JI Exhibit 2

STATE OF INDIANA

BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY ("IPL") FOR (1) AUTHORITY TO INCREASE RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE, (2) APPROVAL OF REVISED DEPRECIATION RATES, ACCOUNTING RELIEF, INCLUDING UPDATE OF THE MAJOR STORM DAMAGE RESTORATION RESERVE ACCOUNT, APPROVAL OF A VEGETATION MANAGEMENT RESERVE ACCOUNT, INCLUSION IN BASIC RATES AND CHARGES OF THE COSTS OF CERTAIN PREVIOUSLY APPROVED PROJECTS, INCLUDING THE EAGLE VALLEY COMBINED CYCLE GAS TURBINE, THE NATIONAL POLLUTION DISCHARGE ELIMINATION SYSTEM AND COAL COMBUSTION RESIDUALS COMPLIANCE PROJECTS, RATE ADJUSTMENT MECHANISM PROPOSALS, COST DEFERRALS, AMORTIZATIONS, AND (3) APPROVAL OF NEW SCHEDULES OF RATES, RULES AND REGULATIONS FOR SERVICE.	**))))))))))))))))))**	**CAUSE NO. 45029**

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.

MAY 24, 2018

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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 90 state, provincial, and federal proceedings in the U.S. and Canada, including before the Indiana Utility

Regulatory Commission ("the Commission") in Cause No. 44967. 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: Bill Impacts from Joint Intervenor's Recommended Customer Charge
- Attachment JFW-3: Citations to Marginal-Price Elasticity Studies
- Attachment JFW-4: IPL response to CAC Data Request 2-3
- Attachment JFW-5: National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016)
- Attachment JFW-6: James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 334 (1961)
- Attachment JFW-7: Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988)
- Attachment JFW-8: Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964)
- Attachment JFW-9: IPL response to CAC Data Request 2-8
- Attachment JFW-10: IURC Cause No. 44945, Petitioner's Exhibit 2S, Attachment ZE-1S
- Attachment JFW-11: IPL 2016 Integrated Resource Plant, Attachment 4.3, Table 2-2
- Attachment JFW-12: IPL response to CAC Data Request 2-2

Q: What is the purpose of your testimony?

A: On December 21, 2017, Indianapolis Power and Light Company ("IPL" or "the Company") filed a petition (including supporting direct testimony) with the Commission for authority to increase electric rates. On February 16, 2018, the Company filed supplemental and revised supporting direct testimony to reflect the Tax Cuts and Jobs Act. My testimony responds to revised direct testimony by IPL witness J. Stephen Gaske regarding the Company's proposed design of residential rates and regarding the Company's allocated cost of service study ("ACOSS"), which served as the basis for the Company's proposed rate designs. Specifically, my testimony addresses IPL's proposals to increase the monthly customer charge for residential customers and to maintain a declining-block rate structure for residential energy rates.[1] My response to Mr. Gaske relies on data and documents provided through discovery. I also rely on information provided in settlement testimony by IPL witness Zac Elliot in Cause No. 44945 and in the Company's 2016 Integrated Resource Plan.

Q: Does your testimony address the allocation of costs among the various customer classes based on the Company's ACOSS?

A: No. My testimony does not assess whether the allocation methods used in the Company's ACOSS produce a reasonable allocation of costs to customer classes. Instead, my testimony addresses the Company's proposal to rely on

[1] By "residential", I mean customers taking service under Rates RS (non-space-heating, non-water-heating service), RH, (space-heating service), and RC (water-heating service). I do not address the Company's proposals regarding the customer charge and energy rates for load-controlled residential customers taking service under Rate CR/CW.

the allocation results from the ACOSS for rate design purposes, specifically for the purposes of setting the level of the residential customer charge.

Q: Please summarize your findings and recommendations with regard to IPL's proposal to increase the residential customer 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 customer charge. As explained in more detail below, the Company's proposal to recover demand-related costs through the residential customer 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 customer charge.

Instead, I recommend that the residential customer charge be set at $8.15 per residential customer per month. Consistent with long-standing cost-causation and rate-design principles, a monthly customer charge of $8.15 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.

A: The Company lacks a reasonable basis for its proposal to maintain the existing declining-block rate structure. The Company's proposal to recover demand-related costs at a higher rate in the first energy block than in the second or third blocks would further dampen energy price signals and promote inefficient customer behavior. In the interests of gradualism, I recommend that the declining-block structure be phased out over this and the next few rate cases.

Q: How is the rest of your testimony organized?

A: In Section II, I describe the Company's proposals for increasing the residential fixed customer charge and volumetric energy rates and explain how IPL relies on the results of its ACOSS to derive its proposed rate design. In Section III, I discuss how the Company's proposal violates long-standing principles of cost-based rate design. In addition, I describe in Section III my derivation of a cost-based fixed customer charge for residential customers. In Section IV, I discuss how the Company's proposal for the residential fixed customer charge would give rise to unreasonable cost subsidization within the residential class, and would dampen energy price signals. In Section V, I discuss why it would be reasonable to phase out the current declining-block structure for residential volumetric energy rates. Finally, Section VI summarizes my conclusions and recommendations.

II. IPL's Proposal to Increase the Residential Fixed Customer Charge and Volumetric Energy Rates

Q: Please summarize the Company's proposals with respect to the fixed customer charge and volumetric energy rates for residential customers.

A: The Company proposes to increase both the fixed customer charge and the volumetric block energy rates in order to recover its proposed allocation of test-year revenue requirements to the residential class. Table 1 shows the current fixed customer charge and volumetric energy rates for residential customers and IPL's proposals for increasing the residential fixed customer charge and volumetric energy rates.[2]

Table 1: IPL Proposed Residential Rate Increase

	Current	IPL Proposed	Rate Increase	% Increase
Customer Charge ($/Bill)				
Up to 325 kWh	11.25	16.00	4.75	42.2%
Over 325 kWh	17.00	27.00	10.00	58.8%
Average	15.91	24.91	9.00	56.6%
Energy Rate (¢/kWh)				
First 500 kWh	10.389	10.532	0.143	1.4%
Over 500 kWh	8.296	8.439	0.143	1.7%
Over 1000 kWh (RH/RC)	7.036	7.178	0.143	2.0%
Average	9.045	9.188	0.143	1.6%

[2] Fixed customer charges and volumetric block energy rates shown in Table 1 are from Petitioner's Witness Gaske's Attachment JSG 8-T. Average customer charges and energy rates were derived based on data provided in Petitioner's Witness Gaske's Attachment JSG 7-T.

A. IPL's Proposal for the Residential Fixed Customer Charge

Q: What is a fixed customer charge?

A: Typically, a customer charge is a fixed fee charged to each customer on their monthly bill regardless of the customer's energy usage during that month. In IPL's case, the residential customer charge is pegged to usage: customers with usage up to 325 kilowatt-hours ("kWh") per month are charged a lower fixed fee than customers whose usage exceeds 325 kWh/month.

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

A: As shown in Table 1 above, for residential customers whose usage is 325 kWh/month or less, IPL proposes to increase the fixed customer charge from $11.25 to $16.00 per customer per month.[3] For customers whose usage exceeds 325 kWh/month, the Company proposes to increase the monthly fixed customer charge from $17.00 to $27.00.[4] On average across all residential customers, IPL proposes to increase the monthly fixed customer charge from $15.91 to $24.91 per customer.[5] The proposed $9.00 average increase represents a 57% increase over the current average customer charge.

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

A: Company witness Gaske contends that the Company's proposal would shift recovery of allegedly "fixed" costs from the volumetric energy rate to the

[3] *Pre-Filed Verified Direct Testimony of J. Stephen Gaske (Revised)*, Cause No. 45029, 33-34 (February 16, 2018) [hereinafter "Gaske Revised Direct"].

[4] *Id.*

[5] Calculated based on data provided in Petitioner's Witness Gaske's Attachment JSG 7-T.

fixed customer charge and thereby move the energy rate closer to marginal cost:

> One principle that I applied was to move the components of the rate design closer to a level that reflects the marginal cost associated with usage. To do that, I generally increased the customer charges and/or the demand charges to a level that recovers a higher proportion of the fixed costs of service.[6]

Q: To which costs is Mr. Gaske referring when he discusses the "fixed costs of service"?

A: Mr. Gaske considers all costs classified as either customer-related or demand-related in the Company's ACOSS to be "fixed".[7]

Q: Please describe how the ACOSS classifies costs.

A: In order to allocate costs to customer classes, the ACOSS 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 customer classes in proportion to each class's contribution to total-system energy sales, peak demand, or number of customers, respectively.

The cost of meters, service drops, and customer services are deemed to be customer-related in the ACOSS. In addition, the ACOSS classifies a portion of pole and conductor costs as customer-related, based on the results of a minimum-system analysis of such distribution plant costs.

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[6] Gaske Revised Direct, 12.

[7] IPL response to CAC Data Request 2-3 (Attachment JFW-4).

The remaining portion of pole and conductor costs not classified as customer-related are instead classified as demand-related in the ACOSS, along with all production, transmission, and line-transformer plant and fixed operations and maintenance ("O&M") costs. Finally, fuel and variable O&M costs are classified as energy-related.

Q: Please describe the Company's minimum-system analysis of pole and conductor costs.

A: The Company's minimum-system analysis attempts to estimate the cost to install the same amount of poles and wires as are currently on the distribution system, assuming that each piece of distribution equipment is sized to meet minimal load.[8] In other words, the Company's minimum-system analysis attempts to estimate the cost to replicate the configuration of the existing distribution system using "minimum-size" equipment.

As discussed above, the "minimum" portion of pole and conductor plant costs (as determined by the minimum-system analysis) is classified as customer-related and then allocated to customer classes in proportion to the number of customers in each class. The remaining portion of such plant costs is classified as demand-related and then allocated to customer classes in proportion to each class's contribution to the sum of all classes non-coincident peaks.

Q: Does IPL propose to recover all costs classified as demand-related and customer-related in the ACOSS through the residential fixed customer charge?

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[8] Gaske Revised Direct, 16-17.

A: No. However, as indicated in Table 2 below, the $24.91 average fixed customer charge proposed by IPL would effectively recover 100% of the Company's estimate of customer-related costs (including pole and conductor costs classified as customer-related) and 74% of the Company's estimate of demand-related transmission and distribution costs.[9]

Table 2: Costs Recovered through IPL Proposed Residential Fixed Customer Charge

	Residential Adjusted Revenue Requirements	**Residential Bills**	**Cost per Bill**	**% Recovered through Customer Charge**	**Cost per Bill Recovered through Customer Charge**
Customer-Related	$74,194,361	5,338,932	$13.90	100%	$13.90
T&D Demand-Related	$79,489,287	5,338,932	$14.89	74%	$11.02
Total	$153,683,648		$28.79		$24.91

B. IPL'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 maintain a "declining-block" rate structure for its residential volumetric energy rates. This means that a residential customer pays a different volumetric rate for usage up to a certain threshold amount (i.e., a "block" of usage) than for usage that exceeds that threshold, and that the volumetric rate charged for the first block of usage is higher than that for the second block. Thus, with a declining-block rate structure, a residential customer will pay a higher volumetric rate for that portion of her monthly

[9] Calculated based on data provided in IPL's response to CAC Data Request 2-3 (Attachment JFW-4).

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, for a residential customer that does not have electric space or water heating, IPL employs two energy blocks: (1) for monthly usage up to 500 kWh; and (2) for monthly usage in excess of 500 kWh. For an electric space heating or water heating customer, IPL adds a third block for monthly usage in excess of 1,000 kWh.[10]

Q: What is the Company's proposal with respect to the volumetric rates for each energy block?

A: The Company proposes to increase volumetric rates in each energy block in order to recover the Company's proposed allocation of test-year revenue requirements to the residential class, net of revenues recovered through the proposed fixed customer charge. As shown in Table 1 above, IPL proposes to increase the volumetric rate for each energy block by the same amount (0.143¢/kWh). As shown in Table 3 below, the Company's proposed approach for increasing volumetric rates for each energy block maintains the same rate discounts between blocks as in current block rates.

Table 3: IPL Proposed Residential Declining-Block Rate Discounts (¢/kWh)

	Current Block Rate	Discount from Prior Block Rate	IPL Proposed Block Rate	Discount from Prior Block Rate
First 500 kWh (RS/RH/RC)	10.389		10.532	
Over 500 kWh (RS/RH/RC)	8.296	(2.094)	8.439	(2.094)
Over 1000 kWh (RH/RC)	7.036	(1.260)	7.178	(1.260)

[10] In this case, IPL charges the same volumetric rate for the second block as charged to customers without electric space or water heating, but applies that rate only to monthly usage up to 1,000 kWh.

III. IPL's Proposal for the Residential Fixed Customer 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.[11]

Accordingly, fixed customer 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 customer charges, then customers will have reduced incentives to control their bills through conservation or investments in energy efficiency or distributed renewable generation.[12]

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

[12] 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-5).

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.[13]

> 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.[14]

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

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[13] 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-6).

[14] *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] ….[15]

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

A: In contrast to the volumetric energy rate, the fixed customer charge is intended to reflect the cost to connect to the distribution system a customer who uses very little or zero energy. 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.[16]

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 customer charge:

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[15] Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988) (excerpt included as Attachment JFW-7).

[16] Bonbright, *op. cit.*, 311 (excerpt included as Attachment JFW-6).

> 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.[17]

More recently, Severin Borenstein restated these principles for designing cost-based fixed customer 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.[18]

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

A: No. Contrary to these principles, IPL proposes to recover through the residential fixed customer charge not just minimum connection costs – i.e., the costs for meters, service drops, and customer services – but also the Company's estimates of the cost per residential customer for: (1) customer-related distribution plant; and (2) demand-related transmission and

[17] Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964) (excerpt included as Attachment JFW-8).

[18] 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/.

distribution plant.[19] As discussed above in Section II, the $24.91 average fixed customer charge proposed by IPL would effectively recover 100% of the Company's estimate of customer-related distribution plant cost per customer and 74% of the Company's estimate of demand-related transmission and distribution plant cost per customer.

Q: How does IPL estimate the customer-related distribution plant cost per residential customer proposed for recovery through the residential fixed customer charge?

A: The Company relies on the results of its minimum-system analysis to estimate the customer-related distribution plant cost per residential customer. Specifically, the Company's ACOSS allocates to the residential class about $30.6 million of distribution plant costs that were classified as customer-related using a minimum-system analysis. Dividing by the number of residential bills in the test year, IPL estimates a customer-related distribution plant cost of $5.74 per residential customer.[20]

Q: Is it reasonable to rely on the results of a minimum-system analysis to estimate the customer-related distribution plant cost per residential customer?

A: No. As noted above in Section II, the purpose of a minimum-system analysis is to determine the portion of distribution plant costs to be allocated to customer classes based on the number of customers in each class. The Company has not offered any evidence that its minimum-system analysis

[19] See IPL's response to CAC Data Request 2-3 for a discussion of the costs to be recovered through the Company's proposed residential customer charge (Attachment JFW-4).

[20] Calculated based on data provided in IPL's response to CAC Data Request 2-3 (Attachment JFW-4).

also yields reliable estimates of the customer-related distribution plant cost *per customer*.

To the contrary, minimum-system analyses overstate the minimum plant cost per customer because they assume that a minimum system carrying minimal load would have the same amount of distribution equipment (e.g., the same number of poles, the same length of conductor) as is currently installed in a distribution system designed to carry actual distribution load. In other words, the minimum-system method assumes that each piece of distribution equipment would serve the same number of customers on average, regardless of whether the customers are average-sized (as for the actual system) or have minimal demand (as for the hypothetical minimum-size system.)

This is not a realistic assumption, since even a minimally sized piece of distribution equipment should be able to serve more minimal-demand customers than the number of average-demand customers served by average-sized distribution equipment. Consequently, the true minimum distribution plant cost to serve a customer with minimal usage is likely to be less than that derived using a minimum-system analysis. Indeed, since the minimum-system method attempts to estimate the plant cost incurred regardless of usage – i.e., the cost to serve load approaching zero – the true minimum plant cost per customer is zero since distribution equipment that carries zero load can serve an infinite number of customers with zero load.

Q: Why does the Company propose to recover demand-related transmission and distribution plant costs through the residential fixed customer charge?

A: As discussed in Section II, IPL contends that all such demand-related costs are "fixed" and therefore appropriately recovered through a fixed customer charge.

Q: Do you agree that demand-related transmission and distribution plant costs are fixed?

A: No. Such costs may appear "fixed" when considered from a short-run accounting perspective, since the revenue requirements associated with debt service and maintenance in any year are unlikely to vary much with load in that year.

However, from the long-run perspective of cost-causation and price efficiency, plant investments are variable with respect to customer demand. The Company's proposal to shift recovery of such demand-related costs from the volumetric energy rate to the fixed customer charge would drive the energy rate from long-run to short-run marginal cost and thereby dampen price signals for efficient customer behavior.[21]

Q: What would be an appropriate rate for the residential fixed customer charge in order to recover the minimum cost to connect a residential customer?

A: As shown in Table 4 below, I derive a cost-based fixed customer charge for residential customers of $8.15 per customer per month. Consistent with long-

[21] I discuss the impact of the Company's proposal on energy price signals in Section IV. I also discuss in Section IV how the Company's proposal would lead to inequitable subsidization of high-usage residential customers' costs by low-usage residential customers.

standing rate design principles, my recommended fixed customer charge would recover only those costs which are truly customer-related, i.e., the costs of meters, service drops, and customer services.

I derived my recommended fixed customer charge based on the results of a modified version of the Company's ACOSS. Specifically, in response to a data request, IPL modified its ACOSS by removing the minimum-system classification of pole and conductor costs and instead classifying all such costs as demand-related.[22] This modified ACOSS without minimum-system classification of distribution plant costs therefore includes only the cost of meters, service drops, and customer services in the calculation of customer-related costs. As shown in Table 4, the modified ACOSS estimates a customer-related cost of about $43.5 million for the residential class.[23] Based on this estimate of customer-related cost, I derive a total customer-related cost per residential customer of $8.15 per month.

Table 4: Derivation of Cost-Based Residential Fixed Customer Charge

	Residential Adjusted Revenue Requirements	**Residential Bills**	**Cost per Bill**
Meters and Service Drops	$19,305,084	5,338,932	$3.62
Customer Service	$24,222,304	5,338,932	$4.54
Total	$43,527,388		$8.15

[22] IPL response to CAC Data Request 2-8 (Attachment JFW-9). The Company has agreed to make public the "Summary" tab of CAC DR 2-8 Confidential Attachment 1, which is included in Attachment JFW-9.

[23] I am not recommending an alternative allocation of test-year revenue requirements on the basis of the results of this modified ACOSS. Instead, I rely on the results of the modified ACOSS solely for the purposes of deriving a cost-based fixed customer charge for the residential class.

Q: Do you recommend charging all residential customers a fixed customer charge of $8.15 per month regardless of customer usage?

A: Yes. Unlike the Company's proposed fixed customer charge, my recommended fixed customer charge reflects only costs that are truly customer-related, i.e. those costs incurred to connect a residential customer regardless of customer size. Consequently, it would be appropriate for all residential customers to be billed my recommended fixed customer charge at a uniform rate.

Q: What accounts for the $16.76 difference between your recommended $8.15 fixed customer charge and the $24.91 average fixed customer charge proposed by IPL?

A: The $16.76 difference between my recommended $8.15 fixed customer charge and the $24.91 average fixed customer charge proposed by IPL represents demand-related pole, conductor, and other transmission and distribution plant costs that would be inappropriately recovered through the fixed customer charge under the Company's proposal. As discussed in Section IV below, this shift in recovery of demand-related costs from the volumetric energy rate to the fixed customer 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: Although not proposed by IPL in this rate case, would it ever be appropriate to recover any demand-related costs through a residential demand charge?

A: No. 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. 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 loading 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."[24]

Q: Have you estimated the bill impacts associated with your recommended residential fixed customer charge?

A: Yes. In Attachment JFW-2, I provide both my estimate of the bill impacts with an $8.15 fixed customer charge and the Company's estimate of bill impacts with its proposed residential fixed customer charge.[25] As shown in Attachment JFW-2 for my recommended fixed customer charge, I increased the volumetric energy rates proposed by IPL to recover the revenues associated with the $16.76 difference between my recommended $8.15 fixed customer charge and the $24.91 average fixed customer charge proposed by

[24] 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.

[25] I derived Attachment JFW-2 by modifying Petitioner's Witness Gaske's Attachment JSG 9-T. My spreadsheet underlying this calculation will be provided with my workpaper submission.

IPL. In order to isolate the bill impacts from a change in the fixed customer charge, I maintained the Company's proposed declining-block structure when calculating the volumetric energy rates associated with an $8.15 fixed customer charge. However, I discuss in Section V why it would be reasonable to phase out the current declining-block structure for residential volumetric energy rates.

IV. Customer Impacts from IPL's Proposal for the Residential Fixed Customer Charge

A. IPL's Proposal Would Lead to Intra-Class Cost Subsidization

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

A: As discussed in Section III, IPL's proposal to increase the residential fixed customer charge would shift recovery of demand-related costs from the volumetric energy rate to the fixed customer 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 customer 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 customer charge?

A: As explained in Section III, the $16.76 difference between the minimum connection cost of $8.15 and the $24.91 average fixed customer charge proposed by IPL represents demand-related transmission and 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 5.3 million residential bills in the test year.[26] This means that $89.5 million of demand-related costs would be recovered annually through the residential fixed customer charge under the Company's proposal.[27]

If the demand-related costs recovered through the residential fixed customer 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 4.9 million megawatt-hours.[28] Therefore, if the $89.5 million of demand-related costs continued to be recovered through the volumetric energy rate rather than through the fixed customer charge, they would be charged at a rate of 1.84

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[26] The number of residential bills in the test year is provided in Petitioner's Witness Gaske's Attachment JSG 7-T.

[27] The $89.5 million result is derived by taking the product of the annual number of residential bills (5.3 million) and the amount of the proposed average residential fixed customer charge in excess of minimum connection cost ($16.76 per bill).

[28] Residential sales for the test year are provided in Petitioner's Witness Gaske's Attachment JSG 7-T.

cents per kilowatt-hour ("¢/kWh").[29] Under the rate structure that I propose, a residential customer with below-average monthly usage of 500 kWh would contribute about $110 per year toward recovery of the $89.5 million of demand-related costs while a customer with above-average monthly usage of 1,500 kWh would contribute about $331 per year.[30] Thus, under my proposal, the 1,500 kWh customer would contribute three times more than the 500 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 $89.5 million of demand-related costs through the fixed customer charge, each residential customer would contribute about $201 per year toward recovery of such costs regardless of that customer's usage. A below-average 500 kWh customer would therefore pay nearly double their fair share of these demand-related costs under the Company's proposal while an above-average 1,500 kWh customer would pay only 61% of their fair share.

B. *IPL's Proposal Would Dampen Energy Price Signals*

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

A: No. As discussed in Section III, IPL proposes to set the residential fixed customer charge at a rate that greatly exceeds the minimum cost to connect a residential customer. The amount in excess of minimum connection costs

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[29] The 1.84¢/kWh result is derived by dividing $89.5 million by residential sales of 4.9 million megawatt-hours. This calculation assumes that the $89.5 million of demand-related costs would be recovered through all residential energy blocks at a uniform rate.

[30] Based on data provided in Petitioner's Witness Gaske's Attachment JSG 7-T, I estimate monthly usage of 910 kWh for an average residential customer.

represents usage-related costs that are more appropriately recovered in the volumetric energy rate. However, under the Company's proposal, this excess over the minimum connection costs would instead be inappropriately recovered through the fixed customer charge. This shift in the recovery of usage-related costs from the volumetric energy rate to the fixed customer 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 customer 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 customer charge, the lower the volumetric energy rate, and vice versa. As shown in Table 5 below, with the average residential fixed customer charge set at $24.91, IPL proposes an average volumetric energy rate of 9.19¢/kWh in order to recover the proposed allocation of test year revenue requirements to residential customers.[31] If, instead, the fixed customer charge were set at the cost-based rate of $8.15, I estimate that the average volumetric energy rate would have to be increased to 11.03¢/kWh to recover the same allocated revenue requirement.[32]

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[31] Petitioner's Witness Gaske's Attachment JSG 7-T.

[32] For the purposes of this calculation, I assume the same declining-block rate structure for the block volumetric energy rates as proposed by IPL. However, as discussed in Section V, I do not recommend maintaining the declining-block rate structure proposed by the Company.

Table 5: Volumetric Energy Rates with Cost-Based and IPL Fixed Customer Charges (¢/kWh)

	Rate With Cost-Based Customer Charge	Rate With IPL Proposed Customer Charge	Difference from Cost-Based	% Difference from Cost-Based
First 500 kWh	12.374	10.532	(1.842)	-14.9%
Over 500 kWh	10.281	8.439	(1.842)	-17.9%
Over 1000 kWh (RH/RC)	9.020	7.178	(1.842)	-20.4%
Average	11.030	9.188	(1.842)	-16.7%

For the average residential customer with a monthly usage of 910 kWh, the price signal would be provided by the volumetric energy rate for the second block (applicable to monthly usage in excess of 500 kWh). As shown in Table 5, IPL proposes a volumetric rate for the second energy block of 8.44¢/kWh. With the fixed customer charge at the cost-based rate of $8.15, I estimate a volumetric rate for the second energy block of 10.28¢/kWh. In other words, IPL is proposing a volumetric rate for the second energy block that is 1.84¢/kWh, or about 18%, less than what the volumetric rate would be if the residential fixed customer charge were set at the cost-based rate of $8.15. Thus, the Company's proposal for the residential customer charge would dampen the price signal provided by the volumetric energy rate by 18%.

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

A: Since the volumetric energy rate under the Company's proposal for the residential fixed customer charge would be lower than the volumetric energy rate with a cost-based fixed customer charge of $8.15, we would expect residential customers to consume more energy with the Company's proposed fixed customer charge than they would with a cost-based fixed customer 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 fixed customer charge is lower than the volumetric energy rate with a cost-based fixed customer 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.[33] 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.[34] Table 6

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

[34] For the average residential customer with a monthly usage of 910 kWh, that would be the volumetric rate for the second energy block (applicable to monthly usage in excess of 500 kWh).

below lists the results of seven studies of marginal-price elasticity over the last forty years.[35]

Table 6: 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 6, 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 for the residential fixed customer charge?

A: As discussed above, if the residential fixed customer charge were increased as proposed by IPL, the volumetric rate for the second energy block would be about 18% less than what the volumetric rate would be if the residential fixed customer charge were set at the cost-based rate of $8.15. Assuming an elasticity of –0.3, this 18% reduction in the volumetric energy rate would result in an increase in energy consumption of more than 5% for the average residential customer. This means that all else equal, residential load after a few years with a residential fixed customer charge as proposed by IPL would

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

be expected to be about 5% higher than it would have been if the residential fixed customer charge had been set at the cost-based rate of $8.15.

For comparison, I estimate that the Company's residential energy efficiency programs over the three years 2018 through 2020 will deliver an amount of energy savings equivalent to about 4% of forecasted annual residential load.[36] Thus, the additional consumption induced by the Company's proposal for the residential fixed customer charge would negate the energy savings achieved by the Company's residential energy efficiency programs between 2018 and 2020.

V. IPL's Proposal for Declining-Block Energy Rates Would Further Dampen Energy Price Signals

Q: How does the Company propose to recover demand-related costs other than those proposed to be recovered through the residential fixed customer charge?

A: As discussed in Section II, the Company's proposed residential fixed customer charge would recover about 74% of the demand-related transmission and distribution costs allocated to the residential class. The Company proposes to recover the remaining 26% of demand-related transmission and distribution costs, along with 100% of residential demand-related production costs, through declining-block volumetric energy rates.

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[36] Based on data regarding residential energy efficiency net savings provided in Attachment ZE-1S to settlement testimony by IPL witness Zac Elliott in Cause No. 44945 and on data regarding the Company's forecast of residential energy sales provided in the Table 2-2 of Attachment 4.3 to the Company's 2016 Integrated Resource Plan. *See* Attachments JFW-10 and JFW-11.

Q: What is the amount of demand-related costs that IPL proposes to recover through residential volumetric energy rates?

A: The Company proposes to allocate about $350 million of demand-related production, transmission, and distribution costs to the residential class.[37] As discussed in Section II, the residential customer charge proposed by IPL would recover about 74% of residential transmission and distribution demand-related costs through the fixed customer charge. Netting out the demand-related transmission and distribution costs to be recovered through the fixed customer charge proposed by IPL, I estimate that about $289 million of demand-related costs would be recovered through the residential volumetric energy rates proposed by IPL.[38] With residential test-year sales of 4.9 million megawatt-hours, this $289 million of demand-related costs would be recovered from residential customers at an average volumetric rate of 5.95¢/kWh.

Q: Is the Company proposing to recover demand-related costs at a uniform volumetric rate of 5.95¢/kWh?

A: No. As discussed in Section II, IPL proposes to retain the current declining-block structure for its volumetric energy rates. Consequently, as illustrated in Table 7 below, the Company proposes to recover demand-related costs at an above-average rate in the first energy block and at below-average rates in the second and third blocks.

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[37] Petitioner's Witness Gaske's Attachment JSG 3-T, 6. The $350 million amount represents the mitigated allocation of demand-related costs to the residential class.

[38] I estimate that demand-related production costs constitute almost 95% of the $289 million of demand-related costs that would be recovered through residential volumetric energy rates under the Company's proposal.

Table 7: Volumetric Rate Recovery of Demand-Related Costs (¢/kWh)

	IPL Proposed Rate	Fuel + Energy-Related Cost	Net Demand-Related Cost	Average Demand-Related Cost	Net/Average Demand-Related Cost
First 500 kWh (RS/RH/RC)	10.53	3.23	7.30	5.95	122.6%
Over 500 kWh (RS/RH/RC)	8.44	3.23	5.20	5.95	87.4%
Over 1000 kWh (RH/RC)	7.18	3.23	3.94	5.95	66.3%

Q: Why is IPL proposing declining-block rate recovery of demand-related costs?

A: According to Company witness Gaske, declining-block rate recovery is the next best option after demand-charge recovery for recovering these allegedly "fixed" costs:

> Because the residential and small commercial customers generally do not have meters that measure their peak monthly demand and allow fixed, demand-related costs to be recovered through a demand charge, a declining block rate structure is a second-best way to recover the fixed costs that are not recovered in the customer charge. IPL's declining block rate structure for these rate schedules helps ensure that an appropriate level of fixed costs is recovered from each customer while also reducing the amount of fixed costs loaded into the marginal energy charges of most customers.[39]

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

A: No. As discussed in Section III, from a long-run cost-causation and 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.

[39] Gaske Revised Direct, 35.

Conversely, the Company's proposal to recover demand-related costs through declining-block volumetric energy rates would drive second- and third-block energy rates from long-run to short-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.[40] 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 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.

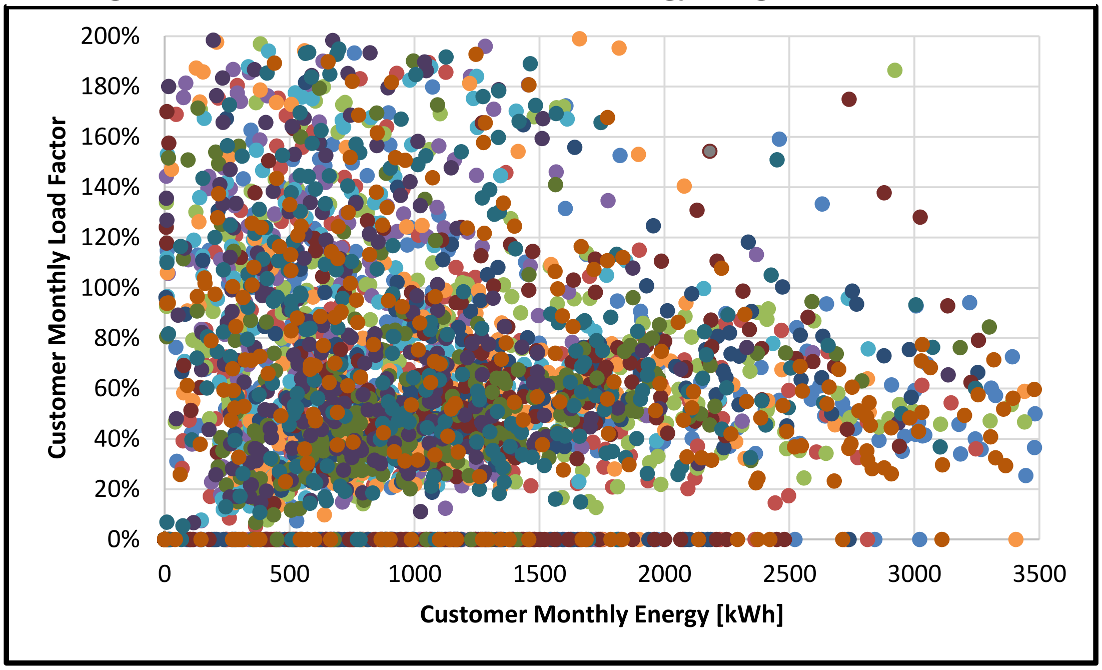
However, load-research data collected by the Company indicates that this is not the case for the Company's residential customers.[41] As illustrated in Figure 1 below, load factors do not appear to increase with customer usage. This means that all residential customers contribute to demand-related

[40] Customer load factor is the ratio of average hourly usage to hourly usage at the time of system 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 system-peak hour. In contrast, a customer who used the same amount of energy every hour except for the system-peak hour, where he used double the amount of energy, would have a load factor of about 0.5.

[41] The Company provided data from its load research program in response to CAC Data Request 2-2 (Attachment JFW-12). Please see my associated workpaper.

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



Q: Do you recommend eliminating the declining-block structure for residential volumetric energy rates?

A: In the interests of gradualism, I do not recommend completely eliminating the declining-block structure for residential volumetric energy rates in this rate case. Instead, I recommend that the rate discounts for the second and third energy blocks be reduced gradually to zero over this and the next two or three rate cases.[42] The exact timing and magnitude of the reductions to block discounts will depend on the magnitude of the revenue increase or decrease

[42] It may be appropriate to phase out the third-block discount for electric space and water heat customers over a longer period.

approved by the Commission in this and subsequent rate cases and on the anticipated frequency of future rate cases.

VI. Conclusions and Recommendations

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

A: The Company's proposal would inappropriately shift load-related costs from the volumetric energy rate to the fixed customer 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 customer charge for residential customers. Instead, consistent with long-standing cost-causation and rate-design principles, I recommend that the residential fixed customer charge be set at a cost-based rate of $8.15 per residential customer per month.

Q: What do you conclude with respect to the Company's proposal for residential volumetric energy rates?

A: The Company lacks a reasonable basis for its proposal to maintain the existing declining-block rate 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 or third blocks would further dampen energy price signals and promote inefficient customer behavior. In the interests of gradualism, I recommend phasing out the declining-block structure over this and the next few rate cases.

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	5/24/18 Date

ATTACHMENT JFW-1

Qualifications of

JONATHAN F. WALLACH

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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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"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.

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"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.

1994 **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.

1996 **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 FirstEnergy 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.

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

Wisconsin PSC Docket No. 6690-UR-124, Wisconsin Public Service Corporation electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, September 2015; Surrebuttal, October 2015.

Cost allocation and rate design.

Wisconsin PSC Docket No. 4220-UR-121, Northern States Power Company gas and electric rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, October 2015.

Cost allocation and rate design.

Maryland PSC Cases Nos. 9226 & 9232, administrative charge for standard-offer service; Maryland Office of People's Counsel. Third Reply, September 2015; Third Rebuttal, October 2015.

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

Nova Scotia UARB Case No. NSUARB P-887(7), Nova Scotia Power fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Evidence, December 2015.

Accounting adjustment for estimated over-earnings. Proposal for modifying procedures for setting the Actual Adjustment.

2016 **Maryland PSC** Case No. 9406, Baltimore Gas & Electric base rate case; Maryland Office of People's Counsel. Direct, February 2016; Rebuttal, March 2016; Surrebuttal, March 2016.

Allocation of Smart Grid costs. Recovery of conduit fees. Rate design.

Nova Scotia UARB Case No. NSUARB P-887(16), Nova Scotia Power 2017-2019 Fuel Stability Plan; Nova Scotia Consumer Advocate. Direct, May 2016; Reply, June 2016.

Base Cost of Fuel forecast. Allocation of Maritime Link capital costs. Fuel cost hedging plan.

Wisconsin PSC Docket No. 3270-UR-121, Madison Gas and Electric Company electric and gas rates; Citizens Utility Board of Wisconsin. Direct, August 2016; Rebuttal, Surrebuttal, September 2016.

Cost allocation and rate design.

Wisconsin PSC Docket No. 6680-UR-120, Wisconsin Power and Light Company electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, Sur-surrebuttal, September 2016.

Cost allocation and rate design.

Minnesota PSC Docket No. E002/GR-15-826, Northern States Power Company electric rates; Clean Energy Organizations. Direct, June 2016; Rebuttal, September 2016; Surrebuttal, October 2016.

Cost basis for residential customer charges.

Nova Scotia UARB Case No. NSUARB M07611, Nova Scotia Power 2016 fuel adjustment mechanism audit; Nova Scotia Consumer Advocate. Direct, November 2016.

Sanctions for imprudent fuel-contracting practices.

2017 **Kentucky PSC** Case No. 2016-00370, Kentucky Utilities Company electric rates; Sierra Club. Direct, March 2017.

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.

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.

PUC Ohio Case Nos. 15-1830-EL-AIR, 15-1831-EL-AAM, 15-1832-EL-ATA; Dayton Power and Light Company electric rates; Natural Resources Defense Council. Direct, April 2018.

Cost basis for residential customer charges.

ATTACHMENT JFW-2

Residential Bill Impacts
RS Customers

Rates

Energy Charge		Including Fuel: Current Rate	Including Fuel: Proposed Rate	Including Fuel & DSM: Current Rate	Including Fuel & DSM: Proposed Rate	Including Fuel: Current Rate	Including Fuel: Cost-Based Rate	Including Fuel & DSM: Current Rate	Including Fuel & DSM: Cost-Based Rate
First 500 kWh		$ 0.103895	$ 0.105322	$ 0.106422	$ 0.107849	$ 0.103895	$ 0.123741	$ 0.106422	$ 0.126268
Over 500 kWh	500	$ 0.082960	$ 0.084387	$ 0.085487	$ 0.086914	$ 0.082960	$ 0.102806	$ 0.085487	$ 0.105333
Customer Charge									
0 to 325 kWh		$ 11.25	$ 16.00	$ 11.25	$ 16.00	$ 11.25	$ 8.15	$ 11.25	$ 8.15
Over 325 kWh	325	$ 17.00	$ 27.00	$ 17.00	$ 27.00	$ 17.00	$ 8.15	$ 17.00	$ 8.15

DSM Charge ($/kWh)	$ 0.002527

Bill Impacts for RS Customers

Line No.	Monthly kWh	% of Customers	Rates with IPL Proposed Customer Charge — Monthly Bill: Present Rates	Monthly Bill: Proposed Rates	Increase / <Decrease>: Amount	Increase / <Decrease>: Percent	Proposed ¢ / kWh	Rates with Cost-Based Customer Charge — Monthly Bill: Present Rates	Monthly Bill: Cost-Based Rates	Increase / <Decrease>: Amount	Increase / <Decrease>: Percent	Proposed ¢ / kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	100	4.37%	$ 21.89	$ 26.78	$ 4.89	22.34%	0.26780	$ 21.89	$ 20.78	$ (1.11)	-5.07%	0.20780
2	200	4.54%	32.53	37.57	5.04	15.49%	0.18785	32.53	33.40	0.87	2.67%	0.16700
3	400	15.72%	59.57	70.14	10.57	17.74%	0.17535	59.57	58.66	(0.91)	-1.53%	0.14665
4	600	20.10%	78.76	89.61	10.85	13.78%	0.14935	78.76	81.81	3.05	3.87%	0.13635
5	800	18.25%	95.86	106.99	11.13	11.61%	0.13374	95.86	102.88	7.02	7.32%	0.12860
6	1,000	13.62%	112.95	124.38	11.43	10.12%	0.12438	112.95	123.95	11.00	9.74%	0.12395
7	1,200	8.80%	130.05	141.76	11.71	9.00%	0.11813	130.05	145.01	14.96	11.50%	0.12084
8	1,500	7.40%	155.70	167.83	12.13	7.79%	0.11189	155.70	176.61	20.91	13.43%	0.11774
9	1,800	3.54%	181.34	193.91	12.57	6.93%	0.10773	181.34	208.21	26.87	14.82%	0.11567
10	2,000	1.25%	198.44	211.29	12.85	6.48%	0.10565	198.44	229.28	30.84	15.54%	0.11464
11	2,400	1.24%	232.64	246.06	13.42	5.77%	0.10253	232.64	271.41	38.77	16.67%	0.11309
12	2,700	0.44%	258.28	272.13	13.85	5.36%	0.10079	258.28	303.01	44.73	17.32%	0.11223
13	3,000	0.25%	283.93	298.21	14.28	5.03%	0.09940	283.93	334.61	50.68	17.85%	0.11154
14	4,000	0.31%	369.41	385.12	15.71	4.25%	0.09628	369.41	439.95	70.54	19.10%	0.10999
15	5,000	0.09%	454.90	472.03	17.13	3.77%	0.09441	454.90	545.28	90.38	19.87%	0.10906
16	7,000	0.05%	625.88	645.86	19.98	3.19%	0.09227	625.88	755.95	130.07	20.78%	0.10799
17	>7,000	0.03%										
	Average											
18	749		91.49	102.56	11.07	12.10%	0.13693	91.49	97.51	6.02	6.58%	0.13019

Residential Bill Impacts
RH/RC Customers

Rates

		Including Fuel		Including Fuel & DSM		Including Fuel		Including Fuel & DSM	
Energy Charge		Current Rate	Proposed Rate	Current Rate	Proposed Rate	Current Rate	Cost-Based Rate	Current Rate	Cost-Based Rate
First 500 kWh		$ 0.103895	$ 0.105322	$ 0.106422	$ 0.107849	$ 0.103895	$ 0.123741	$ 0.106422	$ 0.126268
Over 500 kWh	500	$ 0.082960	$ 0.084387	$ 0.085487	$ 0.086914	$ 0.082960	$ 0.102806	$ 0.085487	$ 0.105333
Over 1,000	1000	$ 0.070357	$ 0.071784	$ 0.072884	$ 0.074311	$ 0.070357	$ 0.090203	$ 0.072884	$ 0.092730
Customer Charge									
0 to 325 kWh		$ 11.25	$ 16.00	$ 11.25	$ 16.00	$ 11.25	$ 8.15	$ 11.25	$ 8.15
Over 325 kWh	325	$ 17.00	$ 27.00	$ 17.00	$ 27.00	$ 17.00	$ 8.15	$ 17.00	$ 8.15

DSM Charge ($/kWh)	$ 0.002527

Bill Impacts for RH/RC Customers

			Rates with IPL Proposed Customer Charge					Rates with Cost-Based Customer Charge				
			Monthly Bill		Increase / <Decrease>			Monthly Bill		Increase / <Decrease>		
Line No.	Monthly kWh	% of Customers	Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh	Present Rates	Cost-Based Rates	Amount	Percent	Proposed ¢ / kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	100	2.71%	$ 21.89	$ 26.78	$ 4.89	22.34%	0.26780	$ 21.89	$ 20.78	$ (1.11)	-5.07%	0.20780
2	200	2.84%	32.53	37.57	5.04	15.49%	0.18785	32.53	33.40	0.87	2.67%	0.16700
3	400	7.61%	59.57	70.14	10.57	17.74%	0.17535	59.57	58.66	(0.91)	-1.53%	0.14665
4	600	11.32%	78.76	89.61	10.85	13.78%	0.14935	78.76	81.81	3.05	3.87%	0.13635
5	800	12.89%	95.86	106.99	11.13	11.61%	0.13374	95.86	102.88	7.02	7.32%	0.12860
6	1,000	12.22%	112.95	124.38	11.43	10.12%	0.12438	112.95	123.95	11.00	9.74%	0.12395
7	1,200	10.93%	127.53	139.24	11.71	9.18%	0.11603	127.53	142.50	14.97	11.74%	0.11875
8	1,500	13.54%	149.39	161.54	12.15	8.13%	0.10769	149.39	170.32	20.93	14.01%	0.11355
9	1,800	10.13%	171.26	183.83	12.57	7.34%	0.10213	171.26	198.13	26.87	15.69%	0.11007
10	2,000	4.65%	185.83	198.69	12.86	6.92%	0.09935	185.83	216.68	30.85	16.60%	0.10834
11	2,400	5.80%	214.99	228.42	13.43	6.25%	0.09518	214.99	253.77	38.78	18.04%	0.10574
12	2,700	2.22%	236.85	250.71	13.86	5.85%	0.09286	236.85	281.59	44.74	18.89%	0.10429
13	3,000	1.25%	258.72	273.00	14.28	5.52%	0.09100	258.72	309.41	50.69	19.59%	0.10314
14	4,000	1.42%	331.60	347.31	15.71	4.74%	0.08683	331.60	402.14	70.54	21.27%	0.10054
15	5,000	0.29%	404.49	421.62	17.13	4.23%	0.08432	404.49	494.87	90.38	22.34%	0.09897
16	7,000	0.13%	550.25	570.25	20.00	3.63%	0.08146	550.25	680.33	130.08	23.64%	0.09719
17	>7,000	0.06%										
	Average											
18	1,134		122.73	134.35	11.62	9.47%	0.11845	122.73	136.39	13.66	11.13%	0.12025

ATTACHMENT JFW-3

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ATTACHMENT JFW-4

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY ("IPL") FOR (1) AUTHORITY TO INCREASE RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE, (2) APPROVAL OF REVISED DEPRECIATION RATES, ACCOUNTING RELIEF, INCLUDING UPDATE OF THE MAJOR STORM DAMAGE RESTORATION RESERVE ACCOUNT, APPROVAL OF A VEGETATION MANAGEMENT RESERVE ACCOUNT, INCLUSION IN BASIC RATES AND CHARGES OF THE COSTS OF CERTAIN PREVIOUSLY APPROVED PROJECTS, INCLUDING THE EAGLE VALLEY COMBINED CYCLE GAS TURBINE, THE NATIONAL POLLUTION DISCHARGE ELIMINATION SYSTEM AND COAL COMBUSTION RESIDUALS COMPLIANCE PROJECTS, RATE ADJUSTMENT MECHANISM PROPOSALS, COST DEFERRALS, AMORTIZATIONS, AND (3) APPROVAL OF NEW SCHEDULES OF RATES, RULES AND REGULATIONS FOR SERVICE.	)	**CAUSE NO. 45029**

INDIANAPOLIS POWER & LIGHT COMPANY'S
OBJECTIONS AND RESPONSES TO THE
CITIZENS ACTION COALITION OF INDIANA, INC.'S
SECOND SET OF DATA REQUESTS TO IPL

Indianapolis Power & Light Company ("Petitioner"), pursuant to 170 IAC 1-1.1-16 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 Citizens Action Coalition of Indiana, Inc.'s ("CAC") Second Set of Data Requests to Indianapolis Power & Light Company ("Requests").

General Objections

A. 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.

B. 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.

C. Petitioner objects to the Requests (including Instruction Nos. 1(a), 1(b) and 2(d)) to the extent they seek responses and information from individuals and entities who are not parties to this proceeding. In particular, Petitioner objects to the CAC's definition of "IPL" as overly broad. Petitioner defines "IPL" for purposes of its responses to include Indianapolis Power & Light Company and its employees. IPL further objects to the Requests to the extent they request the production of information and documents not presently in IPL's possession, custody or control.

D. Petitioner objects to the Requests to the extent the Requests seek information outside the scope of this proceeding, and as such, the Requests seek information not reasonably calculated to lead to the discovery of relevant or admissible evidence.

E. 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.

F. 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.

G. 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 (including Instruction No. 2(f)) purport to impose any greater obligation.

H. 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.

I. The responses constitute the corporate responses of Petitioner and contain information gathered from a variety of sources. Petitioner objects to the Requests (including Instruction Nos. 1(i), 1(j) and 2(g)) 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.

J. 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.

K. 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.

L. Petitioner objects to the Requests (including Instruction Nos. 2(g) and 2(h)) to the extent they request identification of witnesses who will be prepared to testify concerning the matters contained in each response on the grounds that Petitioner is under no obligation to call witnesses to response to questions about information provided in discovery.

Subject to and without waiver of the general and specific objections set forth herein, Petitioner responds to the Requests in the manner set forth below.

Dated this 23rd day of February, 2018.

As to objections,

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DMS 12114144v1

Data Request CAC DR 2 **-** 3

Reference Gaske Direct Testimony (Revised), p. 32, ll. 19-21.
a) Page 12 of Petitioner's Witness JSG Attachment 3-T shows a customer-related cost for the residential class of $72,155,349. In contrast, page 1 of Petitioner's Witness JSG Attachment 7-T shows proposed revenue from the residential customer charge of $133,006,668. Please explain why Mr. Gaske set the residential customer charge at 1.8 times the estimate of residential customer costs in the ACOSS, rather than "at a level close to the level of customer-related costs calculated in Petitioner's Witness JSG Attachment-3-T."
b) Please provide copies of all e-mails, memoranda, or other communications between IPL and Mr. Gaske regarding Mr. Gaske's derivation of his proposed customer charges for the residential class.
c) Please provide copies of all workpapers, including electronic spreadsheets with cell formulas and file linkages intact, relied on to derive the proposed customer charges for the residential class.

Objection:

IPL objects to the request on the grounds and to the extent it is overly broad and unduly burdensome, particularly to the extent it solicits "all" "e-mails, memoranda, or other communications between IPL and Mr. Gaske". Petitioner defines "IPL" for purposes of its responses to include Indianapolis Power & Light Company and its employees. IPL further objects to the Request on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively-sensitive and/or trade secret. IPL further objects to the Request on the grounds and to the extent it solicits information that was prepared in anticipation of litigation or is otherwise subject to the attorney-client, work product or other applicable privileges. Subject to and without waiver of the foregoing objections, IPL provides the following response.

Response:

a. The residential rate class is a two-part rate structure consisting of a customer charge and an energy charge. The residential customers do not have demand meters and therefore, do not receive a demand charge. Consequently, in the absence of a demand charge the rates are designed to recover more than 78 percent of the fixed, demand-related costs in the energy charge and less than 22 percent of the fixed, demand-related costs in the customer charge.

   The customer-related cost amount of $72,153,349 is after a credit for Other Revenue and after the reduction for residential class mitigation. As such, if the customer charge for the residential rate class was set at a level to only recover the $72,155,349 in customer-related costs shown on line 269 of page 12 in Petitioner's Witness JSG Attachment 3-T then the entirety of the demand-related costs would be recovered through the energy charge. The costs classified as demand-related are fixed costs for IPL. As discussed on page 32, lines 14-18 of the revised Direct Testimony of IPL Witness Gaske, rates were designed to increase the portion of fixed costs recovered through either the customer charge or demand charge so as to move the components of the rates design closer to a level that reflects the marginal cost associated with usage.

As shown in the table below, the total residential fixed, demand-related costs after the credit for other revenue, but before rate mitigation, consists of $280.4 million in production/generation costs (78%) and $79.5 million in grid facilities (22%). When the customer costs and the fixed, grid costs classified as demand are combined, the total grid facility cost is $153.7 million, or $28.79 per month per customer.

Line No.			Credit	Residential Fixed Costs	
	Demand-Generation		Other Rev.	Generation	Grid Facilities
189	Production	$ 293,554,709	95.52%	$ 280,416,848	
	Demand-Grid				
190	Transmission	$ 39,364,033			
191	Distribution	$ 14,949,512			
192	Distribution Primary	$ 20,639,989			
193	Distribution Secondary	$ 8,259,920			
		$ 83,213,454	95.52%		$ 79,489,287
	Customer				
202	Distribution Primary	$ 22,980,107			
203	Distribution Secondary	$ 9,102,091			
204	Customer	$ 20,219,112			
205	Customer Service	$ 25,369,145			
		$ 77,670,455	95.52%		$ 74,194,361
	Totals			$ 280,416,848	$ 153,683,648
251	÷ Customer Bills (Count *12)				5,338,932
265	Grid Facility Costs				$ 28.79
	Proposed Customer Charge				$ 27.00

Source: IPL Witness JSG Attachment 3-T and
IPL Witness JSG Workpaper 1.0C-T, "Summary" Tab

For the residential rate class, the customer charge for the large use customers (≥ 325 kWh/month) was set to $27 a level that is slightly below the level needed to recover the customer-related costs plus the grid-related demand costs. Additionally, the customer charge for small customers (< 325 kWh/month) was set to $16 which, as discussed on page 33, lines 7-8 of the revised Direct Testimony of IPL Witness Gaske, was determined to ensure that the smallest customers (in terms of least kWh of consumption) should receive bill increases of less than $6.00 per month.

As shown on line 264 of page 11 in Petitioner's Witness JSG Attachment 3-T, the total grid facility revenue requirement is $153,683,648. The proposed revenue from residential customer charges is $133,006,668 shown on line 9 of page 1 of Petitioner's

Witness JSG Attachment 7-T. Therefore, the proposed revenue from the customer charges does not recover all of the fixed cost related to the grid facilities. A portion of the grid facility costs in addition to all of the demand-related production costs will be recovered through the energy charge. As a result, a substantial portion of fixed costs will still be recovered in the variable energy charge component of the rates for these customers.

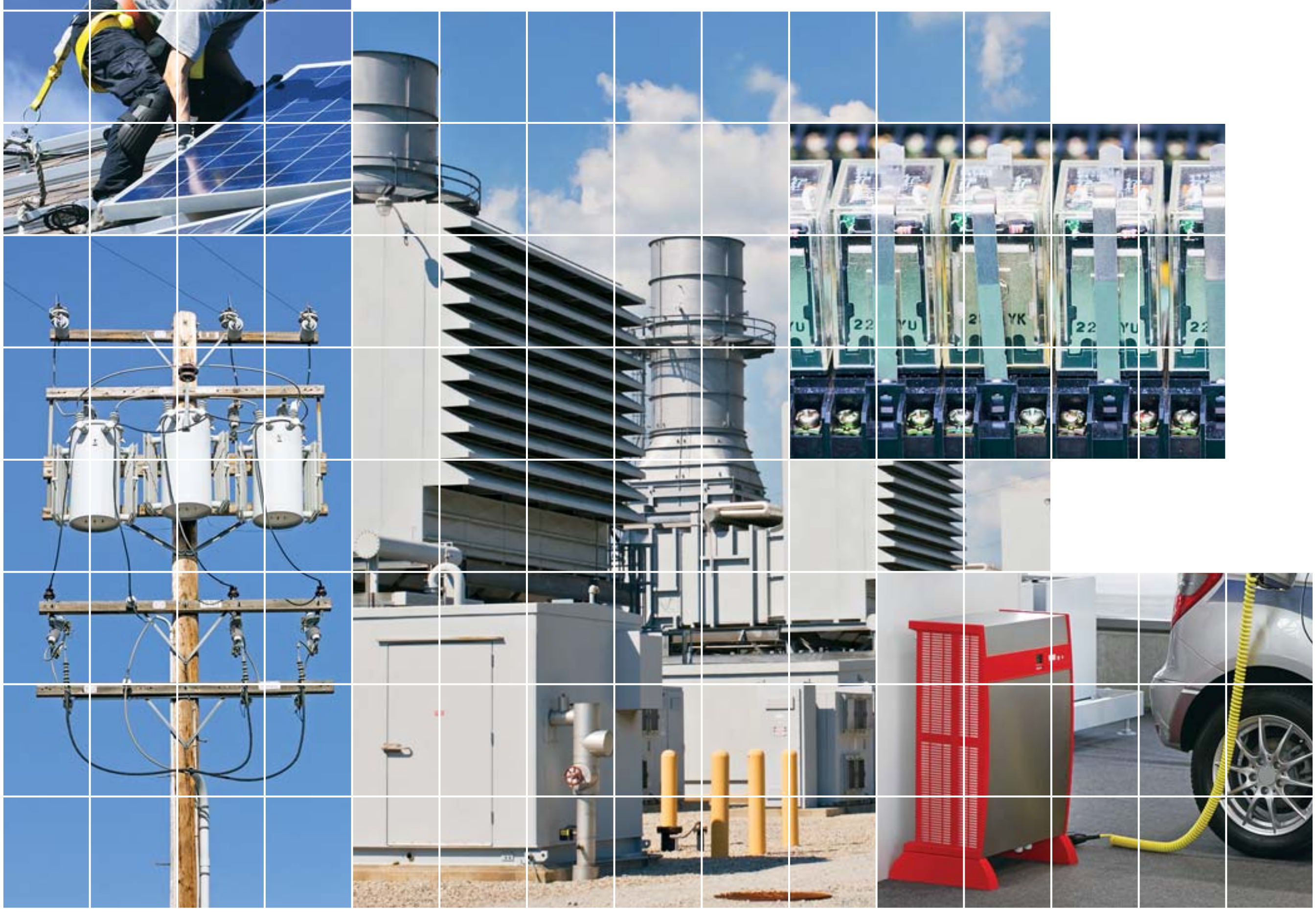
b. Please see CAC DR 2-3b-Attachments 1 through 3.

c. Please see the table below for a list of the workpapers relied on to derive the proposed customer charges for the residential rate class.

Name	Workpaper	Description
Class Allocation Factors – External	IPL Witness JSG Workpaper 2.0-T	Development of the factors used to allocate costs to rate classes in the ACOSS model in Excel format.
CONFIDENTIAL Cost of Service Model	IPL Witness JSG Workpaper 1.0C-T	Concentric ACOSS model in Excel format.
CONFIDENTIAL Rate Design and Revenue Proof Calculations	IPL Witness JSG Workpaper 4.0C-T	Detailed calculations for each rate component of each rate schedule and a proof of proposed revenues by rate schedule in Excel format. The rate design for the residential class can be found on the Rate RS tab.
Residential Bill Impacts Calculation	IPL Witness JSG Workpaper 6.0-T	Calculations of the change in pro forma bills for residential customers with various usage levels.

ATTACHMENT JFW-5

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

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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-6

POWELL GOLDSTEIN LLP

Principles of Public Utiliity Rates by James C. Bonbright

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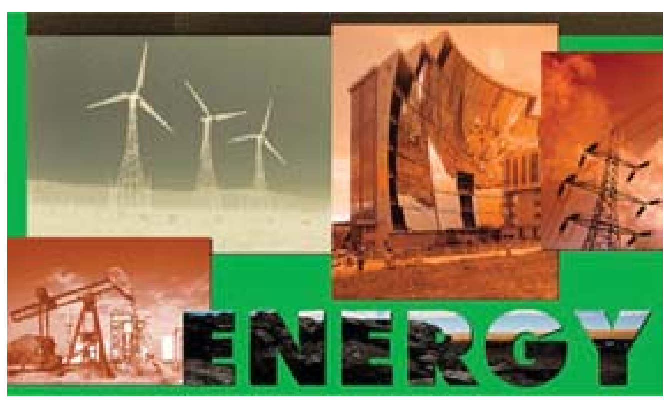

the rates for any given class of service (passenger versus freight, residential versus commercial, etc.) should cover the costs of supplying that class, and so the rates charged to any single customer within that class should cover the costs of supplying this one customer. Under this assumption, the 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 non-additive 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-7

The Economics of Regulation
Principles and Institutions

Volume I Economic Principles
Volume II Institutional Issues

Alfred E. Kahn

The MIT Press
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London, England

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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-8

PUBLIC UTILITY ECONOMICS

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of electric energy used
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-9

Data Request CAC DR 2 **-** 8

Reference Petitioner's Witness JSG Workpaper 1.0C-T.
a) Please provide a modified version of the electronic spreadsheet 45029_IPL_IPL Witness JSG Workpaper 1.0C-T_021618.XLSM (with all cell formulas and file linkages intact) which classifies 100% of the costs recorded in FERC Accounts 364 through 368 as demand-related (i.e., does not classify any costs recorded in FERC Accounts 364 through 368 as customer-related based on a minimum system analysis.)
b) If IPL is unable to provide the requested spreadsheet, please provide detailed instructions for modifying the electronic spreadsheet 45029_IPL_IPL Witness JSG Workpaper 1.0C-T_021618.XLSM in order to create a version that classifies 100% of the costs recorded in FERC Accounts 364 through 368 as demand-related.

Objection:

IPL objects to the Request on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively-sensitive and/or trade secret. Subject to and without waiver of the foregoing objections, IPL provides the following response.

Response:

a. Please see CAC DR 2-8 Confidential Attachment 1.
b. Not applicable.

Class Cost of Service Study
Summary of Results

Row	Line No.	Description	System Total	Residential RS	Secondary Small SS	Space Conditioning SH	Space Conditioning - Schools SE	Water Heating - Controlled CB
6		(A)	(B)	(C)	(D)	(E)	(F)	(G)
7								
8		**Rate Base**						
9	1	Plant in Service	$ 6,066,047,067	$ 2,630,293,050	$ 635,012,538	$ 274,255,342	$ 6,288,711	$ 242,522
10	2	Accumulated Reserve	(2,882,267,569)	(1,249,945,912)	(316,451,685)	(128,778,488)	(2,909,974)	(152,460)
11	3	Other Rate Base Items	213,868,610	90,383,403	21,956,719	9,524,693	226,875	8,101
12	4	Total Rate Base	$ 3,397,648,108	$ 1,470,730,540	$ 340,517,571	$ 155,001,547	$ 3,605,613	$ 98,163
13								
14		**Revenues at Current Rates**						
15	5	Retail Sales	$ 1,320,836,874	$ 537,018,912	$ 151,544,978	$ 50,304,611	$ 1,481,136	$ 41,102
16	6	Other Revenue	20,856,573	12,841,887	1,814,055	562,462	14,197	761
17	7	Sales for Resale	17,611,569	7,482,397	1,655,340	806,282	19,038	371
18	8	Total Revenues	$ 1,359,305,016	$ 557,343,195	$ 155,014,374	$ 51,673,354	$ 1,514,372	$ 42,233
19								
20		**Expenses at Current Rates**						
21	9	Operations & Maintenance Expenses	$ 442,072,993	$ 198,153,731	$ 45,939,813	$ 18,914,614	$ 433,698	$ 20,507
22	10	Depreciation Expense	233,260,407	102,388,872	24,976,579	10,570,805	241,385	9,548
23	11	Amortization Expense	10,737,773	4,654,839	1,127,348	486,039	11,138	433
24	12	Taxes Other Than Income Taxes	50,171,223	21,995,704	5,266,693	2,236,407	51,149	2,059
25	13	Fuel Expenses	436,215,717	160,152,831	40,844,494	17,456,643	509,016	13,732
26	14	Non-FAC Trackable Fuel Expenses	7,129,130	2,617,391	667,527	285,295	8,319	224
27	15	Income Taxes	10,653,903	3,396,105	3,168,486	(259,899)	19,310	(788)
28	16	Total Expenses - Current	$ 1,190,241,146	$ 493,359,472	$ 121,990,940	$ 49,689,905	$ 1,274,015	$ 45,715
29								
30	17	Current Operating Income	169,063,870	63,983,723	33,023,433	1,983,450	240,357	(3,482)
31	18	Return at Current Rates	4.98%	4.35%	9.70%	1.28%	6.67%	-3.55%
32	19	Index Rate of Return	1.00	0.87	1.95	0.26	1.34	(0.71)
33								
34		**Revenue Requirement at Equal Rates of Return at Current Rates**						
35	20	Required Return	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
36	21	Required Operating Income	$ 169,063,870	$ 73,182,210	$ 16,943,844	$ 7,712,736	$ 179,412	$ 4,884
37								
38		**Expenses at Required Return**						
39	22	Operations & Maintenance Expenses	$ 442,072,993	$ 198,153,731	$ 45,939,813	$ 18,914,614	$ 433,698	$ 20,507
40	23	Depreciation Expense	233,260,407	102,388,872	24,976,579	10,570,805	241,385	9,548
41	24	Amortization Expense	10,737,773	4,654,839	1,127,348	486,039	11,138	433
42	25	Taxes Other than Income	50,171,223	21,995,704	5,266,693	2,236,407	51,149	2,059
43	26	Fuel Expenses	436,215,717	160,152,831	40,844,494	17,456,643	509,016	13,732
44	27	Non-FAC Trackable Fuel Expenses	7,129,130	2,617,391	667,527	285,295	8,319	224
45	28	Income Taxes	10,653,903	4,611,726	1,067,751	486,034	11,306	308
46	29	Total Expense - Required	$ 1,190,241,146	$ 494,575,093	$ 119,890,205	$ 50,435,837	$ 1,266,011	$ 46,811
47								
48	30	Total Revenue Requirement at Equal Return	$ 1,359,305,016	$ 567,757,303	$ 136,834,048	$ 58,148,572	$ 1,445,423	$ 51,696
49								
50	31	Current Subsidy	$ -	$ (10,414,108)	$ 18,180,325	$ (6,475,218)	$ 68,949	$ (9,463)
51								

Class Cost of Service Study
Summary of Results

Line No.	Description	System Total	Water Heating - Uncontrolled UW	Secondary Large SL	Industrial PL-HL	Process Heating PH	Automatic Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(H)	(I)	(J)	(K)	(L)	(M)
	Rate Base							
1	Plant in Service	$ 6,066,047,067	$ 482,605	$ 1,430,707,836	$ 926,130,364	$ 15,060,812	$ 60,134,345	$ 87,438,944
2	Accumulated Reserve	(2,882,267,569)	(258,097)	(651,249,276)	(396,860,372)	(7,128,781)	(51,192,450)	(77,340,074)
3	Other Rate Base Items	213,868,610	17,338	51,638,285	35,007,312	540,693	1,845,999	2,719,192
4	Total Rate Base	$ 3,397,648,108	$ 241,847	$ 831,096,844	$ 564,277,304	$ 8,472,723	$ 10,787,894	$ 12,818,062
	Revenues at Current Rates							
5	Retail Sales	$ 1,320,836,874	$ 118,918	$ 325,364,155	$ 234,835,605	$ 3,305,535	$ 7,453,299	$ 9,368,623
6	Other Revenue	20,856,573	2,128	3,104,225	1,920,973	34,772	228,509	332,604
7	Sales for Resale	17,611,569	1,114	4,427,027	3,102,957	44,131	33,067	39,846
8	Total Revenues	$ 1,359,305,016	$ 122,160	$ 332,895,408	$ 239,859,535	$ 3,384,437	$ 7,714,875	$ 9,741,073
	Expenses at Current Rates							
9	Operations & Maintenance Expenses	$ 442,072,993	$ 37,360	$ 102,178,723	$ 64,607,422	$ 1,050,613	$ 4,949,940	$ 5,786,572
10	Depreciation Expense	233,260,407	19,166	55,487,296	36,625,190	568,110	945,960	1,427,496
11	Amortization Expense	10,737,773	858	2,528,699	1,633,137	26,703	108,623	159,955
12	Taxes Other Than Income Taxes	50,171,223	4,055	11,801,693	7,631,035	122,375	468,080	591,974
13	Fuel Expenses	436,215,717	40,954	117,094,154	95,498,334	1,190,000	1,486,541	1,929,019
14	Non-FAC Trackable Fuel Expenses	7,129,130	669	1,913,687	1,560,747	19,448	24,295	31,526
15	Income Taxes	10,653,903	1,485	2,370,383	2,059,924	21,895	(63,185)	(59,813)
16	Total Expenses - Current	$ 1,190,241,146	$ 104,546	$ 293,374,634	$ 209,615,790	$ 2,999,145	$ 7,920,254	$ 9,866,730
17	Current Operating Income	169,063,870	17,614	39,520,773	30,243,745	385,293	(205,380)	(125,656)
18	Return at Current Rates	4.98%	7.28%	4.76%	5.36%	4.55%	-1.90%	-0.98%
19	Index Rate of Return	1.00	1.46	0.96	1.08	0.91	(0.38)	(0.20)
	Revenue Requirement at Equal Rates of Return at Current Rates							
20	Required Return	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%
21	Required Operating Income	$ 169,063,870	$ 12,034	$ 41,354,621	$ 28,077,924	$ 421,595	$ 536,796	$ 637,815
	Expenses at Required Return							
22	Operations & Maintenance Expenses	$ 442,072,993	$ 37,360	$ 102,178,723	$ 64,607,422	$ 1,050,613	$ 4,949,940	$ 5,786,572
23	Depreciation Expense	233,260,407	19,166	55,487,296	36,625,190	568,110	945,960	1,427,496
24	Amortization Expense	10,737,773	858	2,528,699	1,633,137	26,703	108,623	159,955
25	Taxes Other than Income	50,171,223	4,055	11,801,693	7,631,035	122,375	468,080	591,974
26	Fuel Expenses	436,215,717	40,954	117,094,154	95,498,334	1,190,000	1,486,541	1,929,019
27	Non-FAC Trackable Fuel Expenses	7,129,130	669	1,913,687	1,560,747	19,448	24,295	31,526
28	Income Taxes	10,653,903	758	2,606,045	1,769,387	26,568	33,827	40,193
29	Total Expense - Required	$ 1,190,241,146	$ 103,819	$ 293,610,297	$ 209,325,253	$ 3,003,818	$ 8,017,266	$ 9,966,736
30	Total Revenue Requirement at Equal Return	$ 1,359,305,016	$ 115,853	$ 334,964,918	$ 237,403,177	$ 3,425,412	$ 8,554,062	$ 10,604,551
31	Current Subsidy	$ -	$ 6,306	$ (2,069,510)	$ 2,456,358	$ (40,975)	$ (839,187)	$ (863,477)

	A	B	C	D	E	F	G	H	I	J	K
4	**Line**						**Residential**	**Secondary Small**	**Space Conditioning**	**Space Conditioning - Schools**	**Water Heating - Controlled**
5	**No.**		**Description**		**System Total**		**RS**	**SS**	**SH**	**SE**	**CB**
6			(A)		(B)		(C)	(D)	(E)	(F)	(G)
7											
52			**Revenue Requirement at Equal Rates of Return at Proposed Rates**								
53	32		Required Return		7.05%		7.05%	7.05%	7.05%	7.05%	7.05%
54	33		Required Operating Income		$ 239,574,000		$ 103,703,735	$ 24,010,478	$ 10,929,425	$ 254,238	$ 6,922
55	34		Operating Income (Deficiency)/Surplus		$ (70,510,130)		$ (39,720,012)	$ 9,012,955	$ (8,945,975)	$ (13,881)	$ (10,404)
56											
57			**Expenses at Equal Rates of Return at Proposed Rates**								
58	35		Operations & Maintenance Expenses		$ 442,546,993		$ 198,470,904	$ 45,972,539	$ 18,922,007	$ 433,842	$ 20,550
59	36		Depreciation Expense		233,260,407		102,388,872	24,976,579	10,570,805	241,385	9,548
60	37		Amortization Expense		10,737,773		4,654,839	1,127,348	486,039	11,138	433
61	38		Taxes Other than Income		51,520,223		22,582,068	5,402,461	2,297,503	52,568	2,101
62	39		Fuel Expenses		436,215,717		160,152,831	40,844,494	17,456,643	509,016	13,732
63	40		Non-FAC Trackable Fuel Expenses		7,129,130		2,617,391	667,527	285,295	8,319	224
64	41		Income Taxes		35,053,000		15,173,295	3,513,066	1,599,127	37,199	1,013
65	42		Total Expense - Required		$ 1,216,463,243		$ 506,040,201	$ 122,504,014	$ 51,617,418	$ 1,293,466	$ 47,600
66											
67	43a		Interruptble Power Credit		-		-	-	-	-	-
68	43		Total Revenue Requirement at Equal Return		$ 1,456,037,243		$ 609,743,935	$ 146,514,493	$ 62,546,844	$ 1,547,704	$ 54,522
69											
70	44		Revenue (Deficiency)/Surplus		$ (96,732,227)		$ (52,400,740)	$ 8,499,881	$ (10,873,489)	$ (33,332)	$ (12,289)
71	45		Total Revenues		1,359,305,016		557,343,195	155,014,374	51,673,354	1,514,372	42,233
72	46		Total Revenues as Proposed		$ 1,456,037,243		$ 609,743,935	$ 146,514,493	$ 62,546,844	$ 1,547,704	$ 54,522
73											
74	47		Less Total Other Revenues		$ 20,856,573		$ 12,841,887	$ 1,814,055	$ 562,462	$ 14,197	$ 761
75	48		Sales for Resale		17,611,569		7,482,397	1,655,340	806,282	19,038	371
76	49		Total Base Rate Revenues as Proposed		$ 1,417,569,101		$ 589,419,652	$ 143,045,097	$ 61,178,100	$ 1,514,469	$ 53,390
77											
78			**Mitigation**								
79	50		Mitigation		$ 0		$ (5,207,054)	$ 9,090,163	$ (3,237,609)	$ 34,474	$ (4,731)
80	51		Proposed Increase Post Mitigation		96,732,227		47,193,686	590,282	7,635,880	67,807	7,557
81											
82											
83			**Revenue Requirement at Proposed Mitigated Rates**								
84	52		Revenue Defficiency/Surplus		$ 96,732,227		$ 47,193,686	$ 590,282	$ 7,635,880	$ 67,807	$ 7,557
85	53		Total Revenues		1,359,305,016		557,343,195	155,014,374	51,673,354	1,514,372	42,233
86	54		Total Revenues as Proposed		$ 1,456,037,243		$ 604,536,882	$ 155,604,655	$ 59,309,235	$ 1,582,178	$ 49,790
87											
88	55		Less Total Other Revenues		$ 20,856,573		$ 12,841,887	$ 1,814,055	$ 562,462	$ 14,197	$ 761
89	56		Sales for Resale		17,611,569		7,482,397	1,655,340	806,282	19,038	371
90	57		Total Base Rate Revenues as Proposed		$ 1,417,569,101		$ 584,212,598	$ 152,135,260	$ 57,940,491	$ 1,548,943	$ 48,659
91											
92	58		Total Margin in Base Rates		$ 201,105,858		$ 78,172,398	$ 29,631,246	$ 6,323,072	$ 255,477	$ 1,059
93											
94	59		Expenses (excl. Income Taxes)		$ 1,181,410,243		$ 490,866,905	$ 118,990,948	$ 50,018,292	$ 1,256,267	$ 46,587
95	60		Interest Expense		85,621,000		37,062,525	8,581,070	3,906,051	90,862	2,474
96	61		Taxable Income		$ 189,006,000		$ 76,607,451	$ 28,032,638	$ 5,384,891	$ 235,049	$ 729
97											

	A	C	E	L	M	N	O	P	Q
4	**Line**			**Water Heating - Uncontrolled**	**Secondary Large**	**Industrial**	**Process Heating**	**Automatic Protective Lighting**	**Municipal Lighting**
5	**No.**	**Description**	**System Total**	**UW**	**SL**	**PL-HL**	**PH**	**APL**	**MU1**
6		(A)	(B)	(H)	(I)	(J)	(K)	(L)	(M)
7									
52		**Revenue Requirement at Equal Rates of Return at Proposed Rates**							
53	32	Required Return	7.05%	7.05%	7.05%	7.05%	7.05%	7.05%	7.05%
54	33	Required Operating Income	$ 239,574,000	$ 17,053	$ 58,602,065	$ 39,788,161	$ 597,426	$ 760,673	$ 903,824
55	34	Operating Income (Deficiency)/Surplus	$ (70,510,130)	$ 561	$ (19,081,292)	$ (9,544,416)	$ (212,134)	$ (966,053)	$ (1,029,480)
56									
57		**Expenses at Equal Rates of Return at Proposed Rates**							
58	35	Operations & Maintenance Expenses	$ 442,546,993	$ 37,404	$ 102,268,342	$ 64,629,269	$ 1,051,311	$ 4,951,235	$ 5,789,591
59	36	Depreciation Expense	233,260,407	19,166	55,487,296	36,625,190	568,110	945,960	1,427,496
60	37	Amortization Expense	10,737,773	858	2,528,699	1,633,137	26,703	108,623	159,955
61	38	Taxes Other than Income	51,520,223	4,153	12,129,569	7,851,960	125,720	473,609	598,511
62	39	Fuel Expenses	436,215,717	40,954	117,094,154	95,498,334	1,190,000	1,486,541	1,929,019
63	40	Non-FAC Trackable Fuel Expenses	7,129,130	669	1,913,687	1,560,747	19,448	24,295	31,526
64	41	Income Taxes	35,053,000	2,495	8,574,295	5,821,560	87,412	111,297	132,242
65	42	Total Expense - Required	$ 1,216,463,243	$ 105,698	$ 299,996,043	$ 213,620,198	$ 3,068,705	$ 8,101,560	$ 10,068,340
66									
67	43a	Interruptble Power Credit	-	-	-	-	-	-	-
68	43	Total Revenue Requirement at Equal Return	$ 1,456,037,243	$ 122,751	$ 358,598,108	$ 253,408,359	$ 3,666,131	$ 8,862,233	$ 10,972,164
69									
70	44	Revenue (Deficiency)/Surplus	$ (96,732,227)	$ (592)	$ (25,702,700)	$ (13,548,823)	$ (281,694)	$ (1,147,359)	$ (1,231,090)
71	45	Total Revenues	1,359,305,016	122,160	332,895,408	239,859,535	3,384,437	7,714,875	9,741,073
72	46	Total Revenues as Proposed	$ 1,456,037,243	$ 122,751	$ 358,598,108	$ 253,408,359	$ 3,666,131	$ 8,862,233	$ 10,972,164
73									
74	47	Less Total Other Revenues	$ 20,856,573	$ 2,128	$ 3,104,225	$ 1,920,973	$ 34,772	$ 228,509	$ 332,604
75	48	Sales for Resale	17,611,569	1,114	4,427,027	3,102,957	44,131	33,067	39,846
76	49	Total Base Rate Revenues as Proposed	$ 1,417,569,101	$ 119,510	$ 351,066,855	$ 248,384,428	$ 3,587,228	$ 8,600,657	$ 10,599,714
77									
78		**Mitigation**							
79	50	Mitigation	$ 0	$ 3,153	$ (1,034,755)	$ 1,228,179	$ (20,488)	$ (419,594)	$ (431,739)
80	51	Proposed Increase Post Mitigation	96,732,227	3,745	24,667,945	14,777,003	261,206	727,765	799,352
81									
82									
83		**Revenue Requirement at Proposed Mitigated Rates**							
84	52	Revenue Defficiency/Surplus	$ 96,732,227	$ 3,745	$ 24,667,945	$ 14,777,003	$ 261,206	$ 727,765	$ 799,352
85	53	Total Revenues	1,359,305,016	122,160	332,895,408	239,859,535	3,384,437	7,714,875	9,741,073
86	54	Total Revenues as Proposed	$ 1,456,037,243	$ 125,905	$ 357,563,353	$ 254,636,538	$ 3,645,643	$ 8,442,639	$ 10,540,425
87									
88	55	Less Total Other Revenues	$ 20,856,573	$ 2,128	$ 3,104,225	$ 1,920,973	$ 34,772	$ 228,509	$ 332,604
89	56	Sales for Resale	17,611,569	1,114	4,427,027	3,102,957	44,131	33,067	39,846
90	57	Total Base Rate Revenues as Proposed	$ 1,417,569,101	$ 122,663	$ 350,032,100	$ 249,612,608	$ 3,566,741	$ 8,181,064	$ 10,167,975
91									
92	58	Total Margin in Base Rates	$ 201,105,858	$ 16,965	$ 50,036,058	$ 35,992,410	$ 498,036	$ 79,503	$ 99,635
93									
94	59	Expenses (excl. Income Taxes)	$ 1,181,410,243	$ 103,203	$ 291,421,748	$ 207,798,638	$ 2,981,293	$ 7,990,263	$ 9,936,098
95	60	Interest Expense	85,621,000	6,095	20,943,706	14,219,833	213,513	271,856	323,016
96	61	Taxable Income	$ 189,006,000	$ 16,607	$ 45,197,899	$ 32,618,068	$ 450,837	$ 180,520	$ 281,311
97									

	A	B	C	D	E	F	G	H	I	J	K
4	**Line**						**Residential**	**Secondary Small**	**Space Conditioning**	**Space Conditioning - Schools**	**Water Heating - Controlled**
5	**No.**		**Description**		**System Total**		**RS**	**SS**	**SH**	**SE**	**CB**
6			(A)		(B)		(C)	(D)	(E)	(F)	(G)
7											
98	62		Income Taxes		35,053,000		14,207,596	5,198,925	998,680	43,592	135
99	63		Operating Income as Proposed		$ 239,574,000		$ 99,462,380	$ 31,414,782	$ 8,292,262	$ 282,319	$ 3,068
100											
101	64		Return at Proposed Rates		7.05%		6.76%	9.23%	5.35%	7.83%	3.13%
102	65		Index Rate of Return		1.00		0.96	1.31	0.76	1.11	0.44
103											

	A	B	C	D	E	L	M	N	O	P	Q
4	**Line**					**Water Heating - Uncontrolled**	**Secondary Large**	**Industrial**	**Process Heating**	**Automatic Protective Lighting**	**Municipal Lighting**
5	**No.**		**Description**		**System Total**	**UW**	**SL**	**PL-HL**	**PH**	**APL**	**MU1**
6			(A)		(B)	(H)	(I)	(J)	(K)	(L)	(M)
7											
98	62		Income Taxes		35,053,000	3,080	8,382,390	6,049,338	83,612	33,479	52,172
99	63		Operating Income as Proposed		$ 239,574,000	$ 19,621	$ 57,759,215	$ 40,788,563	$ 580,738	$ 418,897	$ 552,155
100											
101	64		Return at Proposed Rates		7.05%	8.11%	6.95%	7.23%	6.85%	3.88%	4.31%
102	65		Index Rate of Return		1.00	1.15	0.99	1.03	0.97	0.55	0.61
103											

	A	C	E	G	H	I	J	K
4	Line			Residential	Secondary Small	Space Conditioning	Space Conditioning - Schools	Water Heating - Controlled
5	No.	Description	System Total	RS	SS	SH	SE	CB
6		(A)	(B)	(C)	(D)	(E)	(F)	(G)
7								
403	**Functional Revenue Requirement**							
404		**Demand**						
405	189	Production	$ 690,949,615	$ 293,554,709	$ 64,943,494	$ 31,632,610	$ 746,916	$ 14,541
406	190	Transmission	$ 92,652,452	$ 39,364,033	$ 8,708,557	$ 4,241,755	$ 100,157	$ 1,950
407	191	Distribution	$ 32,152,911	$ 14,949,512	$ 3,371,454	$ 1,558,512	$ 35,401	$ 602
408	192	Distribution Primary	$ 70,400,188	$ 32,732,603	$ 7,381,945	$ 3,412,430	$ 77,512	$ 1,319
409	193	Distribution Secondary	$ 25,625,060	$ 13,808,804	$ 3,114,030	$ 1,453,158	$ 32,700	$ 562
410	194	Customer	$ -	$ -	$ -	$ -	$ -	$ -
411	195	Customer Service	$ -	$ -	$ -	$ -	$ -	$ -
412	196	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -
413	197	**Total**	$ 911,780,225	$ 394,409,661	$ 87,519,481	$ 42,298,465	$ 992,686	$ 18,974
414	198	Zero-Check	-	-	-	-	-	-
415								
416		**Customer**						
417	199	Production	$ -	$ -	$ -	$ -	$ -	$ -
418	200	Transmission	$ -	$ -	$ -	$ -	$ -	$ -
419	201	Distribution	$ -	$ -	$ -	$ -	$ -	$ -
420	202	Distribution Primary	$ -	$ -	$ -	$ -	$ -	$ -
421	203	Distribution Secondary	$ -	$ -	$ -	$ -	$ -	$ -
422	204	Customer	$ 45,579,095	$ 20,219,112	$ 10,092,119	$ 1,288,210	$ 12,520	$ 10,176
423	205	Customer Service	$ 36,332,799	$ 25,369,145	$ 5,611,805	$ 457,869	$ 2,992	$ 10,817
424	206	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -
425	207	**Total**	$ 81,911,894	$ 45,588,257	$ 15,703,924	$ 1,746,079	$ 15,512	$ 20,993
426	208	Zero-Check	-	-	-	-	-	-
427								
428		**Energy**						
429	209	Production	$ 26,129,407	$ 9,593,186	$ 2,446,593	$ 1,045,656	$ 30,490	$ 823
430	210	Transmission	$ -	$ -	$ -	$ -	$ -	$ -
431	211	Distribution	$ -	$ -	$ -	$ -	$ -	$ -
432	212	Distribution Primary	$ -	$ -	$ -	$ -	$ -	$ -
433	213	Distribution Secondary	$ -	$ -	$ -	$ -	$ -	$ -
434	214	Customer	$ -	$ -	$ -	$ -	$ -	$ -
435	215	Customer Service	$ -	$ -	$ -	$ -	$ -	$ -
436	216	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -
437	217	**Total**	$ 26,129,407	$ 9,593,186	$ 2,446,593	$ 1,045,656	$ 30,490	$ 823
438	218	Zero-Check	$ -	$ -	$ -	$ -	$ -	$ -
439								
440		**Fuel**						
441	219	Fuel Expenses	$ 436,215,717	$ 160,152,831	$ 40,844,494	$ 17,456,643	$ 509,016	$ 13,732
442	220	**Total**	$ 436,215,717	$ 160,152,831	$ 40,844,494	$ 17,456,643	$ 509,016	$ 13,732
443	221	Zero-Check	-	-	-	-	-	-
444								
445	222	**Total**	1,456,037,243	609,743,935	146,514,493	62,546,844	1,547,704	54,522
446								
447		**Total Revenue Requirement**						
448	223	Demand	$ 911,780,225	$ 394,409,661	$ 87,519,481	$ 42,298,465	$ 992,686	$ 18,974
449	224	Customer	$ 81,911,894	$ 45,588,257	$ 15,703,924	$ 1,746,079	$ 15,512	$ 20,993

A	C	E	L	M	N	O	P	Q
Line No.	Description	System Total	Water Heating - Uncontrolled UW	Secondary Large SL	Industrial PL-HL	Process Heating PH	Automatic Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(H)	(I)	(J)	(K)	(L)	(M)
	Functional Revenue Requirement							
	Demand							
189	Production	$ 690,949,615	$ 43,697	$ 173,684,272	$ 121,737,434	$ 1,731,370	$ 1,297,293	$ 1,563,278
190	Transmission	$ 92,652,452	$ 5,859	$ 23,290,083	$ 16,324,304	$ 232,167	$ 173,960	$ 209,627
191	Distribution	$ 32,152,911	$ 1,930	$ 7,443,161	$ 4,333,797	$ 96,023	$ 176,705	$ 185,814
192	Distribution Primary	$ 70,400,188	$ 4,226	$ 16,297,123	$ 9,489,036	$ 210,245	$ 386,903	$ 406,847
193	Distribution Secondary	$ 25,625,060	$ 1,800	$ 6,787,298	$ -	$ 88,696	$ 164,760	$ 173,253
194	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
195	Customer Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -
196	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
197	**Total**	$ 911,780,225	$ 57,512	$ 227,501,936	$ 151,884,571	$ 2,358,500	$ 2,199,620	$ 2,538,818
198	Zero-Check	-	-	-	-	-	-	-
	Customer							
199	Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200	Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -
201	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -
202	Distribution Primary	$ -	$ -	$ -	$ -	$ -	$ -	$ -
203	Distribution Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -
204	Customer	$ 45,579,095	$ 11,937	$ 2,384,094	$ 134,006	$ 16,992	$ 5,087,028	$ 6,322,900
205	Customer Service	$ 36,332,799	$ 9,896	$ 4,603,961	$ 171,079	$ 29,357	$ -	$ 65,878
206	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
207	**Total**	$ 81,911,894	$ 21,833	$ 6,988,055	$ 305,085	$ 46,349	$ 5,087,028	$ 6,388,778
208	Zero-Check	-	-	-	-	-	-	-
	Energy							
209	Production	$ 26,129,407	$ 2,453	$ 7,013,963	$ 5,720,369	$ 71,281	$ 89,044	$ 115,549
210	Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -
211	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -
212	Distribution Primary	$ -	$ -	$ -	$ -	$ -	$ -	$ -
213	Distribution Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -
214	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
215	Customer Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -
216	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
217	**Total**	$ 26,129,407	$ 2,453	$ 7,013,963	$ 5,720,369	$ 71,281	$ 89,044	$ 115,549
218	Zero-Check	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Fuel							
219	Fuel Expenses	$ 436,215,717	$ 40,954	$ 117,094,154	$ 95,498,334	$ 1,190,000	$ 1,486,541	$ 1,929,019
220	**Total**	$ 436,215,717	$ 40,954	$ 117,094,154	$ 95,498,334	$ 1,190,000	$ 1,486,541	$ 1,929,019
221	Zero-Check	-	-	-	-	-	-	-
222	**Total**	1,456,037,243	122,751	358,598,108	253,408,359	3,666,131	8,862,233	10,972,164
	Total Revenue Requirement							
223	Demand	$ 911,780,225	$ 57,512	$ 227,501,936	$ 151,884,571	$ 2,358,500	$ 2,199,620	$ 2,538,818
224	Customer	$ 81,911,894	$ 21,833	$ 6,988,055	$ 305,085	$ 46,349	$ 5,087,028	$ 6,388,778

	A	B	C	D	E	F	G	H	I	J	K
4	**Line**						**Residential**	**Secondary Small**	**Space Conditioning**	**Space Conditioning - Schools**	**Water Heating - Controlled**
5	**No.**		**Description**		**System Total**		**RS**	**SS**	**SH**	**SE**	**CB**
6			(A)		(B)		(C)	(D)	(E)	(F)	(G)
7											
450	225		Energy		$ 26,129,407		$ 9,593,186	$ 2,446,593	$ 1,045,656	$ 30,490	$ 823
451	226		Fuel		$ 436,215,717		$ 160,152,831	$ 40,844,494	$ 17,456,643	$ 509,016	$ 13,732
452	227		**Total**		$ 1,456,037,243		$ 609,743,935	$ 146,514,493	$ 62,546,844	$ 1,547,704	$ 54,522
453	228		Zero-Check		-		-	-	-	-	-
454											

	A	B	C	D	E	L	M	N	O	P	Q
4	**Line**					**Water Heating - Uncontrolled**	**Secondary Large**	**Industrial**	**Process Heating**	**Automatic Protective Lighting**	**Municipal Lighting**
5	**No.**		**Description**		**System Total**	**UW**	**SL**	**PL-HL**	**PH**	**APL**	**MU1**
6			(A)		(B)	(H)	(I)	(J)	(K)	(L)	(M)
7											
450	225		Energy		$ 26,129,407	$ 2,453	$ 7,013,963	$ 5,720,369	$ 71,281	$ 89,044	$ 115,549
451	226		Fuel		$ 436,215,717	$ 40,954	$ 117,094,154	$ 95,498,334	$ 1,190,000	$ 1,486,541	$ 1,929,019
452	227		**Total**		$ 1,456,037,243	$ 122,751	$ 358,598,108	$ 253,408,359	$ 3,666,131	$ 8,862,233	$ 10,972,164
453	228		Zero-Check		-	-	-	-	-	-	-
454											

Line No.	Description	System Total	Residential RS	Secondary Small SS	Space Conditioning SH	Space Conditioning - Schools SE	Water Heating - Controlled CB
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Billing Determinants						
229	Demand	15,292,746	0	0	0	0	0
230	Customer Bills (Count *12)	6,042,488	5,338,932	585,216	47,748	312	1,128
231	Energy	13,243,229,798	4,858,733,890	1,231,269,300	526,224,672	15,344,105	413,938
232	Fuel	13,243,229,798	4,858,733,890	1,231,269,300	526,224,672	15,344,105	413,938
	Unit Costs						
233	Demand	.	$ -	$ -	$ -	$ -	$ -
234	Customer	.	$ 82.41	$ 176.39	$ 922.44	$ 3,231.40	$ 35.43
235	Energy	.	$ 0.001974	$ 0.001987	$ 0.001987	$ 0.001987	$ 0.001987
236	Fuel	.	$ 0.032962	$ 0.033173	$ 0.033173	$ 0.033173	$ 0.033173
237	Demand Revenue	.	$ -	$ -	$ -	$ -	$ -
238	Customer Revenue	.	439,997,918	103,223,405	44,044,545	1,008,198	39,967
239	Energy Revenue	.	9,593,186	2,446,593	1,045,656	30,490	823
240	Fuel Revenue	.	160,152,831	40,844,494	17,456,643	509,016	13,732
241	Total Revenue	.	609,743,935	146,514,493	62,546,844	1,547,704	54,522
242	Zero-Check	.	$ -	$ -	$ -	$ -	$ -
	Adjusted Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)						
243	Ratio of Base Revenue to Total Revenue	96.23%	95.48%	96.72%	96.96%	96.80%	97.23%
	Total Revenue Requirement						
244	Demand	$ 877,573,885	$ 376,579,918	$ 84,646,010	$ 41,014,466	$ 960,923	$ 18,448
245	Customer	$ 78,607,839	$ 43,527,388	$ 15,188,327	$ 1,693,076	$ 15,016	$ 20,411
246	Energy	$ 25,171,660	$ 9,159,515	$ 2,366,266	$ 1,013,915	$ 29,515	$ 800
247	Fuel	$ 436,215,717	$ 160,152,831	$ 40,844,494	$ 17,456,643	$ 509,016	$ 13,732
248	**Total**	$ 1,417,569,101	$ 589,419,652	$ 143,045,097	$ 61,178,100	$ 1,514,469	$ 53,390
249	Zero-Check	-	-	-	-	-	-
	Billing Determinants						
250	Demand	15,292,746	0	0	0	0	0
251	Customer Bills (Count *12)	6,042,488	5,338,932	585,216	47,748	312	1,128
252	Energy	13,243,229,798	4,858,733,890	1,231,269,300	526,224,672	15,344,105	413,938
253	Fuel	13,243,229,798	4,858,733,890	1,231,269,300	526,224,672	15,344,105	413,938
	Unit Costs						
254	Demand	.	$ -	$ -	$ -	$ -	$ -
255	Customer	.	$ 78.69	$ 170.59	$ 894.44	$ 3,128.01	$ 34.45
256	Energy	.	$ 0.001885	$ 0.001922	$ 0.001927	$ 0.001924	$ 0.001932
257	Fuel	.	$ 0.032962	$ 0.033173	$ 0.033173	$ 0.033173	$ 0.033173

A	C	E	L	M	N	O	P	Q
Line No.	Description	System Total	Water Heating - Uncontrolled UW	Secondary Large SL	Industrial PL-HL	Process Heating PH	Automatic Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(H)	(I)	(J)	(K)	(L)	(M)
	Billing Determinants							
229	Demand	15,292,746	0	9,307,348	5,985,398	0	0	0
230	Customer Bills (Count *12)	6,042,488	1,032	54,576	2,028	348	0	11,168
231	Energy	13,243,229,798	1,234,531	3,509,506,542	2,961,899,933	35,641,963	44,811,290	58,149,633
232	Fuel	13,243,229,798	1,234,531	3,509,506,542	2,961,899,933	35,641,963	44,811,290	58,149,633
	Unit Costs							
233	Demand	.	$ -	$ 24.44	$ 25.38	$ -	$ -	$ -
234	Customer	.	$ 76.88	$ 128.04	$ 150.44	$ 6,910.49	$ -	$ 799.39
235	Energy	.	$ 0.001987	$ 0.001999	$ 0.001931	$ 0.002000	$ 0.164595	$ 0.001987
236	Fuel	.	$ 0.033173	$ 0.033365	$ 0.032242	$ 0.033388	$ 0.033173	$ 0.033173
237	Demand Revenue	.	$ -	$ 227,501,936	$ 151,884,571	$ -	$ -	$ -
238	Customer Revenue	.	79,345	6,988,055	305,085	2,404,850	-	8,927,596
239	Energy Revenue	.	2,453	7,013,963	5,720,369	71,281	7,375,692	115,549
240	Fuel Revenue	.	40,954	117,094,154	95,498,334	1,190,000	1,486,541	1,929,019
241	Total Revenue	.	122,751	358,598,108	253,408,359	3,666,131	8,862,233	10,972,164
242	Zero-Check	.	$ -	$ -	$ -	$ -	$ -	$ -
	Adjusted Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)							
243	Ratio of Base Revenue to Total Revenue	96.23%	96.04%	96.88%	96.82%	96.81%	96.45%	95.88%
	Total Revenue Requirement							
244	Demand	$ 877,573,885	$ 55,233	$ 220,407,334	$ 147,052,341	$ 2,283,346	$ 2,121,611	$ 2,434,255
245	Customer	$ 78,607,839	$ 20,968	$ 6,770,134	$ 295,379	$ 44,872	$ 4,906,619	$ 6,125,650
246	Energy	$ 25,171,660	$ 2,356	$ 6,795,234	$ 5,538,375	$ 69,010	$ 85,886	$ 110,790
247	Fuel	$ 436,215,717	$ 40,954	$ 117,094,154	$ 95,498,334	$ 1,190,000	$ 1,486,541	$ 1,929,019
248	**Total**	$ 1,417,569,101	$ 119,510	$ 351,066,855	$ 248,384,428	$ 3,587,228	$ 8,600,657	$ 10,599,714
249	Zero-Check	-	-	-	-	-	-	-
	Billing Determinants							
250	Demand	15,292,746	0	9,307,348	5,985,398	0	0	0
251	Customer Bills (Count *12)	6,042,488	1,032	54,576	2,028	348	0	11,168
252	Energy	13,243,229,798	1,234,531	3,509,506,542	2,961,899,933	35,641,963	44,811,290	58,149,633
253	Fuel	13,243,229,798	1,234,531	3,509,506,542	2,961,899,933	35,641,963	44,811,290	58,149,633
	Unit Costs							
254	Demand	.	$ -	$ 23.68	$ 24.57	$ -	$ -	$ -
255	Customer	.	$ 73.84	$ 124.05	$ 145.65	$ 6,690.28	$ -	$ 766.47
256	Energy	.	$ 0.001908	$ 0.001936	$ 0.001870	$ 0.001936	$ 0.158757	$ 0.001905
257	Fuel	.	$ 0.033173	$ 0.033365	$ 0.032242	$ 0.033388	$ 0.033173	$ 0.033173

	A	B	C	D	E	F	G	H	I	J	K
4	**Line**						**Residential**	**Secondary Small**	**Space Conditioning**	**Space Conditioning - Schools**	**Water Heating - Controlled**
5	**No.**		**Description**		**System Total**		**RS**	**SS**	**SH**	**SE**	**CB**
6			(A)		(B)		(C)	(D)	(E)	(F)	(G)
7											
500	258		Demand Revenue		.		$ -	$ -	$ -	$ -	$ -
501	259		Customer Revenue		.		420,107,306	99,834,337	42,707,542	975,939	38,859
502	260		Energy Revenue		.		9,159,515	2,366,266	1,013,915	29,515	800
503	261		Fuel Revenue		.		160,152,831	40,844,494	17,456,643	509,016	13,732
504	262		Total Revenue		.		589,419,652	143,045,097	61,178,100	1,514,469	53,390
505	263		Zero-Check		.		$ -	$ -	$ -	$ -	$ -
506											
507			**Grid Facility**								
508	264		Grid Facility - Revenue Requirement		$ 291,076,067		$ 139,823,076	$ 37,023,091	$ 12,035,161	$ 252,922	$ 24,721
509	265		Grid Facility - Unit Costs		$ 48.17		$ 26.19	$ 63.26	$ 252.06	$ 810.65	$ 21.92

	A	B	C	D	E	L	M	N	O	P	Q
4	**Line**					**Water Heating - Uncontrolled**	**Secondary Large**	**Industrial**	**Process Heating**	**Automatic Protective Lighting**	**Municipal Lighting**
5	**No.**		**Description**		**System Total**	**UW**	**SL**	**PL-HL**	**PH**	**APL**	**MU1**
6			(A)		(B)	(H)	(I)	(J)	(K)	(L)	(M)
7											
500	258		Demand Revenue		.	$ -	$ 220,407,334	$ 147,052,341	$ -	$ -	$ -
501	259		Customer Revenue		.	76,200	6,770,134	295,379	2,328,218	-	8,559,905
502	260		Energy Revenue		.	2,356	6,795,234	5,538,375	69,010	7,114,116	110,790
503	261		Fuel Revenue		.	40,954	117,094,154	95,498,334	1,190,000	1,486,541	1,929,019
504	262		Total Revenue		.	119,510	351,066,855	248,384,428	3,587,228	8,600,657	10,599,714
505	263		Zero-Check		.	$ -	$ -	$ -	$ -	$ -	$ -
506											
507			**Grid Facility**								
508	264		Grid Facility - Revenue Requirement		$ 291,076,067	$ 34,235	$ 58,909,505	$ 29,483,380	$ 652,019	$ 5,776,945	$ 7,061,012
509	265		Grid Facility - Unit Costs		$ 48.17	$ 33.17	$ 1,079.40	$ 14,538.16	$ 1,873.62	#DIV/0!	$ 632.25

	A	C	E	G	H	I	J	K
4	Line			**Residential**	**Secondary Small**	**Space Conditioning**	**Space Conditioning - Schools**	**Water Heating - Controlled**
5	**No.**	**Description**	**System Total**	**RS**	**SS**	**SH**	**SE**	**CB**
6		(A)	(B)	(C)	(D)	(E)	(F)	(G)
7								
510								
511		**Mitigated Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)**						
512								
513	266	Ratio of Unmitigated Revenue to Mitigated Revenue	100.00%	98.76%	109.11%	92.42%	103.53%	87.82%
514	267	Mitigated Amount	0	(5,207,054)	9,090,163	(3,237,609)	34,474	(4,731)
515								
516		**Total Revenue Requirement**						
517	268	Demand	$ 877,490,554	$ 371,912,368	$ 92,353,238	$ 37,905,207	$ 994,867	$ 16,202
518	269	Customer	$ 78,691,171	$ 42,987,884	$ 16,571,262	$ 1,564,726	$ 15,546	$ 17,926
519	270	Energy	$ 25,171,660	$ 9,159,515	$ 2,366,266	$ 1,013,915	$ 29,515	$ 800
520	271	Fuel	$ 436,215,717	$ 160,152,831	$ 40,844,494	$ 17,456,643	$ 509,016	$ 13,732
521	272	**Total**	$ 1,417,569,101	$ 584,212,598	$ 152,135,260	$ 57,940,491	$ 1,548,943	$ 48,659
522	273	Zero-Check	-	-	-	-	-	-
523								
524								
525		**Billing Determinants**						
526	274	Demand	15,292,746	0	0	0	0	0
527	275	Customer Bills (Count *12)	6,042,488	5,338,932	585,216	47,748	312	1,128
528	276	Energy	13,243,229,798	4,858,733,890	1,231,269,300	526,224,672	15,344,105	413,938
529	277	Fuel	13,243,229,798	4,858,733,890	1,231,269,300	526,224,672	15,344,105	413,938
530								
531		**Unit Costs**						
532	278	Demand	.	$ -	$ -	$ -	$ -	$ -
533	279	Customer	.	$ 77.71	$ 186.13	$ 826.63	$ 3,238.50	$ 30.25
534	280	Energy	.	$ 0.001885	$ 0.001922	$ 0.001927	$ 0.001924	$ 0.001932
535	281	Fuel	.	$ 0.032962	$ 0.033173	$ 0.033173	$ 0.033173	$ 0.033173
536								
537	282	Demand Revenue	.	$ -	$ -	$ -	$ -	$ -
538	283	Customer Revenue	.	414,900,252	108,924,500	39,469,933	1,010,413	34,128
539	284	Energy Revenue	.	9,159,515	2,366,266	1,013,915	29,515	800
540	285	Fuel Revenue	$ -	160,152,831	40,844,494	17,456,643	509,016	13,732
541	286	Total Revenue	.	584,212,598	152,135,260	57,940,491	1,548,943	48,659
542	287	Zero-Check	.	$ -	$ -	$ -	$ -	$ -
543								
544								
545		**Total Revenue Requirement (Excluding Fuel)**						
546	288	Demand	$ 877,490,554	$ 371,912,368	$ 92,353,238	$ 37,905,207	$ 994,867	$ 16,202
547	289	Customer	$ 78,691,171	$ 42,987,884	$ 16,571,262	$ 1,564,726	$ 15,546	$ 17,926
548	290	Energy	$ 25,171,660	$ 9,159,515	$ 2,366,266	$ 1,013,915	$ 29,515	$ 800
549	291	**Total**	$ 981,353,384	$ 424,059,767	$ 111,290,766	$ 40,483,848	$ 1,039,928	$ 34,927
550	292	**Percent of Total**	100.00%	43.21%	11.34%	4.13%	0.11%	0.00%
551	293	Zero-Check	-	-	-	-	-	-

	A	B	C	D	E	L	M	N	O	P	Q
4	**Line**					**Water Heating - Uncontrolled**	**Secondary Large**	**Industrial**	**Process Heating**	**Automatic Protective Lighting**	**Municipal Lighting**
5	**No.**		**Description**		**System Total**	**UW**	**SL**	**PL-HL**	**PH**	**APL**	**MU1**
6			(A)		(B)	(H)	(I)	(J)	(K)	(L)	(M)
7											
510											
511			**Mitigated Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)**								
512											
513	266		Ratio of Unmitigated Revenue to Mitigated Revenue		100.00%	104.14%	99.54%	100.83%	99.12%	94.03%	94.96%
514	267		Mitigated Amount		0	3,153	(1,034,755)	1,228,179	(20,488)	(419,594)	(431,739)
515											
516			**Total Revenue Requirement**								
517	268		Demand		$ 877,490,554	$ 57,518	$ 219,403,416	$ 148,278,059	$ 2,263,253	$ 1,994,948	$ 2,311,478
518	269		Customer		$ 78,691,171	$ 21,835	$ 6,739,297	$ 297,841	$ 44,477	$ 4,613,688	$ 5,816,689
519	270		Energy		$ 25,171,660	$ 2,356	$ 6,795,234	$ 5,538,375	$ 69,010	$ 85,886	$ 110,790
520	271		Fuel		$ 436,215,717	$ 40,954	$ 117,094,154	$ 95,498,334	$ 1,190,000	$ 1,486,541	$ 1,929,019
521	272		**Total**		$ 1,417,569,101	$ 122,663	$ 350,032,100	$ 249,612,608	$ 3,566,741	$ 8,181,064	$ 10,167,975
522	273		Zero-Check		-	-	-	-	-	-	-
523											
524											
525			**Billing Determinants**								
526	274		Demand		15,292,746	0	9,307,348	5,985,398	0	0	0
527	275		Customer Bills (Count *12)		6,042,488	1,032	54,576	2,028	348	0	11,168
528	276		Energy		13,243,229,798	1,234,531	3,509,506,542	2,961,899,933	35,641,963	44,811,290	58,149,633
529	277		Fuel		13,243,229,798	1,234,531	3,509,506,542	2,961,899,933	35,641,963	44,811,290	58,149,633
530											
531			**Unit Costs**								
532	278		Demand		.	$ -	$ 23.57	$ 24.77	$ -	$ -	$ -
533	279		Customer		.	$ 76.89	$ 123.48	$ 146.86	$ 6,631.41	$ -	$ 727.81
534	280		Energy		.	$ 0.001908	$ 0.001936	$ 0.001870	$ 0.001936	$ 0.149394	$ 0.001905
535	281		Fuel		.	$ 0.033173	$ 0.033365	$ 0.032242	$ 0.033388	$ 0.033173	$ 0.033173
536											
537	282		Demand Revenue		.	$ -	$ 219,403,416	$ 148,278,059	$ -	$ -	$ -
538	283		Customer Revenue		.	79,354	6,739,297	297,841	2,307,731	-	8,128,166
539	284		Energy Revenue		.	2,356	6,795,234	5,538,375	69,010	6,694,522	110,790
540	285		Fuel Revenue		$ -	40,954	117,094,154	95,498,334	1,190,000	1,486,541	1,929,019
541	286		Total Revenue		.	122,663	350,032,100	249,612,608	3,566,741	8,181,064	10,167,975
542	287		Zero-Check		.	$ -	$ -	$ -	$ -	$ -	$ -
543											
544											
545			**Total Revenue Requirement (Excluding Fuel)**								
546	288		Demand		$ 877,490,554	$ 57,518	$ 219,403,416	$ 148,278,059	$ 2,263,253	$ 1,994,948	$ 2,311,478
547	289		Customer		$ 78,691,171	$ 21,835	$ 6,739,297	$ 297,841	$ 44,477	$ 4,613,688	$ 5,816,689
548	290		Energy		$ 25,171,660	$ 2,356	$ 6,795,234	$ 5,538,375	$ 69,010	$ 85,886	$ 110,790
549	291		**Total**		$ 981,353,384	$ 81,709	$ 232,937,946	$ 154,114,274	$ 2,376,740	$ 6,694,522	$ 8,238,956
550	292		**Percent of Total**		100.00%	0.01%	23.74%	15.70%	0.24%	0.68%	0.84%
551	293		Zero-Check		-	-	-	-	-	-	-

ATTACHMENT JFW-10

2018 Summary

Program	Budget	Energy Savings		Demand Savings	
		Gross kWh	Net kWh	Gross kW	Net kW
Appliance Recycling	$741,032	3,094,111	2,134,755	435	303
Community Based Lighting	$886,206	6,810,512	6,810,512	0	0
Residential Demand Response	$3,449,024	271,500	271,500	45,013	45,013
Income Qualified Weatherization	$1,796,283	2,075,379	2,050,612	349	333
Lighting & Appliances	$2,857,486	20,101,826	16,081,461	1,662	1,329
Multifamily	$2,162,507	5,712,946	5,668,546	732	702
Peer Comparison	$1,466,814	32,000,000	32,000,000	7,008	7,008
School Education	$765,616	3,645,329	3,645,329	459	459
Whole Home	$3,654,230	7,217,828	6,351,689	1,968	1,732
Business Custom	$3,117,009	20,423,307	16,338,646	4,077	3,261
Business Demand Response	$155,600	10,500	10,500	1,400	1,400
Business Prescriptive	$6,535,566	57,697,862	38,657,568	11,125	7,454
SBDI	$1,157,202	4,787,315	4,543,480	543	515
RES	$17,779,197	80,929,431	75,014,402	57,626	56,879
C&I	$10,965,377	82,918,984	59,550,194	17,145	12,631
Direct Subtotal	$28,744,574	163,848,415	134,564,596	74,771	69,509
Indirect Subtotal	$1,655,000				
Portfolio Total	$30,399,574	163,848,415	134,564,596	74,771	69,509

2019 Summary

Program	Budget	Energy Savings		Demand Savings	
		Gross kWh	Net kWh	Gross kW	Net kW
Appliance Recycling	$742,623	3,094,111	2,134,755	435	303
Community Based Lighting	$842,613	6,810,512	6,810,512	0	0
Residential Demand Response	$3,591,243	240,900	240,900	47,637	47,637
Income Qualified Weatherization	$1,730,803	2,075,379	2,050,612	349	333
Lighting & Appliances	$2,686,088	20,210,358	16,168,286	1,672	1,337
Multifamily	$2,108,419	5,712,946	5,668,546	732	702
Peer Comparison	$1,466,814	32,000,000	32,000,000	7,008	7,008
School Education	$783,518	3,749,481	3,749,481	472	472
Whole Home	$3,598,047	7,217,828	6,351,689	1,968	1,732
Business Custom	$3,623,009	25,376,337	20,301,070	4,655	3,724
Business Demand Response	$155,600	10,500	10,500	1,400	1,400
Business Prescriptive	$6,296,532	52,959,206	35,482,668	10,219	6,847
SBDI	$1,184,594	4,787,315	4,543,480	543	515

RES	$17,550,168	81,111,515	75,174,780	60,273	59,524
C&I	$11,259,734	83,133,359	60,337,718	16,817	12,486
Direct Subtotal	$28,809,902	164,244,874	135,512,498	77,090	72,010

Indirect Subtotal	$1,655,000				

Portfolio Total	$30,464,902	164,244,874	135,512,498	77,090	72,010

2020 Summary

Program	Budget	Energy Savings		Demand Savings	
		Gross kWh	Net kWh	Gross kW	Net kW
Appliance Recycling	$757,096	3,016,303	2,092,738	430	300
Community Based Lighting	$445,249	2,043,824	2,043,824	0	0
Residential Demand Response	$3,722,554	210,312	210,312	50,286	50,286
Income Qualified Weatherization	$1,741,330	1,918,623	1,897,215	349	333
Lighting & Appliances	$2,584,972	10,210,527	8,168,422	630	504
Multifamily	$2,128,545	4,855,313	4,817,008	622	593
Peer Comparison	$1,466,814	32,000,000	32,000,000	7,008	7,008
School Education	$852,761	3,160,849	3,160,849	363	363
Whole Home	$3,627,003	6,618,468	5,824,252	1,890	1,664
Business Custom	$4,187,062	30,921,770	24,737,416	4,338	3,470
Business Demand Response	$155,600	10,500	10,500	1,400	1,400
Business Prescriptive	$6,321,391	39,143,050	26,225,844	7,002	4,692
SBDI	$1,242,885	3,586,338	3,403,424	321	304
RES	$17,326,323	64,034,220	60,214,621	61,579	61,051
C&I	$11,906,938	73,661,659	54,377,184	13,061	9,866
Direct Subtotal	$29,233,261	137,695,878	114,591,805	74,640	70,917
Indirect Subtotal	$1,655,000				
Portfolio Total	$30,888,261	137,695,878	114,591,805	74,640	70,917

ATTACHMENT JFW-11

2 Forecast Approach

The forecast approach is similar to method used by other state electric utilities. The process begins by developing customer sales forecast and using forecast results to drive future energy requirements and peak demand.

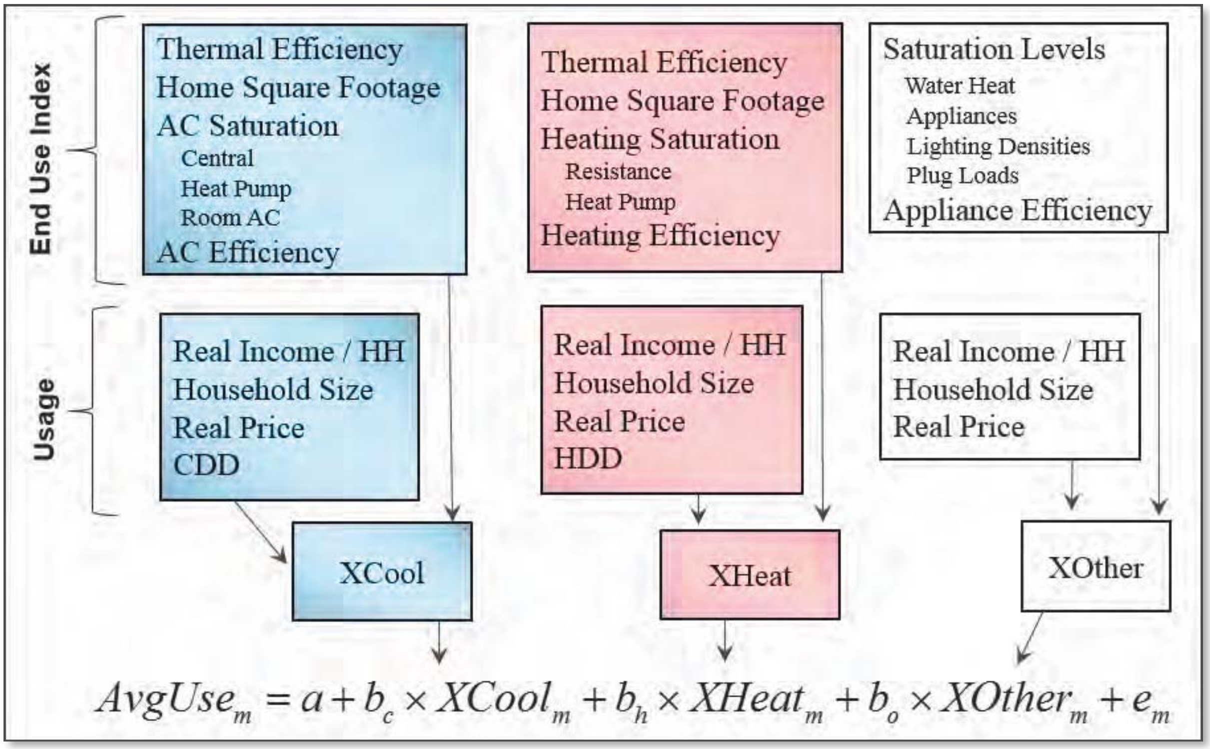
Rather than develop sales forecast for the generalized rate classes (i.e., Residential, Commercial, Industrial, and Street Lighting), IPL forecasts sales at the rate-schedule level and aggregates rate-schedule sales forecast to rate-classes. The reason is that IPL uses a single monthly forecast for near-term budget and financial planning and long-term resource planning. IPL revenue forecast requires sales forecast at the rate-class and even billing determinant level. Table 2-1 shows the specific rate-schedules forecasted and associated customers, sales, and average use.

Table 2-1: 2015 Customers and Sales

Sector	Rate Schedule	Definition	Customers	MWh	Avg kWh
RES	RS	General Service	246,481	2,342,108	9,502
RES	RH	Electric Heat	150,498	2,323,908	15,441
RES	RC	Electric Water Heat	32,022	406,586	12,697
Sml C&I	SS	General Service	46,153	1,228,878	26,626
Sml C&I	SH	GS All Electric	4,035	562,864	139,495
Sml C&I	SE	GS Electric Heat	3,357	19,383	5,774
Sml C&I	CB	GS Water Heat (Controlled)	95	432	4,549
Sml C&I	UW	GS Water Heat (Uncontrolled)	84	1,506	17,923
Sml C&I	APL	GS Security Lighting	364	31,620	86,868
Lrg C&I	SL	Secondary Service	4,539	3,504,652	772,120
Lrg C&I	PL	Primary Service	142	1,260,060	8,873,663
Lrg C&I	HL1	High Load Factor 1	28	1,373,248	49,044,572
Lrg C&I	HL2	High Load Factor 2	5	225,376	45,075,200
Lrg C&I	HL3	High Load Factor 3	3	345,920	115,306,667
Lrg C&I	APL	IND Security Light	364	5,725	15,728
Other	ST	Street Lighting		53,280	
Total			488,170	13,685,546	28,034

Usage measured in kWh per customer has been steadily declining over the last ten years largely driven by end-use efficiency improvements and DSM program activity. As new standards will continue to drive usage downwards it's critical to capture these efficiency improvements in the sales forecast models. The approach is to use an end-use modeling framework where the constructed model variables incorporate structural changes (thermal shell and end-use energy intensity trends) as well as economic activity, electric prices, and weather conditions (heating and cooling degree-days). Figure 3 provides an overview of this framework for the residential rate class; the same framework is used for the commercial rate class.

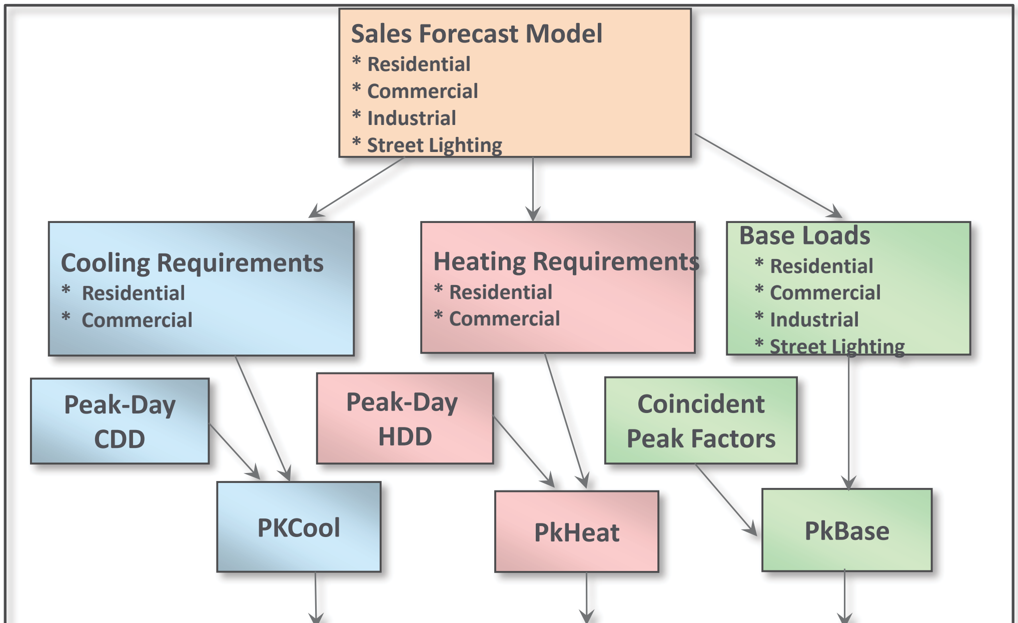
Figure 3: Residential Forecast Model Framework



Average customer use or sales is defined as a function of cooling requirements (XCool), heating requirements (XHeat), and other use (XOther). The model variables incorporate both structural factors such as the average air conditioning saturation and efficiency, and factors that impact utilization of the stock of equipment including the weather conditions, electric prices, number of people per household, and average household income. The model is estimated using linear regression that relates actual monthly sales or average use to the constructed end-use variables. The resulting model coefficients (b_c, b_h, and b_o) are used to generate average use and sales forecasts based on projected economic activity, normal weather, and end-use intensity trends. This is known as a Statistically Adjusted End-Use (SAE) model. A detail description of the model is included in Appendix B.

Energy and Peak. From a supply planning perspective, the most critical planning inputs are total system energy requirements and system peak demand. The energy forecast is derived by aggregating monthly sales forecast and adjusting the total sales forecast for line losses. The peak forecast is based on monthly peak-demand regression model that relates monthly maximum peak demand to cooling and heating requirements, peak-day CDD and HDD, and base energy requirements at time of peak. Heating, cooling, and base use requirements are derived from the rate schedule forecast models. Figure 4 shows the peak model framework.

Figure 4: Peak Model Framework



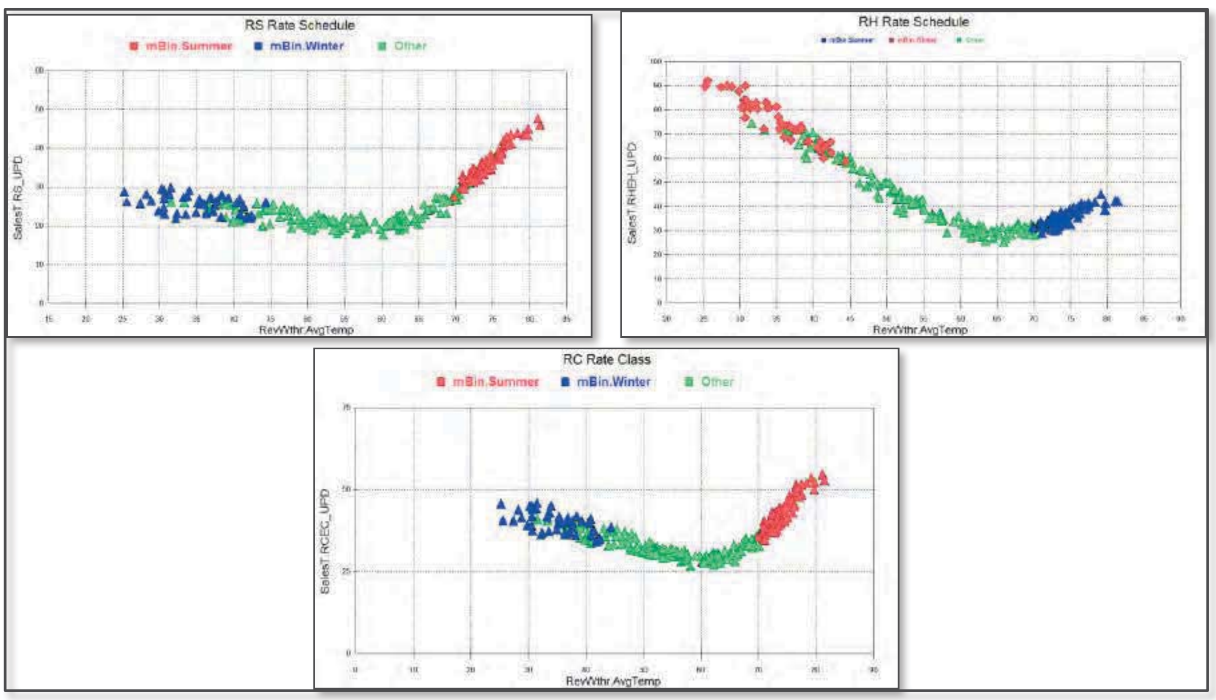
$$Peak_m = a + b_c \times PkCool_m + b_h \times PkHeat_m + b_b \times PkBase_m + e_m$$

Historical and forecasted cooling requirements are interacted with peak-day CDD (PkCool) and heating requirements are interacted with peak-day HDD (PkHDD); the underlying theory is that the impact of peak-day weather conditions will increase with increase in total cooling and heating requirements. System peak base-use (PkBase) is derived by combining base-use energy requirements with end-use coincident peak factors; end-use coincident peak factors are derived from Itron's end-use shape library. The coefficients (b_c, b_h, b_b) are estimated using a linear regression model. The advantage of this approach when compared with a more traditional load factor model is that we can capture factors that may contribute to differences between energy and demand growth. For example, cooling requirements may be increasing faster than heating requirements and as a result the summer peak could potentially increase faster than overall sales and winter peak demand. While lighting sales are declining as a result of the new lighting standards, we can capture the fact that this will impact winter peaks more than summer peaks. As shown in the model section, the model explains historical sales variation well with a high adjusted R-Squared and highly statistically significant model coefficients.

2.1 Residential Models

Average Use. Residential average use is modeled for three rate schedules. Non-electric heat customers (RS), electric heat customers (RH) and electric water heat customers (RC). Each rate schedule has a very different load curves and sensitivity to heating and cooling conditions as result of differences in end-use mix. Figure 5 shows the sales/weather relationship for these classes.

Figure 5: Residential Weather Response Curves



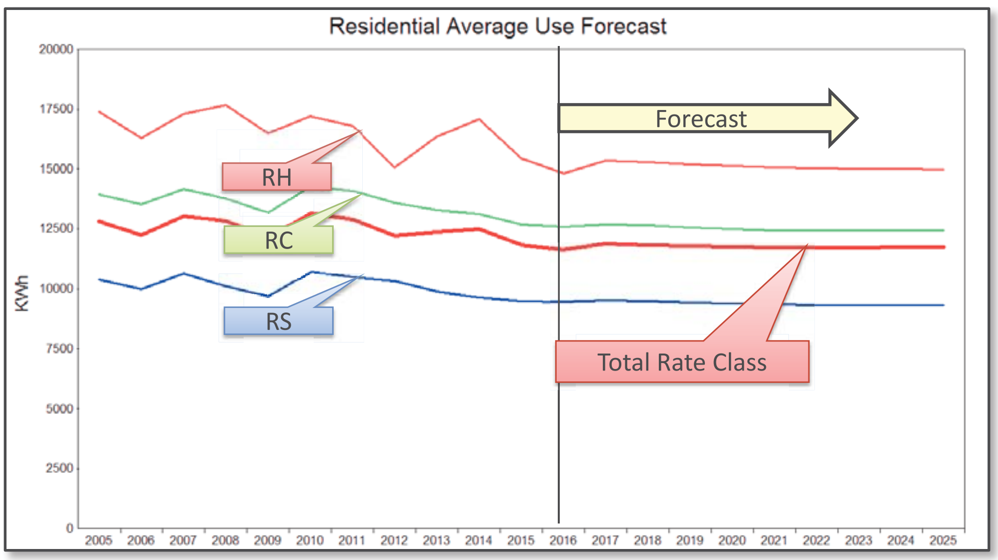
Each slide shows the relationship between average monthly temperature on the X axis and average class monthly use on a per billing-day basis. The curves are quite distinct with the RH rate schedule having a significantly steeper heating-side slope than either the RS or RC rate schedules. The RH and RC rate classes have greater cooling use for given temperature as these customers tend to be larger/single family homes. The base use for RC customers is higher reflecting the high electric water heating saturation.

As discussed earlier, the residential average use model relates customer average monthly use to a customer's heating requirements (XHeat), cooling requirements (XCool), and other use (XOther):

- $ResAvgUse_m = (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$

The model coefficients (B_1, B_2, and B_3) are estimated using a linear regression model. Monthly average use data is derived from historical monthly billed sales and customer data from January 2005 to March 2016. Model statistics are included in Appendix A. Figure 6 shows historical and forecasted average use.

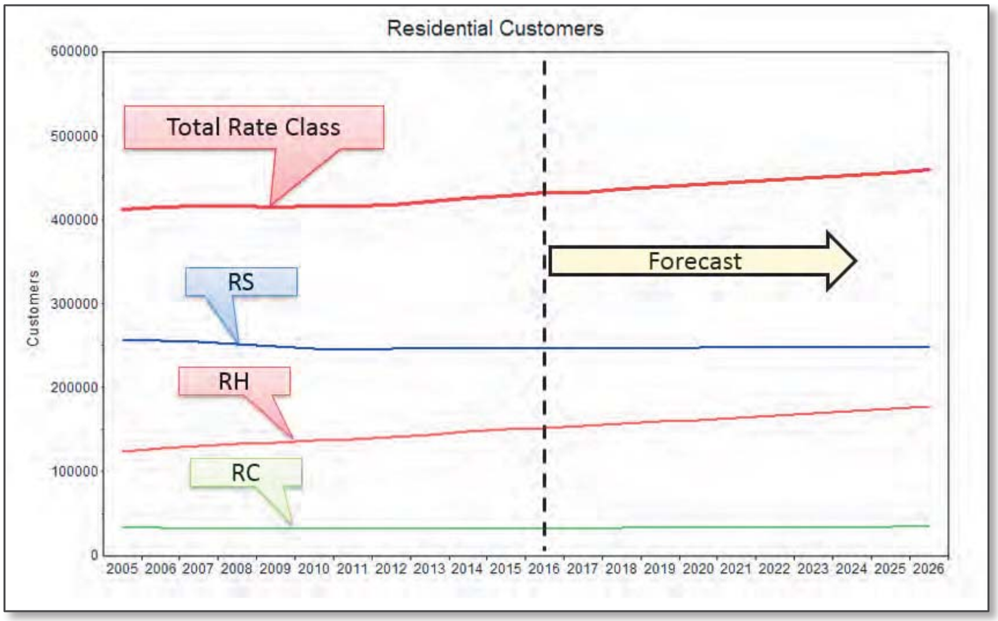
Figure 6: Residential Average Use (Excluding DSM Program Savings)



As depicted in Figure 6, average use has been declining since 2005. We expect average use to flatten out over the forecast period as increase in economic growth counters improving end-use efficiency and customer growth shifts to multifamily apartments. Total rate class average use actually increases somewhat as of increasing share of customers with electric heat.

Customer Forecast. The customer forecast is based on population forecast for Marion County. The correlation between Marion County population and number of IPL residential customers is close to ninety percent. The customer growth across rate schedules is quite different with nearly all the growth falling in RH (electric heat). Figure 7 shows the residential customer forecast.

Figure 7: Residential Customers



The residential sales forecast is generated as the product of the average use and customer forecasts. Total residential sales are calculated by adding across the rate schedule forecasts. Table shows the forecasted residential customer, sales, and average use before DSM adjustments.

Table 2-2: Residential Forecast (Excluding Future DSM Savings)

Year	Sales (MWh)		Customers		Avg. Use (kWh)	
2016	5,044,959		431,927		11,680	
2017	5,143,168	1.9%	433,312	0.3%	11,869	1.6%
2018	5,158,436	0.3%	436,053	0.6%	11,830	-0.3%
2019	5,172,841	0.3%	438,998	0.7%	11,783	-0.4%
2020	5,200,609	0.5%	441,877	0.7%	11,769	-0.1%
2021	5,210,360	0.2%	444,712	0.6%	11,716	-0.5%
2022	5,237,255	0.5%	447,074	0.5%	11,715	0.0%
2023	5,272,924	0.7%	449,772	0.6%	11,724	0.1%
2024	5,325,273	1.0%	452,719	0.7%	11,763	0.3%
2025	5,358,336	0.6%	455,803	0.7%	11,756	-0.1%
2026	5,399,202	0.8%	458,957	0.7%	11,764	0.1%
2027	5,445,053	0.8%	461,977	0.7%	11,786	0.2%
2028	5,503,149	1.1%	464,906	0.6%	11,837	0.4%
2029	5,548,440	0.8%	468,010	0.7%	11,855	0.2%
2030	5,596,246	0.9%	471,305	0.7%	11,874	0.2%
2031	5,647,282	0.9%	474,723	0.7%	11,896	0.2%
2032	5,709,122	1.1%	478,071	0.7%	11,942	0.4%
2033	5,754,021	0.8%	481,341	0.7%	11,954	0.1%
2034	5,811,200	1.0%	484,556	0.7%	11,993	0.3%
2035	5,870,805	1.0%	487,634	0.6%	12,039	0.4%
2036	5,937,316	1.1%	490,584	0.6%	12,103	0.5%
2037	5,981,896	0.8%	493,391	0.6%	12,124	0.2%
16-37		0.8%		0.6%		0.2%

2.2 Nonresidential ~~Commercial and Industrial~~ Models

Commercial ~~The commercial~~ sales aremodel is also estimated using an SAE model structure. The difference is that in the commercial sector sales forecast is based on a total sales model rather than an average use and customer model. Commercial sales are expressed as a function of heating requirements, cooling requirements, and other commercial use:

- $ComSales_m = B_0 + (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$

The constructed model variables include HDD, CDD, billing days, commercial economic activity variable, price, and end-use intensity trends (measured on a kWh per sqft basis). All but miscellaneous end-use intensities are trending down as end-use efficiency improvements

ATTACHMENT JFW-12

Data Request CAC DR 2 **-** 2

Reference Gaske Direct Testimony (Revised), p. 21, ll. 10-11.
a) Please provide in an electronic spreadsheet all data that was "provided to Concentric by IPL based on information collected and calculated as part of the Company's ongoing load research program."
b) For the residential class only, please show in an electronic spreadsheet (with all cell formulas and file linkages intact) the calculations relied on to derive the data that was "provided to Concentric by IPL".
c) For each residential customer participating in "the Company's ongoing load research program", please provide in an electronic spreadsheet the following data for the historical test year ending June 30, 2017:
i) Whether the customer heats with electricity.
ii) Annual kWh sales.
iii) Monthly kWh sales.
iv) Maximum hourly load for the test year.
v) Maximum hourly load in each month of the test year.
vi) Hourly load at the time of system coincident peak for the test year.
vii) Hourly load at the time of system coincident peak in each month of the test year.
viii) Hourly load at the time of the residential class non-coincident peak for the test year.
ix) Hourly load at the time of the residential class non-coincident peak in each month of the test year.

Objection:

Response:

a) The attached file CAC DR 2-2 Attachment 1 - Concentric Final Allocation Factor Study.xls was sent to Concentric for purposes of performing the cost of service study.

b) There are no additional linking files.

c) Requested data is included in the attached spreadsheet CAC DR 2-2 Attachment 2 - Res_SampleLoadCharacteristics.xlsx. We do not have information on individual sample point heating systems (request 2-2.c.i) other than the rate code identifier. Sample points on the RH rate have electric heat, but it is possible that some sample points on the RC and RS rates also heat with electricity.