rate. However, under the Company's proposal, this excess over the minimum connection cost would instead be recovered through the monthly service charge. This shift in the recovery of usage-related costs from the volumetric energy rate to the basic customer charge would dampen energy price signals.

[19] The $3.14 difference between the minimum connection cost for an average residential customer and that for a customer without a dedicated service drop is the annualized plant cost for service drops (as shown in Attachment JFW-2) divided by the number of residential bills.

Q: To what extent would the Company's proposal to increase the residential service charge to $18.00 dampen price signals provided by the Tariff RS energy rate?

A: With a fixed amount of revenue requirements to be recovered from the residential class, the higher the residential service charge, the lower the energy rate, and vice versa. With the residential service charge set at $18.00, I&M proposes an energy rate of 10.82¢/kWh in order to recover the proposed allocation of test year revenue requirements to Tariff RS customers.[20] If, instead, the residential service charge remained at its current rate of $7.30, I estimate that the energy rate would have to be increased to 12.09¢/kWh to recover the same allocated revenue requirement.[21]

In other words, I&M is proposing a Tariff RS energy rate that is 1.27¢/kWh, or about 10.5%, less than what the energy rate would be if the residential service charge remained at its current level. Thus, the Company's proposal to increase the residential service charge from $7.30 to $18.00 would reduce the price signal provided by the energy rate by 10.5%.

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

A: Since the energy rate under the Company's proposed $18.00 residential service charge would be lower than the energy rate with a $7.30 residential service charge, we would expect residential customers to consume more energy with an $18.00 residential service charge than they would with a $7.30 residential service charge. The magnitude of the increase in energy

[20] Workpaper WP-MWN-2, 6.

[21] Based on data provided on page 6 of Workpaper WP-MWN-2.

consumption would depend on: (1) the extent to which the energy rate with an $18.00 residential service charge is lower than the energy rate with a $7.30 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 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.[22] 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.[23] Table 1 lists the results of seven studies of marginal-price elasticity over the last forty years.[24]

[22] The citation for this study is provided in Attachment JFW-3.

[23] For Tariff RS customers, that would be the energy rate.

[24] The citations for these studies are provided in Attachment JFW-3.

Table 1: 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 Tariff RS energy rate?

A: From Table 1, it appears that –0.3 would be a reasonable mid-range estimate of the impact over a few years.

Q: What would be a reasonable estimate of the effect on energy use from the Company's proposal to increase the residential service charge from $7.30 to $18.00?

A: As discussed above, if the residential service charge were increased to $18.00, the Tariff RS energy rate would be about 10.5% less than what the energy rate would be if the residential service charge remained at its current level. Assuming an elasticity of –0.3, this 10.5% reduction in the energy rate would result in an increase in energy consumption of about 3%. This means that all else equal, Tariff RS load a few years after an increase in the residential service charge to $18.00 would be expected to be about 3% higher than it would have been if the residential service charge had not been increased.

For comparison, I estimate that energy savings from the Company's residential energy efficiency programs will increase between 2017 and 2019 on average by an amount equivalent to about 1.3% of forecasted annual residential load.[25] Assuming that such savings are spread uniformly across all residential rate classes, the additional consumption due to the Company's proposed increase in the residential service charge (and the resulting decrease in the energy rate) would undo more than two years of Tariff RS energy savings from the residential energy efficiency portfolio.

V. Conclusions and Recommendations

Q: What do you conclude with respect to the Company's proposal to increase the residential service charge to $18.00?

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 service charge to $18.00 and instead find that it is reasonable to maintain the monthly charge at its current level of $7.30.

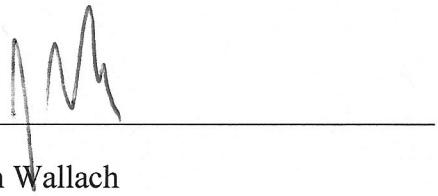
[25] Based on data regarding residential energy efficiency net savings provided in Attachment JCW-2 to direct testimony by I&M witness Jon C. Walter in Cause No. 44841 and on data regarding the Company's forecast of residential energy sales provided in the Company's response to Data Request No. CAC 4-05(a). *See* Attachments JFW-8 and JFW-9.

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

November 7, 2017

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.

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Cost basis for residential customer charges. Design of residential energy charges.

Kentucky PSC Case No. 2016-00371, Louisville Gas & Electric Company electric rates, Sierra Club. Direct, March 2017.

Cost basis for residential customer charges. Design of residential energy charges.

Massachusetts DPU 17-05, Eversource Energy electric rates, Cape Light Compact. Direct, April 2017; Supplemental Direct, Surrebuttal, August 2017.

Cost Allocation. Cost basis for residential customer charges. Demand charges for net metering customers.

Michigan PSC Case No. U-18255, DTE Electric Company electric rates, Natural Resources Defense Council, Michigan Environmental Council, and Sierra Club. Direct, August 2017.

Cost basis for residential customer charges.

North Carolina NCUC Docket No. E-2, Sub 1142, Duke Energy Progress electric rates, North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy. Direct, October 2017.

Cost basis for residential customer charges.

ATTACHMENT JFW-2

Residential Cost of Connection

Customer-related Plant Cost	**Residential**		**Life (yrs)**	
369 - Service Drop Plant in Service	$ 145,759,205	2/	38	1/
Levelized Carrying Charge: 38 Yr	10.50%			
369 - Annualized Cost of Plant	$ 15,301,447			
370 (586) - Meter Plant in Service	$ 32,276,283	2/	15	1/
Levelized Carrying Charge: 15 Yr	14.44%			
370 (586) - Annualized Cost of Plant	$ 4,661,199			

Levelized Carrying Charges 3/			
Component	15	40	
Return	5.88	5.88	5/
Depreciation	4.62	1.13	
FIT	1.88	1.43	
Property Tax, G&A	2.06	2.06	
(%)	14.44	10.50	

RS - Customer-related O&M ($)		2/
586 - Meters Operation	500,144	
597 - Meters Maintenance	23,021	
Total Customer-related O&M	523,165	

RS - Customer Account Expenses ($)		2/
901 - Supervision	772,421	
902 - Meter Read	1,800,250	
903 - Customer Records	8,636,479	
904 - Uncollectibles	0	
905 - Misc.	2,688,942	
907 - Supervision	719,767	
908 - Customer Assistance	7,533,185	
909 - Info & Instr	25,562	
910 - Misc.	0	
911 - Misc. Selling	0	
Total Customer Acct. Expense	$ 22,176,606	

I&M IN RS # Annual Bills	4,871,736	4/
Plant Cost / Customer / Month	$ 4.10	
O&M + Customer Account / Customer / Month	$ 4.66	
Residential Cost of Connection	$ 8.76	

Sources:
1/ AEP Property Accounting Policy & Research
2/ Attachment DEH-1, Class Cost of Service
3/ AEP Corp. Finance, I&M Annual Investment Carrying Charges, As of 12/31/2016
4/ WP-MWN-2, Rate Design
5/ Schedule A-1

ATTACHMENT JFW-3

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ATTACHMENT JFW-4

STATE OF INDIANA

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

INDIANA MICHIGAN POWER COMPANY'S OBJECTIONS AND RESPONSES TO INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S TWENTY-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 Responses to the Indiana Office Of Utility Consumer Counselor's Twenty-fifth Set of Discovery Requests to Indiana Michigan Power Company.

General Objections

The responses provided to the Requests have been prepared pursuant to a reasonable and diligent investigation and search conducted in connection with the Requests in those areas where information is expected to be found. To the extent the Requests purport to require more than a reasonable and diligent investigation and search, Petitioner objects on grounds that they include an undue burden and unreasonable expense.

Petitioner objects to the Requests to the extent they seek documents or information which are not relevant to the subject matter of this proceeding and which are not reasonably calculated to lead to the discovery of admissible evidence.

Petitioner objects to the Requests to the extent they seek an analysis, calculation, or compilation which has not already been performed and which Petitioner objects to performing.

Petitioner objects to the Requests to the extent they are vague and ambiguous and provide no basis from which Petitioner can determine what information is sought.

Petitioner assumes no obligation to supplement these responses except to the extent required by Ind. Tr. R. 26(E) (1) and (2) and objects to the extent the instructions and/or requests purport to impose any greater obligation.

Petitioner objects to the Requests to the extent they seek information that is subject to the attorney-client, work product, settlement negotiation or other applicable privileges.

The responses constitute the corporate responses of Petitioner and contain information gathered from a variety of sources. Petitioner objects to the Requests to the extent they request identification of and personal information about all persons who participated in responding to each data request on the grounds that they are overbroad and unreasonably burdensome given the nature and scope of the requests and the many people who may be consulted about them.

Petitioner objects to the Requests to the extent the discovery sought is unreasonably cumulative or duplicative, or is obtainable from some other source that is more convenient, less burdensome, or less expensive.

Petitioner objects to the Requests to the extent the burden or expense of the proposed discovery outweighs its likely benefit, taking into account the needs of the case, the amount in controversy, the parties' resources, the importance of the issues at stake in litigation, and the importance of the proposed discovery in resolving the issues.

Without waiving these objections, Petitioner responds to the Requests in the manner set forth below.

As to Objections,

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Attorneys for Indiana Michigan Power Company

DATA REQUEST NO OUCC 25-01

REQUEST

Beginning on page 10, line 20, I&M witness Nollenberger states "To arrive at the proposed service charge, I prepared a marginal cost of connection analysis that computes the costs associated with connecting the marginal or incremental residential customer to I&M's system."

a. Please provide the Cause Number of all other IURC cases in which the same or similar "marginal cost of connection analysis" was accepted by the Commission for purposes of establishing service charges at Indiana utilities, and explain how the analysis in each case is believed by I&M to be similar to the analysis presented by this witness.

b. Please provide the Cause Number of all other IURC cases in which marginal costs of any category were accepted by the Commission as the basis for setting rates for Indiana utilities, and explain how the analysis in each case is believed by I&M to represent the acceptance by the Commission of a marginal cost analysis.

c. For purposes of this question, assume that the phrase "embedded cost methodology" to mean the methodology used by the Company to calculate the service charge that was proposed by I&M in its last base rate case (Cause No. 44075). Please calculate and provide the service charge necessary to collect the revenue requirement for the cost of connecting customers to I&M's system using an embedded cost methodology rather than the marginal cost methodology presented in this witness's testimony.

d. By proposing the use of "marginal cost" analysis for purposes of establishing "cost of connection," does I&M intend to accept the validity of marginal cost analysis for other revenue requirement categories, such as generation-related costs? If I&M does not accept the validity of using marginal costs for every revenue requirement category, please explain the basis that I&M would propose upon which the Commission should judge reasonable the use of marginal cost analysis in setting revenue requirements for different cost categories.

RESPONSE

a-b. I&M objects to the request on the grounds and to the extent it seeks an analysis, compilation or study which I&M has not performed and to which I&M objects to performing. I&M further objects to the request to the extent it seeks information that is publicly available.

c. I&M objects to subpart (c) of 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.

d. No. I&M's use of "marginal cost" analysis for purposes of establishing a "cost of connection" is related to the collection of costs through appropriate price signals. It is not proposed in this case as a method of establishing revenue requirements for generation-related costs or other costs.

ATTACHMENT JFW-5

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 25
IURC CAUSE NO. 44967

DATA REQUEST NO OUCC 25-03

REQUEST

Discussing the rationale for I&M's proposal to increase its service charge, Mr. Nollenberger (at p. 13) states that the proposed increase "provides increased customer rate stability[.]" Has I&M asked its customers whether they would prefer the "increased customer rate stability" referenced here as opposed to keeping the service charge at a lower level? If so, please explain how I&M elicited such feedback from its customers and provide the results of that investigation, including any survey instrument used and related data obtained as part of that investigation.

RESPONSE

No. However, to the extent that I&M's proposed monthly residential service charge collects a greater proportion of costs through a fixed charge component, rather than through a variable charge component, I&M's proposal will indeed provide greater rate stability.

ATTACHMENT JFW-6

POWELL GOLDSTEIN LLP

Attachment JFW-6

Principles of Public Utiliity Rates by James C. Bonbright

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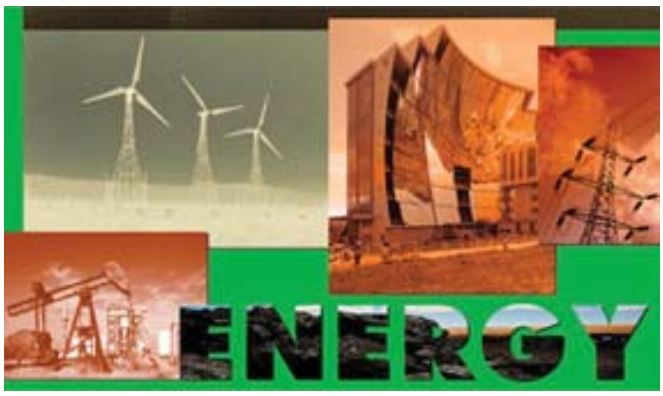


the rates for any given class of service (passenger versus freight, residential versus commercial, etc.) should cover the costs of supplying that class, and so the rates charged to any single customer within that class should cover the costs of supplying this one customer. Under this assumption, the 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. 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."

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.

[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

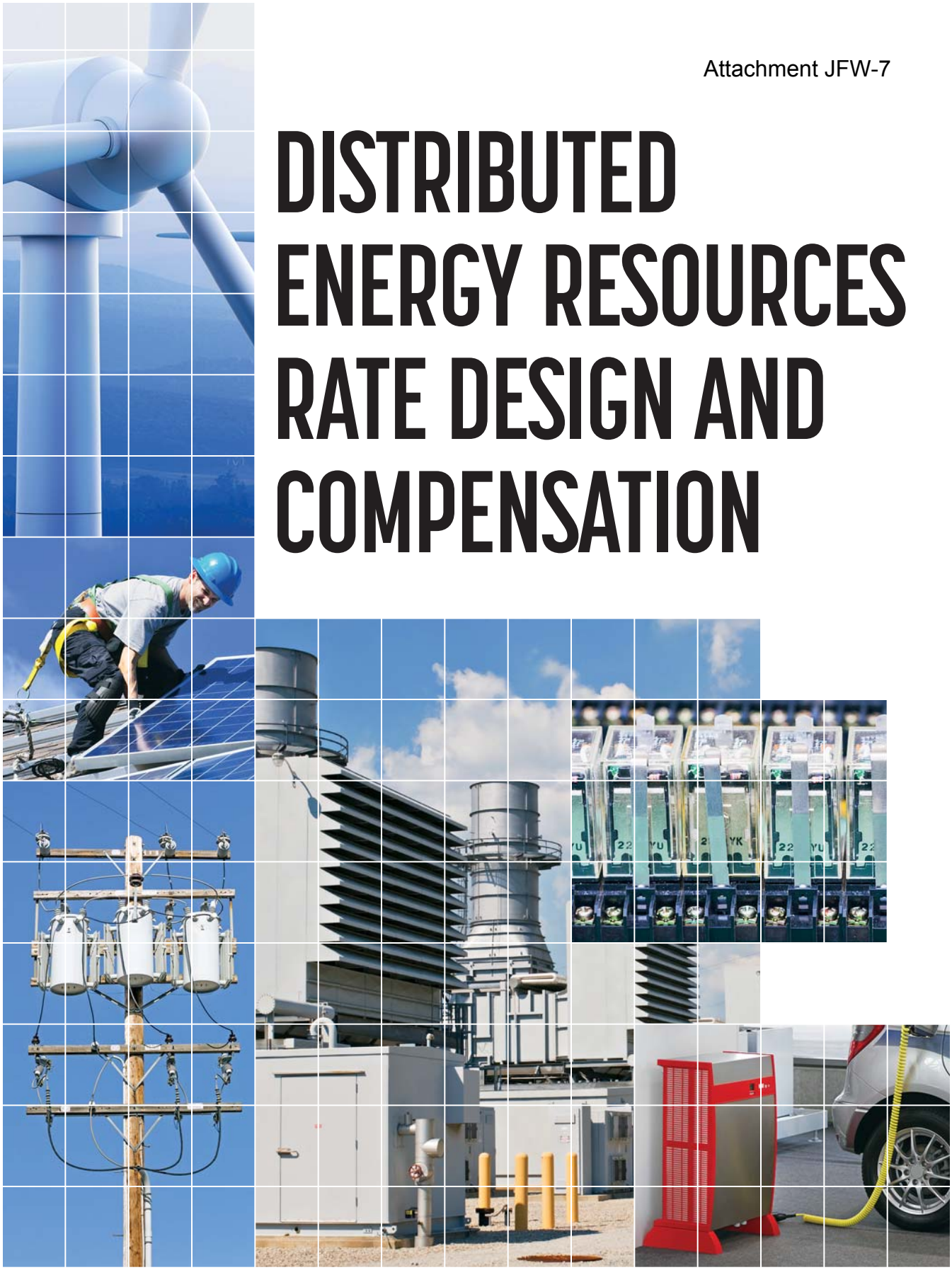
For the reasons just suggested, rates based merely on specific or incremental or marginal costs might well suffice, on occasion, to yield adequate, or even more than adequate, total revenues under a fair-return standard. But the general principles of public utility rates dare not rely on such a convenient 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-7

Attachment JFW-7

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

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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-8

Indiana Michigan Power Company - Indiana
DSM - 3 Year Plan
DSM Plan Program Summary

Attachment JCW-2
Cause No. 44841

	DSM Plan Direct Program*	Program Description	2017 Program Operating Budget ($)	2017 Energy Savings (kWh)	2017 Demand Savings (kW)	2018 Program Operating Budget ($)	2018 Energy Savings (kWh)	2018 Demand Savings (kW)	2019 Program Operating Budget ($)	2019 Energy Savings (kWh)	2019 Demand Savings (kW)	Average Annual Cost of Conserved Energy ($/kwh)	Lifetime Cost of Conserved Energy ($/kwh)	3 Yr. Net Savings (kWh)	3 Yr. Program Operating Budget ($)	3 Yr. Gross Energy Savings (kWh)	3 Yr. Gross Demand Savings (kW)
EE Programs	Home Energy Products	Rebates for efficient residential lighting & other electro-technologies	1,863,726	13,132,892	1,965	1,635,506	10,796,000	1,628	1,383,572	8,901,438	1,354	0.15	0.01	19,371,252	4,882,804	32,830,330	4,947
	Income Qualified Weatherproofing	Low Income home weatherization & efficiency	571,039	724,847	72	571,039	734,847	72	571,039	744,847	72	0.78	0.06	2,204,541	1,713,117	2,204,541	217
	Schools Energy Education	Energy education for elementary age children with take home kits	662,354	3,179,000	880	662,354	3,179,000	880	662,354	3,179,000	880	0.21	0.02	6,580,530	1,987,062	9,537,000	2,640
	Home Appliance Recycling	Rebates for pick up, and recycling of refrigerators and freezers	594,990	3,348,400	400	594,990	3,348,400	400	594,990	3,348,400	400	0.18	0.02	5,424,408	1,784,969	10,045,200	1,199
	Home New Construction	Rebates for efficient new home construction	470,227	808,221	208	497,933	851,741	234	497,933	851,741	234	0.58	0.02	1,934,011	1,466,093	2,511,702	677
	Home Weatherproofing	Walk through audit with rebates for home weatherization & efficiency	518,143	1,129,074	103	518,143	1,129,074	103	518,143	1,129,074	103	0.46	0.03	2,811,393	1,554,429	3,387,221	309
	Home Energy Engagement	Home consumption comparison reports; online audit tool	2,175,592	40,900,405	4,514	2,240,418	41,190,745	4,562	2,382,110	41,629,375	4,619	0.05	0.05	121,657,120	6,798,120	123,720,525	13,695
	Work Prescriptive Rebates	Rebates for efficient lighting, efficient motors, etc.	3,429,980	29,042,325	5,765	2,792,166	22,877,500	4,573	2,052,416	16,665,000	3,373	0.12	0.01	61,040,494	8,274,562	68,584,825	13,712
	Work Custom Rebates	Rebates for custom C&I efficiency improvements	3,852,933	38,418,023	7,252	3,223,543	29,458,023	5,817	3,066,780	27,648,023	5,489	0.11	0.01	88,837,383	10,143,256	95,524,068	18,559
	Work Direct Install	Online & Walk through audits plus direct install cost effective measures for small business	437,543	1,999,500	267	416,489	1,799,550	241	395,435	1,599,600	214	0.23	0.02	5,344,663	1,249,467	5,398,650	722
	Public Efficient Streetlighting	Upgrade existing inefficient streetlighting with LED streetlighting	1,872,655	5,521,964	0	1,872,655	5,521,964	0	1,872,655	5,521,964	0	0.34	0.02	16,565,892	5,617,964	16,565,892	0
	EE Programs Total		**16,449,182**	**138,204,650**	**21,428**	**15,025,235**	**120,886,843**	**18,509**	**13,997,426**	**111,218,461**	**16,739**	**0.12**	**0.01**	**331,771,688**	**45,471,843**	**370,309,954**	**56,675**
DSM Programs	Home Energy Management	Active residential load management	2,495,536	2,389,500	5,974	2,016,096	4,400,500	11,001	1,720,377	6,411,500	16,029	0.47	0.03	7,788,885	6,232,009	13,201,500	33,004
	Work Energy Management	Active C&I load management	752,632	1,968,753	3,333	1,571,647	5,911,740	10,000	1,744,388	5,911,740	10,000	0.29	0.058	13,792,233	4,068,667	13,792,233	23,333
	Electric Energy Consumption Optimization (EECO)	Utility distribution voltage control program to optimize & reduce end use consumption	1,172,060	14,889,034	4,631	1,678,290	19,272,356	6,634	2,285,574	24,942,364	8,725	0.09	0.009	59,103,753	5,135,924	59,103,753	19,991
	DSM Programs Total		**4,420,228**	**19,247,287**	**13,938**	**5,266,032**	**29,584,596**	**27,635**	**5,750,339**	**37,265,604**	**34,754**	**0.18**	**0.01**	**66,892,638**	**15,436,599**	**86,097,486**	**76,328**
	Portfolio Totals		**20,869,410**	**157,451,938**	**35,366**	**20,291,268**	**150,471,438**	**46,145**	**19,747,765**	**148,484,064**	**51,493**	**0.13**	**0.01**	**398,664,326**	**60,908,443**	**456,407,441**	**133,003**

Portfolio Level Operating Costs (Indirect Operating Costs)			
DSM Database & IT Support	$200,000	$200,000	$200,000
Staff Development & Memberships	$45,000	$45,000	$45,000
Portfolio Marketing & Customer Awareness	$100,000	$100,000	$100,000
Planning & Analytic Support	$125,000	$125,000	$125,000
Program Development	$50,000	$50,000	$50,000
Administrative Support	$325,000	$325,000	$325,000
Customer Engagement Platforms (IM HOME, IM WORK)	$250,000	$400,000	$500,000
Customer Energy Information & Messaging	$150,000	$150,000	$150,000
Total Portfolio Level Operating Costs	$1,245,000	$1,395,000	$1,495,000
Total I&M Indiana DSM Plan Portfolio Operating Budget	**$22,114,410**	**$21,686,268**	**$21,242,765**
Count of Direct Programs	**14**	**14**	**14**
DSM Plan Energy Savings as % I&M IN Utility kWh Sales	0.92%	0.88%	0.87%
DSM Plan Operating Cost as % of I&M IN Utility Revenues**	1.78%	1.74%	1.71%
DSM Plan Program Operating Cost	$22,114,410	$21,686,268	$21,242,765
DSM Plan Energy Savings (kWh)	157,451,938	150,471,438	148,484,064
DSM Plan Operating Cost (cents/kwh saved)	$0.14	$0.14	$0.14

Residential	12,747,477	12,650,977	12,875,899
C&I	9,366,933	9,035,291	8,366,867
Check Total	0	0	0

Non-Behavior Measure NTG	**80%**
All Measures NTG	**87%**

* Costs shown in table reflect the Direct costs of the programs and EM&V costs; the indirect costs are summarized below the table and referred to as "Portfolio level" costs.
**I&M Indiana 2015 Forecast

ATTACHMENT JFW-9

	A	B	C	D
1				
2				
3	I&M - Indiana Residential Sales Forecast			
4				
5			Sales (MWh)	DSM/EE Savings Assumptions (MWh)
6	2017		4,177,559	78,424
7	2018		4,140,558	139,109
8	2019		4,054,424	139,109
9	2020		4,003,504	25,283
10	2021		4,017,705	25,283
11	2022		4,038,169	25,283
12	2023		4,062,723	25,283
13	2024		4,089,160	2,615
14	2025		4,121,010	22,335