CAC Exhibit 1

STATE OF INDIANA

BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEDULE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO TO DEFER, AS A REGULATORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	**)**	**CAUSE NO. 45159**

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA, INC.

Resource Insight, Inc.

FEBRUARY 13, 2019

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I. Introduction and Summary

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

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

Q: Please summarize your professional experience.

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

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

My resume is attached as Attachment JFW-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have sponsored expert testimony in more than 90 state, provincial, and federal proceedings in the U.S. and Canada, including before the Indiana Utility Regulatory Commission ("the Commission") in Cause Nos. 44967 and 45029. 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").

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: Industrial Subsidy from Proposed Industrial Service Restructuring
- Attachment JFW-3: Citations to Marginal-Price Elasticity Studies
- Attachment JFW-4: NIPSCO Response to CAC Data Request 5-1
- Attachment JFW-5: NIPSCO Response to CAC Data Request 2-25
- Attachment JFW-6: NIPSCO Response to CAC Data Request 2-26
- Attachment JFW-7: NIPSCO Response to CAC Data Request 3-8
- Attachment JFW-8: Summary tab of NIPSCO Response to CAC Request 5-001 Confidential Attachment A.xlsm
- Attachment JFW-9: NIPSCO Response to OUCC Data Request 5-10
- Attachment JFW-10: Summary tab of 45159_NIPSCO_170 IAC 1-5-15(e) - Confidential Revised ACOSS Model_01222019.xlsm
- Attachment JFW-11: National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016)
- Attachment JFW-12: James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 334 (1961)
- Attachment JFW-13: Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988)
- Attachment JFW-14: Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964)
- Attachment JFW-15: Summary tab of Revised NIPSCO Response to CAC Request 5-002 Confidential Attachment A.xlsm
- Attachment JFW-16: NIPSCO 2018 Integrated Resource Plan, Appendix B, Exhibit 2, Table 1-1

- Attachment JFW-17: NIPSCO Response to Sierra Club Data Request 2-7

Q: What is the purpose of your testimony?

A: On October 31, 2018, Northern Indiana Public Service Company ("NIPSCO" or "the Company") filed a petition (including supporting direct testimony) with the Commission for authority to increase electric rates. My testimony addresses the Company's proposals to:

- Restructure service for large industrial customers, as described in direct testimony by NIPSCO witnesses Paul S. Kelly and Andrew S. Campbell.
- Allocate among the various rate classes the forecasted revenue deficiency for the 2019 test year, as discussed in direct testimony by NIPSCO witness J. Stephen Gaske.
- Increase the monthly customer charge for residential customers based on the results of the Company's allocated cost of service study ("ACOSS"), as described by Mr. Gaske.

Q: Please summarize your findings and conclusions with regard to the Company's proposal for a new industrial service structure.

A: The Company's proposal would unduly subsidize large industrial customers by shifting recovery of embedded production costs to other rate classes. The new service structure proposed by NIPSCO would allow large industrial customers to take fixed rate service at contract demand levels well below total customer demand. The Company further proposes to allocate embedded production costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand not contract demand. Consequently, the proposed industrial rate restructuring would recover from large industrial customers less than their fair share of embedded production costs and instead shift recovery of such costs to other rate classes.

Q: Please summarize your findings and recommendations with regard to NIPSCO's proposal for allocating the requested revenue increase.

A: The Company requests an overall revenue increase of about $111.4 million, or 7.8%, relative to 2019 test-year revenues under current rates. The Company proposes to reduce Rate 831 revenues by 16.1% relative to test-year revenues under current rates, and to increase revenues for all other rate classes by an equal percentage to recover the remaining revenue deficiency.

The Commission should reject the Company's proposal for allocating the 2019 test-year revenue deficiency since it would lock in the subsidy to Rate 831 customers resulting from the proposed restructuring of industrial service. Instead, I recommend that Rate 831 revenues be maintained at test-year levels under current rates (i.e., no increase or decrease) and that revenues for all other classes be increased by an equal percentage to recover the requested revenue increase. My recommended revenue allocation would substantially reduce the industrial subsidy from the Company's restructuring proposal and would provide for a fair allocation of the requested revenue increase.

Q: Please summarize your findings and recommendations with regard to NIPSCO'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 $12.55 per residential customer per month. Consistent with long-standing cost-causation and rate-design principles, a monthly customer charge of $12.55 per customer would provide for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer.

Q: How is the rest of your testimony organized?

A: In Section II, I explain how the Company's proposal for restructuring industrial rates would unduly subsidize large industrial customers by shifting recovery of embedded production costs to other rate classes. In Section III, I describe an alternative to the Company's proposed approach for allocating the test-year revenue deficiency in order to mitigate the harm to other rate classes from the proposed industrial rate restructuring. In Section IV, I explain how NIPSCO's proposal to increase the residential customer charge violates long-standing principles of cost-based rate design, would give rise to unreasonable cost subsidization within the residential class, and would dampen energy price signals. Finally, I provide my conclusions and recommendations in Section V.

II. Industrial Rate Restructuring

A. NIPSCO's Proposal for a New Industrial Service Structure

Q: Please describe the Company's proposal for a new industrial service structure.

A: The Company proposes to replace the current tariffs for industrial customers – Rates 732, 733, and 734 and Rider 775 for interruptible service – with Rates 830 and 831. Rate 830 is designed to provide industrial service to the Company's smaller industrial customers in a manner comparable to that provided under the current Rate 732.[1]

In contrast, Rate 831 is based on a new service structure designed to provide the Company's largest industrial customers with exposure to market pricing for their non-firm loads. Specifically, a Rate 831 customer will enter into a five-year contract to take firm service at a specified demand level ("Tier 1 Contract Demand"). Tier 1 service will be billed at fixed demand and energy rates, with such rates designed to recover, respectively, the demand- and energy-related embedded production costs allocated to the Rate 831 class in the Company's ACOSS.[2]

A Rate 831 customer will have the option to serve its load in excess of Tier 1 Contract Demand under Tier 2 and/or Tier 3 service. All load served under either Tier 2 or 3 will be considered to be curtailable by MISO unless firmed up by purchases of capacity through MISO's annual capacity auctions

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[1] *Verified Direct Testimony of Andrew S. Campbell*, Cause No. 45159, 26-27 (October 31, 2018) [Hereinafter "Campbell Direct"].

[2] The fixed demand rate will also recover all customer-related costs allocated to Rate 831 in the ACOSS. Rate 831 customers will also be charged a fixed transmission rate designed to recover all demand-related transmission costs allocated to Rate 831 in the ACOSS.

or from a third party. Tier 2 energy will be priced at locational marginal price in MISO's day-ahead energy market. Tier 3 energy will also be priced at locational marginal price (plus any market settlement charges) unless the customer has arranged energy service from a third party.[3]

The Company expects that its five largest industrial customers will take service under Rate 831 at a combined Tier 1 Contract Demand of about 184 megawatts.[4]

Q: How does NIPSCO determine the amount of demand-related embedded production costs to be recovered through the proposed Tier 1 demand charge?

A: In the ACOSS, NIPSCO proposes to allocate test-year demand-related production costs to the Rate 831 class on the basis of the sum of Rate 831 customers' Tier 1 Contract Demands. Under this approach, the Rate 831 class would be allocated about 8.2% of test-year demand-related production costs. The Tier 1 demand charge is then set to a rate designed to recover that allocated amount.

Q: How would test-year demand-related production costs be allocated to large industrial customers if industrial service were not restructured as proposed by NIPSCO?

A: Under the current industrial service structure, demand-related production costs would be allocated to large industrial customers on the basis of the sum of their forecasted test-year demands. In this case, I estimate that the five industrial

[3] In essence, the difference between Tier 2 and Tier 3 service is that Tier 3 allows the customer to participate directly in MISO markets. *See* Campbell Direct, 16-17.

[4] *Verified Direct Testimony of Paul S. Kelly (Redacted)*, Cause No. 45159, 8 (October 31, 2018) [hereinafter "Kelly Direct (Redacted)"].

customers expected to take service under Rate 831 would have been allocated about 19.5% of test-year demand-related production costs.[5]

Consequently, the Company's proposed restructuring of industrial service will reduce the large industrial customers' share of test-year demand-related production costs from 19.5% to 8.2%, or by almost 60%. The share of test-year demand-related production costs recovered from all other rate classes would have to be increased commensurately to make up this difference.

Q: Why is NIPSCO proposing a new service structure for its largest industrial customers at this time?

A: The Company has always faced the risk of loss of industrial load – with the associated loss of contribution to NIPSCO's fixed costs – and has attempted to mitigate such risk with special contracts and interruptible rates.[6] However, NIPSCO apparently believes that there is now a heightened risk due to a "changing economic landscape" which has reduced the cost to industrial customers of alternatives to NIPSCO firm service.[7] It was this perception of heightened risk of loss of fixed-cost contribution that drove NIPSCO to consider an alternative service structure for its large industrial customers:

[5] Calculated based on data provided in Attachment B to NIPSCO Response to CAC Data Request 5-1 (Attachment JFW-4).

[6] NIPSCO Response to CAC Data Request 2-25 (Attachment JFW-5).

[7] Kelly Direct (Redacted), 2-3.

> However, in the immediate case, the economics in 2018 were considerably different…. It became clear very quickly that over the long term our largest industrial customers needed an option for more market choices and market-based prices without completely abandoning their contribution to NIPSCO's existing fixed cost to serve…. [W]ith the change in circumstances in 2018, the Rate 831 proposal was the clear path forward to find that appropriate balance among our largest customers, our other customers and stakeholders and NIPSCO.[8]

Q: How did NIPSCO determine that "the Rate 831 proposal was the clear path forward"?

A: The Company's proposal for restructuring industrial service was the product of "months of discussion" with its largest industrial customers.[9]

Q: Did NIPSCO invite any other customer groups or stakeholders to participate in these discussions about how to "find that appropriate balance among our largest customers, our other customers and stakeholders and NIPSCO"?

A: No.[10]

Q: How will other rate classes be affected by the Company's proposed industrial service structure?

A: According to Company witness Kelly, the proposed restructuring "will result in a near term shifting of some fixed costs currently being recovered from the industrial customers to other customers".[11]

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[8] NIPSCO Response to CAC Data Request 2-25 (Attachment JFW-5).

[9] Kelly Direct (Redacted), 5.

[10] NIPSCO Response to CAC Data Request 2-26 (Attachment JFW-6).

[11] Kelly Direct (Redacted), 13-14.

Q: During the "months of discussions" with its largest industrial customers, did NIPSCO consider alternatives to the proposed service structure that would mitigate or eliminate that cost-shifting?

A: I cannot determine whether or to what extent concerns about cost-shifting played a role in the development of the Company's proposal because NIPSCO has refused to provide any information regarding what it considers to be "confidential settlement discussions".[12]

B. NIPSCO's Proposal Would Unduly Subsidize Large Industrial Customers

Q: To what extent would the Company's restructuring proposal shift costs from industrial customers to other customers?

A: I estimate that the Company's proposal would shift recovery of $67-$80 million of non-fuel revenue requirements from industrial customers to other customers. In other words, industrial revenues with the proposed restructuring would be $67-$80 million less (and other rate classes' revenues more) than would be the case without rate restructuring. This cost-shift results from the Company's proposal to allocate demand-related production costs on the basis of Tier 1 Contract Demand rather than forecasted test-year demand, as discussed above.[13]

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[12] NIPSCO Response to CAC Data Request 3-8 (Attachment JFW-7).

[13] My estimate understates the magnitude of the cost-shift because it captures the change in the allocation of non-fuel revenue requirements for all industrial customers, not just for the large customers that would take service under Rate 831. The proposed restructuring would shift costs from just Rate 831 customers and would in fact shift some of those costs onto Rate 830 customers. I was not able to isolate the amount shifted onto Rate 830 customers with the data provided by NIPSCO, so my estimate is of the *net* cost shift from all industrial customers.

Q: Is this cost-shift fair and reasonable?

A: No. Allocating demand-related production costs on the basis of Tier 1 Contract Demand would be contrary to basic principles of cost-causation, since such costs were incurred to serve, and are therefore reasonably considered to be "caused" by, industrial customers' total demand.[14] Thus, the industrial service restructuring proposed by NIPSCO would provide a $67-$80 million subsidy to large industrial customers by allowing these customers to contribute less than their fair share toward recovery of demand-related production costs.

In fact, the Company's restructuring proposal would effectively shift onto other rate classes the large industrials' entire share of the incremental depreciation expense associated with accelerated depreciation of Schahfer and Michigan City plant costs. With the Company's restructuring proposal, large industrial customers would enjoy the future economic benefits from early retirement of the Schahfer and Michigan City coal units without having to pay for the near-term incremental depreciation expense associated with early retirement.

Q: Please describe how you derived your estimate of the cost-shift resulting from the Company's proposal for a new industrial service structure.

A: In response to a data request, NIPSCO prepared a version of the ACOSS that assumes a continuation of the current industrial service structure with Rates 732, 733, and 734 and Interruptible Service Rider 775.[15] I derived my estimate of the cost-shift as the difference between: (1) the amount of non-fuel revenue requirements allocated to industrial customers in this without-restructuring

[14] NIPSCO Response to Sierra Club Data Request 2-7 (Attachment JFW-17).

[15] NIPSCO Response to CAC Data Request 5-1 (Attachment JFW-4).

ACOSS; and (2) the amount allocated to industrial customers in the Company's (i.e. with-restructuring) ACOSS.[16]

As indicated in Attachment JFW-2, I estimate the amount of cost-shifting using two different methods for crediting industrial customers with the value of their interruptible load in the without-restructuring ACOSS.[17] On page 1 of Attachment JFW-2, I estimate a cost-shift of $66.8 million based on a version of the without-restructuring ACOSS that: (1) allocates demand-related production costs to industrial rate classes on the basis of *total* class load inclusive of interruptible load; and (2) credits industrial classes for their interruptible load through Rider 775 interruptible credits. In this case, industrial customers are explicitly credited for the value of their interruptible load in the form of expected revenues received for their interruptible load under Rider 775.

On page 2 of Attachment JFW-2, I estimate a cost-shift of $80.2 million based on a version of the without-restructuring ACOSS that: (1) allocates demand-related production costs to industrial rate classes on the basis of *firm* class load exclusive of interruptible load; and (2) zeroes out the Rider 775 interruptible credits. In this case, industrial customers are implicitly credited for the value of their interruptible load through a reduced allocation of

[16] As noted above, my estimate understates the magnitude of the cost-shift because it takes the difference in allocated non-fuel revenue requirements for all industrial customers, not just for the large customers that would take service under Rate 831.

[17] All data from the electronic spreadsheet 'CAC Request 5-001 Confidential Attachment A.xlsm'. The Company has agreed to make public the "Summary" tab of 'CAC Request 5-001 Confidential Attachment A.xlsm', which is included in Attachment JFW-8. The entire 'CAC Request 5-001 Confidential Attachment A.xlsm' spreadsheet is included as one of my confidential workpapers.

demand-related production costs on the basis of just firm load, but not interruptible load.

Q: Has NIPSCO estimated the cost-shift resulting from the proposed industrial service structure?

A: Yes. In response to a data request, NIPSCO estimated that its proposed industrial restructuring would shift about $40 million from industrial customers and onto all other rate classes.[18]

Q: Did NIPSCO reasonably estimate the cost-shift?

A: No. The Company has underestimated the likely cost-shift resulting from its restructuring proposal. Specifically, the Company's analysis understates the amount of non-fuel revenues that would be recovered from industrial customers in the without-restructuring scenario and thereby understates the difference in industrial non-fuel revenues between the without- and with-restructuring scenarios. The Company's analysis underestimates industrial non-fuel revenues in the without-restructuring scenario by double-counting the credit to industrial customers for the value of their interruptible load. First, NIPSCO implicitly credits industrial customers for the value of their interruptible load by allocating demand-related production costs based solely on firm load. Then, the Company explicitly credits industrial customers for their interruptible load through Rider 775 interruptible credits.

[18] Attachment A to NIPSCO Response to OUCC Data Request 5-10 (Attachment JFW-9).

III. Revenue Allocation

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

A: The Company requests a total-system revenue requirement of $1.546 billion for the 2019 test-year. This requested amount represents a $111.4 million, or 7.8%, increase over test-year revenues under current rates.

Q: Please describe NIPSCO's proposal for allocating the requested revenue increase to rate classes.

A: The Company proposes to recover from Rate 831 customers the portion of system-total test-year revenue requirements allocated to the Rate 831class in the Company's ACOSS. Specifically, NIPSCO proposes to *decrease* Rate 831 revenues by about $29.2 million, or 16.1%, relative to test-year revenues at current rates.[19] As discussed above in Section II, this proposal would lock in a $67-$80 million subsidy to the industrial class.

For all other rate classes, NIPSCO proposes to increase class revenues by an equal percentage in order to recover both the entire $111.4M requested revenue increase and the $29.2 million decrease in Rate 831 revenues. This proposal would increase revenues for all other rate classes by about $140.4 million, or 11.2%, relative to test-year revenues at current rates.[20]

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[19] Petitioner's Ex. No. 18, Attachment 18-G (Revised). *See also* NIPSCO's electronic spreadsheet 'Attachment 18-G (Revised) - Rate Mitigation_01222019.xlsx'.

[20] Calculated based on data provided in NIPSCO's electronic spreadsheet 'Attachment 18-G (Revised) - Rate Mitigation_01222019.xlsx'.

Q: Why is NIPSCO proposing to allocate test-year revenue requirements in this fashion?

A: According to Company witness Kelly, the proposed revenue allocation would better align rates with cost of service:

> Transitioning NIPSCO's industrial load to the proposed market-sensitive rate structure requires better cost recovery alignment. It will result in a near term shifting of some fixed costs currently being recovered from the industrial customers to other customers, but will establish a more sustainable rate platform going forward.[21]

Q: Do you agree that the Company's proposed revenue allocation would better align rates with cost of service?

A: No. To the contrary, the Company's proposal would unduly subsidize large industrial customers by setting Rate 831 rates at substantially less than cost of service.

Specifically, the without-restructuring ACOSS described in Section II shows an average revenue increase across Rates 732, 733, and 734 of 17.4% relative to test-year revenues at current rates.[22] In other words, rates for Rates 732, 733, and 734 would need to be increased on average by 17.4% in order to recover the embedded costs incurred to serve those industrial customers.

In contrast, with the proposed restructuring, NIPSCO would *decrease* rates for Rate 831 by 16.1%. Consequently, the Company's proposed revenue allocation would recover from Rate 831 customers substantially less revenue than the cost to serve those customers.

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[21] Kelly Direct (Redacted), 13-14.

[22] Calculated based on data provided in 'NIPSCO Response to CAC Request 5-001 Confidential Attachment A.xlsm' (Attachment JFW-8).

Q: How should the requested revenue increase be allocated to rate classes?

A: In order to mitigate the industrial subsidy from the Company's restructuring proposal and to provide for a fair allocation of the requested revenue increase, I recommend that Rate 831 revenues be maintained at test-year levels under current rates (i.e., no increase or decrease) and that revenues for all other classes be increased by an equal percentage to recover the requested revenue increase. With a 0% increase to Rate 831 revenues, I estimate that revenues for all other classes would need to be increased by 8.9% to recover the requested revenue increase.[23]

Q: To what extent would your recommended revenue allocation mitigate the industrial subsidy from the Company's proposal for a new industrial service structure?

A: By my estimate, the industrial subsidy would be reduced by about $29 million if Rate 831 revenues were maintained at test-year levels under current rates rather than decreased by 16.1% as proposed by NIPSCO. Thus, under my recommended revenue allocation, the industrial subsidy would be reduced to $38-$51 million.

[23] Calculated based on data provided in Petitioner's Ex. No. 18, Attachment 18-G (Revised).

IV. Residential Customer Charge

A. NIPSCO's Proposal to Increase the Residential Customer Charge

Q: What is a customer charge?

A: 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.

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

A: The Company proposes to increase the fixed customer charge from $14 to $17 per customer per month.[24] The proposed $3 increase represents a 21% increase over the current customer charge.

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

A: Company witness Gaske contends that the Company's proposal would yield a residential customer charge that:

> … more closely reflect the costs of serving each customer, as indicated by the ACOSS…. For the Residential classes the customer charge required to recover all fixed costs in a straight-fixed variable rate design would be approximately $106 per month….[25]

Q: To which costs is Mr. Gaske referring when he discusses the "fixed costs in a straight-fixed variable rate design"?

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

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[24] *Verified Direct Testimony of J. Stephen Gaske*, Cause No. 45159, 51 (October 31, 2018) [hereinafter "Gaske Direct"].

[25] *Id*.

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

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 usage. As discussed below, the Company's proposal to shift recovery of load-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.

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

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

Q: What is the Company's rationale for classifying 100% of secondary line transformer costs as customer-related?

A: Mr. Gaske does not explain why NIPSCO classifies all line transformer costs as customer-related.

Q: Prior to this case, have you ever encountered a cost of service study that classified 100% of line transformer costs as customer-related?

A: No. To the contrary, every cost of service study that I can recall reviewing during my career has classified some portion of line transformer costs as demand-related.[26]

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

A: The Company's minimum-system analysis attempts to estimate the cost to install the same amount of secondary poles and wires as are currently on the distribution system, assuming that each piece of distribution equipment is sized to meet minimal load.[27] In other words, the Company's minimum-system analysis attempts to estimate the cost to replicate the configuration of the existing secondary distribution system using "minimum-size" equipment.

[26] This includes the cost of service studies for Indiana Michigan Power Company in Cause No. 44967 and Indianapolis Power and Light Company in Cause No. 45029, both of which classify all line transformer costs as demand-related.

[27] *Verified Direct Testimony of Bickey Rimal*, Cause No. 45159, 10-11 (October 31, 2018).

As discussed above, the "minimum" portion of secondary 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 NIPSCO propose to recover all costs classified as customer-related in the ACOSS through the residential customer charge?

A: No. However, as indicated in Table 1 below, the $17 fixed customer charge proposed by NIPSCO would effectively recover 100% of the costs deemed to be customer-related in the ACOSS (i.e., the cost for customer services, meters, service drops, and line transformers) and 27% of the secondary pole and conductor costs classified as customer-related under the Company's minimum-system analysis.[28]

[28] Calculated based on data provided in Petitioner's confidential workpaper labeled as '45159_NIPSCO_170 IAC 1-5-15(e) - Confidential Revised ACOSS Model_01222019.xlsm'. The Company has agreed to make public the "Summary" tab of '45159_NIPSCO_170 IAC 1-5-15(e) - Confidential Revised ACOSS Model_01222019.xlsm', which is included in Attachment JFW-10.

Table 1: Costs Recovered through NIPSCO Proposed Residential Customer Charge

	Residential Revenue Requirements	Residential Bills	Cost per Bill	% Recovered through Customer Charge	Cost per Bill Recovered through Customer Charge
Customer Service	$34,464,492	4,946,379	6.97	100%	6.97
Meter, Services, Transformer	$42,028,350	4,946,379	8.50	100%	8.50
Min. System Secondary	$27,870,587	4,946,379	5.63	27%	1.54
Total	$104,363,429		21.10		17.00

B. NIPSCO's Proposal for the Residential 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.[29]

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

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

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.[30]

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.[31]

[30] 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-11).

[31] 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-12).

> 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.[32]

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

> … 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] ….[33]

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 a customer who uses very little or zero energy to the distribution system. Such "minimum connection costs" are generally limited to plant and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer-service expenses. As Bonbright explains:

> But this twofold distinction [between demand and energy in rate design] overlooks the fact that a material part of the operating and capital costs of utility business is more directly and more closely related to the number of customers than to energy consumption on the one hand or maximum kilowatt demand on the other hand. The most obvious examples of these so-called customer costs are the expenses associated with metering and billing.[34]

[32] *Id.*, 336.

[33] Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988) (excerpt included as Attachment JFW-13).

[34] Bonbright, *op. cit.*, 311 (excerpt included as Attachment JFW-12).

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:

> 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.[35]

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.[36]

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

A: No. Contrary to these principles, NIPSCO 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 costs allocated to the residential class under the ACOSS for: (1) secondary

[35] Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964) (excerpt included as Attachment JFW-14).

[36] 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/.

transformers; and (2) customer-related secondary poles and wires. As discussed above in Section II, the $17 residential customer charge proposed by NIPSCO would effectively recover 100% of the minimum connection and line transformer cost per residential customer and 27% of the customer-related secondary distribution cost per residential customer.

Q: Is it reasonable to recover line transformer costs through the fixed customer charge, as the Company proposes?

A: No. The sizing and therefore the cost of a line transformer is driven not by the number of customers served by the transformer but by the load and the diversity of load of those customers taking service from that transformer. In other words, it is unlikely that the Company's line transformer costs would increase when connecting a customer who uses very little or zero energy. Consequently, it would be contrary to long-standing economic principles to recover line transformer costs through the fixed customer charge.

Q: How does NIPSCO estimate the customer-related secondary distribution cost per residential customer proposed for recovery through the residential customer charge?

A: The Company relies on the results of its minimum-system analysis to estimate the customer-related secondary distribution cost per residential customer. Specifically, as shown above in Table 1, the Company's ACOSS allocates to the residential class about $27.9 million of secondary pole and conductor costs that were classified as customer-related using a minimum-system analysis. Dividing by the number of residential bills in the test year, this yields a customer-related secondary distribution cost of $5.63 per residential customer.[37] As shown in Table 1, the $17 residential customer charge proposed by NIPSCO would effectively recover $1.54 of the Company's $5.63 estimate of customer-related secondary distribution cost per residential customer.

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

A: No. Minimum-system analyses overstate the minimum 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 secondary

[37] Calculated based on data provided in Petitioner's confidential workpaper labeled as '45159_NIPSCO_170 IAC 1-5-15(e) - Confidential Revised ACOSS Model_01222019.xlsm'. The public Summary Tab is included as Attachment JFW-10.

distribution cost per customer is zero since distribution equipment that carries zero load can serve an infinite number of customers with zero load.

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

A: As shown in Table 2 below, I derive a cost-based fixed customer charge for NIPSCO residential customers of $12.55 per customer per month. Consistent with long-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, NIPSCO modified its ACOSS by removing the minimum-system classification of pole and conductor costs and instead classifying all such costs as demand-related.[38] I then revised this modified ACOSS in order to classify all secondary line transformer costs as demand-related.[39] My revised ACOSS

[38] Confidential Attachment A to NIPSCO response to CAC Data Request 5-2 (Attachment JFW-15 for the public Summary Tab). The entire 'Revised NIPSCO Response to CAC Request 5-002 Confidential Attachment A.xlsm' spreadsheet is included as one of my confidential workpapers.

[39] CAC Data Request 5-2 requested a spreadsheet version of the ACOSS which classified all secondary pole, conductor, and line transformer costs as demand-related. However, the confidential ACOSS provided in response to CAC Data Request 5-2 continued to classify line transformer costs as customer-related. I therefore revised this version of the ACOSS to also classify line transformer costs as demand-related. In a February 1, 2019 e-mail from NIPSCO to CAC, the Company confirmed that my revisions to the ACOSS provided in response to CAC Data Request 5-2 correctly modeled the classification of all line transformer costs as demand-related.

therefore includes only the cost of meters, service drops, and customer services in the calculation of customer-related costs. As shown in Table 2, the revised ACOSS estimates a customer-related cost of about $62.1 million for the residential class.[40] Based on this estimate of customer-related cost, I derive a total customer-related cost per residential customer of $12.55 per month.

Table 2: Derivation of Cost-Based Residential Fixed Customer Charge[41]

	Residential Revenue Requirements	Residential Bills	Cost per Bill
Meters and Service Drops	$27,614,088	4,946,379	$5.58
Customer Service	$34,451,280	4,946,379	$6.96
Total	$62,065,368		$12.55

Q: What accounts for the $4.45 difference between your recommended $12.55 fixed customer charge and the $17 fixed customer charge proposed by NIPSCO?

A: The $4.45 difference between my recommended $12.55 residential customer charge and the $17 customer charge proposed by NIPSCO represents demand-related secondary pole, conductor, and line transformer costs that would be inappropriately recovered through the fixed customer charge under the

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

[41] All data from the electronic spreadsheet ‘Revised NIPSCO Response to CAC Request 5-002 Confidential Attachment A.xlsm’. The Company has agreed to make public the “Summary” tab of ‘Revised NIPSCO Response to CAC Request 5-002 Confidential Attachment A.xlsm’, which is included in Attachment JFW-15. The entire ‘Revised NIPSCO Response to CAC Request 5-002 Confidential Attachment A.xlsm’ spreadsheet is included as one of my confidential workpapers.

Company's proposal. As discussed 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: NIPSCO's proposal to increase the residential customer charge would shift recovery of demand-related costs from the volumetric energy rate to the fixed customer charge. Although not proposed by NIPSCO 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.”[42]

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[42] 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.

C. NIPSCO's Proposal Would Lead to Intra-Class Cost Subsidization

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

A: As discussed above, NIPSCO's proposal to increase the residential 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 above, the $4.45 difference between the minimum connection cost of $12.55 and the $17 residential customer charge proposed by NIPSCO represents demand-related secondary distribution costs that would be inappropriately recovered from each residential customer every month through a fixed charge on the customer's bill. The Company estimates about 4.9 million residential bills in the test year.[43] This means that $22.0 million of demand-

[43] The number of residential bills in the test year is provided in Petitioner's Ex. No. 18, Attachment 18-H (Revised). *See also* NIPSCO's electronic spreadsheet 'Petitioner's Exhibit 18, Public Workpaper 18-H.1 (Revised) - Rate Design Calculations (Excel File)_01222019.xlsm'.

related costs would be recovered annually through the residential fixed customer charge under the Company's proposal.[44]

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 3.5 million megawatt-hours.[45] Therefore, if the $22.0 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 0.64 cents per kilowatt-hour ("¢/kWh").[46] In this case, a residential customer with below-average monthly usage of 400 kWh would contribute about $31 per year toward recovery of the $22.0 million of demand-related costs while a customer with above-average monthly usage of 1,000 kWh would contribute about $76 per year.[47] Thus, under my proposal, the 1,000 kWh customer would contribute

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[44] The $22.0 million result is derived by taking the product of the annual number of residential bills (4.9 million) and the amount of the proposed residential customer charge in excess of minimum connection cost ($4.45 per bill).

[45] Residential sales for the test year are provided in Petitioner's Ex. No. 18, Attachment 18-H (Revised). *See also* NIPSCO's electronic spreadsheet 'Workpaper 18-H.1 (Revised) - Rate Design Calculations (Excel File)_01222019.xlsm'.

[46] The 0.64¢/kWh result is derived by dividing $22.0 million by residential sales of 3.5 million megawatt-hours.

[47] Based on data provided in Petitioner's Ex. No. 18, Attachment 18-H (Revised), I estimate monthly usage of about 700 kWh for an average residential customer. *See also* NIPSCO's electronic spreadsheet 'Workpaper 18-H.1 (Revised) - Rate Design Calculations (Excel File)_01222019.xlsm'.

2.5 times more than the 400 kWh customer, in direct proportion to their usage and consistent with accepted principles of cost-causation.

In contrast, under the Company's proposal to recover $22.0 million of demand-related costs through the fixed customer charge, each residential customer would contribute about $53 per year toward recovery of such costs regardless of that customer's usage. A below-average 400 kWh customer would therefore pay 1.75 times their fair share of these demand-related costs under the Company's proposal while an above-average 1,000 kWh customer would pay only 70% of their fair share.

D. NIPSCO's Proposal Would Dampen Energy Price Signals

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

A: No. As discussed above, NIPSCO proposes to set the residential customer charge at a rate that greatly exceeds the minimum cost to connect a residential customer. The amount in excess of minimum connection costs represents usage-related costs that are more appropriately recovered in the volumetric energy rate. However, under the Company's proposal, this excess over the 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. With the residential fixed customer charge set at $17, NIPSCO proposes a volumetric energy rate of 12.63¢/kWh in order to recover the proposed allocation of test year revenue requirements to residential customers.[48] If, instead, the fixed customer charge were set at the cost-based rate of $12.55, I estimate that the volumetric energy rate would have to be increased to 13.27¢/kWh to recover the same allocated revenue requirement.

In other words, NIPSCO is proposing a residential energy rate that is 0.64¢/kWh, or about 5%, less than what the volumetric rate would be if the residential fixed customer charge were set at the cost-based rate of $12.55. Thus, the Company's proposal for the residential customer charge would dampen the price signal provided by the volumetric energy rate by about 5%.

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

A: Since the volumetric energy rate under the Company's proposal for the residential customer charge would be lower than the volumetric energy rate with a cost-based fixed customer charge of $12.55, we would expect

[48] Petitioner's Ex. No. 18, Attachment 18-H (Revised). *See also* NIPSCO's electronic spreadsheet Workpaper 18-H.1 (Revised) - Rate Design Calculations (Excel File)_01222019.xlsm.

residential customers to consume more energy with the Company's proposed customer charge than they would with a cost-based 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 customer charge is lower than the volumetric energy rate with a cost-based 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.[49] 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.[50] Table 3 below lists the results of seven studies of marginal-price elasticity over the last forty years.[51]

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

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

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

Table 3: Summary of Marginal-Price Elasticities

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

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

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

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 customer charge were increased as proposed by NIPSCO, the volumetric energy rate would be about 5% less than what the volumetric rate would be if the residential customer charge were set at the cost-based rate of $12.55. Assuming an elasticity of –0.3, this 5% reduction in the volumetric energy rate would result in an increase in energy consumption of about 1.5% for the average residential customer. This means that all else equal, residential load after a few years with a residential customer charge as proposed by NIPSCO would be expected to be about 1.5% higher than it would have been if the residential customer charge had been set at the cost-based rate of $12.55.

For comparison, the Company's residential energy efficiency programs are expected to deliver in each year from 2019 to 2021 an amount of energy savings equivalent to 1.5% of forecasted annual residential sales.[52] Thus, the additional consumption induced by the Company's proposal for the residential fixed customer charge would negate one year's worth of the energy savings achieved by the Company's residential energy efficiency programs between 2019 and 2021.

[52] Table 1-1 of Appendix B, Exhibit 2 of the Company's 2018 Integrated Resource Plan ("IRP"). *See* Attachment JFW-16. NIPSCO has also asked for administrative notice of its 2018 IRP.

V. Conclusions and Recommendations

Q: What do you conclude with regard to the Company's proposal for a new industrial service structure?

A: The Company's proposal would unduly subsidize large industrial customers by shifting recovery of $67-$80 million of embedded production costs to other rate classes. The new service structure proposed by NIPSCO would allow large industrial customers to take fixed rate service at contract demand levels well below total customer demand. The Company further proposes to allocate embedded production costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand not contract demand. Consequently, the proposed industrial rate restructuring would recover from large industrial customers less than their fair share of embedded production costs and instead shift recovery of such costs to other rate classes.

Q: What do you conclude with regard to NIPSCO's proposal for allocating the 2019 test-year revenue deficiency?

A: The Company's proposed allocation of the requested revenue increase would lock in the subsidy to Rate 831 customers resulting from the proposed restructuring of industrial service and consequently recover substantially less revenue from Rate 831 customers than the cost to serve those customers. The Commission should therefore reject the Company's proposal for allocating the 2019 test-year revenue deficiency. Instead, I recommend that Rate 831 revenues be maintained at test-year levels under current rates (i.e., no increase or decrease) and that revenues for all other classes be increased by an equal percentage to recover the requested revenue increase. My recommended revenue allocation would substantially reduce the industrial subsidy from the

Company's restructuring proposal and would provide for a fair allocation of the requested revenue increase.

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 $12.55 per residential customer per month.

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.

____________________	February 13, 2019
Jonathan Wallach	Date

Attachment JFW-1

Qualifications of

JONATHAN F. WALLACH

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

SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

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

EDUCATION

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

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

PUBLICATIONS

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

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

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

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

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

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

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

REPORTS

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

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

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

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"First Year of SOS Procurement." 2004. Prepared for the Maryland Office of People's Counsel.

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

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

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

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

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Reasonableness of proposed fees for electricity-supplier services.

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

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

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

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

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Reasonableness and risks of resource-procurement plan.

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

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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.

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Assessment of effects and risks of proposed merger on ratepayers.

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

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

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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.

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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.

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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.

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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.

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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.

Indiana Utility Regulatory Commission Cause No. 45029, Indianapolis Power and Light Company electric rates; Citizens Action Coalition of Indiana, Indiana Coalition for Human Services, Indiana Community Action Association, and Sierra Club. Direct, May 2018.

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

PUC of Texas Docket No. 48401, Texas-New Mexico Power Company electric rates; Office of Public Utility Counsel. Direct, Cross-Rebuttal, August 2018.

Cost of service study. Allocation of requested revenue increase.

West Virginia PSC Case No. 18-0646, Appalachian Power Company and Wheeling Power Company electric rates; Consumer Advocate Division. Direct, Rebuttal, October 2018.

Cost allocation and rate design.

Attachment JFW-2

Industrial Subsidy from Proposed Service Restructuring

Based on Total Demand Production Allocator

Current Industrial Rate Structure

	Rate 732	Rate 733	Rate 734	Total
Proposed Revenue Requirement	$ 153,828,623	$ 98,584,739	$ 148,257,273	$ 400,670,635
Fuel Expense	$ 50,260,459	$ 39,734,624	$ 57,508,240	$ 147,503,322
Non-Fuel Revenue Requirement	$ 103,568,165	$ 58,850,115	$ 90,749,033	$ 253,167,313
Interruptible Credit	$ (20,353,990)	$ (4,312,396)	$ (17,892,385)	$ (42,558,771)
Net Margin	$ 83,214,175	$ 54,537,719	$ 72,856,648	$ 210,608,542

Proposed Indusrial Rate Restructuring

	Rate 831	Rate 830	Total
Proposed Revenue Requirement	$ 151,823,073	$ 52,665,407	$ 204,488,480
Fuel Expense	$ 42,204,769	$ 18,513,530	$ 60,718,299
Non-Fuel Revenue Requirement	$ 109,618,303	$ 34,151,877	$ 143,770,180
Interruptible Credit	$ -	$ -	$ -
Net Margin	$ 109,618,303	$ 34,151,877	$ 143,770,180

Industrial Subsidy	$ 66,838,361

Industrial Subsidy from Proposed Service Restructuring

Based on Firm Demand Production Allocator

Current Industrial Rate Structure

	Rate 732	Rate 733	Rate 734	Total
Proposed Revenue Requirement	$ 149,514,482	$ 94,791,775	$ 127,139,890	$ 371,446,146
Fuel Expense	$ 50,260,459	$ 39,734,624	$ 57,508,240	$ 147,503,322
Non-Fuel Revenue Requirement	$ 99,254,023	$ 55,057,151	$ 69,631,650	$ 223,942,824
Interruptible Credit	$ -	$ -	$ -	$ -
Net Margin	$ 99,254,023	$ 55,057,151	$ 69,631,650	$ 223,942,824

Proposed Indusrial Rate Restructuring

	Rate 831	Rate 830	Total
Proposed Revenue Requirement	$ 151,823,073	$ 52,665,407	$ 204,488,480
Fuel Expense	$ 42,204,769	$ 18,513,530	$ 60,718,299
Non-Fuel Revenue Requirement	$ 109,618,303	$ 34,151,877	$ 143,770,180
Interruptible Credit	$ -	$ -	$ -
Net Margin	$ 109,618,303	$ 34,151,877	$ 143,770,180

Industrial Subsidy $ 80,172,644

Attachment JFW-3

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Attachment JFW-4

Cause No. 45159
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition's Data Request Set No. 5

CAC Request 5-001:

Reference Gaske Direct, p. 18, ll. 11-15.

a) Please provide an electronic spreadsheet version of the ACOSS, with all cell formulas and file linkages intact, based on the cost of service (as summarized in Petitioner's Exhibit No. 4, Attachment 4-A-S2-A1) and allocators for the scenario where the Commission does not approve the Company's proposed charge in service structure for large industrial customers. For the purposes of responding to this request, the Company may assume that the Commission approves the combination of Rates 731, 732, and 733 into Rates 830 and 831.

b) Please provide copies of all workpapers, including electronic spreadsheets with cell formulas and file linkages intact, relied on to derive the generation energy, generation 4CP demand, and transmission 12 CP demand allocators for each rate class.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

a) An electronic spreadsheet version of the ACOSS, based on the cost of service as summarized in Petitioner's Exhibit No. 4, Attachment 4-A-S2-A1 and allocators assuming the Commission does not approve the company's proposed change in service structure for large industrial customers is provided as CAC Request 5-001 Confidential Attachment A. This assumes that BP will reduce its demand by serving with WCE and that the industrial rate structure will remain as current 732, 733 and 734 rate classes.

b) External allocators and loss adjustment calculations to generation source used for this scenario are provided as CAC Request 5-001 Attachment B. Monthly CP and NCP demands and balancing for load research sampling error are provided

Cause No. 45159
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition's Data Request Set No. 5

as CAC Request 5-001 Attachment C. Industrial net CP and NCP demands are provided as CAC Request 5-001 Attachment D.

Attachment JFW-5

Cause No. 45159
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition's Data Request Set No. 2

CAC Request 2-025:
Please refer to Witness Kelly's direct testimony at page 5, wherein Mr. Kelly testifies that "[i]n the long run, such load loss would subject remaining customers and customer classes to increased costs." Did NIPSCO consider alternatives other than the rate structure proposed in this case, particularly new Rate 831, to mitigate these risks? a. If so, please describe each such alternative in detail. Please provide a detailed explanation of why each alternative was deemed less preferable than the rate changes proposed in this proceeding. b. If not, please explain why not.
Objections:
Response:
NIPSCO has a long history of exploring alternative structures with these customers. As discussed in Mr. Kelly's testimony, NIPSCO has offered interruptible services for years with various configurations that attempted to strike a workable balance for these sophisticated energy-intensive customers and our other customers and stakeholders. Also, NIPSCO has offered special contracts at various times that were custom built for the customer industrial processes as well as their cogeneration activity. In a lot of ways, NIPSCO has "seen it all" when it comes to trying to solve for the multiplicity of changes that these customers experience from market forces within their own industries as well as the progression of energy markets generally and technology and policy changes within the electric industry. So in one sense, NIPSCO feels like we've run the gamut on options to mitigate the risk of customers using their own internal generation to bypass NIPSCO's fixed costs to serve. That said, it is not a new risk, and it is one NIPSCO has had to continue to work with our customers to solve for the last three decades. However, in the immediate case, the economics in 2018 were considerably different. Upon receiving BP's request to join the refinery load with Whiting Clean Energy, NIPSCO assessed the likely customer behavior of maintaining the existing service structure (more industrial customers constructing cogeneration or otherwise reducing firm load). We were also seeing within our IRP analyses that prices for other generating technologies were continuing to decline even from 2016, and that our other customers were taking proactive steps to bring new generation online or otherwise reduce their

Cause No. 45159
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition's Data Request Set No. 2

firm requirements. It became clear very quickly that over the long term our largest industrial customers needed an option for more market choices and market-based prices without completely abandoning their contribution to NIPSCO's existing fixed cost to serve. So in one sense, it has taken NIPSCO years to get to the Rate 831 proposal after trying these other alternatives, but in another sense, with the change in circumstances in 2018, the Rate 831 proposal was the clear path forward to find that appropriate balance among our largest customers, our other customers and stakeholders and NIPSCO.

Attachment JFW-6

Cause No. 45159
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition's Data Request Set No. 2

CAC Request 2-026:
Please refer to Witness Kelly's direct testimony at page 5, wherein Mr. Kelly testifies that the proposed Rate 831 is the result of "months of discussion with our largest industrial customers." a. Please identify the industrial customers that participated in those discussions. b. Please state the date when these discussions commenced. If the specific date is not known, please state the month and year when discussion commenced. c. Where any other stakeholder groups represented in these discussions? If so, please identify these other stakeholders. If not, why not?
Objections:
Response:
a. ArcelorMittal, BP, NLMK, Praxair, US Steel, Pratt Paper, LCR Communications, and Cargill b. Discussions began in May, 2018. c. No. Given the complexity and the time pressure, NIPSCO needed to work with these specific customers initially to design a novel but viable solution before engaging other stakeholder groups.

Attachment JFW-7

Cause No. 45159
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition's Data Request Set No. 3

CAC Request 3-008:
Reference Kelly Direct (Redacted), p. 5, ll. 11-13. a) Please provide copies of all e-mail communications, meeting presentations or notes, memoranda, reports, or other documentation in the Company's possession of the "months of discussion with our largest industrial customers." b) Please provide copies of all e-mail communications, meeting presentations or notes, memoranda, reports, or other documentation of the Company's consideration of alternatives to the current rate structure for large industrial customers and of the Company's decision to adopt the proposed rate structure. c) Please provide copies of all presentations to the NIPSCO Board of Directors or Board committees regarding the proposed rate structure and of any meeting minutes concerning the Board's consideration of the proposed rate structure.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information relating to confidential settlement discussions. NIPSCO further objects to this Request on the grounds and to the extent that this Request seeks information protected from disclosure by the attorney/client privilege and the work product privilege.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: a) Please see objections. b) Please see objections. c) Please see Petitioner's Submission of Minimum Standard Filing Requirements– Parts 10.1 and 10.2 of the working papers required by the Minimum Standard Filing Requirements filed October 31, 2018 (MSFR

Cause No. 45159
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition's Data Request Set No. 3

	1923 through MSFR 1960 and MSFR 1961 through 1971). There are no additional documents responsive to this request.

Attachment JFW-8

NIPSCO Class Cost of Service Study
Summary of Results
800 Series

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Rate Base				
1	Plant in Service	$ 8,111,276,450	$ 3,307,946,191	$ 4,526,894	$ 1,144,232,951
2	Accumulated Reserve	(4,210,571,859)	(1,722,734,463)	(1,992,476)	(580,124,268)
3	Other Rate Base Items	214,675,780	83,229,000	230,644	31,547,074
4	Total Rate Base	$ 4,115,380,372	$ 1,668,440,728	$ 2,765,062	$ 595,655,757
	Revenues at Current Rates				
5	Retail Sales - Non Fuel	$ 1,092,552,179	$ 359,475,597	$ 521,131	$ 179,227,157
6	Retail Sales - Fuel	406,567,423	90,791,267	273,768	40,938,915
7	Total Retail Sales Revenue	$ 1,499,119,602	$ 450,266,864	$ 794,899	$ 220,166,072
8	Other Revenue	25,324,174	10,051,645	14,039	4,218,008
9	Total Other Revenue (To be Credited)	$ 25,324,174	$ 10,051,645	$ 14,039	$ 4,218,008
10	Interruptible Power Credit	$ -	$ 17,368,912	$ 49,131	$ 6,577,958
11	Total Revenues	$ 1,524,443,776	$ 477,687,421	$ 858,069	$ 230,962,037
	Expenses at Current Rates				
12	Operations & Maintenance Expenses	$ 497,797,095	$ 205,365,124	$ 288,858	$ 66,294,509
13	Depreciation Expense	297,033,774	115,783,589	126,575	40,135,034
14	Amortization Expense	50,657,236	25,801,833	28,199	6,793,954
15	Taxes Other Than Income Taxes	39,269,851	16,291,052	22,512	5,486,439
16	Fuel Expenses	406,567,423	91,863,453	277,723	41,558,348
17	Income Taxes	27,477,427	(31,939,931)	(6,825)	26,099,068
18	Total Expenses - Current	$ 1,318,802,805	$ 423,165,119	$ 737,043	$ 186,367,351
19	Current Operating Income	$ 205,640,971	$ 54,522,302	$ 121,027	$ 44,594,686
20	Return at Current Rates	5.00%	3.27%	4.38%	7.49%
21	Index Rate of Return	1.00	0.65	0.88	1.50

NIPSCO Class Cost of Service Study
Summary of Results
800 Series

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Rate Base				
1	Plant in Service	$ 8,111,276,450	$ 4,818,080	$ 732,019,629	$ 805,837,105
2	Accumulated Reserve	(4,210,571,859)	(2,157,626)	(370,612,016)	(410,945,273)
3	Other Rate Base Items	214,675,780	248,548	18,307,240	22,142,661
4	Total Rate Base	$ 4,115,380,372	$ 2,909,002	$ 379,714,853	$ 417,034,494
	Revenues at Current Rates				
5	Retail Sales - Non Fuel	$ 1,092,552,179	$ 749,188	$ 124,685,757	$ 143,496,780
6	Retail Sales - Fuel	406,567,423	308,000	36,753,329	52,714,526
7	Total Retail Sales Revenue	$ 1,499,119,602	$ 1,057,188	$ 161,439,086	$ 196,211,306
8	Other Revenue	25,324,174	18,590	2,521,285	2,996,916
9	Total Other Revenue (To be Credited)	$ 25,324,174	$ 18,590	$ 2,521,285	$ 2,996,916
10	Interruptible Power Credit	$ -	$ 61,911	$ 6,951,810	$ 7,188,947
11	Total Revenues	$ 1,524,443,776	$ 1,137,690	$ 170,912,181	$ 206,397,169
	Expenses at Current Rates				
12	Operations & Maintenance Expenses	$ 497,797,095	$ 287,594	$ 43,777,585	$ 49,385,699
13	Depreciation Expense	297,033,774	132,729	27,521,399	30,928,719
14	Amortization Expense	50,657,236	32,104	3,574,032	3,913,242
15	Taxes Other Than Income Taxes	39,269,851	23,204	3,493,298	3,838,352
16	Fuel Expenses	406,567,423	312,513	37,362,433	53,666,929
17	Income Taxes	27,477,427	130,068	22,693,359	27,343,532
18	Total Expenses - Current	$ 1,318,802,805	$ 918,212	$ 138,422,106	$ 169,076,473
19	Current Operating Income	$ 205,640,971	$ 219,477	$ 32,490,076	$ 37,320,695
20	Return at Current Rates	5.00%	7.54%	8.56%	8.95%
21	Index Rate of Return	1.00	1.51	1.71	1.79

NIPSCO Class Cost of Service Study
Summary of Results
800 Series

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. Rate 732	HLF Ind Pwr Serv. Rate 733
	(A)	(B)	(I)	(J)	(K)	(L)
	Rate Base					
1	Plant in Service	$ 8,111,276,450	$ 24,574,852	$ 500,503,033	$ 649,521,449	$ 352,340,861
2	Accumulated Reserve	(4,210,571,859)	(11,974,257)	(255,219,384)	(347,397,201)	(188,634,693)
3	Other Rate Base Items	214,675,780	950,353	12,293,772	15,183,232	10,357,471
4	Total Rate Base	$ 4,115,380,372	$ 13,550,948	$ 257,577,421	$ 317,307,480	$ 174,063,639
	Revenues at Current Rates					
5	Retail Sales - Non Fuel	$ 1,092,552,179	$ 3,820,267	$ 60,129,428	$ 83,644,534	$ 53,345,235
6	Retail Sales - Fuel	406,567,423	2,501,305	27,239,411	51,194,818	41,674,562
7	Total Retail Sales Revenue	$ 1,499,119,602	$ 6,321,572	$ 87,368,839	$ 134,839,352	$ 95,019,797
8	Other Revenue	25,324,174	75,035	1,240,648	1,567,491	992,861
9	Total Other Revenue (To be Credited)	$ 25,324,174	$ 75,035	$ 1,240,648	$ 1,567,491	$ 992,861
10	Interruptible Power Credit	$ -	$ 433,234	$ 3,462,534	$ (20,353,990)	$ (4,312,396)
11	Total Revenues	$ 1,524,443,776	$ 6,829,841	$ 92,072,021	$ 116,052,854	$ 91,700,262
	Expenses at Current Rates					
12	Operations & Maintenance Expenses	$ 497,797,095	$ 1,606,610	$ 30,453,812	$ 40,439,705	$ 22,948,874
13	Depreciation Expense	297,033,774	876,115	19,092,363	26,043,514	14,093,883
14	Amortization Expense	50,657,236	128,919	2,379,004	3,061,577	1,736,748
15	Taxes Other Than Income Taxes	39,269,851	117,617	2,385,451	3,114,099	1,688,568
16	Fuel Expenses	406,567,423	2,522,836	27,492,212	50,260,459	39,734,624
17	Income Taxes	27,477,427	575,645	(873,198)	(12,733,801)	2,147,461
18	Total Expenses - Current	$ 1,318,802,805	$ 5,827,742	$ 80,929,644	$ 110,185,553	$ 82,350,157
19	Current Operating Income	$ 205,640,971	$ 1,002,099	$ 11,142,377	$ 5,867,301	$ 9,350,105
20	Return at Current Rates	5.00%	7.40%	4.33%	1.85%	5.37%
21	Index Rate of Return	1.00	1.48	0.87	0.37	1.08

NIPSCO Class Cost of Service Study
Summary of Results
800 Series

Line No.	Description	System Total	Air Separation Rate 734	Muni. Power Rate 841	Int WW Pumping Rate 842
	(A)	(B)	(M)	(N)	(O)
	Rate Base				
1	Plant in Service	$ 8,111,276,450	$ 445,396,600	$ 17,301,593	$ 121,044
2	Accumulated Reserve	(4,210,571,859)	(234,600,748)	(8,599,372)	(61,939)
3	Other Rate Base Items	214,675,780	14,858,007	551,477	3,531
4	Total Rate Base	$ 4,115,380,372	$ 225,653,858	$ 9,253,698	$ 62,636
	Revenues at Current Rates				
5	Retail Sales - Non Fuel	$ 1,092,552,179	$ 66,760,320	$ 2,400,446	$ 92,989
6	Retail Sales - Fuel	406,567,423	58,462,318	749,204	9,127
7	Total Retail Sales Revenue	$ 1,499,119,602	$ 125,222,638	$ 3,149,650	$ 102,116
8	Other Revenue	25,324,174	1,254,154	48,366	1,685
9	Total Other Revenue (To be Credited)	$ 25,324,174	$ 1,254,154	$ 48,366	$ 1,685
10	Interruptible Power Credit	$ -	$ (17,892,385)	$ 91,209	$ 655
11	Total Revenues	$ 1,524,443,776	$ 108,584,407	$ 3,289,225	$ 104,456
	Expenses at Current Rates				
12	Operations & Maintenance Expenses	$ 497,797,095	$ 29,374,617	$ 983,802	$ 9,859
13	Depreciation Expense	297,033,774	16,955,825	588,009	4,440
14	Amortization Expense	50,657,236	2,257,802	103,051	800
15	Taxes Other Than Income Taxes	39,269,851	2,130,501	82,100	627
16	Fuel Expenses	406,567,423	57,508,240	758,283	9,265
17	Income Taxes	27,477,427	(5,920,046)	211,547	45,841
18	Total Expenses - Current	$ 1,318,802,805	$ 102,306,939	$ 2,726,791	$ 70,833
19	Current Operating Income	$ 205,640,971	$ 6,277,469	$ 562,434	$ 33,623
20	Return at Current Rates	5.00%	2.78%	6.08%	53.68%
21	Index Rate of Return	1.00	0.56	1.22	10.74

NIPSCO Class Cost of Service Study
Summary of Results
800 Series

Line No.	Description	System Total	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860
	(A)	(B)	(P)	(Q)	(R)	(S)
	Rate Base					
1	Plant in Service	$ 8,111,276,450	$ 10,690,446	$ 65,300,542	$ 3,581,082	$ 17,450,032
2	Accumulated Reserve	(4,210,571,859)	(4,736,189)	(43,447,479)	(2,026,466)	(12,873,609)
3	Other Rate Base Items	214,675,780	402,168	2,921,916	117,272	755,673
4	Total Rate Base	$ 4,115,380,372	$ 6,356,425	$ 24,774,979	$ 1,671,889	$ 5,332,096
	Revenues at Current Rates					
5	Retail Sales - Non Fuel	$ 1,092,552,179	$ 1,544,537	$ 6,270,876	$ 646,776	$ 2,028,671
6	Retail Sales - Fuel	406,567,423	560,179	901,306	161,857	341,490
7	Total Retail Sales Revenue	$ 1,499,119,602	$ 2,104,716	$ 7,172,182	$ 808,633	$ 2,370,161
8	Other Revenue	25,324,174	31,585	150,859	12,647	60,526
9	Total Other Revenue (To be Credited)	$ 25,324,174	$ 31,585	$ 150,859	$ 12,647	$ 60,526
10	Interruptible Power Credit	$ -	$ 73,272	$ 100,173	$ 34,355	$ 27,279
11	Total Revenues	$ 1,524,443,776	$ 2,209,573	$ 7,423,215	$ 855,635	$ 2,457,966
	Expenses at Current Rates					
12	Operations & Maintenance Expenses	$ 497,797,095	$ 474,713	$ 3,048,383	$ 187,850	$ 1,433,908
13	Depreciation Expense	297,033,774	350,290	2,833,179	141,726	486,776
14	Amortization Expense	50,657,236	54,753	357,961	20,962	293,839
15	Taxes Other Than Income Taxes	39,269,851	47,508	310,166	16,605	103,104
16	Fuel Expenses	406,567,423	559,742	1,118,563	170,544	895,237
17	Income Taxes	27,477,427	259,550	(820,228)	144,781	(596,897)
18	Total Expenses - Current	$ 1,318,802,805	$ 1,746,556	$ 6,848,024	$ 682,468	$ 2,615,968
19	Current Operating Income	$ 205,640,971	$ 463,016	$ 575,191	$ 173,167	$ (158,001)
20	Return at Current Rates	5.00%	7.28%	2.32%	10.36%	-2.96%
21	Index Rate of Return	1.00	1.46	0.46	2.07	(0.59)

NIPSCO Class Cost of Service Study
Summary of Results
800 Series

Line No.	Description	System Total	Interdepartmental Interdepartmental
	(A)	(B)	(S)
	Rate Base		
1	Plant in Service	$ 8,111,276,450	$ 25,114,066
2	Accumulated Reserve	(4,210,571,859)	(12,434,399)
3	Other Rate Base Items	214,675,780	575,741
4	Total Rate Base	$ 4,115,380,372	$ 13,255,408
	Revenues at Current Rates		
5	Retail Sales - Non Fuel	$ 1,092,552,179	$ 3,712,488
6	Retail Sales - Fuel	406,567,423	992,041
7	Total Retail Sales Revenue	$ 1,499,119,602	$ 4,704,529
8	Other Revenue	25,324,174	67,835
9	Total Other Revenue (To be Credited)	$ 25,324,174	$ 67,835
10	Interruptible Power Credit	$ -	$ 137,391
11	Total Revenues	$ 1,524,443,776	$ 4,909,755
	Expenses at Current Rates		
12	Operations & Maintenance Expenses	$ 497,797,095	$ 1,435,591
13	Depreciation Expense	297,033,774	939,609
14	Amortization Expense	50,657,236	118,457
15	Taxes Other Than Income Taxes	39,269,851	118,648
16	Fuel Expenses	406,567,423	496,020
17	Income Taxes	27,477,427	717,501
18	Total Expenses - Current	$ 1,318,802,805	$ 3,825,825
19	Current Operating Income	$ 205,640,971	$ 1,083,930
20	Return at Current Rates	5.00%	8.18%
21	Index Rate of Return	1.00	1.64

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Revenue Requirement at Equal Rates of Return at Current Rates				
22	Required Return	5.00%	5.00%	5.00%	5.00%
23	Required Operating Income	$ 205,640,971	$ 83,370,124	$ 138,167	$ 29,764,254
	Expenses at Required Return				
24	Operations & Maintenance Expenses	$ 497,797,095	$ 205,365,124	$ 288,858	$ 66,294,509
25	Depreciation Expense	297,033,774	115,783,589	126,575	40,135,034
26	Amortization Expense	50,657,236	25,801,833	28,199	6,793,954
27	Taxes Other Than Income Taxes	39,269,851	16,291,052	22,512	5,486,439
28	Fuel Expenses	406,567,423	91,863,453	277,723	41,558,348
29	Income Taxes	27,477,427	11,139,786	18,462	3,977,053
30	Total Expenses - Required	$ 1,318,802,805	$ 466,244,837	$ 762,329	$ 164,245,337
31	Total Revenue Requirement at Equal Return	$ 1,524,443,776	$ 549,614,961	$ 900,496	$ 194,009,591
32	Current Subsidy	$ -	$ (71,927,540)	$ (42,427)	$ 36,952,446
	Revenue Requirement at Equal Rates of Return at Proposed Rates				
33	Required Return	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,899,702	$ 117,124,539	$ 194,107	$ 41,815,034
35	Operating Income (Deficiency)/Surplus	$ (83,258,731)	$ (62,602,238)	$ (73,081)	$ 2,779,652
	Expenses at Required Return				
36	Operations & Maintenance Expenses	$ 498,017,292	$ 205,529,187	$ 288,858	$ 66,304,989
37	Depreciation Expense	297,033,774	115,783,589	126,575	40,135,034
38	Amortization Expense	50,657,236	25,801,833	28,199	6,793,954
39	Taxes Other than Income	39,404,512	16,345,970	22,587	5,505,435
40	Fuel Expenses	406,567,423	91,863,453	277,723	41,558,348
41	Income Taxes	55,891,067	22,659,128	37,552	8,089,613
42	Total Expense - Required	$ 1,347,571,303	$ 477,983,160	$ 781,495	$ 168,387,372
43	Total Revenue Requirement at Equal Return	$ 1,636,471,005	$ 595,107,699	$ 975,602	$ 210,202,406
44	Revenue (Deficiency)/Surplus	$ (112,027,229)	$ (117,420,278)	$ (117,533)	$ 20,759,631
45	Total Revenues	1,524,443,776	477,687,421	858,069	230,962,037
46	Total Revenues as Proposed	$ 1,636,471,005	$ 595,107,699	$ 975,602	$ 210,202,406
47	Less Total Other Revenues	$ 25,324,174	$ 10,051,645	$ 14,039	$ 4,218,008
48	Total Base Rate Revenues as Proposed	$ 1,611,146,831	$ 585,056,054	$ 961,564	$ 205,984,399
	Mitigation				
49	Mitigation	$ -	$ -	$ -	$ -
50	Proposed Increase Post Mitigation	112,027,229	117,420,278	117,533	(20,759,631)

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Revenue Requirement at Equal Rates of Return at Current Rates				
22	Required Return	5.00%	5.00%	5.00%	5.00%
23	Required Operating Income	$ 205,640,971	$ 145,360	$ 18,973,928	$ 20,838,749
	Expenses at Required Return				
24	Operations & Maintenance Expenses	$ 497,797,095	$ 287,594	$ 43,777,585	$ 49,385,699
25	Depreciation Expense	297,033,774	132,729	27,521,399	30,928,719
26	Amortization Expense	50,657,236	32,104	3,574,032	3,913,242
27	Taxes Other Than Income Taxes	39,269,851	23,204	3,493,298	3,838,352
28	Fuel Expenses	406,567,423	312,513	37,362,433	53,666,929
29	Income Taxes	27,477,427	19,423	2,535,267	2,784,441
30	Total Expenses - Required	$ 1,318,802,805	$ 807,568	$ 118,264,014	$ 144,517,382
31	Total Revenue Requirement at Equal Return	$ 1,524,443,776	$ 952,927	$ 137,237,942	$ 165,356,131
32	Current Subsidy	$ -	$ 184,763	$ 33,674,240	$ 41,041,038
	Revenue Requirement at Equal Rates of Return at Proposed Rates				
33	Required Return	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,899,702	$ 204,212	$ 26,655,983	$ 29,275,821
35	Operating Income (Deficiency)/Surplus	$ (83,258,731)	$ 15,265	$ 5,834,093	$ 8,044,874
	Expenses at Required Return				
36	Operations & Maintenance Expenses	$ 498,017,292	$ 287,598	$ 43,780,546	$ 49,401,701
37	Depreciation Expense	297,033,774	132,729	27,521,399	30,928,719
38	Amortization Expense	50,657,236	32,104	3,574,032	3,913,242
39	Taxes Other than Income	39,404,512	23,284	3,505,451	3,851,730
40	Fuel Expenses	406,567,423	312,513	37,362,433	53,666,929
41	Income Taxes	55,891,067	39,507	5,156,915	5,663,754
42	Total Expense - Required	$ 1,347,571,303	$ 827,736	$ 120,900,775	$ 147,426,075
43	Total Revenue Requirement at Equal Return	$ 1,636,471,005	$ 1,031,948	$ 147,556,758	$ 176,701,897
44	Revenue (Deficiency)/Surplus	$ (112,027,229)	$ 105,742	$ 23,355,423	$ 29,695,272
45	Total Revenues	1,524,443,776	1,137,690	170,912,181	206,397,169
46	Total Revenues as Proposed	$ 1,636,471,005	$ 1,031,948	$ 147,556,758	$ 176,701,897
47	Less Total Other Revenues	$ 25,324,174	$ 18,590	$ 2,521,285	$ 2,996,916
48	Total Base Rate Revenues as Proposed	$ 1,611,146,831	$ 1,013,357	$ 145,035,473	$ 173,704,981
	Mitigation				
49	Mitigation	$ -	$ -	$ -	$ -
50	Proposed Increase Post Mitigation	112,027,229	(105,742)	(23,355,423)	(29,695,272)

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. Rate 732	HLF Ind Pwr Serv. Rate 733
	(A)	(B)	(I)	(J)	(K)	(L)
	Revenue Requirement at Equal Rates of Return at Current Rates					
22	Required Return	5.00%	5.00%	5.00%	5.00%	5.00%
23	Required Operating Income	$ 205,640,971	$ 677,126	$ 12,870,857	$ 15,855,501	$ 8,697,766
	Expenses at Required Return					
24	Operations & Maintenance Expenses	$ 497,797,095	$ 1,606,610	$ 30,453,812	$ 40,439,705	$ 22,948,874
25	Depreciation Expense	297,033,774	876,115	19,092,363	26,043,514	14,093,883
26	Amortization Expense	50,657,236	128,919	2,379,004	3,061,577	1,736,748
27	Taxes Other Than Income Taxes	39,269,851	117,617	2,385,451	3,114,099	1,688,568
28	Fuel Expenses	406,567,423	2,522,836	27,492,212	50,260,459	39,734,624
29	Income Taxes	27,477,427	90,476	1,719,784	2,118,587	1,162,182
30	Total Expenses - Required	$ 1,318,802,805	$ 5,342,574	$ 83,522,626	$ 125,037,942	$ 81,364,878
31	Total Revenue Requirement at Equal Return	$ 1,524,443,776	$ 6,019,700	$ 96,393,482	$ 140,893,443	$ 90,062,644
32	Current Subsidy	$ -	$ 810,141	$ (4,321,462)	$ (24,840,589)	$ 1,637,618
	Revenue Requirement at Equal Rates of Return at Proposed Rates					
33	Required Return	7.02%	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,899,702	$ 951,277	$ 18,081,935	$ 22,274,985	$ 12,219,267
35	Operating Income (Deficiency)/Surplus	$ (83,258,731)	$ 50,822	$ (6,939,558)	$ (16,407,685)	$ (2,869,163)
	Expenses at Required Return					
36	Operations & Maintenance Expenses	$ 498,017,292	$ 1,606,610	$ 30,480,114	$ 40,439,705	$ 22,948,874
37	Depreciation Expense	297,033,774	876,115	19,092,363	26,043,514	14,093,883
38	Amortization Expense	50,657,236	128,919	2,379,004	3,061,577	1,736,748
39	Taxes Other than Income	39,404,512	118,025	2,393,760	3,124,883	1,694,417
40	Fuel Expenses	406,567,423	2,522,836	27,492,212	50,260,459	39,734,624
41	Income Taxes	55,891,067	184,036	3,498,164	4,309,360	2,363,962
42	Total Expense - Required	$ 1,347,571,303	$ 5,436,541	$ 85,335,617	$ 127,239,497	$ 82,572,508
43	Total Revenue Requirement at Equal Return	$ 1,636,471,005	$ 6,387,818	$ 103,417,552	$ 149,514,482	$ 94,791,775
44	Revenue (Deficiency)/Surplus	$ (112,027,229)	$ 442,023	$ (11,345,531)	$ (33,461,628)	$ (3,091,513)
45	Total Revenues	1,524,443,776	6,829,841	92,072,021	116,052,854	91,700,262
46	Total Revenues as Proposed	$ 1,636,471,005	$ 6,387,818	$ 103,417,552	$ 149,514,482	$ 94,791,775
47	Less Total Other Revenues	$ 25,324,174	$ 75,035	$ 1,240,648	$ 1,567,491	$ 992,861
48	Total Base Rate Revenues as Proposed	$ 1,611,146,831	$ 6,312,783	$ 102,176,904	$ 147,946,991	$ 93,798,914
	Mitigation					
49	Mitigation	$ -	$ -	$ -	$ -	$ -
50	Proposed Increase Post Mitigation	112,027,229	(442,023)	11,345,531	33,461,628	3,091,513

Line No.	Description	System Total	Air Separation Rate 734	Muni. Power Rate 841	Int WW Pumping Rate 842
	(A)	(B)	(M)	(N)	(O)
	Revenue Requirement at Equal Rates of Return at Current Rates				
22	Required Return	5.00%	5.00%	5.00%	5.00%
23	Required Operating Income	$ 205,640,971	$ 11,275,672	$ 462,397	$ 3,130
	Expenses at Required Return				
24	Operations & Maintenance Expenses	$ 497,797,095	$ 29,374,617	$ 983,802	$ 9,859
25	Depreciation Expense	297,033,774	16,955,825	588,009	4,440
26	Amortization Expense	50,657,236	2,257,802	103,051	800
27	Taxes Other Than Income Taxes	39,269,851	2,130,501	82,100	627
28	Fuel Expenses	406,567,423	57,508,240	758,283	9,265
29	Income Taxes	27,477,427	1,506,638	61,785	418
30	Total Expenses - Required	$ 1,318,802,805	$ 109,733,622	$ 2,577,029	$ 25,410
31	Total Revenue Requirement at Equal Return	$ 1,524,443,776	$ 121,009,294	$ 3,039,426	$ 28,540
32	Current Subsidy	$ -	$ (12,424,887)	$ 249,799	$ 75,916
	Revenue Requirement at Equal Rates of Return at Proposed Rates				
33	Required Return	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,899,702	$ 15,840,901	$ 649,610	$ 4,397
35	Operating Income (Deficiency)/Surplus	$ (83,258,731)	$ (9,563,432)	$ (87,176)	$ 29,226
	Expenses at Required Return				
36	Operations & Maintenance Expenses	$ 498,017,292	$ 29,374,617	$ 983,802	$ 9,859
37	Depreciation Expense	297,033,774	16,955,825	588,009	4,440
38	Amortization Expense	50,657,236	2,257,802	103,051	800
39	Taxes Other than Income	39,404,512	2,137,896	82,387	629
40	Fuel Expenses	406,567,423	57,508,240	758,283	9,265
41	Income Taxes	55,891,067	3,064,610	125,675	851
42	Total Expense - Required	$ 1,347,571,303	$ 111,298,989	$ 2,641,206	$ 25,844
43	Total Revenue Requirement at Equal Return	$ 1,636,471,005	$ 127,139,890	$ 3,290,816	$ 30,241
44	Revenue (Deficiency)/Surplus	$ (112,027,229)	$ (18,555,482)	$ (1,591)	$ 74,214
45	Total Revenues	1,524,443,776	108,584,407	3,289,225	104,456
46	Total Revenues as Proposed	$ 1,636,471,005	$ 127,139,890	$ 3,290,816	$ 30,241
47	Less Total Other Revenues	$ 25,324,174	$ 1,254,154	$ 48,366	$ 1,685
48	Total Base Rate Revenues as Proposed	$ 1,611,146,831	$ 125,885,736	$ 3,242,450	$ 28,557
	Mitigation				
49	Mitigation	$ -	$ -	$ -	$ -
50	Proposed Increase Post Mitigation	112,027,229	18,555,482	1,591	(74,214)

Line No.	Description	System Total	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860
	(A)	(B)	(P)	(Q)	(R)	(S)
	Revenue Requirement at Equal Rates of Return at Current Rates					
22	Required Return	5.00%	5.00%	5.00%	5.00%	5.00%
23	Required Operating Income	$ 205,640,971	$ 317,623	$ 1,237,978	$ 83,542	$ 266,439
	Expenses at Required Return					
24	Operations & Maintenance Expenses	$ 497,797,095	$ 474,713	$ 3,048,383	$ 187,850	$ 1,433,908
25	Depreciation Expense	297,033,774	350,290	2,833,179	141,726	486,776
26	Amortization Expense	50,657,236	54,753	357,961	20,962	293,839
27	Taxes Other Than Income Taxes	39,269,851	47,508	310,166	16,605	103,104
28	Fuel Expenses	406,567,423	559,742	1,118,563	170,544	895,237
29	Income Taxes	27,477,427	42,440	165,417	11,163	35,601
30	Total Expenses - Required	$ 1,318,802,805	$ 1,529,447	$ 7,833,669	$ 548,850	$ 3,248,465
31	Total Revenue Requirement at Equal Return	$ 1,524,443,776	$ 1,847,070	$ 9,071,647	$ 632,392	$ 3,514,904
32	Current Subsidy	$ -	$ 362,502	$ (1,648,432)	$ 223,243	$ (1,056,938)
	Revenue Requirement at Equal Rates of Return at Proposed Rates					
33	Required Return	7.02%	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,899,702	$ 446,221	$ 1,739,204	$ 117,367	$ 374,313
35	Operating Income (Deficiency)/Surplus	$ (83,258,731)	$ 16,795	$ (1,164,013)	$ 55,801	$ (532,314)
	Expenses at Required Return					
36	Operations & Maintenance Expenses	$ 498,017,292	$ 474,713	$ 3,048,392	$ 187,851	$ 1,434,285
37	Depreciation Expense	297,033,774	350,290	2,833,179	141,726	486,776
38	Amortization Expense	50,657,236	54,753	357,961	20,962	293,839
39	Taxes Other than Income	39,404,512	47,685	311,251	16,664	103,393
40	Fuel Expenses	406,567,423	559,742	1,118,563	170,544	895,237
41	Income Taxes	55,891,067	86,327	336,470	22,706	72,415
42	Total Expense - Required	$ 1,347,571,303	$ 1,573,511	$ 8,005,815	$ 560,453	$ 3,285,946
43	Total Revenue Requirement at Equal Return	$ 1,636,471,005	$ 2,019,732	$ 9,745,018	$ 677,820	$ 3,660,259
44	Revenue (Deficiency)/Surplus	$ (112,027,229)	$ 189,841	$ (2,321,803)	$ 177,815	$ (1,202,293)
45	Total Revenues	1,524,443,776	2,209,573	7,423,215	855,635	2,457,966
46	Total Revenues as Proposed	$ 1,636,471,005	$ 2,019,732	$ 9,745,018	$ 677,820	$ 3,660,259
47	Less Total Other Revenues	$ 25,324,174	$ 31,585	$ 150,859	$ 12,647	$ 60,526
48	Total Base Rate Revenues as Proposed	$ 1,611,146,831	$ 1,988,147	$ 9,594,159	$ 665,172	$ 3,599,733
	Mitigation					
49	Mitigation	$ -	$ -	$ -	$ -	$ -
50	Proposed Increase Post Mitigation	112,027,229	(189,841)	2,321,803	(177,815)	1,202,293

Line No.	Description		System Total		Interdepartmental Interdepartmental
	(A)		(B)		(S)
	Revenue Requirement at Equal Rates of Return at Current Rates				
22	Required Return		5.00%		5.00%
23	Required Operating Income	$	205,640,971	$	662,358
	Expenses at Required Return				
24	Operations & Maintenance Expenses	$	497,797,095	$	1,435,591
25	Depreciation Expense		297,033,774		939,609
26	Amortization Expense		50,657,236		118,457
27	Taxes Other Than Income Taxes		39,269,851		118,648
28	Fuel Expenses		406,567,423		496,020
29	Income Taxes		27,477,427		88,503
30	Total Expenses - Required	$	1,318,802,805	$	3,196,828
31	Total Revenue Requirement at Equal Return	$	1,524,443,776	$	3,859,186
32	Current Subsidy	$	-	$	1,050,569
	Revenue Requirement at Equal Rates of Return at Proposed Rates				
33	Required Return		7.02%		7.02%
34	Required Operating Income	$	288,899,702	$	930,530
35	Operating Income (Deficiency)/Surplus	$	(83,258,731)	$	153,400
	Expenses at Required Return				
36	Operations & Maintenance Expenses	$	498,017,292	$	1,435,591
37	Depreciation Expense		297,033,774		939,609
38	Amortization Expense		50,657,236		118,457
39	Taxes Other than Income		39,404,512		119,065
40	Fuel Expenses		406,567,423		496,020
41	Income Taxes		55,891,067		180,022
42	Total Expense - Required	$	1,347,571,303	$	3,288,763
43	Total Revenue Requirement at Equal Return	$	1,636,471,005	$	4,219,293
44	Revenue (Deficiency)/Surplus	$	(112,027,229)	$	690,462
45	Total Revenues		1,524,443,776		4,909,755
46	Total Revenues as Proposed	$	1,636,471,005	$	4,219,293
47	Less Total Other Revenues	$	25,324,174	$	67,835
48	Total Base Rate Revenues as Proposed	$	1,611,146,831	$	4,151,458
	Mitigation				
49	Mitigation	$	-	$	-
50	Proposed Increase Post Mitigation		112,027,229		(690,462)

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Revenue Requirement at Proposed Mitigated Rates				
51	Revenue Deficiency/Surplus (line 50)	$ 112,027,229	$ 117,420,278	$ 117,533	$ (20,759,631)
52	Total Revenues (line 11)	1,524,443,776	477,687,421	858,069	230,962,037
53	Total Revenues at Proposed	$ 1,636,471,005	$ 595,107,699	$ 975,602	$ 210,202,406
54	Less Total Other Revenues (line)	$ 25,324,174	$ 10,051,645	$ 14,039	$ 4,218,008
55	Total Base Rate Revenue at Proposed	$ 1,611,146,831	$ 585,056,054	$ 961,564	$ 205,984,399
56	Total Margin at Current Rates (line 5)	$ 1,092,552,179	$ 376,844,509	$ 570,262	$ 185,805,115
57	Total Margin in Base Rates (line 55 - line 40)	1,204,579,408	493,192,601	683,840	164,426,051
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 112,027,229	$ 116,348,092	$ 113,578	$ (21,379,064)
59	Percent Revenue Change (line 58 / line 56)	10.25%	30.87%	19.92%	-11.51%
60	Expenses (excl. Income Taxes)	$ 1,291,680,236	$ 455,324,031	$ 743,943	$ 160,297,759
61	Interest Expense	186,838,269	75,747,209	125,534	27,042,771
62	Taxable Income	$ 157,952,500	$ 64,036,459	$ 106,126	$ 22,861,876
63	Income Taxes at Proposed	55,891,067	22,659,128	37,552	8,089,613
64	Operating Income at Proposed	$ 288,899,702	$ 117,124,539	$ 194,107	$ 41,815,034
65	Return at Proposed	7.02%	7.02%	7.02%	7.02%
66	Index Rate of Return	1.00	1.00	1.00	1.00

Line No.	Description		System Total		Comml SH Rate 822		GS Medium Rate 823		GS Large Rate 824
	(A)		(B)		(F)		(G)		(H)
	Revenue Requirement at Proposed Mitigated Rates								
51	Revenue Deficiency/Surplus (line 50)	$	112,027,229	$	(105,742)	$	(23,355,423)	$	(29,695,272)
52	Total Revenues (line 11)		1,524,443,776		1,137,690		170,912,181		206,397,169
53	Total Revenues at Proposed	$	1,636,471,005	$	1,031,948	$	147,556,758	$	176,701,897
54	Less Total Other Revenues (line)	$	25,324,174	$	18,590	$	2,521,285	$	2,996,916
55	Total Base Rate Revenue at Proposed	$	1,611,146,831	$	1,013,357	$	145,035,473	$	173,704,981
56	Total Margin at Current Rates (line 5)	$	1,092,552,179	$	811,099	$	131,637,567	$	150,685,727
57	Total Margin in Base Rates (line 55 - line 40)		1,204,579,408		700,844		107,673,040		120,038,052
58	$ Increase/ (Decrease) (line 57 - line 56)	$	112,027,229	$	(110,255)	$	(23,964,527)	$	(30,647,675)
59	Percent Revenue Change (line 58 / line 56)		10.25%		-13.59%		-18.20%		-20.34%
60	Expenses (excl. Income Taxes)	$	1,291,680,236	$	788,229	$	115,743,860	$	141,762,321
61	Interest Expense		186,838,269		132,069		17,239,054		18,933,366
62	Taxable Income	$	157,952,500	$	111,650	$	14,573,844	$	16,006,210
63	Income Taxes at Proposed		55,891,067		39,507		5,156,915		5,663,754
64	Operating Income at Proposed	$	288,899,702	$	204,212	$	26,655,983	$	29,275,821
65	Return at Proposed		7.02%		7.02%		7.02%		7.02%
66	Index Rate of Return		1.00		1.00		1.00		1.00

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. Rate 732	HLF Ind Pwr Serv. Rate 733
	(A)	(B)	(I)	(J)	(K)	(L)
	Revenue Requirement at Proposed Mitigated Rates					
51	Revenue Deficiency/Surplus (line 50)	$ 112,027,229	$ (442,023)	$ 11,345,531	$ 33,461,628	$ 3,091,513
52	Total Revenues (line 11)	1,524,443,776	6,829,841	92,072,021	116,052,854	91,700,262
53	Total Revenues at Proposed	$ 1,636,471,005	$ 6,387,818	$ 103,417,552	$ 149,514,482	$ 94,791,775
54	Less Total Other Revenues (line)	$ 25,324,174	$ 75,035	$ 1,240,648	$ 1,567,491	$ 992,861
55	Total Base Rate Revenue at Proposed	$ 1,611,146,831	$ 6,312,783	$ 102,176,904	$ 147,946,991	$ 93,798,914
56	Total Margin at Current Rates (line 5)	$ 1,092,552,179	$ 4,253,501	$ 63,591,962	$ 63,290,544	$ 49,032,839
57	Total Margin in Base Rates (line 55 - line 40)	1,204,579,408	3,789,947	74,684,692	97,686,532	54,064,291
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 112,027,229	$ (463,554)	$ 11,092,730	$ 34,395,988	$ 5,031,451
59	Percent Revenue Change (line 58 / line 56)	10.25%	-10.90%	17.44%	54.35%	10.26%
60	Expenses (excl. Income Taxes)	$ 1,291,680,236	$ 5,252,505	$ 81,837,453	$ 122,930,137	$ 80,208,546
61	Interest Expense	186,838,269	615,213	11,694,015	14,405,760	7,902,489
62	Taxable Income	$ 157,952,500	$ 520,099	$ 9,886,084	$ 12,178,585	$ 6,680,740
63	Income Taxes at Proposed	55,891,067	184,036	3,498,164	4,309,360	2,363,962
64	Operating Income at Proposed	$ 288,899,702	$ 951,277	$ 18,081,935	$ 22,274,985	$ 12,219,267
65	Return at Proposed	7.02%	7.02%	7.02%	7.02%	7.02%
66	Index Rate of Return	1.00	1.00	1.00	1.00	1.00

Line No.	Description		System Total		Air Separation Rate 734		Muni. Power Rate 841		Int WW Pumping Rate 842
	(A)		(B)		(M)		(N)		(O)
	Revenue Requirement at Proposed Mitigated Rates								
51	Revenue Deficiency/Surplus (line 50)	$	112,027,229	$	18,555,482	$	1,591	$	(74,214)
52	Total Revenues (line 11)		1,524,443,776		108,584,407		3,289,225		104,456
53	Total Revenues at Proposed	$	1,636,471,005	$	127,139,890	$	3,290,816	$	30,241
54	Less Total Other Revenues (line)	$	25,324,174	$	1,254,154	$	48,366	$	1,685
55	Total Base Rate Revenue at Proposed	$	1,611,146,831	$	125,885,736	$	3,242,450	$	28,557
56	Total Margin at Current Rates (line 5)	$	1,092,552,179	$	48,867,935	$	2,491,655	$	93,644
57	Total Margin in Base Rates (line 55 - line 40)		1,204,579,408		68,377,496		2,484,167		19,292
58	$ Increase/ (Decrease) (line 57 - line 56)	$	112,027,229	$	19,509,560	$	(7,488)	$	(74,352)
59	Percent Revenue Change (line 58 / line 56)		10.25%		39.92%		-0.30%		-79.40%
60	Expenses (excl. Income Taxes)	$	1,291,680,236	$	108,234,379	$	2,515,532	$	24,994
61	Interest Expense		186,838,269		10,244,685		420,118		2,844
62	Taxable Income	$	157,952,500	$	8,660,825	$	355,166	$	2,404
63	Income Taxes at Proposed		55,891,067		3,064,610		125,675		851
64	Operating Income at Proposed	$	288,899,702	$	15,840,901	$	649,610	$	4,397
65	Return at Proposed		7.02%		7.02%		7.02%		7.02%
66	Index Rate of Return		1.00		1.00		1.00		1.00

Line No.	Description	System Total	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860
	(A)	(B)	(P)	(Q)	(R)	(S)
	Revenue Requirement at Proposed Mitigated Rates					
51	Revenue Deficiency/Surplus (line 50)	$ 112,027,229	$ (189,841)	$ 2,321,803	$ (177,815)	$ 1,202,293
52	Total Revenues (line 11)	1,524,443,776	2,209,573	7,423,215	855,635	2,457,966
53	Total Revenues at Proposed	$ 1,636,471,005	$ 2,019,732	$ 9,745,018	$ 677,820	$ 3,660,259
54	Less Total Other Revenues (line)	$ 25,324,174	$ 31,585	$ 150,859	$ 12,647	$ 60,526
55	Total Base Rate Revenue at Proposed	$ 1,611,146,831	$ 1,988,147	$ 9,594,159	$ 665,172	$ 3,599,733
56	Total Margin at Current Rates (line 5)	$ 1,092,552,179	$ 1,617,809	$ 6,371,049	$ 681,131	$ 2,055,950
57	Total Margin in Base Rates (line 55 - line 40)	1,204,579,408	1,428,404	8,475,596	494,628	2,704,496
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 112,027,229	$ (189,404)	$ 2,104,547	$ (186,503)	$ 648,546
59	Percent Revenue Change (line 58 / line 56)	10.25%	-11.71%	33.03%	-27.38%	31.54%
60	Expenses (excl. Income Taxes)	$ 1,291,680,236	$ 1,487,184	$ 7,669,345	$ 537,747	$ 3,213,531
61	Interest Expense	186,838,269	288,582	1,124,784	75,904	242,077
62	Taxable Income	$ 157,952,500	$ 243,966	$ 950,889	$ 64,169	$ 204,651
63	Income Taxes at Proposed	55,891,067	86,327	336,470	22,706	72,415
64	Operating Income at Proposed	$ 288,899,702	$ 446,221	$ 1,739,204	$ 117,367	$ 374,313
65	Return at Proposed	7.02%	7.02%	7.02%	7.02%	7.02%
66	Index Rate of Return	1.00	1.00	1.00	1.00	1.00

Line No.	Description		System Total		Interdepartmental Interdepartmental
	(A)		(B)		(S)
	Revenue Requirement at Proposed Mitigated Rates				
51	Revenue Deficiency/Surplus (line 50)	$	112,027,229	$	(690,462)
52	Total Revenues (line 11)		1,524,443,776		4,909,755
53	Total Revenues at Proposed	$	1,636,471,005	$	4,219,293
54	Less Total Other Revenues (line)	$	25,324,174	$	67,835
55	Total Base Rate Revenue at Proposed	$	1,611,146,831	$	4,151,458
56	Total Margin at Current Rates (line 5)	$	1,092,552,179	$	3,849,879
57	Total Margin in Base Rates (line 55 - line 40)		1,204,579,408		3,655,438
58	$ Increase/ (Decrease) (line 57 - line 56)	$	112,027,229	$	(194,441)
59	Percent Revenue Change (line 58 / line 56)		10.25%		-5.05%
60	Expenses (excl. Income Taxes)	$	1,291,680,236	$	3,108,741
61	Interest Expense		186,838,269		601,796
62	Taxable Income	$	157,952,500	$	508,756
63	Income Taxes at Proposed		55,891,067		180,022
64	Operating Income at Proposed	$	288,899,702	$	930,530
65	Return at Proposed		7.02%		7.02%
66	Index Rate of Return		1.00		1.00

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Residential Rate 811**	**C&GS Heat Pump Rate 820**	**GS Small Rate 821**
	Demand				
67	Production	$ 669,215,067	$ 246,755,139	$ -	$ 81,883,478
68	Transmission	160,074,585	42,803,878	112,901	19,025,889
69	Sub-Transmission	23,566,741	10,237,030	48,245	4,108,447
70	Railroad	682,517	-	-	-
71	Distribution Primary	175,815,733	82,995,154	391,137	32,810,151
72	Distribution Secondary	9,087,434	4,508,939	11,247	2,060,038
73	Customer	-	-	-	-
74	Customer Service	-	-	-	-
75	**Total**	$ 1,038,442,076	$ 387,300,139	$ 563,530	$ 139,888,004
	Customer				
76	Production	-	-	-	-
77	Transmission	-	-	-	-
78	Sub-Transmission	-	-	-	-
79	Railroad	-	-	-	-
80	Distribution Primary	-	-	-	-
81	Distribution Secondary	$ 32,445,700	$ 28,358,792	$ 7,499	$ 3,574,183
82	Customer	69,228,495	42,767,462	36,420	14,563,205
83	Customer Service	46,394,282	35,005,924	60,766	6,179,822
84	**Total**	$ 148,068,477	$ 106,132,178	$ 104,685	$ 24,317,211
	Energy				
85	Production	$ 43,393,030	$ 9,811,929	$ 29,664	$ 4,438,844
86	Transmission	-	-	-	-
87	Sub-Transmission	-	-	-	-
88	Railroad	-	-	-	-
89	Distribution Primary	-	-	-	-
90	Distribution Secondary	-	-	-	-
91	Customer	-	-	-	-
92	Customer Service	-	-	-	-
93	**Total**	$ 43,393,030	$ 9,811,929	$ 29,664	$ 4,438,844
	Fuel				
94	Fuel Expenses	$ 406,567,423	$ 91,863,453	$ 277,723	$ 41,558,348
95	**Total**	$ 406,567,423	$ 91,863,453	$ 277,723	$ 41,558,348
96	**Total**	$ 1,636,471,005	$ 595,107,699	$ 975,602	$ 210,202,406
	Total Revenue Requirement				
97	Demand	$ 1,038,442,076	$ 387,300,139	$ 563,530	$ 139,888,004
98	Customer	148,068,477	106,132,178	104,685	24,317,211
99	Energy	43,393,030	9,811,929	29,664	4,438,844
100	Fuel	406,567,423	91,863,453	277,723	41,558,348
101	**Total**	$ 1,636,471,005	$ 595,107,699	$ 975,602	$ 210,202,406
102	Zero-Check	$ -	$ -	$ -	$ -

Line No.	Description		System Total		Comml SH Rate 822		GS Medium Rate 823		GS Large Rate 824
	(A)		(B)		(F)		(G)		(H)
	Functionalized Revenue Requirement Before Other Revenue Credit		**System Total**		**Comml SH Rate 822**		**GS Medium Rate 823**		**GS Large Rate 824**
	Demand								
67	Production	$	669,215,067	$	-	$	65,126,671	$	71,187,415
68	Transmission		160,074,585		130,799		14,421,480		18,067,246
69	Sub-Transmission		23,566,741		45,745		2,496,073		3,089,795
70	Railroad		682,517		-		-		-
71	Distribution Primary		175,815,733		370,868		20,117,870		22,824,022
72	Distribution Secondary		9,087,434		13,133		1,256,098		664,713
73	Customer		-		-		-		-
74	Customer Service		-		-		-		-
75	**Total**	$	1,038,442,076	$	560,545	$	103,418,191	$	115,833,191
	Customer								
76	Production		-		-		-		-
77	Transmission		-		-		-		-
78	Sub-Transmission		-		-		-		-
79	Railroad		-		-		-		-
80	Distribution Primary		-		-		-		-
81	Distribution Secondary	$	32,445,700	$	14,106	$	250,449	$	19,331
82	Customer		69,228,495		60,854		1,630,158		313,322
83	Customer Service		46,394,282		50,549		904,848		1,136,963
84	**Total**	$	148,068,477	$	125,510	$	2,785,455	$	1,469,616
	Energy								
85	Production	$	43,393,030	$	33,379	$	3,990,679	$	5,732,161
86	Transmission		-		-		-		-
87	Sub-Transmission		-		-		-		-
88	Railroad		-		-		-		-
89	Distribution Primary		-		-		-		-
90	Distribution Secondary		-		-		-		-
91	Customer		-		-		-		-
92	Customer Service		-		-		-		-
93	**Total**	$	43,393,030	$	33,379	$	3,990,679	$	5,732,161
	Fuel								
94	Fuel Expenses	$	406,567,423	$	312,513	$	37,362,433	$	53,666,929
95	**Total**	$	406,567,423	$	312,513	$	37,362,433	$	53,666,929
96	**Total**	$	1,636,471,005	$	1,031,948	$	147,556,758	$	176,701,897
	Total Revenue Requirement								
97	Demand	$	1,038,442,076	$	560,545	$	103,418,191	$	115,833,191
98	Customer		148,068,477		125,510		2,785,455		1,469,616
99	Energy		43,393,030		33,379		3,990,679		5,732,161
100	Fuel		406,567,423		312,513		37,362,433		53,666,929
101	**Total**	$	1,636,471,005	$	1,031,948	$	147,556,758	$	176,701,897
102	Zero-Check	$	-	$	-	$	-	$	-

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. Rate 732	HLF Ind Pwr Serv. Rate 733
	(A)	(B)	(I)	(J)	(K)	(L)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Metal Melting Rate 825**	**Off-Peak Serv. Rate 826**	**Ind. Pwr Serv. Rate 732**	**HLF Ind Pwr Serv. Rate 733**
	Demand					
67	Production	$ 669,215,067	$ 1,644,384	$ 46,390,608	$ 70,594,037	$ 37,222,556
68	Transmission	160,074,585	501,570	10,736,458	21,924,306	12,899,617
69	Sub-Transmission	23,566,741	198,403	1,766,870	874,542	310,057
70	Railroad	682,517	-	-	-	-
71	Distribution Primary	175,815,733	1,124,268	12,642,246	-	0
72	Distribution Secondary	9,087,434	28,811	412,523	-	-
73	Customer	-	-	-	-	-
74	Customer Service	-	-	-	-	-
75	**Total**	$ 1,038,442,076	$ 3,497,437	$ 71,948,704	$ 93,392,885	$ 50,432,231
	Customer					
76	Production	-	-	-	-	-
77	Transmission	-	-	-	-	-
78	Sub-Transmission	-	-	-	-	-
79	Railroad	-	-	-	-	-
80	Distribution Primary	-	-	-	-	-
81	Distribution Secondary	$ 32,445,700	$ 206	$ 9,527	$ -	$ -
82	Customer	69,228,495	6,752	250,233	210,054	132,681
83	Customer Service	46,394,282	91,123	780,435	282,768	248,187
84	**Total**	$ 148,068,477	$ 98,081	$ 1,040,195	$ 492,823	$ 380,868
	Energy					
85	Production	$ 43,393,030	$ 269,464	$ 2,936,441	$ 5,368,316	$ 4,244,052
86	Transmission	-	-	-	-	-
87	Sub-Transmission	-	-	-	-	-
88	Railroad	-	-	-	-	-
89	Distribution Primary	-	-	-	-	-
90	Distribution Secondary	-	-	-	-	-
91	Customer	-	-	-	-	-
92	Customer Service	-	-	-	-	-
93	**Total**	$ 43,393,030	$ 269,464	$ 2,936,441	$ 5,368,316	$ 4,244,052
	Fuel					
94	Fuel Expenses	$ 406,567,423	$ 2,522,836	$ 27,492,212	$ 50,260,459	$ 39,734,624
95	**Total**	$ 406,567,423	$ 2,522,836	$ 27,492,212	$ 50,260,459	$ 39,734,624
96	**Total**	$ 1,636,471,005	$ 6,387,818	$ 103,417,552	$ 149,514,482	$ 94,791,775
	Total Revenue Requirement					
97	Demand	$ 1,038,442,076	$ 3,497,437	$ 71,948,704	$ 93,392,885	$ 50,432,231
98	Customer	148,068,477	98,081	1,040,195	492,823	380,868
99	Energy	43,393,030	269,464	2,936,441	5,368,316	4,244,052
100	Fuel	406,567,423	2,522,836	27,492,212	50,260,459	39,734,624
101	**Total**	$ 1,636,471,005	$ 6,387,818	$ 103,417,552	$ 149,514,482	$ 94,791,775
102	Zero-Check	$ -	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Air Separation Rate 734	Muni. Power Rate 841	Int WW Pumping Rate 842
	(A)	(B)	(M)	(N)	(O)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Air Separation Rate 734**	**Muni. Power Rate 841**	**Int WW Pumping Rate 842**
	Demand				
67	Production	$ 669,215,067	$ 44,542,809	$ 1,042,181	$ 10,329
68	Transmission	160,074,585	18,595,640	284,067	2,699
69	Sub-Transmission	23,566,741	-	77,734	353
70	Railroad	682,517	-	-	-
71	Distribution Primary	175,815,733	-	630,215	2,864
72	Distribution Secondary	9,087,434	-	35,606	237
73	Customer	-	-	-	-
74	Customer Service	-	-	-	-
75	**Total**	$ 1,038,442,076	$ 63,138,449	$ 2,069,803	$ 16,482
	Customer				
76	Production	-	-	-	-
77	Transmission	-	-	-	-
78	Sub-Transmission	-	-	-	-
79	Railroad	-	-	-	-
80	Distribution Primary	-	-	-	-
81	Distribution Secondary	$ 32,445,700	$ -	$ 48,396	$ 550
82	Customer	69,228,495	149,569	260,402	99
83	Customer Service	46,394,282	201,180	72,940	2,856
84	**Total**	$ 148,068,477	$ 350,750	$ 381,738	$ 3,505
	Energy				
85	Production	$ 43,393,030	$ 6,142,451	$ 80,992	$ 990
86	Transmission	-	-	-	-
87	Sub-Transmission	-	-	-	-
88	Railroad	-	-	-	-
89	Distribution Primary	-	-	-	-
90	Distribution Secondary	-	-	-	-
91	Customer	-	-	-	-
92	Customer Service	-	-	-	-
93	**Total**	$ 43,393,030	$ 6,142,451	$ 80,992	$ 990
	Fuel				
94	Fuel Expenses	$ 406,567,423	$ 57,508,240	$ 758,283	$ 9,265
95	**Total**	$ 406,567,423	$ 57,508,240	$ 758,283	$ 9,265
96	**Total**	$ 1,636,471,005	$ 127,139,890	$ 3,290,816	$ 30,241
	Total Revenue Requirement				
97	Demand	$ 1,038,442,076	$ 63,138,449	$ 2,069,803	$ 16,482
98	Customer	148,068,477	350,750	381,738	3,505
99	Energy	43,393,030	6,142,451	80,992	990
100	Fuel	406,567,423	57,508,240	758,283	9,265
101	**Total**	$ 1,636,471,005	$ 127,139,890	$ 3,290,816	$ 30,241
102	Zero-Check	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860
	(A)	(B)	(P)	(Q)	(R)	(S)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Railroad Rate 844**	**Street Lighting Rate 850**	**Traffic Lighting Rate 855**	**Dusk-to-Dawn Rate 860**
	Demand					
67	Production	$ 669,215,067	$ 486,565	$ -	$ 213,136	$ -
68	Transmission	160,074,585	132,503	41,342	54,640	19,615
69	Sub-Transmission	23,566,741	78,235	65,107	7,477	33,155
70	Railroad	682,517	682,517	-	-	-
71	Distribution Primary	175,815,733	-	527,845	60,623	268,798
72	Distribution Secondary	9,087,434	-	40,760	4,799	20,156
73	Customer	-	-	-	-	-
74	Customer Service	-	-	-	-	-
75	**Total**	$ 1,038,442,076	$ 1,379,820	$ 675,054	$ 340,675	$ 341,724
	Customer					
76	Production	-	-	-	-	-
77	Transmission	-	-	-	-	-
78	Sub-Transmission	-	-	-	-	-
79	Railroad	-	-	-	-	-
80	Distribution Primary	-	-	-	-	-
81	Distribution Secondary	$ 32,445,700	$ -	$ 15,188	$ 2,408	$ 141,900
82	Customer	69,228,495	2,650	6,949,366	135,788	1,759,479
83	Customer Service	46,394,282	17,733	867,375	10,188	479,279
84	**Total**	$ 148,068,477	$ 20,383	$ 7,831,928	$ 148,384	$ 2,380,658
	Energy					
85	Production	$ 43,393,030	$ 59,786	$ 119,474	$ 18,216	$ 42,640
86	Transmission	-	-	-	-	-
87	Sub-Transmission	-	-	-	-	-
88	Railroad	-	-	-	-	-
89	Distribution Primary	-	-	-	-	-
90	Distribution Secondary	-	-	-	-	-
91	Customer	-	-	-	-	-
92	Customer Service	-	-	-	-	-
93	**Total**	$ 43,393,030	$ 59,786	$ 119,474	$ 18,216	$ 42,640
	Fuel					
94	Fuel Expenses	$ 406,567,423	$ 559,742	$ 1,118,563	$ 170,544	$ 895,237
95	**Total**	$ 406,567,423	$ 559,742	$ 1,118,563	$ 170,544	$ 895,237
96	**Total**	$ 1,636,471,005	$ 2,019,732	$ 9,745,018	$ 677,820	$ 3,660,259
	Total Revenue Requirement					
97	Demand	$ 1,038,442,076	$ 1,379,820	$ 675,054	$ 340,675	$ 341,724
98	Customer	148,068,477	20,383	7,831,928	148,384	2,380,658
99	Energy	43,393,030	59,786	119,474	18,216	42,640
100	Fuel	406,567,423	559,742	1,118,563	170,544	895,237
101	**Total**	$ 1,636,471,005	$ 2,019,732	$ 9,745,018	$ 677,820	$ 3,660,259
102	Zero-Check	$ -	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Interdepartmental Interdepartmental
	(A)	(B)	(S)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Interdepartmental Interdepartmental**
	Demand		
67	Production	$ 669,215,067	$ 2,115,760
68	Transmission	160,074,585	319,933
69	Sub-Transmission	23,566,741	129,472
70	Railroad	682,517	-
71	Distribution Primary	175,815,733	1,049,671
72	Distribution Secondary	9,087,434	30,375
73	Customer	-	-
74	Customer Service	-	-
75	**Total**	$ 1,038,442,076	$ 3,645,212
	Customer		
76	Production	-	-
77	Transmission	-	-
78	Sub-Transmission	-	-
79	Railroad	-	-
80	Distribution Primary	-	-
81	Distribution Secondary	$ 32,445,700	$ 3,165
82	Customer	69,228,495	-
83	Customer Service	46,394,282	1,343
84	**Total**	$ 148,068,477	$ 4,508
	Energy		
85	Production	$ 43,393,030	$ 73,553
86	Transmission	-	-
87	Sub-Transmission	-	-
88	Railroad	-	-
89	Distribution Primary	-	-
90	Distribution Secondary	-	-
91	Customer	-	-
92	Customer Service	-	-
93	**Total**	$ 43,393,030	$ 73,553
	Fuel		
94	Fuel Expenses	$ 406,567,423	$ 496,020
95	**Total**	$ 406,567,423	$ 496,020
96	**Total**	$ 1,636,471,005	$ 4,219,293
	Total Revenue Requirement		
97	Demand	$ 1,038,442,076	$ 3,645,212
98	Customer	148,068,477	4,508
99	Energy	43,393,030	73,553
100	Fuel	406,567,423	496,020
101	**Total**	$ 1,636,471,005	$ 4,219,293
102	Zero-Check	$ -	$ -

Line No.	Description	System Total	Residential Rate 811		C&GS Heat Pump Rate 820		GS Small Rate 821
	(A)	(B)	(C)		(D)		(E)
	Billing Determinants						
103	Demand (KW) - Production	21,538,854	0		0		0
104	Demand (KW) - Other	21,538,854	0		0		0
105	Customer (Customer Bills or No. Customers * 12)	6,529,485	4,946,379		1,244		627,481
106	Energy (kWh)	15,153,990,077	3,406,296,779		10,300,522		1,541,544,882
107	Fuel (kWh)	15,153,990,077	3,406,296,779		10,300,522		1,541,544,882
	Unit Costs						
108	Demand - Production		$ -	$	-	$	-
109	Demand - Other		$ -	$	-	$	-
110	Customer		$ 99.76	$	537.04	$	261.69
111	Energy		$ 0.002881	$	0.002880	$	0.002879
112	Fuel		$ 0.026969	$	0.026962	$	0.026959
113	Demand Revenue		$ -	$	-	$	-
114	Customer Revenue		493,432,318		668,215		164,205,215
115	Energy Revenue		9,811,929		29,664		4,438,844
116	Fuel Revenue		91,863,453		277,723		41,558,348
117	Total Revenue		595,107,699		975,602		210,202,406
118	Zero-Check		$ -	$	-	$	-

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Billing Determinants				
103	Demand (KW) - Production	21,538,854	0	4,094,516	4,746,678
104	Demand (KW) - Other	21,538,854	0	4,094,516	4,746,678
105	Customer (Customer Bills or No. Customers * 12)	6,529,485	1,640	44,986	5,466
106	Energy (kWh)	15,153,990,077	11,587,981	1,386,084,286	1,998,019,018
107	Fuel (kWh)	15,153,990,077	11,587,981	1,386,084,286	1,998,019,018
	Unit Costs				
108	Demand - Production		$ -	$ 15.91	$ 15.00
109	Demand - Other		$ -	$ 9.35	$ 9.41
110	Customer		$ 418.27	$ 61.92	$ 268.85
111	Energy		$ 0.002881	$ 0.002879	$ 0.002869
112	Fuel		$ 0.026969	$ 0.026955	$ 0.026860
113	Demand Revenue		$ -	$ 103,418,191	$ 115,833,191
114	Customer Revenue		686,055	2,785,455	1,469,616
115	Energy Revenue		33,379	3,990,679	5,732,161
116	Fuel Revenue		312,513	37,362,433	53,666,929
117	Total Revenue		1,031,948	147,556,758	176,701,897
118	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. Rate 732	HLF Ind Pwr Serv. Rate 733
	(A)	(B)	(I)	(J)	(K)	(L)
	Billing Determinants					
103	Demand (KW) - Production	21,538,854	108,013	1,882,443	5,236,861	2,698,052
104	Demand (KW) - Other	21,538,854	108,013	1,882,443	5,236,861	2,698,052
105	Customer (Customer Bills or No. Customers * 12)	6,529,485	72	2,208	132	84
106	Energy (kWh)	15,153,990,077	94,118,668	1,023,539,449	1,888,838,716	1,493,743,680
107	Fuel (kWh)	15,153,990,077	94,118,668	1,023,539,449	1,888,838,716	1,493,743,680
	Unit Costs					
108	Demand - Production		$ 15.22	$ 24.64	$ 13.48	$ 13.80
109	Demand - Other		$ 17.16	$ 13.58	$ 4.35	$ 4.90
110	Customer		$ 1,362.24	$ 471.10	$ 3,733.50	$ 4,534.15
111	Energy		$ 0.002863	$ 0.002869	$ 0.002842	$ 0.002841
112	Fuel		$ 0.026805	$ 0.026860	$ 0.026609	$ 0.026601
113	Demand Revenue		$ 3,497,437	$ 71,948,704	$ 93,392,885	$ 50,432,231
114	Customer Revenue		98,081	1,040,195	492,823	380,868
115	Energy Revenue		269,464	2,936,441	5,368,316	4,244,052
116	Fuel Revenue		2,522,836	27,492,212	50,260,459	39,734,624
117	Total Revenue		6,387,818	103,417,552	149,514,482	94,791,775
118	Zero-Check		$ -	$ -	$ -	$ -

Line No.	Description	System Total	Air Separation Rate 734	Muni. Power Rate 841	Int WW Pumping Rate 842
	(A)	(B)	(M)	(N)	(O)
	Billing Determinants				
103	Demand (KW) - Production	21,538,854	2,700,000	0	0
104	Demand (KW) - Other	21,538,854	2,700,000	0	0
105	Customer (Customer Bills or No. Customers * 12)	6,529,485	12	8,501	96
106	Energy (kWh)	15,153,990,077	2,162,295,201	28,139,780	343,541
107	Fuel (kWh)	15,153,990,077	2,162,295,201	28,139,780	343,541
	Unit Costs				
108	Demand - Production		$ 16.50	$ -	$ -
109	Demand - Other		$ 6.89	$ -	$ -
110	Customer		$ 29,229.16	$ 288.39	$ 208.20
111	Energy		$ 0.002841	$ 0.002878	$ 0.002881
112	Fuel		$ 0.026596	$ 0.026947	$ 0.026969
113	Demand Revenue		$ 63,138,449	$ -	$ -
114	Customer Revenue		350,750	2,451,541	19,987
115	Energy Revenue		6,142,451	80,992	990
116	Fuel Revenue		57,508,240	758,283	9,265
117	Total Revenue		127,139,890	3,290,816	30,241
118	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860
	(A)	(B)	(P)	(Q)	(R)	(S)
	Billing Determinants					
103	Demand (KW) - Production	21,538,854	72,290	0	0	0
104	Demand (KW) - Other	21,538,854	72,290	0	0	0
105	Customer (Customer Bills or No. Customers * 12)	6,529,485	12	758,388	14,592	179,664
106	Energy (kWh)	15,153,990,077	21,000,000	41,476,293	6,323,787	14,802,974
107	Fuel (kWh)	15,153,990,077	21,000,000	41,476,293	6,323,787	14,802,974
	Unit Costs					
108	Demand - Production		$ 6.73	$ -	$ -	$ -
109	Demand - Other		$ 12.36	$ -	$ -	$ -
110	Customer		$ 1,698.57	$ 11.22	$ 33.52	$ 15.15
111	Energy		$ 0.002847	$ 0.002881	$ 0.002881	$ 0.002881
112	Fuel		$ 0.026654	$ 0.026969	$ 0.026969	$ 0.060477
113	Demand Revenue		$ 1,379,820	$ -	$ -	$ -
114	Customer Revenue		20,383	8,506,982	489,059	2,722,382
115	Energy Revenue		59,786	119,474	18,216	42,640
116	Fuel Revenue		559,742	1,118,563	170,544	895,237
117	Total Revenue		2,019,732	9,745,018	677,820	3,660,259
118	Zero-Check		$ -	$ -	$ -	$ -

Line No.	Description	System Total		Interdepartmental Interdepartmental
	(A)	(B)		(S)
	Billing Determinants			
103	Demand (KW) - Production	21,538,854		0
104	Demand (KW) - Other	21,538,854		0
105	Customer (Customer Bills or No. Customers * 12)	6,529,485		552
106	Energy (kWh)	15,153,990,077		25,534,520
107	Fuel (kWh)	15,153,990,077		25,534,520
	Unit Costs			
108	Demand - Production		$	-
109	Demand - Other		$	-
110	Customer		$	6,611.81
111	Energy		$	0.002881
112	Fuel		$	0.019425
113	Demand Revenue		$	-
114	Customer Revenue			3,649,720
115	Energy Revenue			73,553
116	Fuel Revenue			496,020
117	Total Revenue			4,219,293
118	Zero-Check		$	-

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Functionalized Revenue Requirement After Other Revenue Credit				
119	Other Rev as % of Functionalized Revenue	2.13%	2.04%	2.10%	2.57%
120	Ratio (Inverse of Percentage)	97.87%	97.96%	97.90%	97.43%
	Demand				
121	Production	$ 655,034,312	$ 241,728,522	$ -	$ 79,780,103
122	Transmission	156,708,290	41,931,926	110,529	18,537,163
123	Sub-Transmission	23,049,566	10,028,492	47,231	4,002,912
124	Railroad	667,121	-	-	-
125	Distribution Primary	171,915,812	81,304,471	382,919	31,967,343
126	Distribution Secondary	8,885,076	4,417,088	11,011	2,007,121
127	Customer	-	-	-	-
128	Customer Service	-	-	-	-
129	**Total**	$ 1,016,260,178	$ 379,410,499	$ 551,691	$ 136,294,643
	Customer				
130	Production	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-
132	Sub-Transmission	-	-	-	-
133	Railroad	-	-	-	-
134	Distribution Primary	-	-	-	-
135	Distribution Secondary	31,764,504	27,781,099	7,342	3,482,371
136	Customer	67,749,553	41,896,252	35,655	14,189,114
137	Customer Service	45,412,144	34,292,823	59,490	6,021,079
138	**Total**	$ 144,926,201	$ 103,970,174	$ 102,486	$ 23,692,564
	Energy				
139	Production	$ 43,393,030	$ 9,811,929	$ 29,664	$ 4,438,844
140	Transmission	-	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -
147	**Total**	$ 43,393,030	$ 9,811,929	$ 29,664	$ 4,438,844
	Fuel				
148	Fuel Expenses	$ 406,567,423	$ 91,863,453	$ 277,723	$ 41,558,348
149	**Total**	$ 406,567,423	$ 91,863,453	$ 277,723	$ 41,558,348
150	**Total**	$ 1,611,146,831	$ 585,056,054	$ 961,564	$ 205,984,399
	Total Revenue Requirement				
151	Demand	$ 1,016,260,178	$ 379,410,499	$ 551,691	$ 136,294,643
152	Customer	144,926,201	103,970,174	102,486	23,692,564
153	Energy	43,393,030	9,811,929	29,664	4,438,844
154	Fuel	406,567,423	91,863,453	277,723	41,558,348
155	**Total**	$ 1,611,146,831	$ 585,056,054	$ 961,564	$ 205,984,399
156	Zero-Check	-	-	-	-

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Functionalized Revenue Requirement After Other Revenue Credit				
119	Other Rev as % of Functionalized Revenue	2.13%	2.71%	2.37%	2.55%
120	Ratio (Inverse of Percentage)	97.87%	97.29%	97.63%	97.45%
	Demand				
121	Production	$ 655,034,312	$ -	$ 63,580,557	$ 69,368,680
122	Transmission	156,708,290	127,255	14,079,112	17,605,655
123	Sub-Transmission	23,049,566	44,505	2,436,816	3,010,855
124	Railroad	667,121	-	-	-
125	Distribution Primary	171,915,812	360,819	19,640,270	22,240,901
126	Distribution Secondary	8,885,076	12,777	1,226,278	647,731
127	Customer	-	-	-	-
128	Customer Service	-	-	-	-
129	**Total**	$ 1,016,260,178	$ 545,356	$ 100,963,033	$ 112,873,822
	Customer				
130	Production	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-
132	Sub-Transmission	-	-	-	-
133	Railroad	-	-	-	-
134	Distribution Primary	-	-	-	-
135	Distribution Secondary	31,764,504	13,724	244,503	18,837
136	Customer	67,749,553	59,205	1,591,458	305,317
137	Customer Service	45,412,144	49,180	883,367	1,107,916
138	**Total**	$ 144,926,201	$ 122,109	$ 2,719,328	$ 1,432,069
	Energy				
139	Production	$ 43,393,030	$ 33,379	$ 3,990,679	$ 5,732,161
140	Transmission	-	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -
147	**Total**	$ 43,393,030	$ 33,379	$ 3,990,679	$ 5,732,161
	Fuel				
148	Fuel Expenses	$ 406,567,423	$ 312,513	$ 37,362,433	$ 53,666,929
149	**Total**	$ 406,567,423	$ 312,513	$ 37,362,433	$ 53,666,929
150	**Total**	$ 1,611,146,831	$ 1,013,357	$ 145,035,473	$ 173,704,981
	Total Revenue Requirement				
151	Demand	$ 1,016,260,178	$ 545,356	$ 100,963,033	$ 112,873,822
152	Customer	144,926,201	122,109	2,719,328	1,432,069
153	Energy	43,393,030	33,379	3,990,679	5,732,161
154	Fuel	406,567,423	312,513	37,362,433	53,666,929
155	**Total**	$ 1,611,146,831	$ 1,013,357	$ 145,035,473	$ 173,704,981
156	Zero-Check	-	-	-	-

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. Rate 732	HLF Ind Pwr Serv. Rate 733
	(A)	(B)	(I)	(J)	(K)	(L)
	Functionalized Revenue Requirement After Other Revenue Credit					
119	Other Rev as % of Functionalized Revenue	2.13%	2.09%	1.70%	1.67%	1.95%
120	Ratio (Inverse of Percentage)	97.87%	97.91%	98.30%	98.33%	98.05%
	Demand					
121	Production	$ 655,034,312	$ 1,610,068	$ 45,602,071	$ 69,415,417	$ 36,495,248
122	Transmission	156,708,290	491,103	10,553,962	21,558,263	12,647,566
123	Sub-Transmission	23,049,566	194,263	1,736,837	859,941	303,999
124	Railroad	667,121	-	-	-	-
125	Distribution Primary	171,915,812	1,100,806	12,427,356	-	0
126	Distribution Secondary	8,885,076	28,210	405,511	-	-
127	Customer	-	-	-	-	-
128	Customer Service	-	-	-	-	-
129	**Total**	$ 1,016,260,178	$ 3,424,449	$ 70,725,737	$ 91,833,622	$ 49,446,812
	Customer					
130	Production	$ -	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-	-
132	Sub-Transmission	-	-	-	-	-
133	Railroad	-	-	-	-	-
134	Distribution Primary	-	-	-	-	-
135	Distribution Secondary	31,764,504	202	9,365	-	-
136	Customer	67,749,553	6,611	245,979	206,547	130,089
137	Customer Service	45,412,144	89,221	767,169	278,047	243,338
138	**Total**	$ 144,926,201	$ 96,034	$ 1,022,514	$ 484,595	$ 373,426
	Energy					
139	Production	$ 43,393,030	$ 269,464	$ 2,936,441	$ 5,368,316	$ 4,244,052
140	Transmission	-	$ -	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -	$ -
147	**Total**	$ 43,393,030	$ 269,464	$ 2,936,441	$ 5,368,316	$ 4,244,052
	Fuel					
148	Fuel Expenses	$ 406,567,423	$ 2,522,836	$ 27,492,212	$ 50,260,459	$ 39,734,624
149	**Total**	$ 406,567,423	$ 2,522,836	$ 27,492,212	$ 50,260,459	$ 39,734,624
150	**Total**	$ 1,611,146,831	$ 6,312,783	$ 102,176,904	$ 147,946,991	$ 93,798,914
	Total Revenue Requirement					
151	Demand	$ 1,016,260,178	$ 3,424,449	$ 70,725,737	$ 91,833,622	$ 49,446,812
152	Customer	144,926,201	96,034	1,022,514	484,595	373,426
153	Energy	43,393,030	269,464	2,936,441	5,368,316	4,244,052
154	Fuel	406,567,423	2,522,836	27,492,212	50,260,459	39,734,624
155	**Total**	$ 1,611,146,831	$ 6,312,783	$ 102,176,904	$ 147,946,991	$ 93,798,914
156	Zero-Check	-	-	-	-	-

Line No.	Description	System Total	Air Separation Rate 734	Muni. Power Rate 841	Int WW Pumping Rate 842
	(A)	(B)	(M)	(N)	(O)
	Functionalized Revenue Requirement After Other Revenue Credit				
119	Other Rev as % of Functionalized Revenue	2.13%	1.98%	1.97%	8.43%
120	Ratio (Inverse of Percentage)	97.87%	98.02%	98.03%	91.57%
	Demand				
121	Production	$ 655,034,312	$ 43,662,918	$ 1,021,620	$ 9,458
122	Transmission	156,708,290	18,228,305	278,463	2,471
123	Sub-Transmission	23,049,566	-	76,200	323
124	Railroad	667,121	-	-	-
125	Distribution Primary	171,915,812	-	617,782	2,623
126	Distribution Secondary	8,885,076	-	34,903	217
127	Customer	-	-	-	-
128	Customer Service	-	-	-	-
129	**Total**	$ 1,016,260,178	$ 61,891,224	$ 2,028,968	$ 15,092
	Customer				
130	Production	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-
132	Sub-Transmission	-	-	-	-
133	Railroad	-	-	-	-
134	Distribution Primary	-	-	-	-
135	Distribution Secondary	31,764,504	-	47,442	504
136	Customer	67,749,553	146,615	255,264	91
137	Customer Service	45,412,144	197,206	71,501	2,615
138	**Total**	$ 144,926,201	$ 343,821	$ 374,207	$ 3,210
	Energy				
139	Production	$ 43,393,030	$ 6,142,451	$ 80,992	$ 990
140	Transmission	-	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -
147	**Total**	$ 43,393,030	$ 6,142,451	$ 80,992	$ 990
	Fuel				
148	Fuel Expenses	$ 406,567,423	$ 57,508,240	$ 758,283	$ 9,265
149	**Total**	$ 406,567,423	$ 57,508,240	$ 758,283	$ 9,265
150	**Total**	$ 1,611,146,831	$ 125,885,736	$ 3,242,450	$ 28,557
	Total Revenue Requirement				
151	Demand	$ 1,016,260,178	$ 61,891,224	$ 2,028,968	$ 15,092
152	Customer	144,926,201	343,821	374,207	3,210
153	Energy	43,393,030	6,142,451	80,992	990
154	Fuel	406,567,423	57,508,240	758,283	9,265
155	**Total**	$ 1,611,146,831	$ 125,885,736	$ 3,242,450	$ 28,557
156	Zero-Check	-	-	-	-

Line No.	Description	System Total	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860
	(A)	(B)	(P)	(Q)	(R)	(S)
	Functionalized Revenue Requirement After Other Revenue Credit					
119	Other Rev as % of Functionalized Revenue	2.13%	2.26%	1.77%	2.59%	2.22%
120	Ratio (Inverse of Percentage)	97.87%	97.74%	98.23%	97.41%	97.78%
	Demand					
121	Production	$ 655,034,312	$ 475,589	$ -	$ 207,624	$ -
122	Transmission	156,708,290	129,514	40,609	53,227	19,179
123	Sub-Transmission	23,049,566	76,471	63,952	7,284	32,418
124	Railroad	667,121	667,121	-	-	-
125	Distribution Primary	171,915,812	-	518,484	59,055	262,822
126	Distribution Secondary	8,885,076	-	40,037	4,675	19,708
127	Customer	-	-	-	-	-
128	Customer Service	-	-	-	-	-
129	**Total**	$ 1,016,260,178	$ 1,348,695	$ 663,082	$ 331,865	$ 334,127
	Customer					
130	Production	$ -	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-	-
132	Sub-Transmission	-	-	-	-	-
133	Railroad	-	-	-	-	-
134	Distribution Primary	-	-	-	-	-
135	Distribution Secondary	31,764,504	-	14,918	2,346	138,745
136	Customer	67,749,553	2,590	6,826,129	132,276	1,720,360
137	Customer Service	45,412,144	17,333	851,993	9,925	468,623
138	**Total**	$ 144,926,201	$ 19,923	$ 7,693,040	$ 144,547	$ 2,327,729
	Energy					
139	Production	$ 43,393,030	$ 59,786	$ 119,474	$ 18,216	$ 42,640
140	Transmission	-	$ -	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -	$ -
147	**Total**	$ 43,393,030	$ 59,786	$ 119,474	$ 18,216	$ 42,640
	Fuel					
148	Fuel Expenses	$ 406,567,423	$ 559,742	$ 1,118,563	$ 170,544	$ 895,237
149	**Total**	$ 406,567,423	$ 559,742	$ 1,118,563	$ 170,544	$ 895,237
150	**Total**	$ 1,611,146,831	$ 1,988,147	$ 9,594,159	$ 665,172	$ 3,599,733
	Total Revenue Requirement					
151	Demand	$ 1,016,260,178	$ 1,348,695	$ 663,082	$ 331,865	$ 334,127
152	Customer	144,926,201	19,923	7,693,040	144,547	2,327,729
153	Energy	43,393,030	59,786	119,474	18,216	42,640
154	Fuel	406,567,423	559,742	1,118,563	170,544	895,237
155	**Total**	$ 1,611,146,831	$ 1,988,147	$ 9,594,159	$ 665,172	$ 3,599,733
156	Zero-Check	-	-	-	-	-

Line No.	Description	System Total	Interdepartmental Interdepartmental
	(A)	(B)	(S)
	Functionalized Revenue Requirement After Other Revenue Credit		
119	Other Rev as % of Functionalized Revenue	2.13%	1.86%
120	Ratio (Inverse of Percentage)	97.87%	98.14%
	Demand		
121	Production	$ 655,034,312	$ 2,076,436
122	Transmission	156,708,290	313,987
123	Sub-Transmission	23,049,566	127,065
124	Railroad	667,121	-
125	Distribution Primary	171,915,812	1,030,162
126	Distribution Secondary	8,885,076	29,811
127	Customer	-	-
128	Customer Service	-	-
129	**Total**	$ 1,016,260,178	$ 3,577,461
	Customer		
130	Production	$ -	$ -
131	Transmission	-	-
132	Sub-Transmission	-	-
133	Railroad	-	-
134	Distribution Primary	-	-
135	Distribution Secondary	31,764,504	3,106
136	Customer	67,749,553	-
137	Customer Service	45,412,144	1,318
138	**Total**	$ 144,926,201	$ 4,424
	Energy		
139	Production	$ 43,393,030	$ 73,553
140	Transmission	-	$ -
141	Sub-Transmission	-	$ -
142	Railroad	-	$ -
143	Distribution Primary	-	$ -
144	Distribution Secondary	-	$ -
145	Customer	-	$ -
146	Customer Service	-	$ -
147	**Total**	$ 43,393,030	$ 73,553
	Fuel		
148	Fuel Expenses	$ 406,567,423	$ 496,020
149	**Total**	$ 406,567,423	$ 496,020
150	**Total**	$ 1,611,146,831	$ 4,151,458
	Total Revenue Requirement		
151	Demand	$ 1,016,260,178	$ 3,577,461
152	Customer	144,926,201	4,424
153	Energy	43,393,030	73,553
154	Fuel	406,567,423	496,020
155	**Total**	$ 1,611,146,831	$ 4,151,458
156	Zero-Check	-	-

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Billing Determinants				
157	Demand (KW) - Production	21,538,854	0	0	0
158	Demand (KW) - Other	21,538,854	0	0	0
159	Customer (Customer Bills or No. Customers * 12)	6,529,485	4,946,379	1,244	627,481
160	Energy (kWh)	15,153,990,077	3,406,296,779	10,300,522	1,541,544,882
161	Fuel (kWh)	15,153,990,077	3,406,296,779	10,300,522	1,541,544,882
162	Demand Unit Cost - Production		0.00	0.00	0.00
163	Demand Unit Cost - Other		0.00	0.00	0.00
164	Customer Unit Cost		97.72	525.75	254.97
165	Energy Unit Cost		0.0028805	0.0028798	0.0028795
166	Fuel Unit Cost		0.0269687	0.0269621	0.0269589
167	Demand Revenue		$ -	$ -	$ -
168	Customer Revenue		483,380,673	654,176	159,987,207
169	Energy Revenue		9,811,929	29,664	4,438,844
170	Fuel Revenue		91,863,453	277,723	41,558,348
171	Total Revenue		585,056,054	961,564	205,984,399
172	Zero-Check		$ -	$ -	$ -
	Grid Facility				
173	Grid Facility - Revenue Requirement	506,152,066	241,652,150	654,176	80,207,104
174	Grid Facility - Unit Costs	77.51792141	48.85	525.75	127.82

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Billing Determinants				
157	Demand (KW) - Production	21,538,854	0	4,094,516	4,746,678
158	Demand (KW) - Other	21,538,854	0	4,094,516	4,746,678
159	Customer (Customer Bills or No. Customers * 12)	6,529,485	1,640	44,986	5,466
160	Energy (kWh)	15,153,990,077	11,587,981	1,386,084,286	1,998,019,018
161	Fuel (kWh)	15,153,990,077	11,587,981	1,386,084,286	1,998,019,018
162	Demand Unit Cost - Production		0.00	15.53	14.61
163	Demand Unit Cost - Other		0.00	9.13	9.17
164	Customer Unit Cost		406.94	60.45	261.98
165	Energy Unit Cost		0.0028805	0.0028791	0.0028689
166	Fuel Unit Cost		0.0269687	0.0269554	0.0268601
167	Demand Revenue		$ -	$ 100,963,033	$ 112,873,822
168	Customer Revenue		667,465	2,719,328	1,432,069
169	Energy Revenue		33,379	3,990,679	5,732,161
170	Fuel Revenue		312,513	37,362,433	53,666,929
171	Total Revenue		1,013,357	145,035,473	173,704,981
172	Zero-Check		$ -	$ -	$ -
	Grid Facility				
173	Grid Facility - Revenue Requirement	506,152,066	667,465	40,101,805	44,937,211
174	Grid Facility - Unit Costs	77.51792141	406.94	891.42	8,220.84

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. Rate 732	HLF Ind Pwr Serv. Rate 733
	(A)	(B)	(I)	(J)	(K)	(L)
	Billing Determinants					
157	Demand (KW) - Production	21,538,854	108,013	1,882,443	5,236,861	2,698,052
158	Demand (KW) - Other	21,538,854	108,013	1,882,443	5,236,861	2,698,052
159	Customer (Customer Bills or No. Customers * 12)	6,529,485	72	2,208	132	84
160	Energy (kWh)	15,153,990,077	94,118,668	1,023,539,449	1,888,838,716	1,493,743,680
161	Fuel (kWh)	15,153,990,077	94,118,668	1,023,539,449	1,888,838,716	1,493,743,680
162	Demand Unit Cost - Production		14.91	24.22	13.26	13.53
163	Demand Unit Cost - Other		16.80	13.35	4.28	4.80
164	Customer Unit Cost		1,333.81	463.09	3,671.17	4,445.55
165	Energy Unit Cost		0.0028630	0.0028689	0.0028421	0.0028412
166	Fuel Unit Cost		0.0268048	0.0268599	0.0266092	0.0266007
167	Demand Revenue		$ 3,424,449	$ 70,725,737	$ 91,833,622	$ 49,446,812
168	Customer Revenue		96,034	1,022,514	484,595	373,426
169	Energy Revenue		269,464	2,936,441	5,368,316	4,244,052
170	Fuel Revenue		2,522,836	27,492,212	50,260,459	39,734,624
171	Total Revenue		6,312,783	102,176,904	147,946,991	93,798,914
172	Zero-Check		$ -	$ -	$ -	$ -
	Grid Facility					
173	Grid Facility - Revenue Requirement	506,152,066	1,910,416	26,146,180	22,902,799	13,324,991
174	Grid Facility - Unit Costs	77.51792141	26,533.55	11,841.57	173,506.05	158,630.84

Line No.	Description	System Total	Air Separation Rate 734	Muni. Power Rate 841	Int WW Pumping Rate 842
	(A)	(B)	(M)	(N)	(O)
	Billing Determinants				
157	Demand (KW) - Production	21,538,854	2,700,000	0	0
158	Demand (KW) - Other	21,538,854	2,700,000	0	0
159	Customer (Customer Bills or No. Customers * 12)	6,529,485	12	8,501	96
160	Energy (kWh)	15,153,990,077	2,162,295,201	28,139,780	343,541
161	Fuel (kWh)	15,153,990,077	2,162,295,201	28,139,780	343,541
162	Demand Unit Cost - Production		16.17	0.00	0.00
163	Demand Unit Cost - Other		6.75	0.00	0.00
164	Customer Unit Cost		28,651.77	282.70	190.65
165	Energy Unit Cost		0.0028407	0.0028782	0.0028805
166	Fuel Unit Cost		0.0265959	0.0269470	0.0269687
167	Demand Revenue		$ 61,891,224	$ -	$ -
168	Customer Revenue		343,821	2,403,175	18,302
169	Energy Revenue		6,142,451	80,992	990
170	Fuel Revenue		57,508,240	758,283	9,265
171	Total Revenue		125,885,736	3,242,450	28,557
172	Zero-Check		$ -	$ -	$ -
	Grid Facility				
173	Grid Facility - Revenue Requirement	506,152,066	18,572,127	1,381,555	8,844
174	Grid Facility - Unit Costs	77.51792141	1,547,677.22	162.52	92.13

Line No.	Description	System Total	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860
	(A)	(B)	(P)	(Q)	(R)	(S)
	Billing Determinants					
157	Demand (KW) - Production	21,538,854	72,290	0	0	0
158	Demand (KW) - Other	21,538,854	72,290	0	0	0
159	Customer (Customer Bills or No. Customers * 12)	6,529,485	12	758,388	14,592	179,664
160	Energy (kWh)	15,153,990,077	21,000,000	41,476,293	6,323,787	14,802,974
161	Fuel (kWh)	15,153,990,077	21,000,000	41,476,293	6,323,787	14,802,974
162	Demand Unit Cost - Production		6.58	0.00	0.00	0.00
163	Demand Unit Cost - Other		12.08	0.00	0.00	0.00
164	Customer Unit Cost		1,660.25	11.02	32.65	14.82
165	Energy Unit Cost		0.0028470	0.0028805	0.0028805	0.0028805
166	Fuel Unit Cost		0.0266544	0.0269687	0.0269687	0.0604769
167	Demand Revenue		$ 1,348,695	$ -	$ -	$ -
168	Customer Revenue		19,923	8,356,122	476,412	2,661,855
169	Energy Revenue		59,786	119,474	18,216	42,640
170	Fuel Revenue		559,742	1,118,563	170,544	895,237
171	Total Revenue		1,988,147	9,594,159	665,172	3,599,733
172	Zero-Check		$ -	$ -	$ -	$ -
	Grid Facility					
173	Grid Facility - Revenue Requirement	506,152,066	893,029	8,356,122	268,788	2,661,855
174	Grid Facility - Unit Costs	77.51792141	74,419.09	11.02	18.42	14.82

Line No.	Description	System Total	Interdepartmental Interdepartmental
	(A)	(B)	(S)
	Billing Determinants		
157	Demand (KW) - Production	21,538,854	0
158	Demand (KW) - Other	21,538,854	0
159	Customer (Customer Bills or No. Customers * 12)	6,529,485	552
160	Energy (kWh)	15,153,990,077	25,534,520
161	Fuel (kWh)	15,153,990,077	25,534,520
162	Demand Unit Cost - Production		0.00
163	Demand Unit Cost - Other		0.00
164	Customer Unit Cost		6,488.92
165	Energy Unit Cost		0.0028805
166	Fuel Unit Cost		0.0194255
167	Demand Revenue		$ -
168	Customer Revenue		3,581,885
169	Energy Revenue		73,553
170	Fuel Revenue		496,020
171	Total Revenue		4,151,458
172	Zero-Check		$ -
	Grid Facility		
173	Grid Facility - Revenue Requirement	506,152,066	1,505,449
174	Grid Facility - Unit Costs	77.51792141	2,727.26

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Mitigated Revenue Requirement After Other Revenue Credit				
175	Other Rev as % of Functionalized Revenue	2.06%	2.00%	2.01%	2.50%
176	Ratio (Inverse of Percentage)	97.94%	98.00%	97.99%	97.50%
177	Mitigated Amount	0	0	0	0
	Total Revenue Requirement				
178	Demand	$ 1,016,260,178	$ 379,410,499	$ 551,691	$ 136,294,643
179	Customer	144,926,201	103,970,174	102,486	23,692,564
180	Energy	43,393,030	9,811,929	29,664	4,438,844
181	Fuel	406,567,423	91,863,453	277,723	41,558,348
182	**Total**	$ 1,611,146,831	$ 585,056,054	$ 961,564	$ 205,984,399
183	Zero-Check	-	-	-	-
	Billing Determinants				
184	Demand (KW) - Production	21,538,854	0	0	0
185	Demand (KW) - Other	21,538,854	0	0	0
186	Customer (Customer Bills or No. Customers * 12)	6,529,485	4,946,379	1,244	627,481
187	Energy (kWh)	15,153,990,077	3,406,296,779	10,300,522	1,541,544,882
188	Fuel (kWh)	15,153,990,077	3,406,296,779	10,300,522	1,541,544,882
189	Demand Unit Cost - Production		0.00	0.00	0.00
190	Demand Unit Cost - Other		0.00	0.00	0.00
191	Customer Unit Cost		97.72	525.75	254.97
192	Energy Unit Cost		0.0028805	0.0028798	0.0028795
193	Fuel Unit Cost		0.0269687	0.0269621	0.0269589
194	Demand Revenue		$ -	$ -	$ -
195	Customer Revenue		483,380,673	654,176	159,987,207
196	Energy Revenue		9,811,929	29,664	4,438,844
197	Fuel Revenue		91,863,453	277,723	41,558,348
198	Total Revenue		585,056,054	961,564	205,984,399
199	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Mitigated Revenue Requirement After Other Revenue Credit				
175	Other Rev as % of Functionalized Revenue	2.06%	2.58%	2.29%	2.44%
176	Ratio (Inverse of Percentage)	97.94%	97.42%	97.71%	97.56%
177	Mitigated Amount	0	0	0	0
	Total Revenue Requirement				
178	Demand	$ 1,016,260,178	$ 545,356	$ 100,963,033	$ 112,873,822
179	Customer	144,926,201	122,109	2,719,328	1,432,069
180	Energy	43,393,030	33,379	3,990,679	5,732,161
181	Fuel	406,567,423	312,513	37,362,433	53,666,929
182	**Total**	$ 1,611,146,831	$ 1,013,357	$ 145,035,473	$ 173,704,981
183	Zero-Check	-	-	-	-
	Billing Determinants				
184	Demand (KW) - Production	21,538,854	0	4,094,516	4,746,678
185	Demand (KW) - Other	21,538,854	0	4,094,516	4,746,678
186	Customer (Customer Bills or No. Customers * 12)	6,529,485	1,640	44,986	5,466
187	Energy (kWh)	15,153,990,077	11,587,981	1,386,084,286	1,998,019,018
188	Fuel (kWh)	15,153,990,077	11,587,981	1,386,084,286	1,998,019,018
189	Demand Unit Cost - Production		0.00	15.53	14.61
190	Demand Unit Cost - Other		0.00	9.13	9.17
191	Customer Unit Cost		406.94	60.45	261.98
192	Energy Unit Cost		0.0028805	0.0028791	0.0028689
193	Fuel Unit Cost		0.0269687	0.0269554	0.0268601
194	Demand Revenue		$ -	$ 100,963,033	$ 112,873,822
195	Customer Revenue		667,465	2,719,328	1,432,069
196	Energy Revenue		33,379	3,990,679	5,732,161
197	Fuel Revenue		312,513	37,362,433	53,666,929
198	Total Revenue		1,013,357	145,035,473	173,704,981
199	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. Rate 732	HLF Ind Pwr Serv. Rate 733
	(A)	(B)	(I)	(J)	(K)	(L)
	Mitigated Revenue Requirement After Other Revenue Credit					
175	Other Rev as % of Functionalized Revenue	2.06%	1.94%	1.63%	1.58%	1.80%
176	Ratio (Inverse of Percentage)	97.94%	98.06%	98.37%	98.42%	98.20%
177	Mitigated Amount	0	0	0	0	0
	Total Revenue Requirement					
178	Demand	$ 1,016,260,178	$ 3,424,449	$ 70,725,737	$ 91,833,622	$ 49,446,812
179	Customer	144,926,201	96,034	1,022,514	484,595	373,426
180	Energy	43,393,030	269,464	2,936,441	5,368,316	4,244,052
181	Fuel	406,567,423	2,522,836	27,492,212	50,260,459	39,734,624
182	**Total**	$ 1,611,146,831	$ 6,312,783	$ 102,176,904	$ 147,946,991	$ 93,798,914
183	Zero-Check	-	-	-	-	-
	Billing Determinants					
184	Demand (KW) - Production	21,538,854	108,013	1,882,443	5,236,861	2,698,052
185	Demand (KW) - Other	21,538,854	108,013	1,882,443	5,236,861	2,698,052
186	Customer (Customer Bills or No. Customers * 12)	6,529,485	72	2,208	132	84
187	Energy (kWh)	15,153,990,077	94,118,668	1,023,539,449	1,888,838,716	1,493,743,680
188	Fuel (kWh)	15,153,990,077	94,118,668	1,023,539,449	1,888,838,716	1,493,743,680
189	Demand Unit Cost - Production		14.91	24.22	13.26	13.53
190	Demand Unit Cost - Other		16.80	13.35	4.28	4.80
191	Customer Unit Cost		1,333.81	463.09	3,671.17	4,445.55
192	Energy Unit Cost		0.0028630	0.0028689	0.0028421	0.0028412
193	Fuel Unit Cost		0.0268048	0.0268599	0.0266092	0.0266007
194	Demand Revenue		$ 3,424,449	$ 70,725,737	$ 91,833,622	$ 49,446,812
195	Customer Revenue		96,034	1,022,514	484,595	373,426
196	Energy Revenue		269,464	2,936,441	5,368,316	4,244,052
197	Fuel Revenue		2,522,836	27,492,212	50,260,459	39,734,624
198	Total Revenue		6,312,783	102,176,904	147,946,991	93,798,914
199	Zero-Check		$ -	$ -	$ -	$ -

Line No.	Description	System Total	Air Separation Rate 734	Muni. Power Rate 841	Int WW Pumping Rate 842
	(A)	(B)	(M)	(N)	(O)
	Mitigated Revenue Requirement After Other Revenue Credit				
175	Other Rev as % of Functionalized Revenue	2.06%	1.80%	1.91%	8.03%
176	Ratio (Inverse of Percentage)	97.94%	98.20%	98.09%	91.97%
177	Mitigated Amount	0	0	0	0
	Total Revenue Requirement				
178	Demand	$ 1,016,260,178	$ 61,891,224	$ 2,028,968	$ 15,092
179	Customer	144,926,201	343,821	374,207	3,210
180	Energy	43,393,030	6,142,451	80,992	990
181	Fuel	406,567,423	57,508,240	758,283	9,265
182	**Total**	$ 1,611,146,831	$ 125,885,736	$ 3,242,450	$ 28,557
183	Zero-Check	-	-	-	-
	Billing Determinants				
184	Demand (KW) - Production	21,538,854	2,700,000	0	0
185	Demand (KW) - Other	21,538,854	2,700,000	0	0
186	Customer (Customer Bills or No. Customers * 12)	6,529,485	12	8,501	96
187	Energy (kWh)	15,153,990,077	2,162,295,201	28,139,780	343,541
188	Fuel (kWh)	15,153,990,077	2,162,295,201	28,139,780	343,541
189	Demand Unit Cost - Production		16.17	0.00	0.00
190	Demand Unit Cost - Other		6.75	0.00	0.00
191	Customer Unit Cost		28,651.77	282.70	190.65
192	Energy Unit Cost		0.0028407	0.0028782	0.0028805
193	Fuel Unit Cost		0.0265959	0.0269470	0.0269687
194	Demand Revenue		$ 61,891,224	$ -	$ -
195	Customer Revenue		343,821	2,403,175	18,302
196	Energy Revenue		6,142,451	80,992	990
197	Fuel Revenue		57,508,240	758,283	9,265
198	Total Revenue		125,885,736	3,242,450	28,557
199	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Railroad Rate 844	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860
	(A)	(B)	(P)	(Q)	(R)	(S)
	Mitigated Revenue Requirement After Other Revenue Credit					
175	Other Rev as % of Functionalized Revenue	2.06%	2.16%	1.75%	2.49%	2.19%
176	Ratio (Inverse of Percentage)	97.94%	97.84%	98.25%	97.51%	97.81%
177	Mitigated Amount	0	0	0	0	0
	Total Revenue Requirement					
178	Demand	$ 1,016,260,178	$ 1,348,695	$ 663,082	$ 331,865	$ 334,127
179	Customer	144,926,201	19,923	7,693,040	144,547	2,327,729
180	Energy	43,393,030	59,786	119,474	18,216	42,640
181	Fuel	406,567,423	559,742	1,118,563	170,544	895,237
182	**Total**	$ 1,611,146,831	$ 1,988,147	$ 9,594,159	$ 665,172	$ 3,599,733
183	Zero-Check	-	-	-	-	-
	Billing Determinants					
184	Demand (KW) - Production	21,538,854	72,290	0	0	0
185	Demand (KW) - Other	21,538,854	72,290	0	0	0
186	Customer (Customer Bills or No. Customers * 12)	6,529,485	12	758,388	14,592	179,664
187	Energy (kWh)	15,153,990,077	21,000,000	41,476,293	6,323,787	14,802,974
188	Fuel (kWh)	15,153,990,077	21,000,000	41,476,293	6,323,787	14,802,974
189	Demand Unit Cost - Production		6.58	0.00	0.00	0.00
190	Demand Unit Cost - Other		12.08	0.00	0.00	0.00
191	Customer Unit Cost		1,660.25	11.02	32.65	14.82
192	Energy Unit Cost		0.0028470	0.0028805	0.0028805	0.0028805
193	Fuel Unit Cost		0.0266544	0.0269687	0.0269687	0.0604769
194	Demand Revenue		$ 1,348,695	$ -	$ -	$ -
195	Customer Revenue		19,923	8,356,122	476,412	2,661,855
196	Energy Revenue		59,786	119,474	18,216	42,640
197	Fuel Revenue		559,742	1,118,563	170,544	895,237
198	Total Revenue		1,988,147	9,594,159	665,172	3,599,733
199	Zero-Check		$ -	$ -	$ -	$ -

Line No.	Description	System Total	Interdepartmental Interdepartmental
	(A)	(B)	(S)
	Mitigated Revenue Requirement After Other Revenue Credit		
175	Other Rev as % of Functionalized Revenue	2.06%	1.82%
176	Ratio (Inverse of Percentage)	97.94%	98.18%
177	Mitigated Amount	0	0
	Total Revenue Requirement		
178	Demand	$ 1,016,260,178	$ 3,577,461
179	Customer	144,926,201	4,424
180	Energy	43,393,030	73,553
181	Fuel	406,567,423	496,020
182	**Total**	$ 1,611,146,831	$ 4,151,458
183	Zero-Check	-	-
	Billing Determinants		
184	Demand (KW) - Production	21,538,854	0
185	Demand (KW) - Other	21,538,854	0
186	Customer (Customer Bills or No. Customers * 12)	6,529,485	552
187	Energy (kWh)	15,153,990,077	25,534,520
188	Fuel (kWh)	15,153,990,077	25,534,520
189	Demand Unit Cost - Production		0.00
190	Demand Unit Cost - Other		0.00
191	Customer Unit Cost		6,488.92
192	Energy Unit Cost		0.0028805
193	Fuel Unit Cost		0.0194255
194	Demand Revenue		$ -
195	Customer Revenue		3,581,885
196	Energy Revenue		73,553
197	Fuel Revenue		496,020
198	Total Revenue		4,151,458
199	Zero-Check		$ -

Attachment JFW-9

Cause No. 45159
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Set No. 5

OUCC Request 5-010:
Regarding Q/A 22 on page 13 of witness Hooper's testimony: a) Mr. Hooper states that transitioning much of NIPSCO's industrial load to the proposed market-sensitive rate structure ". . . will result in a near term shifting of some fixed costs currently being recovered from the industrial customers to other customers . . ." Please identify the magnitude of this shift. To the extent that magnitude is supported by calculations, please provide those calculations and, to the extent electronic spreadsheets were used in performing those calculations, please provide those spreadsheets in electronic format with formulas intact. b) He further states "I have no doubt that if the economics continue, and NIPSCO does not respond, there is a high probability that more industrial load will leave the system . . . " Please provide the basis for Mr. Hooper's contention that more industrial load will leave the system.
Objections:
Response:
a) The magnitude of the shift of costs currently being recovered from the industrial customers to other customers as a result of the new market-sensitive rate structure is $40,244,957 as shown as the change in margin for the large industrial rates from step 3 to step 4 in OUCC Request 5-010 Attachment A. NIPSCO would further note that, as stated in Mr. Hooper's testimony at page 12, it is the current interruptible load which has facilitated the retirement of Bailly which results in savings for ratepayers. b) Please see response to OUCC Request 5-007 subpart a).

Attachment JFW-10

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821	Comml SH Rate 822
	(A)	(B)	(C)	(D)	(E)	(F)
	Rate Base					
1	Plant in Service	$ 8,111,276,450	$ 3,531,932,890	$ 4,515,213	$ 1,217,946,584	$ 4,803,655
2	Accumulated Reserve	(4,210,571,859)	(1,846,155,017)	(1,986,732)	(620,786,422)	(2,150,568)
3	Other Rate Base Items	212,741,209	86,076,565	239,918	32,910,076	258,931
4	Total Rate Base	$ 4,113,445,801	$ 1,771,854,438	$ 2,768,398	$ 630,070,238	$ 2,912,017
	Revenues at Current Rates					
5	Retail Sales - Non Fuel	$ 1,089,552,179	$ 359,534,736	$ 521,256	$ 179,254,376	$ 749,365
6	Retail Sales - Fuel	322,936,621	90,791,267	273,768	40,938,915	308,000
7	Total Retail Sales Revenue	$ 1,412,488,800	$ 450,326,003	$ 795,024	$ 220,193,291	$ 1,057,365
8	Other Revenue	21,940,650	8,965,465	12,461	3,676,623	16,324
9	Total Other Revenue (To be Credited)	$ 21,940,650	$ 8,965,465	$ 12,461	$ 3,676,623	$ 16,324
10	Interruptible Power Credit	$ -	$ 17,368,912	$ 49,131	$ 6,577,958	$ 61,911
11	Total Revenues	$ 1,434,429,450	$ 476,660,380	$ 856,616	$ 230,447,872	$ 1,135,600
	Expenses at Current Rates					
12	Operations & Maintenance Expenses	$ 491,038,911	$ 218,995,676	$ 292,147	$ 70,973,404	$ 291,187
13	Depreciation Expense	297,033,774	125,884,154	126,301	43,471,719	132,387
14	Amortization Expense	50,657,236	26,814,608	28,566	7,145,829	32,509
15	Taxes Other Than Income Taxes	39,161,650	17,341,681	22,406	5,832,040	23,082
16	Fuel Expenses	322,936,621	92,632,429	282,891	42,326,221	318,327
17	Income Taxes	27,609,096	(50,890,417)	(12,743)	19,043,243	122,245
18	Total Expenses - Current	$ 1,228,437,287	$ 430,778,131	$ 739,568	$ 188,792,455	$ 919,738
19	Current Operating Income	$ 205,992,163	$ 45,882,249	$ 117,048	$ 41,655,417	$ 215,863
20	Return at Current Rates	5.01%	2.59%	4.23%	6.61%	7.41%
21	Index Rate of Return	1.00	0.52	0.84	1.32	1.48

Line No.	Description	System Total	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(G)	(H)
	Rate Base			
1	Plant in Service	$ 8,111,276,450	$ 790,689,216	$ 869,810,191
2	Accumulated Reserve	(4,210,571,859)	(402,976,979)	(446,248,109)
3	Other Rate Base Items	212,741,209	19,545,668	23,871,693
4	Total Rate Base	$ 4,113,445,801	$ 407,257,906	$ 447,433,775
	Revenues at Current Rates			
5	Retail Sales - Non Fuel	$ 1,089,552,179	$ 124,708,349	$ 143,524,164
6	Retail Sales - Fuel	322,936,621	36,753,329	52,714,526
7	Total Retail Sales Revenue	$ 1,412,488,800	$ 161,461,678	$ 196,238,690
8	Other Revenue	21,940,650	2,144,515	2,563,265
9	Total Other Revenue (To be Credited)	$ 21,940,650	$ 2,144,515	$ 2,563,265
10	Interruptible Power Credit	$ -	$ 6,951,810	$ 7,188,947
11	Total Revenues	$ 1,434,429,450	$ 170,558,003	$ 205,990,902
	Expenses at Current Rates			
12	Operations & Maintenance Expenses	$ 491,038,911	$ 47,557,476	$ 53,639,194
13	Depreciation Expense	297,033,774	30,175,951	33,826,437
14	Amortization Expense	50,657,236	3,860,499	4,242,352
15	Taxes Other Than Income Taxes	39,161,650	3,770,820	4,141,092
16	Fuel Expenses	322,936,621	38,058,912	54,276,650
17	Income Taxes	27,609,096	17,003,851	21,097,179
18	Total Expenses - Current	$ 1,228,437,287	$ 140,427,508	$ 171,222,904
19	Current Operating Income	$ 205,992,163	$ 30,130,495	$ 34,767,998
20	Return at Current Rates	5.01%	7.40%	7.77%
21	Index Rate of Return	1.00	1.48	1.55

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830	Muni. Power Rate 841
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Rate Base						
1	Plant in Service	$ 8,111,276,450	$ 26,047,640	$ 542,242,491	$ 762,211,729	$ 218,014,113	$ 18,236,176
2	Accumulated Reserve	(4,210,571,859)	(12,787,055)	(278,248,249)	(394,476,612)	(118,646,132)	(9,115,095)
3	Other Rate Base Items	212,741,209	1,027,920	13,166,323	24,603,577	5,598,109	576,183
4	Total Rate Base	$ 4,113,445,801	$ 14,288,505	$ 277,160,566	$ 392,338,694	$ 104,966,091	$ 9,697,263
	Revenues at Current Rates						
5	Retail Sales - Non Fuel	$ 1,089,552,179	$ 3,821,199	$ 60,142,467	$ 172,461,961	$ 28,346,403	$ 2,400,881
6	Retail Sales - Fuel	322,936,621	2,501,305	27,239,411	50,407,897	17,292,999	749,204
7	Total Retail Sales Revenue	$ 1,412,488,800	$ 6,322,504	$ 87,381,878	$ 222,869,857	$ 45,639,403	$ 3,150,085
8	Other Revenue	21,940,650	63,491	1,058,642	2,725,773	440,349	41,113
9	Total Other Revenue (To be Credited)	$ 21,940,650	$ 63,491	$ 1,058,642	$ 2,725,773	$ 440,349	$ 41,113
10	Interruptible Power Credit	$ -	$ 433,234	$ 3,462,534	$ (44,568,656)	$ 2,009,885	$ 91,209
11	Total Revenues	$ 1,434,429,450	$ 6,819,228	$ 91,903,053	$ 181,026,974	$ 48,089,637	$ 3,282,408
	Expenses at Current Rates						
12	Operations & Maintenance Expenses	$ 491,038,911	$ 1,717,548	$ 33,131,842	$ 42,553,090	$ 14,075,443	$ 1,045,941
13	Depreciation Expense	297,033,774	942,962	20,981,962	26,811,643	9,178,007	630,395
14	Amortization Expense	50,657,236	138,170	2,582,619	3,790,985	1,052,297	107,841
15	Taxes Other Than Income Taxes	39,161,650	124,532	2,583,112	3,580,255	1,048,575	86,450
16	Fuel Expenses	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530	769,185
17	Income Taxes	27,609,096	431,914	(4,624,056)	26,288,886	(325,051)	120,000
18	Total Expenses - Current	$ 1,228,437,287	$ 5,874,819	$ 82,444,490	$ 145,229,628	$ 43,542,801	$ 2,759,812
19	Current Operating Income	$ 205,992,163	$ 944,409	$ 9,458,563	$ 35,797,346	$ 4,546,835	$ 522,596
20	Return at Current Rates	5.01%	6.61%	3.41%	9.12%	4.33%	5.39%
21	Index Rate of Return	1.00	1.32	0.68	1.82	0.86	1.08

Line No.	Description	System Total	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(N)	(O)
	Rate Base			
1	Plant in Service	$ 8,111,276,450	$ 130,288	$ 11,129,219
2	Accumulated Reserve	(4,210,571,859)	(67,044)	(4,978,052)
3	Other Rate Base Items	212,741,209	3,800	420,882
4	Total Rate Base	$ 4,113,445,801	$ 67,044	$ 6,572,049
	Revenues at Current Rates			
5	Retail Sales - Non Fuel	$ 1,089,552,179	$ 93,004	$ 1,544,820
6	Retail Sales - Fuel	322,936,621	9,127	560,179
7	Total Retail Sales Revenue	$ 1,412,488,800	$ 102,131	$ 2,104,999
8	Other Revenue	21,940,650	1,404	26,924
9	Total Other Revenue (To be Credited)	$ 21,940,650	$ 1,404	$ 26,924
10	Interruptible Power Credit	$ -	$ 655	$ 73,272
11	Total Revenues	$ 1,434,429,450	$ 104,190	$ 2,205,195
	Expenses at Current Rates			
12	Operations & Maintenance Expenses	$ 491,038,911	$ 10,475	$ 506,486
13	Depreciation Expense	297,033,774	4,860	370,148
14	Amortization Expense	50,657,236	849	57,312
15	Taxes Other Than Income Taxes	39,161,650	671	49,520
16	Fuel Expenses	322,936,621	9,197	567,744
17	Income Taxes	27,609,096	44,601	211,107
18	Total Expenses - Current	$ 1,228,437,287	$ 70,653	$ 1,762,315
19	Current Operating Income	$ 205,992,163	$ 33,538	$ 442,879
20	Return at Current Rates	5.01%	50.02%	6.74%
21	Index Rate of Return	1.00	9.99	1.35

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Rate Base					
1	Plant in Service	$ 8,111,276,450	$ 65,300,558	$ 3,771,996	$ 17,450,182	$ 27,044,310
2	Accumulated Reserve	(4,210,571,859)	(43,447,370)	(2,131,868)	(12,873,597)	(13,496,959)
3	Other Rate Base Items	212,741,209	2,956,126	122,191	767,889	595,358
4	Total Rate Base	$ 4,113,445,801	$ 24,809,314	$ 1,762,319	$ 5,344,475	$ 14,142,709
	Revenues at Current Rates					
5	Retail Sales - Non Fuel	$ 1,089,552,179	$ 6,272,059	$ 646,898	$ 2,028,970	$ 3,501,270
6	Retail Sales - Fuel	322,936,621	901,306	161,857	341,490	992,041
7	Total Retail Sales Revenue	$ 1,412,488,800	$ 7,173,365	$ 808,755	$ 2,370,460	$ 4,493,311
8	Other Revenue	21,940,650	131,969	10,694	54,416	7,222
9	Total Other Revenue (To be Credited)	$ 21,940,650	$ 131,969	$ 10,694	$ 54,416	$ 7,222
10	Interruptible Power Credit	$ -	$ 100,173	$ 34,355	$ 27,279	$ 137,391
11	Total Revenues	$ 1,434,429,450	$ 7,405,507	$ 853,805	$ 2,452,155	$ 4,637,924
	Expenses at Current Rates					
12	Operations & Maintenance Expenses	$ 491,038,911	$ 3,060,206	$ 200,353	$ 1,438,151	$ 1,550,291
13	Depreciation Expense	297,033,774	2,833,195	150,386	486,789	1,026,477
14	Amortization Expense	50,657,236	359,508	21,938	294,386	126,970
15	Taxes Other Than Income Taxes	39,161,650	309,314	17,492	102,878	127,729
16	Fuel Expenses	322,936,621	1,110,412	169,302	396,308	992,040
17	Income Taxes	27,609,096	(828,291)	127,260	(302,724)	102,094
18	Total Expenses - Current	$ 1,228,437,287	$ 6,844,344	$ 686,730	$ 2,415,789	$ 3,925,601
19	Current Operating Income	$ 205,992,163	$ 561,163	$ 167,074	$ 36,366	$ 712,323
20	Return at Current Rates	5.01%	2.26%	9.48%	0.68%	5.04%
21	Index Rate of Return	1.00	0.45	1.89	0.14	1.01

Line No.	Description		System Total		Residential Rate 811		C&GS Heat Pump Rate 820		GS Small Rate 821		Comml SH Rate 822
	(A)		(B)		(C)		(D)		(E)		(F)
	Revenue Requirement at Equal Rates of Return at Current Rates										
22	Required Return		5.01%		5.01%		5.01%		5.01%		5.01%
23	Required Operating Income	$	205,992,163	$	88,730,506	$	138,635	$	31,552,508	$	145,827
	Expenses at Required Return										
24	Operations & Maintenance Expenses	$	491,038,911	$	218,995,676	$	292,147	$	70,973,404	$	291,187
25	Depreciation Expense		297,033,774		125,884,154		126,301		43,471,719		132,387
26	Amortization Expense		50,657,236		26,814,608		28,566		7,145,829		32,509
27	Taxes Other Than Income Taxes		39,161,650		17,341,681		22,406		5,832,040		23,082
28	Fuel Expenses		322,936,621		92,632,429		282,891		42,326,221		318,327
29	Income Taxes		27,609,096		11,892,535		18,581		4,228,977		19,545
30	Total Expenses - Required	$	1,228,437,287	$	493,561,083	$	770,893	$	173,978,189	$	817,037
31	Total Revenue Requirement at Equal Return	$	1,434,429,450	$	582,291,590	$	909,528	$	205,530,697	$	962,865
32	Current Subsidy	$	-	$	(105,631,210)	$	(52,912)	$	24,917,175	$	172,736
	Revenue Requirement at Equal Rates of Return at Proposed Rates										
33	Required Return		7.02%		7.02%		7.02%		7.02%		7.02%
34	Required Operating Income	$	288,763,895	$	124,384,182	$	194,342	$	44,230,931	$	204,424
35	Operating Income (Deficiency)/Surplus	$	(82,771,732)	$	(78,501,932)	$	(77,294)	$	(2,575,513)	$	11,439
	Expenses at Required Return										
36	Operations & Maintenance Expenses	$	491,271,586	$	219,169,037	$	292,147	$	70,984,477	$	291,191
37	Depreciation Expense		297,033,774		125,884,154		126,301		43,471,719		132,387
38	Amortization Expense		50,657,236		26,814,608		28,566		7,145,829		32,509
39	Taxes Other than Income		39,295,540		17,399,981		22,481		5,852,144		23,161
40	Fuel Expenses		322,936,621		92,632,429		282,891		42,326,221		318,327
41	Income Taxes		55,856,537		24,060,036		37,592		8,555,732		39,542
42	Total Expense - Required	$	1,257,051,293	$	505,960,245	$	789,978	$	178,336,122	$	837,118
43	Total Revenue Requirement at Equal Return	$	1,545,815,189	$	630,344,426	$	984,320	$	222,567,053	$	1,041,541
44	Revenue (Deficiency)/Surplus	$	(111,385,738)	$	(153,684,046)	$	(127,704)	$	7,880,819	$	94,059
45	Total Revenues		1,434,429,450		476,660,380		856,616		230,447,872		1,135,600
46	Total Revenues as Proposed	$	1,545,815,189	$	630,344,426	$	984,320	$	222,567,053	$	1,041,541
47	Less Total Other Revenues	$	22,123,710	$	9,026,066	$	12,549	$	3,706,837	$	16,450
48	Total Base Rate Revenues as Proposed	$	1,523,691,478	$	621,318,360	$	971,771	$	218,860,215	$	1,025,091
	Mitigation										
49	Mitigation	$	(0)	$	(100,218,769)	$	(31,620)	$	33,729,327	$	221,435
50	Proposed Increase Post Mitigation		111,385,738		53,465,277		96,084		25,848,507		127,376

Line No.	Description	System Total	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(G)	(H)
	Revenue Requirement at Equal Rates of Return at Current Rates			
22	Required Return	5.01%	5.01%	5.01%
23	Required Operating Income	$ 205,992,163	$ 20,394,565	$ 22,406,482
	Expenses at Required Return			
24	Operations & Maintenance Expenses	$ 491,038,911	$ 47,557,476	$ 53,639,194
25	Depreciation Expense	297,033,774	30,175,951	33,826,437
26	Amortization Expense	50,657,236	3,860,499	4,242,352
27	Taxes Other Than Income Taxes	39,161,650	3,770,820	4,141,092
28	Fuel Expenses	322,936,621	38,058,912	54,276,650
29	Income Taxes	27,609,096	2,733,480	3,003,137
30	Total Expenses - Required	$ 1,228,437,287	$ 126,157,138	$ 153,128,862
31	Total Revenue Requirement at Equal Return	$ 1,434,429,450	$ 146,551,702	$ 175,535,345
32	Current Subsidy	$ -	$ 24,006,301	$ 30,455,557
	Revenue Requirement at Equal Rates of Return at Proposed Rates			
33	Required Return	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,763,895	$ 28,589,505	$ 31,409,851
35	Operating Income (Deficiency)/Surplus	$ (82,771,732)	$ 1,540,990	$ 3,358,147
	Expenses at Required Return			
36	Operations & Maintenance Expenses	$ 491,271,586	$ 47,560,604	$ 53,656,103
37	Depreciation Expense	297,033,774	30,175,951	33,826,437
38	Amortization Expense	50,657,236	3,860,499	4,242,352
39	Taxes Other than Income	39,295,540	3,783,872	4,155,450
40	Fuel Expenses	322,936,621	38,058,912	54,276,650
41	Income Taxes	55,856,537	5,530,161	6,075,709
42	Total Expense - Required	$ 1,257,051,293	$ 128,969,998	$ 156,232,701
43	Total Revenue Requirement at Equal Return	$ 1,545,815,189	$ 157,559,503	$ 187,642,552
44	Revenue (Deficiency)/Surplus	$ (111,385,738)	$ 12,998,500	$ 18,348,351
45	Total Revenues	1,434,429,450	170,558,003	205,990,902
46	Total Revenues as Proposed	$ 1,545,815,189	$ 157,559,503	$ 187,642,552
47	Less Total Other Revenues	$ 22,123,710	$ 2,165,536	$ 2,587,457
48	Total Base Rate Revenues as Proposed	$ 1,523,691,478	$ 155,393,967	$ 185,055,095
	Mitigation			
49	Mitigation	$ (0)	$ 32,129,377	$ 41,453,608
50	Proposed Increase Post Mitigation	111,385,738	19,130,877	23,105,257

Summary Tab Made PUBLIC by NIPSCO

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830	Muni. Power Rate 841
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Revenue Requirement at Equal Rates of Return at Current Rates						
22	Required Return	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%
23	Required Operating Income	$ 205,992,163	$ 715,536	$ 13,879,581	$ 19,647,444	$ 5,256,467	$ 485,617
	Expenses at Required Return						
24	Operations & Maintenance Expenses	$ 491,038,911	$ 1,717,548	$ 33,131,842	$ 42,553,090	$ 14,075,443	$ 1,045,941
25	Depreciation Expense	297,033,774	942,962	20,981,962	26,811,643	9,178,007	630,395
26	Amortization Expense	50,657,236	138,170	2,582,619	3,790,985	1,052,297	107,841
27	Taxes Other Than Income Taxes	39,161,650	124,532	2,583,112	3,580,255	1,048,575	86,450
28	Fuel Expenses	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530	769,185
29	Income Taxes	27,609,096	95,903	1,860,278	2,633,344	704,523	65,087
30	Total Expenses - Required	$ 1,228,437,287	$ 5,538,808	$ 88,928,824	$ 121,574,086	$ 44,572,376	$ 2,704,899
31	Total Revenue Requirement at Equal Return	$ 1,434,429,450	$ 6,254,344	$ 102,808,405	$ 141,221,530	$ 49,828,843	$ 3,190,517
32	Current Subsidy	$ -	$ 564,884	$ (10,905,352)	$ 39,805,444	$ (1,739,206)	$ 91,891
	Revenue Requirement at Equal Rates of Return at Proposed Rates						
33	Required Return	7.02%	7.02%	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,763,895	$ 1,003,053	$ 19,456,672	$ 27,542,176	$ 7,368,620	$ 680,748
35	Operating Income (Deficiency)/Surplus	$ (82,771,732)	$ (58,644)	$ (9,998,109)	$ 8,255,169	$ (2,821,784)	$ (158,152)
	Expenses at Required Return						
36	Operations & Maintenance Expenses	$ 491,271,586	$ 1,717,548	$ 33,159,634	$ 42,553,090	$ 14,075,443	$ 1,045,941
37	Depreciation Expense	297,033,774	942,962	20,981,962	26,811,643	9,178,007	630,395
38	Amortization Expense	50,657,236	138,170	2,582,619	3,790,985	1,052,297	107,841
39	Taxes Other than Income	39,295,540	124,962	2,592,063	3,592,837	1,052,173	86,751
40	Fuel Expenses	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530	769,185
41	Income Taxes	55,856,537	194,024	3,763,567	5,327,573	1,425,336	131,679
42	Total Expense - Required	$ 1,257,051,293	$ 5,637,359	$ 90,868,856	$ 124,280,896	$ 45,296,787	$ 2,771,792
43	Total Revenue Requirement at Equal Return	$ 1,545,815,189	$ 6,640,412	$ 110,325,528	$ 151,823,073	$ 52,665,407	$ 3,452,540
44	Revenue (Deficiency)/Surplus	$ (111,385,738)	$ 178,817	$ (18,422,474)	$ 29,203,901	$ (4,575,770)	$ (170,133)
45	Total Revenues	1,434,429,450	6,819,228	91,903,053	181,026,974	48,089,637	3,282,408
46	Total Revenues as Proposed	$ 1,545,815,189	$ 6,640,412	$ 110,325,528	$ 151,823,073	$ 52,665,407	$ 3,452,540
47	Less Total Other Revenues	$ 22,123,710	$ 64,135	$ 1,068,779	$ 2,754,842	$ 445,127	$ 41,518
48	Total Base Rate Revenues as Proposed	$ 1,523,691,478	$ 6,576,277	$ 109,256,748	$ 149,068,230	$ 52,220,280	$ 3,411,022
	Mitigation						
49	Mitigation	$ (0)	$ 943,705	$ (8,114,040)	$ -	$ 818,271	$ 198,043
50	Proposed Increase Post Mitigation	111,385,738	764,888	10,308,434	(29,203,901)	5,394,041	368,176

Line No.	Description	System Total	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(N)	(O)
	Revenue Requirement at Equal Rates of Return at Current Rates			
22	Required Return	5.01%	5.01%	5.01%
23	Required Operating Income	$ 205,992,163	$ 3,357	$ 329,114
	Expenses at Required Return			
24	Operations & Maintenance Expenses	$ 491,038,911	$ 10,475	$ 506,486
25	Depreciation Expense	297,033,774	4,860	370,148
26	Amortization Expense	50,657,236	849	57,312
27	Taxes Other Than Income Taxes	39,161,650	671	49,520
28	Fuel Expenses	322,936,621	9,197	567,744
29	Income Taxes	27,609,096	450	44,111
30	Total Expenses - Required	$ 1,228,437,287	$ 26,502	$ 1,595,320
31	Total Revenue Requirement at Equal Return	$ 1,434,429,450	$ 29,860	$ 1,924,433
32	Current Subsidy	$ -	$ 74,331	$ 280,762
	Revenue Requirement at Equal Rates of Return at Proposed Rates			
33	Required Return	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,763,895	$ 4,707	$ 461,358
35	Operating Income (Deficiency)/Surplus	$ (82,771,732)	$ 28,831	$ (18,478)
	Expenses at Required Return			
36	Operations & Maintenance Expenses	$ 491,271,586	$ 10,475	$ 506,486
37	Depreciation Expense	297,033,774	4,860	370,148
38	Amortization Expense	50,657,236	849	57,312
39	Taxes Other than Income	39,295,540	673	49,703
40	Fuel Expenses	322,936,621	9,197	567,744
41	Income Taxes	55,856,537	910	89,242
42	Total Expense - Required	$ 1,257,051,293	$ 26,965	$ 1,640,634
43	Total Revenue Requirement at Equal Return	$ 1,545,815,189	$ 31,671	$ 2,101,992
44	Revenue (Deficiency)/Surplus	$ (111,385,738)	$ 72,519	$ 103,203
45	Total Revenues	1,434,429,450	104,190	2,205,195
46	Total Revenues as Proposed	$ 1,545,815,189	$ 31,671	$ 2,101,992
47	Less Total Other Revenues	$ 22,123,710	$ 1,420	$ 27,184
48	Total Base Rate Revenues as Proposed	$ 1,523,691,478	$ 30,251	$ 2,074,808
	Mitigation			
49	Mitigation	$ (0)	$ 84,206	$ 350,551
50	Proposed Increase Post Mitigation	111,385,738	11,687	247,349

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Revenue Requirement at Equal Rates of Return at Current Rates					
22	Required Return	5.01%	5.01%	5.01%	5.01%	5.01%
23	Required Operating Income	$ 205,992,163	$ 1,242,395	$ 88,253	$ 267,639	$ 708,235
	Expenses at Required Return					
24	Operations & Maintenance Expenses	$ 491,038,911	$ 3,060,206	$ 200,353	$ 1,438,151	$ 1,550,291
25	Depreciation Expense	297,033,774	2,833,195	150,386	486,789	1,026,477
26	Amortization Expense	50,657,236	359,508	21,938	294,386	126,970
27	Taxes Other Than Income Taxes	39,161,650	309,314	17,492	102,878	127,729
28	Fuel Expenses	322,936,621	1,110,412	169,302	396,308	992,040
29	Income Taxes	27,609,096	166,518	11,829	35,872	94,925
30	Total Expenses - Required	$ 1,228,437,287	$ 7,839,153	$ 571,299	$ 2,754,385	$ 3,918,432
31	Total Revenue Requirement at Equal Return	$ 1,434,429,450	$ 9,081,548	$ 659,552	$ 3,022,024	$ 4,626,667
32	Current Subsidy	$ -	$ (1,676,040)	$ 194,253	$ (569,869)	$ 11,257
	Revenue Requirement at Equal Rates of Return at Proposed Rates					
33	Required Return	7.02%	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,763,895	$ 1,741,614	$ 123,715	$ 375,182	$ 992,818
35	Operating Income (Deficiency)/Surplus	$ (82,771,732)	$ (1,180,451)	$ 43,360	$ (338,816)	$ (280,495)
	Expenses at Required Return					
36	Operations & Maintenance Expenses	$ 491,271,586	$ 3,060,215	$ 200,354	$ 1,438,550	$ 1,550,291
37	Depreciation Expense	297,033,774	2,833,195	150,386	486,789	1,026,477
38	Amortization Expense	50,657,236	359,508	21,938	294,386	126,970
39	Taxes Other than Income	39,295,540	310,392	17,555	103,166	128,176
40	Fuel Expenses	322,936,621	1,110,412	169,302	396,308	992,040
41	Income Taxes	55,856,537	336,886	23,931	72,573	192,044
42	Total Expense - Required	$ 1,257,051,293	$ 8,010,608	$ 583,465	$ 2,791,773	$ 4,015,998
43	Total Revenue Requirement at Equal Return	$ 1,545,815,189	$ 9,752,222	$ 707,179	$ 3,166,955	$ 5,008,816
44	Revenue (Deficiency)/Surplus	$ (111,385,738)	$ (2,346,714)	$ 146,626	$ (714,800)	$ (370,892)
45	Total Revenues	1,434,429,450	7,405,507	853,805	2,452,155	4,637,924
46	Total Revenues as Proposed	$ 1,545,815,189	$ 9,752,222	$ 707,179	$ 3,166,955	$ 5,008,816
47	Less Total Other Revenues	$ 22,123,710	$ 133,026	$ 10,804	$ 54,758	$ 7,222
48	Total Base Rate Revenues as Proposed	$ 1,523,691,478	$ 9,619,196	$ 696,376	$ 3,112,197	$ 5,001,594
	Mitigation					
49	Mitigation	$ (0)	$ (1,516,065)	$ 242,394	$ (439,750)	$ 149,327
50	Proposed Increase Post Mitigation	111,385,738	830,649	95,768	275,049	520,219

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821	Comml SH Rate 822
	(A)	(B)	(C)	(D)	(E)	(F)
	Revenue Requirement at Proposed Mitigated Rates					
51	Revenue Deficiency/Surplus (line 50)	$ 111,385,738	$ 53,465,277	$ 96,084	$ 25,848,507	$ 127,376
52	Total Revenues (line 11)	1,434,429,450	476,660,380	856,616	230,447,872	1,135,600
53	Total Revenues at Proposed	$ 1,545,815,189	$ 530,125,657	$ 952,700	$ 256,296,379	$ 1,262,976
54	Less Total Other Revenues (line)	$ 22,123,710	$ 9,026,066	$ 12,549	$ 3,706,837	$ 16,450
55	Total Base Rate Revenue at Proposed	$ 1,523,691,478	$ 521,099,591	$ 940,151	$ 252,589,542	$ 1,246,526
56	Total Margin at Current Rates (line 5)	$ 1,089,552,179	$ 376,903,648	$ 570,387	$ 185,832,334	$ 811,276
57	Total Margin in Base Rates (line 55 - line 40)	1,200,754,857	428,467,162	657,260	210,263,321	928,199
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 111,202,678	$ 51,563,514	$ 86,873	$ 24,430,987	$ 116,923
59	Percent Revenue Change (line 58 / line 56)	10.21%	13.68%	15.23%	13.15%	14.41%
60	Expenses (excl. Income Taxes)	$ 1,201,194,756	$ 481,900,209	$ 752,386	$ 169,780,389	$ 797,575
61	Interest Expense	186,750,439	80,442,191	125,685	28,605,189	132,206
62	Taxable Income	$ 157,869,993	$ (32,216,743)	$ 74,628	$ 57,910,801	$ 333,195
63	Income Taxes at Proposed	55,856,537	(11,398,719)	26,404	20,489,624	117,889
64	Operating Income at Proposed	$ 288,763,895	$ 59,624,167	$ 173,909	$ 66,026,366	$ 347,512
65	Return at Proposed	7.02%	3.37%	6.28%	10.48%	11.93%
66	Index Rate of Return	1.00	0.48	0.89	1.49	1.70

Line No.	Description	System Total	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(G)	(H)
	Revenue Requirement at Proposed Mitigated Rates			
51	Revenue Deficiency/Surplus (line 50)	$ 111,385,738	$ 19,130,877	$ 23,105,257
52	Total Revenues (line 11)	1,434,429,450	170,558,003	205,990,902
53	Total Revenues at Proposed	$ 1,545,815,189	$ 189,688,880	$ 229,096,160
54	Less Total Other Revenues (line)	$ 22,123,710	$ 2,165,536	$ 2,587,457
55	Total Base Rate Revenue at Proposed	$ 1,523,691,478	$ 187,523,344	$ 226,508,703
56	Total Margin at Current Rates (line 5)	$ 1,089,552,179	$ 131,660,159	$ 150,713,111
57	Total Margin in Base Rates (line 55 - line 40)	1,200,754,857	149,464,432	172,232,053
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 111,202,678	$ 17,804,274	$ 21,518,942
59	Percent Revenue Change (line 58 / line 56)	10.21%	13.52%	14.28%
60	Expenses (excl. Income Taxes)	$ 1,201,194,756	$ 123,439,837	$ 150,156,991
61	Interest Expense	186,750,439	18,489,509	20,313,493
62	Taxable Income	$ 157,869,993	$ 47,759,533	$ 58,625,675
63	Income Taxes at Proposed	55,856,537	16,897,968	20,742,556
64	Operating Income at Proposed	$ 288,763,895	$ 49,351,074	$ 58,196,612
65	Return at Proposed	7.02%	12.12%	13.01%
66	Index Rate of Return	1.00	1.73	1.85

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830	Muni. Power Rate 841
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Revenue Requirement at Proposed Mitigated Rates						
51	Revenue Deficiency/Surplus (line 50)	$ 111,385,738	$ 764,888	$ 10,308,434	$ (29,203,901)	$ 5,394,041	$ 368,176
52	Total Revenues (line 11)	1,434,429,450	6,819,228	91,903,053	181,026,974	48,089,637	3,282,408
53	Total Revenues at Proposed	$ 1,545,815,189	$ 7,584,117	$ 102,211,488	$ 151,823,073	$ 53,483,678	$ 3,650,583
54	Less Total Other Revenues (line)	$ 22,123,710	$ 64,135	$ 1,068,779	$ 2,754,842	$ 445,127	$ 41,518
55	Total Base Rate Revenue at Proposed	$ 1,523,691,478	$ 7,519,982	$ 101,142,709	$ 149,068,230	$ 53,038,551	$ 3,609,065
56	Total Margin at Current Rates (line 5)	$ 1,089,552,179	$ 4,254,433	$ 63,605,001	$ 127,893,304	$ 30,356,288	$ 2,492,090
57	Total Margin in Base Rates (line 55 - line 40)	1,200,754,857	5,000,289	73,353,698	106,863,461	34,525,021	2,839,880
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 111,202,678	$ 745,856	$ 9,748,697	$ (21,029,843)	$ 4,168,733	$ 347,790
59	Percent Revenue Change (line 58 / line 56)	10.21%	17.53%	15.33%	-16.44%	13.73%	13.96%
60	Expenses (excl. Income Taxes)	$ 1,201,194,756	$ 5,443,335	$ 87,105,289	$ 118,953,324	$ 43,871,451	$ 2,640,113
61	Interest Expense	186,750,439	648,698	12,583,090	17,812,177	4,765,461	440,256
62	Taxable Income	$ 157,869,993	$ 1,492,084	$ 2,523,109	$ 15,057,572	$ 4,846,766	$ 570,215
63	Income Taxes at Proposed	55,856,537	527,919	892,710	5,327,573	1,714,851	201,750
64	Operating Income at Proposed	$ 288,763,895	$ 1,612,862	$ 14,213,489	$ 27,542,176	$ 7,897,375	$ 808,721
65	Return at Proposed	7.02%	11.29%	5.13%	7.02%	7.52%	8.34%
66	Index Rate of Return	1.00	1.61	0.73	1.00	1.07	1.19

Line No.	Description	System Total	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(N)	(O)
	Revenue Requirement at Proposed Mitigated Rates			
51	Revenue Deficiency/Surplus (line 50)	$ 111,385,738	$ 11,687	$ 247,349
52	Total Revenues (line 11)	1,434,429,450	104,190	2,205,195
53	Total Revenues at Proposed	$ 1,545,815,189	$ 115,877	$ 2,452,544
54	Less Total Other Revenues (line)	$ 22,123,710	$ 1,420	$ 27,184
55	Total Base Rate Revenue at Proposed	$ 1,523,691,478	$ 114,457	$ 2,425,360
56	Total Margin at Current Rates (line 5)	$ 1,089,552,179	$ 93,659	$ 1,618,092
57	Total Margin in Base Rates (line 55 - line 40)	1,200,754,857	105,260	1,857,616
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 111,202,678	$ 11,601	$ 239,524
59	Percent Revenue Change (line 58 / line 56)	10.21%	12.39%	14.80%
60	Expenses (excl. Income Taxes)	$ 1,201,194,756	$ 26,054	$ 1,551,392
61	Interest Expense	186,750,439	3,044	298,371
62	Taxable Income	$ 157,869,993	$ 86,779	$ 602,780
63	Income Taxes at Proposed	55,856,537	30,704	213,272
64	Operating Income at Proposed	$ 288,763,895	$ 59,119	$ 687,879
65	Return at Proposed	7.02%	88.18%	10.47%
66	Index Rate of Return	1.00	12.56	1.49

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Revenue Requirement at Proposed Mitigated Rates					
51	Revenue Deficiency/Surplus (line 50)	$ 111,385,738	$ 830,649	$ 95,768	$ 275,049	$ 520,219
52	Total Revenues (line 11)	1,434,429,450	7,405,507	853,805	2,452,155	4,637,924
53	Total Revenues at Proposed	$ 1,545,815,189	$ 8,236,157	$ 949,573	$ 2,727,204	$ 5,158,143
54	Less Total Other Revenues (line)	$ 22,123,710	$ 133,026	$ 10,804	$ 54,758	$ 7,222
55	Total Base Rate Revenue at Proposed	$ 1,523,691,478	$ 8,103,130	$ 938,770	$ 2,672,447	$ 5,150,921
56	Total Margin at Current Rates (line 5)	$ 1,089,552,179	$ 6,372,232	$ 681,253	$ 2,056,249	$ 3,638,661
57	Total Margin in Base Rates (line 55 - line 40)	1,200,754,857	6,992,718	769,468	2,276,138	4,158,881
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 111,202,678	$ 620,486	$ 88,214	$ 219,889	$ 520,220
59	Percent Revenue Change (line 58 / line 56)	10.21%	9.74%	12.95%	10.69%	14.30%
60	Expenses (excl. Income Taxes)	$ 1,201,194,756	$ 7,673,722	$ 559,534	$ 2,719,200	$ 3,823,954
61	Interest Expense	186,750,439	1,126,343	80,009	242,639	642,079
62	Taxable Income	$ 157,869,993	$ (563,908)	$ 310,030	$ (234,635)	$ 692,111
63	Income Taxes at Proposed	55,856,537	(199,518)	109,693	(83,017)	244,878
64	Operating Income at Proposed	$ 288,763,895	$ 761,953	$ 280,346	$ 91,021	$ 1,089,312
65	Return at Proposed	7.02%	3.07%	15.91%	1.70%	7.70%
66	Index Rate of Return	1.00	0.44	2.27	0.24	1.10

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821	Comml SH Rate 822
	(A)	(B)	(C)	(D)	(E)	(F)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Residential Rate 811**	**C&GS Heat Pump Rate 820**	**GS Small Rate 821**	**Comml SH Rate 822**
	Demand					
67	Production	$ 666,367,244	$ 280,339,857	$ -	$ 93,028,265	$ -
68	Transmission	160,057,262	42,060,872	110,942	18,695,631	128,528
69	Sub-Transmission	23,564,618	10,361,390	48,831	4,157,676	46,300
70	Railroad	682,439	-	-	-	-
71	Distribution Primary	175,799,322	82,987,407	391,100	32,807,089	370,834
72	Distribution Secondary	9,086,212	4,508,332	11,246	2,059,761	13,131
73	Customer	-	-	-	-	-
74	Customer Service	-	-	-	-	-
75	**Total**	$ 1,035,557,097	$ 420,257,859	$ 562,118	$ 150,748,421	$ 558,794
	Customer					
76	Production	-	-	-	-	-
77	Transmission	-	-	-	-	-
78	Sub-Transmission	-	-	-	-	-
79	Railroad	-	-	-	-	-
80	Distribution Primary	-	-	-	-	-
81	Distribution Secondary	$ 32,443,394	$ 28,356,776	$ 7,499	$ 3,573,929	$ 14,105
82	Customer	69,219,318	42,761,514	36,415	14,561,267	60,847
83	Customer Service	46,406,145	35,065,708	60,979	6,207,588	50,739
84	**Total**	$ 148,068,857	$ 106,183,998	$ 104,893	$ 24,342,783	$ 125,691
	Energy					
85	Production	$ 39,252,614	$ 11,270,140	$ 34,418	$ 5,149,627	$ 38,729
86	Transmission	-	-	-	-	-
87	Sub-Transmission	-	-	-	-	-
88	Railroad	-	-	-	-	-
89	Distribution Primary	-	-	-	-	-
90	Distribution Secondary	-	-	-	-	-
91	Customer	-	-	-	-	-
92	Customer Service	-	-	-	-	-
93	**Total**	$ 39,252,614	$ 11,270,140	$ 34,418	$ 5,149,627	$ 38,729
	Fuel					
94	Fuel Expenses	$ 322,936,621	$ 92,632,429	$ 282,891	$ 42,326,221	$ 318,327
95	**Total**	$ 322,936,621	$ 92,632,429	$ 282,891	$ 42,326,221	$ 318,327
96	**Total**	$ 1,545,815,189	$ 630,344,426	$ 984,320	$ 222,567,053	$ 1,041,541
	Total Revenue Requirement					
97	Demand	$ 1,035,557,097	$ 420,257,859	$ 562,118	$ 150,748,421	$ 558,794
98	Customer	148,068,857	106,183,998	104,893	24,342,783	125,691
99	Energy	39,252,614	11,270,140	34,418	5,149,627	38,729
100	Fuel	322,936,621	92,632,429	282,891	42,326,221	318,327
101	**Total**	$ 1,545,815,189	$ 630,344,426	$ 984,320	$ 222,567,053	$ 1,041,541
102	Zero-Check	$ -	$ -	$ -	$ -	$ -

Line No.	Description	System Total	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(G)	(H)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**GS Medium Rate 823**	**GS Large Rate 824**
	Demand			
67	Production	$ 666,367,244	$ 73,990,765	$ 80,876,409
68	Transmission	160,057,262	14,171,146	17,771,662
69	Sub-Transmission	23,564,618	2,526,225	3,125,115
70	Railroad	682,439	-	-
71	Distribution Primary	175,799,322	20,115,992	22,821,891
72	Distribution Secondary	9,086,212	1,255,929	664,624
73	Customer	-	-	-
74	Customer Service	-	-	-
75	**Total**	$ 1,035,557,097	$ 112,060,058	$ 125,259,702
	Customer			
76	Production	-	-	-
77	Transmission	-	-	-
78	Sub-Transmission	-	-	-
79	Railroad	-	-	-
80	Distribution Primary	-	-	-
81	Distribution Secondary	$ 32,443,394	$ 250,431	$ 19,329
82	Customer	69,219,318	1,629,990	313,296
83	Customer Service	46,406,145	929,668	1,169,997
84	**Total**	$ 148,068,857	$ 2,810,089	$ 1,502,623
	Energy			
85	Production	$ 39,252,614	$ 4,630,444	$ 6,603,578
86	Transmission	-	-	-
87	Sub-Transmission	-	-	-
88	Railroad	-	-	-
89	Distribution Primary	-	-	-
90	Distribution Secondary	-	-	-
91	Customer	-	-	-
92	Customer Service	-	-	-
93	**Total**	$ 39,252,614	$ 4,630,444	$ 6,603,578
	Fuel			
94	Fuel Expenses	$ 322,936,621	$ 38,058,912	$ 54,276,650
95	**Total**	$ 322,936,621	$ 38,058,912	$ 54,276,650
96	**Total**	$ 1,545,815,189	$ 157,559,503	$ 187,642,552
	Total Revenue Requirement			
97	Demand	$ 1,035,557,097	$ 112,060,058	$ 125,259,702
98	Customer	148,068,857	2,810,089	1,502,623
99	Energy	39,252,614	4,630,444	6,603,578
100	Fuel	322,936,621	38,058,912	54,276,650
101	**Total**	$ 1,545,815,189	$ 157,559,503	$ 187,642,552
102	Zero-Check	$ -	$ -	$ -

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830	Muni. Power Rate 841
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Metal Melting Rate 825**	**Off-Peak Serv. Rate 826**	**Ind. Pwr Serv. - Large Rate 831**	**Ind. Pwr Serv. - Small Rate 830**	**Muni. Power Rate 841**
	Demand						
67	Production	$ 666,367,244	$ 1,868,194	$ 52,704,622	$ 54,413,630	$ 24,751,078	$ 1,184,027
68	Transmission	160,057,262	492,864	10,552,667	48,974,257	6,258,731	279,136
69	Sub-Transmission	23,564,618	200,643	1,787,482	413,965	500,871	78,678
70	Railroad	682,439	-	-	-	-	-
71	Distribution Primary	175,799,322	1,124,163	12,641,066	(0)	-	630,157
72	Distribution Secondary	9,086,212	28,807	412,467	-	-	35,601
73	Customer	-	-	-	-	-	-
74	Customer Service	-	-	-	-	-	-
75	**Total**	$ 1,035,557,097	$ 3,714,671	$ 78,098,304	$ 103,801,853	$ 31,510,680	$ 2,207,599
	Customer						
76	Production	-	-	-	-	-	-
77	Transmission	-	-	-	-	-	-
78	Sub-Transmission	-	-	-	-	-	-
79	Railroad	-	-	-	-	-	-
80	Distribution Primary	-	-	-	-	-	-
81	Distribution Secondary	$ 32,443,394	$ 206	$ 9,526	$ -	$ -	$ 48,393
82	Customer	69,219,318	6,751	250,201	401,143	91,138	260,369
83	Customer Service	46,406,145	92,531	797,531	280,458	297,607	73,411
84	**Total**	$ 148,068,857	$ 99,489	$ 1,057,259	$ 681,601	$ 388,745	$ 382,173
	Energy						
85	Production	$ 39,252,614	$ 306,559	$ 3,380,955	$ 5,134,850	$ 2,252,452	$ 93,583
86	Transmission	-	-	-	-	-	-
87	Sub-Transmission	-	-	-	-	-	-
88	Railroad	-	-	-	-	-	-
89	Distribution Primary	-	-	-	-	-	-
90	Distribution Secondary	-	-	-	-	-	-
91	Customer	-	-	-	-	-	-
92	Customer Service	-	-	-	-	-	-
93	**Total**	$ 39,252,614	$ 306,559	$ 3,380,955	$ 5,134,850	$ 2,252,452	$ 93,583
	Fuel						
94	Fuel Expenses	$ 322,936,621	$ 2,519,693	$ 27,789,010	$ 42,204,769	$ 18,513,530	$ 769,185
95	**Total**	$ 322,936,621	$ 2,519,693	$ 27,789,010	$ 42,204,769	$ 18,513,530	$ 769,185
96	**Total**	$ 1,545,815,189	$ 6,640,412	$ 110,325,528	$ 151,823,073	$ 52,665,407	$ 3,452,540
	Total Revenue Requirement						
97	Demand	$ 1,035,557,097	$ 3,714,671	$ 78,098,304	$ 103,801,853	$ 31,510,680	$ 2,207,599
98	Customer	148,068,857	99,489	1,057,259	681,601	388,745	382,173
99	Energy	39,252,614	306,559	3,380,955	5,134,850	2,252,452	93,583
100	Fuel	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530	769,185
101	**Total**	$ 1,545,815,189	$ 6,640,412	$ 110,325,528	$ 151,823,073	$ 52,665,407	$ 3,452,540
102	Zero-Check	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(N)	(O)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Int WW Pumping Rate 842**	**Railroad Rate 844**
	Demand			
67	Production	$ 666,367,244	$ 11,734	$ 552,789
68	Transmission	160,057,262	2,652	130,203
69	Sub-Transmission	23,564,618	358	79,015
70	Railroad	682,439	-	682,439
71	Distribution Primary	175,799,322	2,864	-
72	Distribution Secondary	9,086,212	237	-
73	Customer	-	-	-
74	Customer Service	-	-	-
75	**Total**	$ 1,035,557,097	$ 17,845	$ 1,444,446
	Customer			
76	Production	-	-	-
77	Transmission	-	-	-
78	Sub-Transmission	-	-	-
79	Railroad	-	-	-
80	Distribution Primary	-	-	-
81	Distribution Secondary	$ 32,443,394	$ 550	$ -
82	Customer	69,219,318	99	2,650
83	Customer Service	46,406,145	2,861	18,078
84	**Total**	$ 148,068,857	$ 3,510	$ 20,727
	Energy			
85	Production	$ 39,252,614	$ 1,119	$ 69,075
86	Transmission	-	-	-
87	Sub-Transmission	-	-	-
88	Railroad	-	-	-
89	Distribution Primary	-	-	-
90	Distribution Secondary	-	-	-
91	Customer	-	-	-
92	Customer Service	-	-	-
93	**Total**	$ 39,252,614	$ 1,119	$ 69,075
	Fuel			
94	Fuel Expenses	$ 322,936,621	$ 9,197	$ 567,744
95	**Total**	$ 322,936,621	$ 9,197	$ 567,744
96	**Total**	$ 1,545,815,189	$ 31,671	$ 2,101,992
	Total Revenue Requirement			
97	Demand	$ 1,035,557,097	$ 17,845	$ 1,444,446
98	Customer	148,068,857	3,510	20,727
99	Energy	39,252,614	1,119	69,075
100	Fuel	322,936,621	9,197	567,744
101	**Total**	$ 1,545,815,189	$ 31,671	$ 2,101,992
102	Zero-Check	$ -	$ -	$ -

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Street Lighting Rate 850**	**Traffic Lighting Rate 855**	**Dusk-to-Dawn Rate 860**	**Interdepartmental Interdepartmental**
	Demand					
67	Production	$ 666,367,244	$ -	$ 242,145	$ -	$ 2,403,727
68	Transmission	160,057,262	40,624	53,692	19,275	314,380
69	Sub-Transmission	23,564,618	65,898	7,568	33,558	131,044
70	Railroad	682,439	-	-	-	-
71	Distribution Primary	175,799,322	527,796	60,617	268,773	1,049,574
72	Distribution Secondary	9,086,212	40,754	4,798	20,153	30,371
73	Customer	-	-	-	-	-
74	Customer Service	-	-	-	-	-
75	**Total**	$ 1,035,557,097	$ 675,072	$ 368,820	$ 341,759	$ 3,929,096
	Customer					
76	Production	-	-	-	-	-
77	Transmission	-	-	-	-	-
78	Sub-Transmission	-	-	-	-	-
79	Railroad	-	-	-	-	-
80	Distribution Primary	-	-	-	-	-
81	Distribution Secondary	$ 32,443,394	$ 15,187	$ 2,408	$ 141,890	$ 3,165
82	Customer	69,219,318	6,948,570	135,772	1,759,297	-
83	Customer Service	46,406,145	867,883	10,279	479,483	1,343
84	**Total**	$ 148,068,857	$ 7,831,639	$ 148,459	$ 2,380,671	$ 4,508
	Energy					
85	Production	$ 39,252,614	$ 135,098	$ 20,598	$ 48,217	$ 83,172
86	Transmission	-	-	-	-	-
87	Sub-Transmission	-	-	-	-	-
88	Railroad	-	-	-	-	-
89	Distribution Primary	-	-	-	-	-
90	Distribution Secondary	-	-	-	-	-
91	Customer	-	-	-	-	-
92	Customer Service	-	-	-	-	-
93	**Total**	$ 39,252,614	$ 135,098	$ 20,598	$ 48,217	$ 83,172
	Fuel					
94	Fuel Expenses	$ 322,936,621	$ 1,110,412	$ 169,302	$ 396,308	$ 992,040
95	**Total**	$ 322,936,621	$ 1,110,412	$ 169,302	$ 396,308	$ 992,040
96	**Total**	$ 1,545,815,189	$ 9,752,222	$ 707,179	$ 3,166,955	$ 5,008,816
	Total Revenue Requirement					
97	Demand	$ 1,035,557,097	$ 675,072	$ 368,820	$ 341,759	$ 3,929,096
98	Customer	148,068,857	7,831,639	148,459	2,380,671	4,508
99	Energy	39,252,614	135,098	20,598	48,217	83,172
100	Fuel	322,936,621	1,110,412	169,302	396,308	992,040
101	**Total**	$ 1,545,815,189	$ 9,752,222	$ 707,179	$ 3,166,955	$ 5,008,816
102	Zero-Check	$ -	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821	Comml SH Rate 822
	(A)	(B)	(C)	(D)	(E)	(F)
	Billing Determinants					
103	Demand (KW) - Production	14,180,260	0	0	0	0
104	Demand (KW) - Other	21,213,001	0	0	0	0
105	Customer (Customer Bills or No. Customers * 12)	6,541,009	4,946,379	1,220	627,541	1,640
106	Energy (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398	11,890,211
107	Fuel (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398	11,890,211
	Unit Costs					
108	Demand - Production		$ -	$ -	$ -	$ -
109	Demand - Other		$ -	$ -	$ -	$ -
110	Customer		$ 106.43	$ 546.61	$ 279.01	$ 417.31
111	Energy		$ 0.003257	$ 0.003256	$ 0.003256	$ 0.003257
112	Fuel		$ 0.026772	$ 0.026766	$ 0.026762	$ 0.026772
113	Demand Revenue		$ -	$ -	$ -	$ -
114	Customer Revenue		526,441,857	667,011	175,091,205	684,485
115	Energy Revenue		11,270,140	34,418	5,149,627	38,729
116	Fuel Revenue		92,632,429	282,891	42,326,221	318,327
117	Total Revenue		630,344,426	984,320	222,567,053	1,041,541
118	Zero-Check		$ -	$ -	$ -	$ -

Line No.	Description	System Total	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(G)	(H)
	Billing Determinants			
103	Demand (KW) - Production	14,180,260	4,003,187	4,659,514
104	Demand (KW) - Other	21,213,001	4,003,187	4,659,514
105	Customer (Customer Bills or No. Customers * 12)	6,541,009	44,986	5,466
106	Energy (kWh)	12,096,308,562	1,422,286,366	2,035,551,481
107	Fuel (kWh)	12,096,308,562	1,422,286,366	2,035,551,481
	Unit Costs			
108	Demand - Production		$ 18.48	$ 17.36
109	Demand - Other		$ 9.51	$ 9.53
110	Customer		$ 62.47	$ 274.89
111	Energy		$ 0.003256	$ 0.003244
112	Fuel		$ 0.026759	$ 0.026664
113	Demand Revenue		$ 112,060,058	$ 125,259,702
114	Customer Revenue		2,810,089	1,502,623
115	Energy Revenue		4,630,444	6,603,578
116	Fuel Revenue		38,058,912	54,276,650
117	Total Revenue		157,559,503	187,642,552
118	Zero-Check		$ -	$ -

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830	Muni. Power Rate 841
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Billing Determinants						
103	Demand (KW) - Production	14,180,260	105,561	1,852,987	2,214,672	1,272,049	0
104	Demand (KW) - Other	21,213,001	105,561	1,852,987	9,247,414	1,272,049	0
105	Customer (Customer Bills or No. Customers * 12)	6,541,009	72	2,208	108	120	8,501
106	Energy (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124	28,753,903
107	Fuel (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124	28,753,903
	Unit Costs						
108	Demand - Production		$ 17.70	$ 28.44	$ 24.57	$ 19.46	$ -
109	Demand - Other		$ 17.49	$ 13.70	$ 5.34	$ 5.31	$ -
110	Customer		$ 1,381.79	$ 478.83	$ 6,311.12	$ 3,239.54	$ 304.65
111	Energy		$ 0.003237	$ 0.003244	$ 0.003213	$ 0.003215	$ 0.003255
112	Fuel		$ 0.026610	$ 0.026664	$ 0.026405	$ 0.026429	$ 0.026751
113	Demand Revenue		$ 3,714,671	$ 78,098,304	$ 103,801,853	$ 31,510,680	$ -
114	Customer Revenue		99,489	1,057,259	681,601	388,745	2,589,772
115	Energy Revenue		306,559	3,380,955	5,134,850	2,252,452	93,583
116	Fuel Revenue		2,519,693	27,789,010	42,204,769	18,513,530	769,185
117	Total Revenue		6,640,412	110,325,528	151,823,073	52,665,407	3,452,540
118	Zero-Check		$ -	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(N)	(O)
	Billing Determinants			
103	Demand (KW) - Production	14,180,260	0	72,290
104	Demand (KW) - Other	21,213,001	0	72,290
105	Customer (Customer Bills or No. Customers * 12)	6,541,009	96	12
106	Energy (kWh)	12,096,308,562	343,541	21,456,529
107	Fuel (kWh)	12,096,308,562	343,541	21,456,529
	Unit Costs			
108	Demand - Production		$ -	$ 7.65
109	Demand - Other		$ -	$ 12.33
110	Customer		$ 223.60	$ 1,727.29
111	Energy		$ 0.003257	$ 0.003219
112	Fuel		$ 0.026772	$ 0.026460
113	Demand Revenue		$ -	$ 1,444,446
114	Customer Revenue		21,355	20,727
115	Energy Revenue		1,119	69,075
116	Fuel Revenue		9,197	567,744
117	Total Revenue		31,671	2,101,992
118	Zero-Check		$ -	$ -

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Billing Determinants					
103	Demand (KW) - Production	14,180,260	0	0	0	0
104	Demand (KW) - Other	21,213,001	0	0	0	0
105	Customer (Customer Bills or No. Customers * 12)	6,541,009	758,328	13,861	191,944	552
106	Energy (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
107	Fuel (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
	Unit Costs					
108	Demand - Production		$ -	$ -	$ -	$ -
109	Demand - Other		$ -	$ -	$ -	$ -
110	Customer		$ 11.22	$ 37.32	$ 14.18	$ 7,126.09
111	Energy		$ 0.003257	$ 0.003257	$ 0.003257	$ 0.003257
112	Fuel		$ 0.026772	$ 0.026772	$ 0.026772	$ 0.038851
113	Demand Revenue		$ -	$ -	$ -	$ -
114	Customer Revenue		8,506,711	517,279	2,722,429	3,933,604
115	Energy Revenue		135,098	20,598	48,217	83,172
116	Fuel Revenue		1,110,412	169,302	396,308	992,040
117	Total Revenue		9,752,222	707,179	3,166,955	5,008,816
118	Zero-Check		$ -	$ -	$ -	$ -

Line No.	Description		System Total		Residential Rate 811		C&GS Heat Pump Rate 820		GS Small Rate 821		Comml SH Rate 822
	(A)		(B)		(C)		(D)		(E)		(F)
	Functionalized Revenue Requirement After Other Revenue Credit										
119	Other Rev as % of Functionalized Revenue		1.87%		1.71%		1.88%		2.12%		2.40%
120	Ratio (Inverse of Percentage)		98.13%		98.29%		98.12%		97.88%		97.60%
	Demand										
121	Production	$	653,982,894	$	275,533,313	$	-	$	91,058,773	$	-
122	Transmission		156,766,057		41,339,721		108,854		18,299,827		125,439
123	Sub-Transmission		23,135,232		10,183,740		47,912		4,069,654		45,188
124	Railroad		669,777		-		-		-		-
125	Distribution Primary		172,603,847		81,564,554		383,742		32,112,533		361,921
126	Distribution Secondary		8,919,699		4,431,035		11,034		2,016,154		12,816
127	Customer		-		-		-		-		-
128	Customer Service		-		-		-		-		-
129	**Total**	$	1,016,077,506	$	413,052,362	$	551,543	$	147,556,943	$	545,364
	Customer										
130	Production	$	-	$	-	$	-	$	-	$	-
131	Transmission		-		-		-		-		-
132	Sub-Transmission		-		-		-		-		-
133	Railroad		-		-		-		-		-
134	Distribution Primary		-		-		-		-		-
135	Distribution Secondary		31,871,854		27,870,587		7,358		3,498,266		13,766
136	Customer		67,972,156		42,028,350		35,730		14,252,991		59,384
137	Customer Service		45,580,727		34,464,492		59,831		6,076,168		49,520
138	**Total**	$	145,424,737	$	104,363,429	$	102,919	$	23,827,425	$	122,670
	Energy										
139	Production	$	39,252,614	$	11,270,140	$	34,418	$	5,149,627	$	38,729
140	Transmission		-	$	-	$	-	$	-	$	-
141	Sub-Transmission		-	$	-	$	-	$	-	$	-
142	Railroad		-	$	-	$	-	$	-	$	-
143	Distribution Primary		-	$	-	$	-	$	-	$	-
144	Distribution Secondary		-	$	-	$	-	$	-	$	-
145	Customer		-	$	-	$	-	$	-	$	-
146	Customer Service		-	$	-	$	-	$	-	$	-
147	**Total**	$	39,252,614	$	11,270,140	$	34,418	$	5,149,627	$	38,729
	Fuel										
148	Fuel Expenses	$	322,936,621	$	92,632,429	$	282,891	$	42,326,221	$	318,327
149	**Total**	$	322,936,621	$	92,632,429	$	282,891	$	42,326,221	$	318,327
150	**Total**	$	1,523,691,478	$	621,318,360	$	971,771	$	218,860,215	$	1,025,091
	Total Revenue Requirement										
151	Demand	$	1,016,077,506	$	413,052,362	$	551,543	$	147,556,943	$	545,364
152	Customer		145,424,737		104,363,429		102,919		23,827,425		122,670
153	Energy		39,252,614		11,270,140		34,418		5,149,627		38,729
154	Fuel		322,936,621		92,632,429		282,891		42,326,221		318,327
155	**Total**	$	1,523,691,478	$	621,318,360	$	971,771	$	218,860,215	$	1,025,091
156	Zero-Check		-		-		-		-		-

Line No.	Description	System Total	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(G)	(H)
	Functionalized Revenue Requirement After Other Revenue Credit			
119	Other Rev as % of Functionalized Revenue	1.87%	1.89%	2.04%
120	Ratio (Inverse of Percentage)	98.13%	98.11%	97.96%
	Demand			
121	Production	$ 653,982,894	$ 72,595,889	$ 79,225,570
122	Transmission	156,766,057	13,903,991	17,408,909
123	Sub-Transmission	23,135,232	2,478,601	3,061,325
124	Railroad	669,777	-	-
125	Distribution Primary	172,603,847	19,736,765	22,356,054
126	Distribution Secondary	8,919,699	1,232,252	651,057
127	Customer	-	-	-
128	Customer Service	-	-	-
129	**Total**	$ 1,016,077,506	$ 109,947,498	$ 122,702,916
	Customer			
130	Production	$ -	$ -	$ -
131	Transmission	-	-	-
132	Sub-Transmission	-	-	-
133	Railroad	-	-	-
134	Distribution Primary	-	-	-
135	Distribution Secondary	31,871,854	245,710	18,935
136	Customer	67,972,156	1,599,262	306,901
137	Customer Service	45,580,727	912,142	1,146,116
138	**Total**	$ 145,424,737	$ 2,757,114	$ 1,471,951
	Energy			
139	Production	$ 39,252,614	$ 4,630,444	$ 6,603,578
140	Transmission	-	$ -	$ -
141	Sub-Transmission	-	$ -	$ -
142	Railroad	-	$ -	$ -
143	Distribution Primary	-	$ -	$ -
144	Distribution Secondary	-	$ -	$ -
145	Customer	-	$ -	$ -
146	Customer Service	-	$ -	$ -
147	**Total**	$ 39,252,614	$ 4,630,444	$ 6,603,578
	Fuel			
148	Fuel Expenses	$ 322,936,621	$ 38,058,912	$ 54,276,650
149	**Total**	$ 322,936,621	$ 38,058,912	$ 54,276,650
150	**Total**	$ 1,523,691,478	$ 155,393,967	$ 185,055,095
	Total Revenue Requirement			
151	Demand	$ 1,016,077,506	$ 109,947,498	$ 122,702,916
152	Customer	145,424,737	2,757,114	1,471,951
153	Energy	39,252,614	4,630,444	6,603,578
154	Fuel	322,936,621	38,058,912	54,276,650
155	**Total**	$ 1,523,691,478	$ 155,393,967	$ 185,055,095
156	Zero-Check	-	-	-

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830	Muni. Power Rate 841
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Functionalized Revenue Requirement After Other Revenue Credit						
119	Other Rev as % of Functionalized Revenue	1.87%	1.68%	1.35%	2.64%	1.40%	1.60%
120	Ratio (Inverse of Percentage)	98.13%	98.32%	98.65%	97.36%	98.60%	98.40%
	Demand						
121	Production	$ 653,982,894	$ 1,836,780	$ 51,992,990	$ 52,978,944	$ 24,405,700	$ 1,165,046
122	Transmission	156,766,057	484,576	10,410,182	47,682,987	6,171,396	274,661
123	Sub-Transmission	23,135,232	197,269	1,763,347	403,051	493,882	77,417
124	Railroad	669,777	-	-	-	-	-
125	Distribution Primary	172,603,847	1,105,261	12,470,383	(0)	-	620,054
126	Distribution Secondary	8,919,699	28,323	406,898	-	-	35,030
127	Customer	-	-	-	-	-	-
128	Customer Service	-	-	-	-	-	-
129	**Total**	$ 1,016,077,506	$ 3,652,209	$ 77,043,800	$ 101,064,981	$ 31,070,978	$ 2,172,208
	Customer						
130	Production	$ -	$ -	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-	-	-
132	Sub-Transmission	-	-	-	-	-	-
133	Railroad	-	-	-	-	-	-
134	Distribution Primary	-	-	-	-	-	-
135	Distribution Secondary	31,871,854	203	9,398	-	-	47,617
136	Customer	67,972,156	6,638	246,823	390,566	89,866	256,194
137	Customer Service	45,580,727	90,975	786,763	273,063	293,454	72,234
138	**Total**	$ 145,424,737	$ 97,816	$ 1,042,983	$ 663,629	$ 383,320	$ 376,046
	Energy						
139	Production	$ 39,252,614	$ 306,559	$ 3,380,955	$ 5,134,850	$ 2,252,452	$ 93,583
140	Transmission	-	$ -	$ -	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -	$ -	$ -
147	**Total**	$ 39,252,614	$ 306,559	$ 3,380,955	$ 5,134,850	$ 2,252,452	$ 93,583
	Fuel						
148	Fuel Expenses	$ 322,936,621	$ 2,519,693	$ 27,789,010	$ 42,204,769	$ 18,513,530	$ 769,185
149	**Total**	$ 322,936,621	$ 2,519,693	$ 27,789,010	$ 42,204,769	$ 18,513,530	$ 769,185
150	**Total**	$ 1,523,691,478	$ 6,576,277	$ 109,256,748	$ 149,068,230	$ 52,220,280	$ 3,411,022
	Total Revenue Requirement						
151	Demand	$ 1,016,077,506	$ 3,652,209	$ 77,043,800	$ 101,064,981	$ 31,070,978	$ 2,172,208
152	Customer	145,424,737	97,816	1,042,983	663,629	383,320	376,046
153	Energy	39,252,614	306,559	3,380,955	5,134,850	2,252,452	93,583
154	Fuel	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530	769,185
155	**Total**	$ 1,523,691,478	$ 6,576,277	$ 109,256,748	$ 149,068,230	$ 52,220,280	$ 3,411,022
156	Zero-Check	-	-	-	-	-	-

Line No.	Description	System Total	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(N)	(O)
	Functionalized Revenue Requirement After Other Revenue Credit			
119	Other Rev as % of Functionalized Revenue	1.87%	6.65%	1.86%
120	Ratio (Inverse of Percentage)	98.13%	93.35%	98.14%
	Demand			
121	Production	$ 653,982,894	$ 10,954	$ 542,533
122	Transmission	156,766,057	2,475	127,787
123	Sub-Transmission	23,135,232	334	77,549
124	Railroad	669,777	-	669,777
125	Distribution Primary	172,603,847	2,673	-
126	Distribution Secondary	8,919,699	221	-
127	Customer	-	-	-
128	Customer Service	-	-	-
129	**Total**	$ 1,016,077,506	$ 16,658	$ 1,417,647
	Customer			
130	Production	$ -	$ -	$ -
131	Transmission	-	-	-
132	Sub-Transmission	-	-	-
133	Railroad	-	-	-
134	Distribution Primary	-	-	-
135	Distribution Secondary	31,871,854	514	-
136	Customer	67,972,156	93	2,600
137	Customer Service	45,580,727	2,670	17,742
138	**Total**	$ 145,424,737	$ 3,277	$ 20,343
	Energy			
139	Production	$ 39,252,614	$ 1,119	$ 69,075
140	Transmission	-	$ -	$ -
141	Sub-Transmission	-	$ -	$ -
142	Railroad	-	$ -	$ -
143	Distribution Primary	-	$ -	$ -
144	Distribution Secondary	-	$ -	$ -
145	Customer	-	$ -	$ -
146	Customer Service	-	$ -	$ -
147	**Total**	$ 39,252,614	$ 1,119	$ 69,075
	Fuel			
148	Fuel Expenses	$ 322,936,621	$ 9,197	$ 567,744
149	**Total**	$ 322,936,621	$ 9,197	$ 567,744
150	**Total**	$ 1,523,691,478	$ 30,251	$ 2,074,808
	Total Revenue Requirement			
151	Demand	$ 1,016,077,506	$ 16,658	$ 1,417,647
152	Customer	145,424,737	3,277	20,343
153	Energy	39,252,614	1,119	69,075
154	Fuel	322,936,621	9,197	567,744
155	**Total**	$ 1,523,691,478	$ 30,251	$ 2,074,808
156	Zero-Check	-	-	-

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Functionalized Revenue Requirement After Other Revenue Credit					
119	Other Rev as % of Functionalized Revenue	1.87%	1.56%	2.09%	2.01%	0.18%
120	Ratio (Inverse of Percentage)	98.13%	98.44%	97.91%	97.99%	99.82%
	Demand					
121	Production	$ 653,982,894	$ -	$ 237,088	$ -	$ 2,399,314
122	Transmission	156,766,057	39,989	52,570	18,887	313,803
123	Sub-Transmission	23,135,232	64,867	7,410	32,883	130,804
124	Railroad	669,777	-	-	-	-
125	Distribution Primary	172,603,847	519,542	59,351	263,367	1,047,647
126	Distribution Secondary	8,919,699	40,117	4,698	19,748	30,315
127	Customer	-	-	-	-	-
128	Customer Service	-	-	-	-	-
129	**Total**	$ 1,016,077,506	$ 664,516	$ 361,118	$ 334,885	$ 3,921,882
	Customer					
130	Production	$ -	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-	-
132	Sub-Transmission	-	-	-	-	-
133	Railroad	-	-	-	-	-
134	Distribution Primary	-	-	-	-	-
135	Distribution Secondary	31,871,854	14,949	2,358	139,036	3,159
136	Customer	67,972,156	6,839,910	132,936	1,723,912	-
137	Customer Service	45,580,727	854,311	10,065	469,839	1,341
138	**Total**	$ 145,424,737	$ 7,709,170	$ 145,358	$ 2,332,787	$ 4,500
	Energy					
139	Production	$ 39,252,614	$ 135,098	$ 20,598	$ 48,217	$ 83,172
140	Transmission	-	$ -	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -	$ -
147	**Total**	$ 39,252,614	$ 135,098	$ 20,598	$ 48,217	$ 83,172
	Fuel					
148	Fuel Expenses	$ 322,936,621	$ 1,110,412	$ 169,302	$ 396,308	$ 992,040
149	**Total**	$ 322,936,621	$ 1,110,412	$ 169,302	$ 396,308	$ 992,040
150	**Total**	$ 1,523,691,478	$ 9,619,196	$ 696,376	$ 3,112,197	$ 5,001,594
	Total Revenue Requirement					
151	Demand	$ 1,016,077,506	$ 664,516	$ 361,118	$ 334,885	$ 3,921,882
152	Customer	145,424,737	7,709,170	145,358	2,332,787	4,500
153	Energy	39,252,614	135,098	20,598	48,217	83,172
154	Fuel	322,936,621	1,110,412	169,302	396,308	992,040
155	**Total**	$ 1,523,691,478	$ 9,619,196	$ 696,376	$ 3,112,197	$ 5,001,594
156	Zero-Check	-	-	-	-	-

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821	Comml SH Rate 822
	(A)	(B)	(C)	(D)	(E)	(F)
	Billing Determinants					
157	Demand (KW) - Production	14,180,260	0	0	0	0
158	Demand (KW) - Other	21,213,001	0	0	0	0
159	Customer (Customer Bills or No. Customers * 12)	6,541,009	4,946,379	1,220	627,541	1,640
160	Energy (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398	11,890,211
161	Fuel (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398	11,890,211
162	Demand Unit Cost - Production		0.00	0.00	0.00	0.00
163	Demand Unit Cost - Other		0.00	0.00	0.00	0.00
164	Customer Unit Cost		104.60	536.33	273.10	407.28
165	Energy Unit Cost		0.0032572	0.0032564	0.0032561	0.0032572
166	Fuel Unit Cost		0.0267722	0.0267656	0.0267625	0.0267722
167	Demand Revenue		$ -	$ -	$ -	$ -
168	Customer Revenue		517,415,791	654,462	171,384,367	668,034
169	Energy Revenue		11,270,140	34,418	5,149,627	38,729
170	Fuel Revenue		92,632,429	282,891	42,326,221	318,327
171	Total Revenue		621,318,360	971,771	218,860,215	1,025,091
172	Zero-Check		$ -	$ -	$ -	$ -
	Grid Facility					
173	Grid Facility - Revenue Requirement	507,519,349	241,882,478	654,462	80,325,594	668,034
174	Grid Facility - Unit Costs	77.5903779	48.90	536.33	128.00	407.28

Line No.	Description	System Total	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(G)	(H)
	Billing Determinants			
157	Demand (KW) - Production	14,180,260	4,003,187	4,659,514
158	Demand (KW) - Other	21,213,001	4,003,187	4,659,514
159	Customer (Customer Bills or No. Customers * 12)	6,541,009	44,986	5,466
160	Energy (kWh)	12,096,308,562	1,422,286,366	2,035,551,481
161	Fuel (kWh)	12,096,308,562	1,422,286,366	2,035,551,481
162	Demand Unit Cost - Production		18.13	17.00
163	Demand Unit Cost - Other		9.33	9.33
164	Customer Unit Cost		61.29	269.28
165	Energy Unit Cost		0.0032556	0.0032441
166	Fuel Unit Cost		0.0267590	0.0266643
167	Demand Revenue		$ 109,947,498	$ 122,702,916
168	Customer Revenue		2,757,114	1,471,951
169	Energy Revenue		4,630,444	6,603,578
170	Fuel Revenue		38,058,912	54,276,650
171	Total Revenue		155,393,967	185,055,095
172	Zero-Check		$ -	$ -
	Grid Facility			
173	Grid Facility - Revenue Requirement	507,519,349	40,108,723	44,949,297
174	Grid Facility - Unit Costs	77.5903779	891.58	8,223.05

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830	Muni. Power Rate 841
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Billing Determinants						
157	Demand (KW) - Production	14,180,260	105,561	1,852,987	2,214,672	1,272,049	0
158	Demand (KW) - Other	21,213,001	105,561	1,852,987	9,247,414	1,272,049	0
159	Customer (Customer Bills or No. Customers * 12)	6,541,009	72	2,208	108	120	8,501
160	Energy (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124	28,753,903
161	Fuel (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124	28,753,903
162	Demand Unit Cost - Production		17.40	28.06	23.92	19.19	0.00
163	Demand Unit Cost - Other		17.20	13.52	5.20	5.24	0.00
164	Customer Unit Cost		1,358.56	472.37	6,144.72	3,194.34	299.77
165	Energy Unit Cost		0.0032375	0.0032441	0.0032126	0.0032155	0.0032546
166	Fuel Unit Cost		0.0266095	0.0266642	0.0264049	0.0264291	0.0267506
167	Demand Revenue		$ 3,652,209	$ 77,043,800	$ 101,064,981	$ 31,070,978	$ -
168	Customer Revenue		97,816	1,042,983	663,629	383,320	2,548,254
169	Energy Revenue		306,559	3,380,955	5,134,850	2,252,452	93,583
170	Fuel Revenue		2,519,693	27,789,010	42,204,769	18,513,530	769,185
171	Total Revenue		6,576,277	109,256,748	149,068,230	52,220,280	3,411,022
172	Zero-Check		$ -	$ -	$ -	$ -	$ -
	Grid Facility						
173	Grid Facility - Revenue Requirement	507,519,349	1,913,245	26,093,793	48,749,666	7,048,598	1,383,208
174	Grid Facility - Unit Costs	77.5903779	26,572.84	11,817.84	451,385.80	58,738.32	162.72

Line No.	Description	System Total	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(N)	(O)
	Billing Determinants			
157	Demand (KW) - Production	14,180,260	0	72,290
158	Demand (KW) - Other	21,213,001	0	72,290
159	Customer (Customer Bills or No. Customers * 12)	6,541,009	96	12
160	Energy (kWh)	12,096,308,562	343,541	21,456,529
161	Fuel (kWh)	12,096,308,562	343,541	21,456,529
162	Demand Unit Cost - Production		0.00	7.50
163	Demand Unit Cost - Other		0.00	12.11
164	Customer Unit Cost		208.73	1,695.24
165	Energy Unit Cost		0.0032572	0.0032193
166	Fuel Unit Cost		0.0267722	0.0264602
167	Demand Revenue		$ -	$ 1,417,647
168	Customer Revenue		19,935	20,343
169	Energy Revenue		1,119	69,075
170	Fuel Revenue		9,197	567,744
171	Total Revenue		30,251	2,074,808
172	Zero-Check		$ -	$ -
	Grid Facility			
173	Grid Facility - Revenue Requirement	507,519,349	8,981	895,457
174	Grid Facility - Unit Costs	77.5903779	94.03	74,621.42

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Billing Determinants					
157	Demand (KW) - Production	14,180,260	0	0	0	0
158	Demand (KW) - Other	21,213,001	0	0	0	0
159	Customer (Customer Bills or No. Customers * 12)	6,541,009	758,328	13,861	191,944	552
160	Energy (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
161	Fuel (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
162	Demand Unit Cost - Production		0.00	0.00	0.00	0.00
163	Demand Unit Cost - Other		0.00	0.00	0.00	0.00
164	Customer Unit Cost		11.04	36.54	13.90	7,113.01
165	Energy Unit Cost		0.0032572	0.0032572	0.0032572	0.0032572
166	Fuel Unit Cost		0.0267722	0.0267722	0.0267722	0.0388509
167	Demand Revenue		$ -	$ -	$ -	$ -
168	Customer Revenue		8,373,685	506,476	2,667,672	3,926,382
169	Energy Revenue		135,098	20,598	48,217	83,172
170	Fuel Revenue		1,110,412	169,302	396,308	992,040
171	Total Revenue		9,619,196	696,376	3,112,197	5,001,594
172	Zero-Check		$ -	$ -	$ -	$ -
	Grid Facility					
173	Grid Facility - Revenue Requirement	507,519,349	8,373,685	269,388	2,667,672	1,527,068
174	Grid Facility - Unit Costs	77.5903779	11.04	19.44	13.90	2,766.43

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821	Comml SH Rate 822
	(A)	(B)	(C)	(D)	(E)	(F)
	Mitigated Revenue Requirement After Other Revenue Credit					
175	Other Rev as % of Functionalized Revenue	1.81%	1.68%	1.79%	2.06%	2.27%
176	Ratio (Inverse of Percentage)	98.19%	98.32%	98.21%	97.94%	97.73%
177	Mitigated Amount	(0)	(100,218,769)	(31,620)	33,729,327	221,435
	Total Revenue Requirement					
178	Demand	$ 1,032,025,665	$ 333,047,847	$ 524,895	$ 176,596,909	$ 726,138
179	Customer	129,476,578	84,149,175	97,947	28,516,785	163,332
180	Energy	39,252,614	11,270,140	34,418	5,149,627	38,729
181	Fuel	322,936,621	92,632,429	282,891	42,326,221	318,327
182	**Total**	$ 1,523,691,478	$ 521,099,591	$ 940,151	$ 252,589,542	$ 1,246,526
183	Zero-Check	-	-	-	-	-
	Billing Determinants					
184	Demand (KW) - Production	14,180,260	0	0	0	0
185	Demand (KW) - Other	21,213,001	0	0	0	0
186	Customer (Customer Bills or No. Customers * 12)	6,541,009	4,946,379	1,220	627,541	1,640
187	Energy (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398	11,890,211
188	Fuel (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398	11,890,211
189	Demand Unit Cost - Production		0.00	0.00	0.00	0.00
190	Demand Unit Cost - Other		0.00	0.00	0.00	0.00
191	Customer Unit Cost		84.34	510.42	326.85	542.29
192	Energy Unit Cost		0.0032572	0.0032564	0.0032561	0.0032572
193	Fuel Unit Cost		0.0267722	0.0267656	0.0267625	0.0267722
194	Demand Revenue		$ -	$ -	$ -	$ -
195	Customer Revenue		417,197,022	622,842	205,113,694	889,469
196	Energy Revenue		11,270,140	34,418	5,149,627	38,729
197	Fuel Revenue		92,632,429	282,891	42,326,221	318,327
198	Total Revenue		521,099,591	940,151	252,589,542	1,246,526
199	Zero-Check		$ -	$ -	$ -	$ -

Line No.	Description	System Total	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(G)	(H)
	Mitigated Revenue Requirement After Other Revenue Credit			
175	Other Rev as % of Functionalized Revenue	1.81%	1.81%	1.94%
176	Ratio (Inverse of Percentage)	98.19%	98.19%	98.06%
177	Mitigated Amount	(0)	32,129,377	41,453,608
	Total Revenue Requirement			
178	Demand	$ 1,032,025,665	$ 141,290,888	$ 163,665,139
179	Customer	129,476,578	3,543,100	1,963,336
180	Energy	39,252,614	4,630,444	6,603,578
181	Fuel	322,936,621	38,058,912	54,276,650
182	**Total**	$ 1,523,691,478	$ 187,523,344	$ 226,508,703
183	Zero-Check	-	-	-
	Billing Determinants			
184	Demand (KW) - Production	14,180,260	4,003,187	4,659,514
185	Demand (KW) - Other	21,213,001	4,003,187	4,659,514
186	Customer (Customer Bills or No. Customers * 12)	6,541,009	44,986	5,466
187	Energy (kWh)	12,096,308,562	1,422,286,366	2,035,551,481
188	Fuel (kWh)	12,096,308,562	1,422,286,366	2,035,551,481
189	Demand Unit Cost - Production		23.30	22.68
190	Demand Unit Cost - Other		11.99	12.45
191	Customer Unit Cost		78.76	359.17
192	Energy Unit Cost		0.0032556	0.0032441
193	Fuel Unit Cost		0.0267590	0.0266643
194	Demand Revenue		$ 141,290,888	$ 163,665,139
195	Customer Revenue		3,543,100	1,963,336
196	Energy Revenue		4,630,444	6,603,578
197	Fuel Revenue		38,058,912	54,276,650
198	Total Revenue		187,523,344	226,508,703
199	Zero-Check		$ -	$ -

Summary Tab Made PUBLIC by NIPSCO

Attachment JFW-10

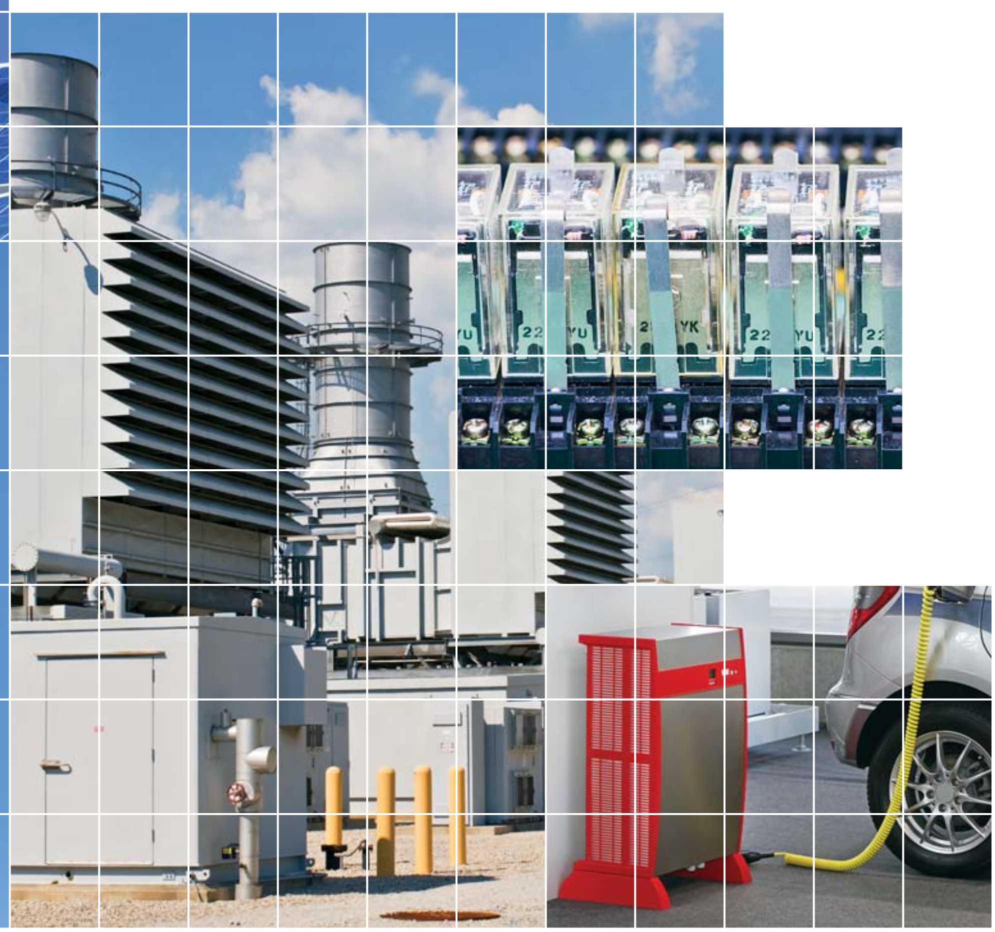
Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830	Muni. Power Rate 841
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Mitigated Revenue Requirement After Other Revenue Credit						
175	Other Rev as % of Functionalized Revenue	1.81%	1.56%	1.29%	2.51%	1.30%	1.55%
176	Ratio (Inverse of Percentage)	98.19%	98.44%	98.71%	97.49%	98.70%	98.45%
177	Mitigated Amount	(0)	943,705	(8,114,040)	0	818,271	198,043
	Total Revenue Requirement						
178	Demand	$ 1,032,025,665	$ 4,571,298	$ 69,038,137	$ 101,064,981	$ 31,879,277	$ 2,341,026
179	Customer	129,476,578	122,432	934,606	663,629	393,292	405,271
180	Energy	39,252,614	306,559	3,380,955	5,134,850	2,252,452	93,583
181	Fuel	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530	769,185
182	**Total**	$ 1,523,691,478	$ 7,519,982	$ 101,142,709	$ 149,068,230	$ 53,038,551	$ 3,609,065
183	Zero-Check	-	-	-	-	-	-
	Billing Determinants						
184	Demand (KW) - Production	14,180,260	105,561	1,852,987	2,214,672	1,272,049	0
185	Demand (KW) - Other	21,213,001	105,561	1,852,987	9,247,414	1,272,049	0
186	Customer (Customer Bills or No. Customers * 12)	6,541,009	72	2,208	108	120	8,501
187	Energy (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124	28,753,903
188	Fuel (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124	28,753,903
189	Demand Unit Cost - Production		21.78	25.14	23.92	19.69	0.00
190	Demand Unit Cost - Other		21.53	12.11	5.20	5.38	0.00
191	Customer Unit Cost		1,700.44	423.28	6,144.72	3,277.44	323.07
192	Energy Unit Cost		0.0032375	0.0032441	0.0032126	0.0032155	0.0032546
193	Fuel Unit Cost		0.0266095	0.0266642	0.0264049	0.0264291	0.0267506
194	Demand Revenue		$ 4,571,298	$ 69,038,137	$ 101,064,981	$ 31,879,277	$ -
195	Customer Revenue		122,432	934,606	663,629	393,292	2,746,297
196	Energy Revenue		306,559	3,380,955	5,134,850	2,252,452	93,583
197	Fuel Revenue		2,519,693	27,789,010	42,204,769	18,513,530	769,185
198	Total Revenue		7,519,982	101,142,709	149,068,230	53,038,551	3,609,065
199	Zero-Check		$ -	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(N)	(O)
	Mitigated Revenue Requirement			
	After Other Revenue Credit			
175	Other Rev as % of Functionalized Revenue	1.81%	6.32%	1.77%
176	Ratio (Inverse of Percentage)	98.19%	93.68%	98.23%
177	Mitigated Amount	(0)	84,206	350,551
	Total Revenue Requirement			
178	Demand	$ 1,032,025,665	$ 87,022	$ 1,763,239
179	Customer	129,476,578	17,118	25,302
180	Energy	39,252,614	1,119	69,075
181	Fuel	322,936,621	9,197	567,744
182	**Total**	$ 1,523,691,478	$ 114,457	$ 2,425,360
183	Zero-Check	-	-	-
	Billing Determinants			
184	Demand (KW) - Production	14,180,260	0	72,290
185	Demand (KW) - Other	21,213,001	0	72,290
186	Customer (Customer Bills or No. Customers * 12)	6,541,009	96	12
187	Energy (kWh)	12,096,308,562	343,541	21,456,529
188	Fuel (kWh)	12,096,308,562	343,541	21,456,529
189	Demand Unit Cost - Production		0.00	9.33
190	Demand Unit Cost - Other		0.00	15.06
191	Customer Unit Cost		1,090.42	2,108.50
192	Energy Unit Cost		0.0032572	0.0032193
193	Fuel Unit Cost		0.0267722	0.0264602
194	Demand Revenue		$ -	$ 1,763,239
195	Customer Revenue		104,141	25,302
196	Energy Revenue		1,119	69,075
197	Fuel Revenue		9,197	567,744
198	Total Revenue		114,457	2,425,360
199	Zero-Check		$ -	$ -

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Mitigated Revenue Requirement After Other Revenue Credit					
175	Other Rev as % of Functionalized Revenue	1.81%	1.54%	2.01%	1.98%	0.18%
176	Ratio (Inverse of Percentage)	98.19%	98.46%	97.99%	98.02%	99.82%
177	Mitigated Amount	(0)	(1,516,065)	242,394	(439,750)	149,327
	Total Revenue Requirement					
178	Demand	$ 1,032,025,665	$ 544,204	$ 533,944	$ 279,681	$ 4,071,038
179	Customer	129,476,578	6,313,416	214,925	1,948,241	4,671
180	Energy	39,252,614	135,098	20,598	48,217	83,172
181	Fuel	322,936,621	1,110,412	169,302	396,308	992,040
182	**Total**	$ 1,523,691,478	$ 8,103,130	$ 938,770	$ 2,672,447	$ 5,150,921
183	Zero-Check	-	-	-	-	-
	Billing Determinants					
184	Demand (KW) - Production	14,180,260	0	0	0	0
185	Demand (KW) - Other	21,213,001	0	0	0	0
186	Customer (Customer Bills or No. Customers * 12)	6,541,009	758,328	13,861	191,944	552
187	Energy (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
188	Fuel (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
189	Demand Unit Cost - Production		0.00	0.00	0.00	0.00
190	Demand Unit Cost - Other		0.00	0.00	0.00	0.00
191	Customer Unit Cost		9.04	54.03	11.61	7,383.53
192	Energy Unit Cost		0.0032572	0.0032572	0.0032572	0.0032572
193	Fuel Unit Cost		0.0267722	0.0267722	0.0267722	0.0388509
194	Demand Revenue		$ -	$ -	$ -	$ -
195	Customer Revenue		6,857,620	748,870	2,227,922	4,075,709
196	Energy Revenue		135,098	20,598	48,217	83,172
197	Fuel Revenue		1,110,412	169,302	396,308	992,040
198	Total Revenue		8,103,130	938,770	2,672,447	5,150,921
199	Zero-Check		$ -	$ -	$ -	$ -

Attachment JFW-11

DISTRIBUTED ENERGY RESOURCES RATE DESIGN AND COMPENSATION



A Manual Prepared by the NARUC Staff Subcommittee on Rate Design

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

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

2. Fixed Charges and Minimum Bills

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Attachment JFW-12

POWELL GOLDSTEIN LLP

Attachment JFW-12

Principles of Public Utiliity Rates by James C. Bonbright

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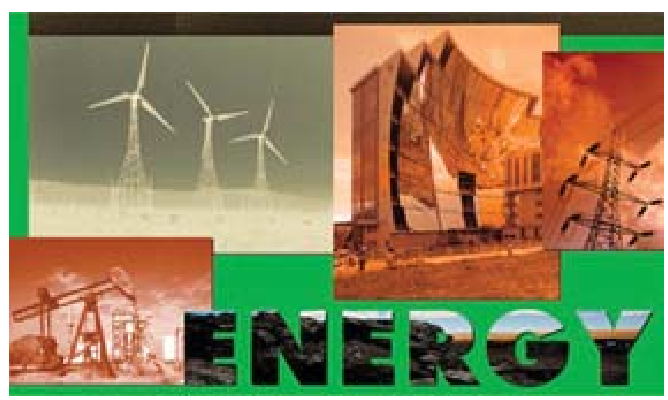

the rates for any given class of service (passenger versus freight, residential versus commercial, etc.) should cover the costs of supplying that class, and so the rates charged to any single customer within that class should cover the costs of supplying this one customer. Under this assumption, the 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-13

The Economics of Regulation
Principles and Institutions

Volume I Economic Principles
Volume II Institutional Issues

Alfred E. Kahn

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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-14

PUBLIC UTILITY ECONOMICS

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Rate Schedules. Pub
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average effective rate
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eased use. Flat rates
phone companies for

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

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

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

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

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

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

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

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

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

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

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Rate Base				
1	Plant in Service	$ 8,111,276,450	$ 3,434,873,162	$ 4,836,263	$ 1,203,580,989
2	Accumulated Reserve	(4,210,571,859)	(1,800,269,470)	(2,141,190)	(612,096,120)
3	Other Rate Base Items	212,741,209	81,990,995	253,521	32,242,583
4	Total Rate Base	$ 4,113,445,801	$ 1,716,594,687	$ 2,948,593	$ 623,727,452
	Revenues at Current Rates				
5	Retail Sales - Non Fuel	$ 1,089,552,179	$ 359,534,736	$ 521,256	$ 179,254,376
6	Retail Sales - Fuel	322,936,621	90,791,267	273,768	40,938,915
7	Total Retail Sales Revenue	$ 1,412,488,800	$ 450,326,003	$ 795,024	$ 220,193,291
8	Other Revenue	21,940,650	8,902,562	12,669	3,667,313
9	Total Other Revenue (To be Credited)	$ 21,940,650	$ 8,902,562	$ 12,669	$ 3,667,313
10	Interruptible Power Credit	$ -	$ 17,368,912	$ 49,131	$ 6,577,958
11	Total Revenues	$ 1,434,429,450	$ 476,597,478	$ 856,824	$ 230,438,562
	Expenses at Current Rates				
12	Operations & Maintenance Expenses	$ 491,038,911	$ 212,343,246	$ 310,553	$ 72,539,327
13	Depreciation Expense	297,033,774	123,246,657	134,651	43,346,915
14	Amortization Expense	50,657,236	26,301,604	30,244	7,082,958
15	Taxes Other Than Income Taxes	39,161,650	16,865,487	23,898	5,820,955
16	Fuel Expenses	322,936,621	92,632,429	282,891	42,326,221
17	Income Taxes	27,609,096	(43,331,505)	(35,256)	18,396,867
18	Total Expenses - Current	$ 1,228,437,287	$ 428,057,918	$ 746,981	$ 189,513,244
19	Current Operating Income	$ 205,992,163	$ 48,539,560	$ 109,843	$ 40,925,318
20	Return at Current Rates	5.01%	2.83%	3.73%	6.56%
21	Index Rate of Return	1.00	0.56	0.74	1.31

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Rate Base				
1	Plant in Service	$ 8,111,276,450	$ 5,002,248	$ 845,685,618	$ 902,422,256
2	Accumulated Reserve	(4,210,571,859)	(2,241,842)	(429,897,371)	(462,264,764)
3	Other Rate Base Items	212,741,209	267,204	21,891,094	25,264,257
4	Total Rate Base	$ 4,113,445,801	$ 3,027,610	$ 437,679,341	$ 465,421,748
	Revenues at Current Rates				
5	Retail Sales - Non Fuel	$ 1,089,552,179	$ 749,365	$ 124,708,349	$ 143,524,164
6	Retail Sales - Fuel	322,936,621	308,000	36,753,329	52,714,526
7	Total Retail Sales Revenue	$ 1,412,488,800	$ 1,057,365	$ 161,461,678	$ 196,238,690
8	Other Revenue	21,940,650	16,453	2,180,157	2,584,400
9	Total Other Revenue (To be Credited)	$ 21,940,650	$ 16,453	$ 2,180,157	$ 2,584,400
10	Interruptible Power Credit	$ -	$ 61,911	$ 6,951,810	$ 7,188,947
11	Total Revenues	$ 1,434,429,450	$ 1,135,729	$ 170,593,645	$ 206,012,037
	Expenses at Current Rates				
12	Operations & Maintenance Expenses	$ 491,038,911	$ 308,308	$ 50,090,477	$ 55,069,696
13	Depreciation Expense	297,033,774	138,149	31,541,681	34,628,847
14	Amortization Expense	50,657,236	33,577	4,144,850	4,410,602
15	Taxes Other Than Income Taxes	39,161,650	24,138	4,011,850	4,282,354
16	Fuel Expenses	322,936,621	318,327	38,058,912	54,276,650
17	Income Taxes	27,609,096	104,350	13,576,484	19,114,305
18	Total Expenses - Current	$ 1,228,437,287	$ 926,849	$ 141,424,253	$ 171,782,453
19	Current Operating Income	$ 205,992,163	$ 208,880	$ 29,169,392	$ 34,229,585
20	Return at Current Rates	5.01%	6.90%	6.66%	7.35%
21	Index Rate of Return	1.00	1.38	1.33	1.47

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830
	(A)	(B)	(I)	(J)	(K)	(L)
	Rate Base					
1	Plant in Service	$ 8,111,276,450	$ 27,450,478	$ 560,978,479	$ 762,209,702	$ 218,011,861
2	Accumulated Reserve	(4,210,571,859)	(13,475,550)	(287,412,335)	(394,475,567)	(118,644,970)
3	Other Rate Base Items	212,741,209	1,087,806	13,965,121	24,603,489	5,598,011
4	Total Rate Base	$ 4,113,445,801	$ 15,062,734	$ 287,531,266	$ 392,337,624	$ 104,964,902
	Revenues at Current Rates					
5	Retail Sales - Non Fuel	$ 1,089,552,179	$ 3,821,199	$ 60,142,467	$ 172,461,961	$ 28,346,403
6	Retail Sales - Fuel	322,936,621	2,501,305	27,239,411	50,407,897	17,292,999
7	Total Retail Sales Revenue	$ 1,412,488,800	$ 6,322,504	$ 87,381,878	$ 222,869,857	$ 45,639,403
8	Other Revenue	21,940,650	64,400	1,070,784	2,725,772	440,348
9	Total Other Revenue (To be Credited)	$ 21,940,650	$ 64,400	$ 1,070,784	$ 2,725,772	$ 440,348
10	Interruptible Power Credit	$ -	$ 433,234	$ 3,462,534	$ (44,568,656)	$ 2,009,885
11	Total Revenues	$ 1,434,429,450	$ 6,820,138	$ 91,915,196	$ 181,026,973	$ 48,089,635
	Expenses at Current Rates					
12	Operations & Maintenance Expenses	$ 491,038,911	$ 1,779,721	$ 34,004,262	$ 42,553,068	$ 14,075,419
13	Depreciation Expense	297,033,774	977,545	21,448,223	26,811,600	9,177,960
14	Amortization Expense	50,657,236	145,411	2,679,539	3,790,975	1,052,286
15	Taxes Other Than Income Taxes	39,161,650	130,624	2,665,446	3,580,248	1,048,567
16	Fuel Expenses	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530
17	Income Taxes	27,609,096	346,177	(5,798,244)	26,288,963	(324,966)
18	Total Expenses - Current	$ 1,228,437,287	$ 5,899,170	$ 82,788,236	$ 145,229,623	$ 43,542,795
19	Current Operating Income	$ 205,992,163	$ 920,967	$ 9,126,960	$ 35,797,350	$ 4,546,840
20	Return at Current Rates	5.01%	6.11%	3.17%	9.12%	4.33%
21	Index Rate of Return	1.00	1.22	0.63	1.82	0.87

Line No.	Description	System Total	Muni. Power Rate 841	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(M)	(N)	(O)
	Rate Base				
1	Plant in Service	$ 8,111,276,450	$ 18,113,692	$ 138,446	$ 11,129,219
2	Accumulated Reserve	(4,210,571,859)	(9,025,222)	(71,150)	(4,978,052)
3	Other Rate Base Items	212,741,209	569,970	4,152	420,882
4	Total Rate Base	$ 4,113,445,801	$ 9,658,439	$ 71,448	$ 6,572,049
	Revenues at Current Rates				
5	Retail Sales - Non Fuel	$ 1,089,552,179	$ 2,400,881	$ 93,004	$ 1,544,820
6	Retail Sales - Fuel	322,936,621	749,204	9,127	560,179
7	Total Retail Sales Revenue	$ 1,412,488,800	$ 3,150,085	$ 102,131	$ 2,104,999
8	Other Revenue	21,940,650	41,034	1,410	26,924
9	Total Other Revenue (To be Credited)	$ 21,940,650	$ 41,034	$ 1,410	$ 26,924
10	Interruptible Power Credit	$ -	$ 91,209	$ 655	$ 73,272
11	Total Revenues	$ 1,434,429,450	$ 3,282,328	$ 104,196	$ 2,205,195
	Expenses at Current Rates				
12	Operations & Maintenance Expenses	$ 491,038,911	$ 1,080,484	$ 10,700	$ 506,486
13	Depreciation Expense	297,033,774	631,538	5,047	370,148
14	Amortization Expense	50,657,236	107,413	890	57,312
15	Taxes Other Than Income Taxes	39,161,650	86,849	703	49,520
16	Fuel Expenses	322,936,621	769,185	9,197	567,744
17	Income Taxes	27,609,096	99,822	44,197	211,107
18	Total Expenses - Current	$ 1,228,437,287	$ 2,775,292	$ 70,734	$ 1,762,315
19	Current Operating Income	$ 205,992,163	$ 507,036	$ 33,462	$ 442,879
20	Return at Current Rates	5.01%	5.25%	46.83%	6.74%
21	Index Rate of Return	1.00	1.05	9.35	1.35

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Rate Base					
1	Plant in Service	$ 8,111,276,450	$ 66,889,793	$ 3,985,026	$ 17,407,396	$ 28,561,824
2	Accumulated Reserve	(4,210,571,859)	(44,222,581)	(2,236,714)	(12,875,268)	(14,243,692)
3	Other Rate Base Items	212,741,209	3,023,812	131,295	766,812	660,205
4	Total Rate Base	$ 4,113,445,801	$ 25,691,024	$ 1,879,608	$ 5,298,940	$ 14,978,336
	Revenues at Current Rates					
5	Retail Sales - Non Fuel	$ 1,089,552,179	$ 6,272,059	$ 646,898	$ 2,028,970	$ 3,501,270
6	Retail Sales - Fuel	322,936,621	901,306	161,857	341,490	992,041
7	Total Retail Sales Revenue	$ 1,412,488,800	$ 7,173,365	$ 808,755	$ 2,370,460	$ 4,493,311
8	Other Revenue	21,940,650	132,999	10,833	54,388	8,205
9	Total Other Revenue (To be Credited)	$ 21,940,650	$ 132,999	$ 10,833	$ 54,388	$ 8,205
10	Interruptible Power Credit	$ -	$ 100,173	$ 34,355	$ 27,279	$ 137,391
11	Total Revenues	$ 1,434,429,450	$ 7,406,537	$ 853,943	$ 2,452,127	$ 4,638,907
	Expenses at Current Rates					
12	Operations & Maintenance Expenses	$ 491,038,911	$ 3,137,040	$ 209,401	$ 1,405,804	$ 1,614,919
13	Depreciation Expense	297,033,774	2,873,040	155,597	482,564	1,063,613
14	Amortization Expense	50,657,236	367,743	23,035	294,009	134,789
15	Taxes Other Than Income Taxes	39,161,650	316,363	18,408	101,983	134,258
16	Fuel Expenses	322,936,621	1,110,412	169,302	396,308	992,040
17	Income Taxes	27,609,096	(929,849)	114,512	(279,035)	11,167
18	Total Expenses - Current	$ 1,228,437,287	$ 6,874,750	$ 690,255	$ 2,401,634	$ 3,950,785
19	Current Operating Income	$ 205,992,163	$ 531,788	$ 163,688	$ 50,493	$ 688,122
20	Return at Current Rates	5.01%	2.07%	8.71%	0.95%	4.59%
21	Index Rate of Return	1.00	0.41	1.74	0.19	0.92

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Revenue Requirement at Equal Rates of Return at Current Rates				
22	Required Return	5.01%	5.01%	5.01%	5.01%
23	Required Operating Income	$ 205,992,163	$ 85,963,222	$ 147,659	$ 31,234,875
	Expenses at Required Return				
24	Operations & Maintenance Expenses	$ 491,038,911	$ 212,343,246	$ 310,553	$ 72,539,327
25	Depreciation Expense	297,033,774	123,246,657	134,651	43,346,915
26	Amortization Expense	50,657,236	26,301,604	30,244	7,082,958
27	Taxes Other Than Income Taxes	39,161,650	16,865,487	23,898	5,820,955
28	Fuel Expenses	322,936,621	92,632,429	282,891	42,326,221
29	Income Taxes	27,609,096	11,521,637	19,791	4,186,405
30	Total Expenses - Required	$ 1,228,437,287	$ 482,911,059	$ 802,027	$ 175,302,782
31	Total Revenue Requirement at Equal Return	$ 1,434,429,450	$ 568,874,281	$ 949,686	$ 206,537,657
32	Current Subsidy	$ -	$ (92,276,803)	$ (92,862)	$ 23,900,905
	Revenue Requirement at Equal Rates of Return at Proposed Rates				
33	Required Return	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,763,895	$ 120,504,947	$ 206,991	$ 43,785,667
35	Operating Income (Deficiency)/Surplus	$ (82,771,732)	$ (71,965,387)	$ (97,148)	$ (2,860,349)
	Expenses at Required Return				
36	Operations & Maintenance Expenses	$ 491,271,586	$ 212,516,606	$ 310,553	$ 72,550,401
37	Depreciation Expense	297,033,774	123,246,657	134,651	43,346,915
38	Amortization Expense	50,657,236	26,301,604	30,244	7,082,958
39	Taxes Other than Income	39,295,540	16,922,185	23,977	5,840,822
40	Fuel Expenses	322,936,621	92,632,429	282,891	42,326,221
41	Income Taxes	55,856,537	23,309,663	40,039	8,469,604
42	Total Expense - Required	$ 1,257,051,293	$ 494,929,144	$ 822,355	$ 179,616,921
43	Total Revenue Requirement at Equal Return	$ 1,545,815,189	$ 615,434,091	$ 1,029,347	$ 223,402,588
44	Revenue (Deficiency)/Surplus	$ (111,385,738)	$ (138,836,613)	$ (172,522)	$ 7,035,974
45	Total Revenues	1,434,429,450	476,597,478	856,824	230,438,562
46	Total Revenues as Proposed	$ 1,545,815,189	$ 615,434,091	$ 1,029,347	$ 223,402,588
47	Less Total Other Revenues	$ 22,123,710	$ 8,963,164	$ 12,757	$ 3,697,527
48	Total Base Rate Revenues as Proposed	$ 1,523,691,478	$ 606,470,927	$ 1,016,589	$ 219,705,061
	Mitigation				
49	Mitigation	$ (0)	$ (85,378,327)	$ (76,415)	$ 32,883,469
50	Proposed Increase Post Mitigation	111,385,738	53,458,287	96,107	25,847,495

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Revenue Requirement at Equal Rates of Return at Current Rates				
22	Required Return	5.01%	5.01%	5.01%	5.01%
23	Required Operating Income	$ 205,992,163	$ 151,616	$ 21,918,002	$ 23,307,280
	Expenses at Required Return				
24	Operations & Maintenance Expenses	$ 491,038,911	$ 308,308	$ 50,090,477	$ 55,069,696
25	Depreciation Expense	297,033,774	138,149	31,541,681	34,628,847
26	Amortization Expense	50,657,236	33,577	4,144,850	4,410,602
27	Taxes Other Than Income Taxes	39,161,650	24,138	4,011,850	4,282,354
28	Fuel Expenses	322,936,621	318,327	38,058,912	54,276,650
29	Income Taxes	27,609,096	20,321	2,937,666	3,123,871
30	Total Expenses - Required	$ 1,228,437,287	$ 842,820	$ 130,785,436	$ 155,792,019
31	Total Revenue Requirement at Equal Return	$ 1,434,429,450	$ 994,436	$ 152,703,438	$ 179,099,299
32	Current Subsidy	$ -	$ 141,293	$ 17,890,207	$ 26,912,738
	Revenue Requirement at Equal Rates of Return at Proposed Rates				
33	Required Return	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,763,895	$ 212,538	$ 30,725,090	$ 32,672,607
35	Operating Income (Deficiency)/Surplus	$ (82,771,732)	$ (3,658)	$ (1,555,698)	$ 1,556,978
	Expenses at Required Return				
36	Operations & Maintenance Expenses	$ 491,271,586	$ 308,312	$ 50,093,606	$ 55,086,604
37	Depreciation Expense	297,033,774	138,149	31,541,681	34,628,847
38	Amortization Expense	50,657,236	33,577	4,144,850	4,410,602
39	Taxes Other than Income	39,295,540	24,221	4,025,809	4,297,250
40	Fuel Expenses	322,936,621	318,327	38,058,912	54,276,650
41	Income Taxes	55,856,537	41,112	5,943,254	6,319,968
42	Total Expense - Required	$ 1,257,051,293	$ 863,697	$ 133,808,111	$ 159,019,921
43	Total Revenue Requirement at Equal Return	$ 1,545,815,189	$ 1,076,235	$ 164,533,201	$ 191,692,528
44	Revenue (Deficiency)/Surplus	$ (111,385,738)	$ 59,493	$ 6,060,444	$ 14,319,510
45	Total Revenues	1,434,429,450	1,135,729	170,593,645	206,012,037
46	Total Revenues as Proposed	$ 1,545,815,189	$ 1,076,235	$ 164,533,201	$ 191,692,528
47	Less Total Other Revenues	$ 22,123,710	$ 16,579	$ 2,201,178	$ 2,608,592
48	Total Base Rate Revenues as Proposed	$ 1,523,691,478	$ 1,059,656	$ 162,332,023	$ 189,083,936
	Mitigation				
49	Mitigation	$ (0)	$ 186,884	$ 25,195,342	$ 37,427,166
50	Proposed Increase Post Mitigation	111,385,738	127,391	19,134,898	23,107,656

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830
	(A)	(B)	(I)	(J)	(K)	(L)
	Revenue Requirement at Equal Rates of Return at Current Rates					
22	Required Return	5.01%	5.01%	5.01%	5.01%	5.01%
23	Required Operating Income	$ 205,992,163	$ 754,308	$ 14,398,923	$ 19,647,390	$ 5,256,407
	Expenses at Required Return					
24	Operations & Maintenance Expenses	$ 491,038,911	$ 1,779,721	$ 34,004,262	$ 42,553,068	$ 14,075,419
25	Depreciation Expense	297,033,774	977,545	21,448,223	26,811,600	9,177,960
26	Amortization Expense	50,657,236	145,411	2,679,539	3,790,975	1,052,286
27	Taxes Other Than Income Taxes	39,161,650	130,624	2,665,446	3,580,248	1,048,567
28	Fuel Expenses	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530
29	Income Taxes	27,609,096	101,100	1,929,885	2,633,337	704,515
30	Total Expenses - Required	$ 1,228,437,287	$ 5,654,093	$ 90,516,365	$ 121,573,996	$ 44,572,277
31	Total Revenue Requirement at Equal Return	$ 1,434,429,450	$ 6,408,401	$ 104,915,288	$ 141,221,387	$ 49,828,684
32	Current Subsidy	$ -	$ 411,736	$ (13,000,092)	$ 39,805,586	$ (1,739,049)
	Revenue Requirement at Equal Rates of Return at Proposed Rates					
33	Required Return	7.02%	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,763,895	$ 1,057,404	$ 20,184,695	$ 27,542,101	$ 7,368,536
35	Operating Income (Deficiency)/Surplus	$ (82,771,732)	$ (136,436)	$ (11,057,735)	$ 8,255,249	$ (2,821,696)
	Expenses at Required Return					
36	Operations & Maintenance Expenses	$ 491,271,586	$ 1,779,721	$ 34,032,054	$ 42,553,068	$ 14,075,419
37	Depreciation Expense	297,033,774	977,545	21,448,223	26,811,600	9,177,960
38	Amortization Expense	50,657,236	145,411	2,679,539	3,790,975	1,052,286
39	Taxes Other than Income	39,295,540	131,077	2,674,706	3,592,830	1,052,165
40	Fuel Expenses	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530
41	Income Taxes	55,856,537	204,537	3,904,391	5,327,558	1,425,320
42	Total Expense - Required	$ 1,257,051,293	$ 5,757,984	$ 92,527,923	$ 124,280,799	$ 45,296,680
43	Total Revenue Requirement at Equal Return	$ 1,545,815,189	$ 6,815,387	$ 112,712,618	$ 151,822,901	$ 52,665,216
44	Revenue (Deficiency)/Surplus	$ (111,385,738)	$ 4,750	$ (20,797,422)	$ 29,204,072	$ (4,575,580)
45	Total Revenues	1,434,429,450	6,820,138	91,915,196	181,026,973	48,089,635
46	Total Revenues as Proposed	$ 1,545,815,189	$ 6,815,387	$ 112,712,618	$ 151,822,901	$ 52,665,216
47	Less Total Other Revenues	$ 22,123,710	$ 65,044	$ 1,080,922	$ 2,754,841	$ 445,126
48	Total Base Rate Revenues as Proposed	$ 1,523,691,478	$ 6,750,344	$ 111,631,696	$ 149,068,059	$ 52,220,090
	Mitigation					
49	Mitigation	$ (0)	$ 769,741	$ (10,487,613)	$ -	$ 818,467
50	Proposed Increase Post Mitigation	111,385,738	764,991	10,309,809	(29,204,072)	5,394,048

Line No.	Description	System Total	Muni. Power Rate 841	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(M)	(N)	(O)
	Revenue Requirement at Equal Rates of Return at Current Rates				
22	Required Return	5.01%	5.01%	5.01%	5.01%
23	Required Operating Income	$ 205,992,163	$ 483,673	$ 3,578	$ 329,114
	Expenses at Required Return				
24	Operations & Maintenance Expenses	$ 491,038,911	$ 1,080,484	$ 10,700	$ 506,486
25	Depreciation Expense	297,033,774	631,538	5,047	370,148
26	Amortization Expense	50,657,236	107,413	890	57,312
27	Taxes Other Than Income Taxes	39,161,650	86,849	703	49,520
28	Fuel Expenses	322,936,621	769,185	9,197	567,744
29	Income Taxes	27,609,096	64,827	480	44,111
30	Total Expenses - Required	$ 1,228,437,287	$ 2,740,296	$ 27,016	$ 1,595,320
31	Total Revenue Requirement at Equal Return	$ 1,434,429,450	$ 3,223,969	$ 30,594	$ 1,924,433
32	Current Subsidy	$ -	$ 58,359	$ 73,601	$ 280,762
	Revenue Requirement at Equal Rates of Return at Proposed Rates				
33	Required Return	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,763,895	$ 678,022	$ 5,016	$ 461,358
35	Operating Income (Deficiency)/Surplus	$ (82,771,732)	$ (170,986)	$ 28,446	$ (18,478)
	Expenses at Required Return				
36	Operations & Maintenance Expenses	$ 491,271,586	$ 1,080,484	$ 10,700	$ 506,486
37	Depreciation Expense	297,033,774	631,538	5,047	370,148
38	Amortization Expense	50,657,236	107,413	890	57,312
39	Taxes Other than Income	39,295,540	87,148	705	49,703
40	Fuel Expenses	322,936,621	769,185	9,197	567,744
41	Income Taxes	55,856,537	131,152	970	89,242
42	Total Expense - Required	$ 1,257,051,293	$ 2,806,920	$ 27,509	$ 1,640,634
43	Total Revenue Requirement at Equal Return	$ 1,545,815,189	$ 3,484,943	$ 32,525	$ 2,101,992
44	Revenue (Deficiency)/Surplus	$ (111,385,738)	$ (202,615)	$ 71,671	$ 103,203
45	Total Revenues	1,434,429,450	3,282,328	104,196	2,205,195
46	Total Revenues as Proposed	$ 1,545,815,189	$ 3,484,943	$ 32,525	$ 2,101,992
47	Less Total Other Revenues	$ 22,123,710	$ 41,439	$ 1,425	$ 27,184
48	Total Base Rate Revenues as Proposed	$ 1,523,691,478	$ 3,443,504	$ 31,100	$ 2,074,808
	Mitigation				
49	Mitigation	$ (0)	$ 165,553	$ 83,358	$ 350,552
50	Proposed Increase Post Mitigation	111,385,738	368,167	11,687	247,349

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Revenue Requirement at Equal Rates of Return at Current Rates					
22	Required Return	5.01%	5.01%	5.01%	5.01%	5.01%
23	Required Operating Income	$ 205,992,163	$ 1,286,549	$ 94,127	$ 265,359	$ 750,082
	Expenses at Required Return					
24	Operations & Maintenance Expenses	$ 491,038,911	$ 3,137,040	$ 209,401	$ 1,405,804	$ 1,614,919
25	Depreciation Expense	297,033,774	2,873,040	155,597	482,564	1,063,613
26	Amortization Expense	50,657,236	367,743	23,035	294,009	134,789
27	Taxes Other Than Income Taxes	39,161,650	316,363	18,408	101,983	134,258
28	Fuel Expenses	322,936,621	1,110,412	169,302	396,308	992,040
29	Income Taxes	27,609,096	172,436	12,616	35,566	100,533
30	Total Expenses - Required	$ 1,228,437,287	$ 7,977,035	$ 588,359	$ 2,716,235	$ 4,040,152
31	Total Revenue Requirement at Equal Return	$ 1,434,429,450	$ 9,263,584	$ 682,485	$ 2,981,594	$ 4,790,234
32	Current Subsidy	$ -	$ (1,857,046)	$ 171,458	$ (529,467)	$ (151,326)
	Revenue Requirement at Equal Rates of Return at Proposed Rates					
33	Required Return	7.02%	7.02%	7.02%	7.02%	7.02%
34	Required Operating Income	$ 288,763,895	$ 1,803,510	$ 131,948	$ 371,986	$ 1,051,479
35	Operating Income (Deficiency)/Surplus	$ (82,771,732)	$ (1,271,722)	$ 31,739	$ (321,492)	$ (363,357)
	Expenses at Required Return					
36	Operations & Maintenance Expenses	$ 491,271,586	$ 3,137,049	$ 209,402	$ 1,406,203	$ 1,614,919
37	Depreciation Expense	297,033,774	2,873,040	155,597	482,564	1,063,613
38	Amortization Expense	50,657,236	367,743	23,035	294,009	134,789
39	Taxes Other than Income	39,295,540	317,468	18,474	102,271	134,729
40	Fuel Expenses	322,936,621	1,110,412	169,302	396,308	992,040
41	Income Taxes	55,856,537	348,859	25,523	71,954	203,391
42	Total Expense - Required	$ 1,257,051,293	$ 8,154,571	$ 601,333	$ 2,753,310	$ 4,143,481
43	Total Revenue Requirement at Equal Return	$ 1,545,815,189	$ 9,958,081	$ 733,281	$ 3,125,295	$ 5,194,960
44	Revenue (Deficiency)/Surplus	$ (111,385,738)	$ (2,551,544)	$ 120,662	$ (673,168)	$ (556,053)
45	Total Revenues	1,434,429,450	7,406,537	853,943	2,452,127	4,638,907
46	Total Revenues as Proposed	$ 1,545,815,189	$ 9,958,081	$ 733,281	$ 3,125,295	$ 5,194,960
47	Less Total Other Revenues	$ 22,123,710	$ 134,056	$ 10,942	$ 54,730	$ 8,205
48	Total Base Rate Revenues as Proposed	$ 1,523,691,478	$ 9,824,025	$ 722,340	$ 3,070,566	$ 5,186,755
	Mitigation					
49	Mitigation	$ (0)	$ (1,720,778)	$ 216,446	$ (398,121)	$ (35,723)
50	Proposed Increase Post Mitigation	111,385,738	830,766	95,784	275,047	520,330

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Revenue Requirement at Proposed Mitigated Rates				
51	Revenue Deficiency/Surplus (line 50)	$ 111,385,738	$ 53,458,287	$ 96,107	$ 25,847,495
52	Total Revenues (line 11)	1,434,429,450	476,597,478	856,824	230,438,562
53	Total Revenues at Proposed	$ 1,545,815,189	$ 530,055,764	$ 952,931	$ 256,286,057
54	Less Total Other Revenues (line)	$ 22,123,710	$ 8,963,164	$ 12,757	$ 3,697,527
55	Total Base Rate Revenue at Proposed	$ 1,523,691,478	$ 521,092,601	$ 940,174	$ 252,588,529
56	Total Margin at Current Rates (line 5)	$ 1,089,552,179	$ 376,903,648	$ 570,387	$ 185,832,334
57	Total Margin in Base Rates (line 55 - line 40)	1,200,754,857	428,460,172	657,283	210,262,308
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 111,202,678	$ 51,556,523	$ 86,896	$ 24,429,974
59	Percent Revenue Change (line 58 / line 56)	10.21%	13.68%	15.23%	13.15%
60	Expenses (excl. Income Taxes)	$ 1,201,194,756	$ 471,619,481	$ 782,316	$ 171,147,317
61	Interest Expense	186,750,439	77,933,399	133,866	28,317,226
62	Taxable Income	$ 157,869,993	$ (19,497,116)	$ 36,749	$ 56,821,513
63	Income Taxes at Proposed	55,856,537	(6,898,343)	13,002	20,104,219
64	Operating Income at Proposed	$ 288,763,895	$ 65,334,626	$ 157,613	$ 65,034,520
65	Return at Proposed	7.02%	3.81%	5.35%	10.43%
66	Index Rate of Return	1.00	0.54	0.76	1.49

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Revenue Requirement at Proposed Mitigated Rates				
51	Revenue Deficiency/Surplus (line 50)	$ 111,385,738	$ 127,391	$ 19,134,898	$ 23,107,656
52	Total Revenues (line 11)	1,434,429,450	1,135,729	170,593,645	206,012,037
53	Total Revenues at Proposed	$ 1,545,815,189	$ 1,263,120	$ 189,728,543	$ 229,119,693
54	Less Total Other Revenues (line)	$ 22,123,710	$ 16,579	$ 2,201,178	$ 2,608,592
55	Total Base Rate Revenue at Proposed	$ 1,523,691,478	$ 1,246,541	$ 187,527,365	$ 226,511,101
56	Total Margin at Current Rates (line 5)	$ 1,089,552,179	$ 811,276	$ 131,660,159	$ 150,713,111
57	Total Margin in Base Rates (line 55 - line 40)	1,200,754,857	928,213	149,468,453	172,234,452
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 111,202,678	$ 116,937	$ 17,808,295	$ 21,521,340
59	Percent Revenue Change (line 58 / line 56)	10.21%	14.41%	13.53%	14.28%
60	Expenses (excl. Income Taxes)	$ 1,201,194,756	$ 822,585	$ 127,864,857	$ 152,699,953
61	Interest Expense	186,750,439	137,454	19,870,642	21,130,147
62	Taxable Income	$ 157,869,993	$ 303,081	$ 41,993,043	$ 55,289,593
63	Income Taxes at Proposed	55,856,537	107,234	14,857,706	19,562,205
64	Operating Income at Proposed	$ 288,763,895	$ 333,300	$ 47,005,979	$ 56,857,535
65	Return at Proposed	7.02%	11.01%	10.74%	12.22%
66	Index Rate of Return	1.00	1.57	1.53	1.74

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830
	(A)	(B)	(I)	(J)	(K)	(L)
	Revenue Requirement at Proposed Mitigated Rates					
51	Revenue Deficiency/Surplus (line 50)	$ 111,385,738	$ 764,991	$ 10,309,809	$ (29,204,072)	$ 5,394,048
52	Total Revenues (line 11)	1,434,429,450	6,820,138	91,915,196	181,026,973	48,089,635
53	Total Revenues at Proposed	$ 1,545,815,189	$ 7,585,129	$ 102,225,005	$ 151,822,901	$ 53,483,683
54	Less Total Other Revenues (line)	$ 22,123,710	$ 65,044	$ 1,080,922	$ 2,754,841	$ 445,126
55	Total Base Rate Revenue at Proposed	$ 1,523,691,478	$ 7,520,085	$ 101,144,083	$ 149,068,059	$ 53,038,558
56	Total Margin at Current Rates (line 5)	$ 1,089,552,179	$ 4,254,433	$ 63,605,001	$ 127,893,304	$ 30,356,288
57	Total Margin in Base Rates (line 55 - line 40)	1,200,754,857	5,000,392	73,355,073	106,863,290	34,525,027
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 111,202,678	$ 745,959	$ 9,750,072	$ (21,030,014)	$ 4,168,739
59	Percent Revenue Change (line 58 / line 56)	10.21%	17.53%	15.33%	-16.44%	13.73%
60	Expenses (excl. Income Taxes)	$ 1,201,194,756	$ 5,553,446	$ 88,623,532	$ 118,953,241	$ 43,871,360
61	Interest Expense	186,750,439	683,848	13,053,919	17,812,128	4,765,407
62	Taxable Income	$ 157,869,993	$ 1,347,834	$ 547,554	$ 15,057,531	$ 4,846,917
63	Income Taxes at Proposed	55,856,537	476,882	193,732	5,327,558	1,714,905
64	Operating Income at Proposed	$ 288,763,895	$ 1,554,800	$ 13,407,741	$ 27,542,101	$ 7,897,419
65	Return at Proposed	7.02%	10.32%	4.66%	7.02%	7.52%
66	Index Rate of Return	1.00	1.47	0.66	1.00	1.07

Line No.	Description		System Total		Muni. Power Rate 841		Int WW Pumping Rate 842		Railroad Rate 844
	(A)		(B)		(M)		(N)		(O)
	Revenue Requirement at Proposed Mitigated Rates								
51	Revenue Deficiency/Surplus (line 50)	$	111,385,738	$	368,167	$	11,687	$	247,349
52	Total Revenues (line 11)		1,434,429,450		3,282,328		104,196		2,205,195
53	Total Revenues at Proposed	$	1,545,815,189	$	3,650,496	$	115,883	$	2,452,544
54	Less Total Other Revenues (line)	$	22,123,710	$	41,439	$	1,425	$	27,184
55	Total Base Rate Revenue at Proposed	$	1,523,691,478	$	3,609,057	$	114,457	$	2,425,360
56	Total Margin at Current Rates (line 5)	$	1,089,552,179	$	2,492,090	$	93,659	$	1,618,092
57	Total Margin in Base Rates (line 55 - line 40)		1,200,754,857		2,839,871		105,260		1,857,616
58	$ Increase/ (Decrease) (line 57 - line 56)	$	111,202,678	$	347,781	$	11,601	$	239,524
59	Percent Revenue Change (line 58 / line 56)		10.21%		13.96%		12.39%		14.80%
60	Expenses (excl. Income Taxes)	$	1,201,194,756	$	2,675,768	$	26,539	$	1,551,392
61	Interest Expense		186,750,439		438,493		3,244		298,371
62	Taxable Income	$	157,869,993	$	536,234	$	86,100	$	602,781
63	Income Taxes at Proposed		55,856,537		189,727		30,463		213,272
64	Operating Income at Proposed	$	288,763,895	$	785,000	$	58,880	$	687,880
65	Return at Proposed		7.02%		8.13%		82.41%		10.47%
66	Index Rate of Return		1.00		1.16		11.74		1.49

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Revenue Requirement at Proposed Mitigated Rates					
51	Revenue Deficiency/Surplus (line 50)	$ 111,385,738	$ 830,766	$ 95,784	$ 275,047	$ 520,330
52	Total Revenues (line 11)	1,434,429,450	7,406,537	853,943	2,452,127	4,638,907
53	Total Revenues at Proposed	$ 1,545,815,189	$ 8,237,303	$ 949,727	$ 2,727,174	$ 5,159,238
54	Less Total Other Revenues (line)	$ 22,123,710	$ 134,056	$ 10,942	$ 54,730	$ 8,205
55	Total Base Rate Revenue at Proposed	$ 1,523,691,478	$ 8,103,247	$ 938,785	$ 2,672,444	$ 5,151,032
56	Total Margin at Current Rates (line 5)	$ 1,089,552,179	$ 6,372,232	$ 681,253	$ 2,056,249	$ 3,638,661
57	Total Margin in Base Rates (line 55 - line 40)	1,200,754,857	6,992,835	769,483	2,276,136	4,158,992
58	$ Increase/ (Decrease) (line 57 - line 56)	$ 111,202,678	$ 620,602	$ 88,230	$ 219,886	$ 520,331
59	Percent Revenue Change (line 58 / line 56)	10.21%	9.74%	12.95%	10.69%	14.30%
60	Expenses (excl. Income Taxes)	$ 1,201,194,756	$ 7,805,712	$ 575,809	$ 2,681,355	$ 3,940,090
61	Interest Expense	186,750,439	1,166,372	85,334	240,572	680,016
62	Taxable Income	$ 157,869,993	$ (734,782)	$ 288,583	$ (194,753)	$ 539,131
63	Income Taxes at Proposed	55,856,537	(259,976)	102,105	(68,906)	190,752
64	Operating Income at Proposed	$ 288,763,895	$ 691,566	$ 271,813	$ 114,725	$ 1,028,396
65	Return at Proposed	7.02%	2.69%	14.46%	2.17%	6.87%
66	Index Rate of Return	1.00	0.38	2.06	0.31	0.98

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Residential Rate 811**	**C&GS Heat Pump Rate 820**	**GS Small Rate 821**
	Demand				
67	Production	$ 666,367,244	$ 280,339,857	$ -	$ 93,028,265
68	Transmission	160,057,262	42,060,872	110,942	18,695,631
69	Sub-Transmission	23,564,618	10,361,390	48,831	4,157,676
70	Railroad	682,439	-	-	-
71	Distribution Primary	175,799,322	82,987,407	391,100	32,807,089
72	Distribution Secondary	65,722,469	32,609,709	81,343	14,898,684
73	Customer	-	-	-	-
74	Customer Service	-	-	-	-
75	**Total**	$ 1,092,193,354	$ 448,359,236	$ 632,215	$ 163,587,344
	Customer				
76	Production	-	-	-	-
77	Transmission	-	-	-	-
78	Sub-Transmission	-	-	-	-
79	Railroad	-	-	-	-
80	Distribution Primary	-	-	-	-
81	Distribution Secondary	$ 0	$ 0	$ 0	$ 0
82	Customer	45,026,455	28,106,578	18,844	6,131,807
83	Customer Service	46,406,145	35,065,708	60,979	6,207,588
84	**Total**	$ 91,432,600	$ 63,172,286	$ 79,823	$ 12,339,395
			12.77		
	Energy				
85	Production	$ 39,252,614	$ 11,270,140	$ 34,418	$ 5,149,627
86	Transmission	-	-	-	-
87	Sub-Transmission	-	-	-	-
88	Railroad	-	-	-	-
89	Distribution Primary	-	-	-	-
90	Distribution Secondary	-	-	-	-
91	Customer	-	-	-	-
92	Customer Service	-	-	-	-
93	**Total**	$ 39,252,614	$ 11,270,140	$ 34,418	$ 5,149,627
	Fuel				
94	Fuel Expenses	$ 322,936,621	$ 92,632,429	$ 282,891	$ 42,326,221
95	**Total**	$ 322,936,621	$ 92,632,429	$ 282,891	$ 42,326,221
96	**Total**	$ 1,545,815,189	$ 615,434,091	$ 1,029,347	$ 223,402,588
	Total Revenue Requirement				
97	Demand	$ 1,092,193,354	$ 448,359,236	$ 632,215	$ 163,587,344

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Comml SH Rate 822**	**GS Medium Rate 823**	**GS Large Rate 824**
	Demand				
67	Production	$ 666,367,244	$ -	$ 73,990,765	$ 80,876,409
68	Transmission	160,057,262	128,528	14,171,146	17,771,662
69	Sub-Transmission	23,564,618	46,300	2,526,225	3,125,115
70	Railroad	682,439	-	-	-
71	Distribution Primary	175,799,322	370,834	20,115,992	22,821,891
72	Distribution Secondary	65,722,469	94,982	9,084,394	4,807,361
73	Customer	-	-	-	-
74	Customer Service	-	-	-	-
75	**Total**	$ 1,092,193,354	$ 640,645	$ 119,888,523	$ 129,402,439
	Customer				
76	Production	-	-	-	-
77	Transmission	-	-	-	-
78	Sub-Transmission	-	-	-	-
79	Railroad	-	-	-	-
80	Distribution Primary	-	-	-	-
81	Distribution Secondary	$ 0	$ 0	$ 0	$ 0
82	Customer	45,026,455	27,795	1,025,653	239,863
83	Customer Service	46,406,145	50,739	929,668	1,169,997
84	**Total**	$ 91,432,600	$ 78,534	$ 1,955,322	$ 1,409,861
	Energy				
85	Production	$ 39,252,614	$ 38,729	$ 4,630,444	$ 6,603,578
86	Transmission	-	-	-	-
87	Sub-Transmission	-	-	-	-
88	Railroad	-	-	-	-
89	Distribution Primary	-	-	-	-
90	Distribution Secondary	-	-	-	-
91	Customer	-	-	-	-
92	Customer Service	-	-	-	-
93	**Total**	$ 39,252,614	$ 38,729	$ 4,630,444	$ 6,603,578
	Fuel				
94	Fuel Expenses	$ 322,936,621	$ 318,327	$ 38,058,912	$ 54,276,650
95	**Total**	$ 322,936,621	$ 318,327	$ 38,058,912	$ 54,276,650
96	**Total**	$ 1,545,815,189	$ 1,076,235	$ 164,533,201	$ 191,692,528
	Total Revenue Requirement				
97	Demand	$ 1,092,193,354	$ 640,645	$ 119,888,523	$ 129,402,439

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830
	(A)	(B)	(I)	(J)	(K)	(L)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Metal Melting Rate 825**	**Off-Peak Serv. Rate 826**	**Ind. Pwr Serv. - Large Rate 831**	**Ind. Pwr Serv. - Small Rate 830**
	Demand					
67	Production	$ 666,367,244	$ 1,868,194	$ 52,704,622	$ 54,413,630	$ 24,751,078
68	Transmission	160,057,262	492,864	10,552,667	48,974,257	6,258,731
69	Sub-Transmission	23,564,618	200,643	1,787,482	413,965	500,871
70	Railroad	682,439	-	-	-	-
71	Distribution Primary	175,799,322	1,124,163	12,641,066	(0)	-
72	Distribution Secondary	65,722,469	208,367	2,983,461	-	-
73	Customer	-	-	-	-	-
74	Customer Service	-	-	-	-	-
75	**Total**	$ 1,092,193,354	$ 3,894,231	$ 80,669,297	$ 103,801,853	$ 31,510,680
	Customer					
76	Production	-	-	-	-	-
77	Transmission	-	-	-	-	-
78	Sub-Transmission	-	-	-	-	-
79	Railroad	-	-	-	-	-
80	Distribution Primary	-	-	-	-	-
81	Distribution Secondary	$ 0	$ 0	$ 0	$ -	$ -
82	Customer	45,026,455	2,374	75,824	400,970	90,946
83	Customer Service	46,406,145	92,531	797,531	280,458	297,607
84	**Total**	$ 91,432,600	$ 94,905	$ 873,355	$ 681,428	$ 388,554
	Energy					
85	Production	$ 39,252,614	$ 306,559	$ 3,380,955	$ 5,134,850	$ 2,252,452
86	Transmission	-	-	-	-	-
87	Sub-Transmission	-	-	-	-	-
88	Railroad	-	-	-	-	-
89	Distribution Primary	-	-	-	-	-
90	Distribution Secondary	-	-	-	-	-
91	Customer	-	-	-	-	-
92	Customer Service	-	-	-	-	-
93	**Total**	$ 39,252,614	$ 306,559	$ 3,380,955	$ 5,134,850	$ 2,252,452
	Fuel					
94	Fuel Expenses	$ 322,936,621	$ 2,519,693	$ 27,789,010	$ 42,204,769	$ 18,513,530
95	**Total**	$ 322,936,621	$ 2,519,693	$ 27,789,010	$ 42,204,769	$ 18,513,530
96	**Total**	$ 1,545,815,189	$ 6,815,387	$ 112,712,618	$ 151,822,901	$ 52,665,216
	Total Revenue Requirement					
97	Demand	$ 1,092,193,354	$ 3,894,231	$ 80,669,297	$ 103,801,853	$ 31,510,680

Line No.	Description	System Total	Muni. Power Rate 841	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(M)	(N)	(O)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Muni. Power Rate 841**	**Int WW Pumping Rate 842**	**Railroad Rate 844**
	Demand				
67	Production	$ 666,367,244	$ 1,184,027	$ 11,734	$ 552,789
68	Transmission	160,057,262	279,136	2,652	130,203
69	Sub-Transmission	23,564,618	78,678	358	79,015
70	Railroad	682,439	-	-	682,439
71	Distribution Primary	175,799,322	630,157	2,864	-
72	Distribution Secondary	65,722,469	257,509	1,714	-
73	Customer	-	-	-	-
74	Customer Service	-	-	-	-
75	**Total**	$ 1,092,193,354	$ 2,429,507	$ 19,322	$ 1,444,446
	Customer				
76	Production	-	-	-	-
77	Transmission	-	-	-	-
78	Sub-Transmission	-	-	-	-
79	Railroad	-	-	-	-
80	Distribution Primary	-	-	-	-
81	Distribution Secondary	$ 0	$ 0	$ 0	$ -
82	Customer	45,026,455	119,256	26	2,650
83	Customer Service	46,406,145	73,411	2,861	18,078
84	**Total**	$ 91,432,600	$ 192,667	$ 2,887	$ 20,727
	Energy				
85	Production	$ 39,252,614	$ 93,583	$ 1,119	$ 69,075
86	Transmission	-	-	-	-
87	Sub-Transmission	-	-	-	-
88	Railroad	-	-	-	-
89	Distribution Primary	-	-	-	-
90	Distribution Secondary	-	-	-	-
91	Customer	-	-	-	-
92	Customer Service	-	-	-	-
93	**Total**	$ 39,252,614	$ 93,583	$ 1,119	$ 69,075
	Fuel				
94	Fuel Expenses	$ 322,936,621	$ 769,185	$ 9,197	$ 567,744
95	**Total**	$ 322,936,621	$ 769,185	$ 9,197	$ 567,744
96	**Total**	$ 1,545,815,189	$ 3,484,943	$ 32,525	$ 2,101,992
	Total Revenue Requirement				
97	Demand	$ 1,092,193,354	$ 2,429,507	$ 19,322	$ 1,444,446

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Functionalized Revenue Requirement Before Other Revenue Credit	**System Total**	**Street Lighting Rate 850**	**Traffic Lighting Rate 855**	**Dusk-to-Dawn Rate 860**	**Interdepartmental Interdepartmental**
	Demand					
67	Production	$ 666,367,244	$ -	$ 242,145	$ -	$ 2,403,727
68	Transmission	160,057,262	40,624	53,692	19,275	314,380
69	Sub-Transmission	23,564,618	65,898	7,568	33,558	131,044
70	Railroad	682,439	-	-	-	-
71	Distribution Primary	175,799,322	527,796	60,617	268,773	1,049,574
72	Distribution Secondary	65,722,469	294,785	34,707	145,772	219,680
73	Customer	-	-	-	-	-
74	Customer Service	-	-	-	-	-
75	**Total**	$ 1,092,193,354	$ 929,103	$ 398,729	$ 467,378	$ 4,118,405
	Customer					
76	Production	-	-	-	-	-
77	Transmission	-	-	-	-	-
78	Sub-Transmission	-	-	-	-	-
79	Railroad	-	-	-	-	-
80	Distribution Primary	-	-	-	-	-
81	Distribution Secondary	$ 0	$ 0	$ 0	$ 0	$ 0
82	Customer	45,026,455	6,915,585	134,372	1,733,909	-
83	Customer Service	46,406,145	867,883	10,279	479,483	1,343
84	**Total**	$ 91,432,600	$ 7,783,468	$ 144,652	$ 2,213,392	$ 1,343
	Energy					
85	Production	$ 39,252,614	$ 135,098	$ 20,598	$ 48,217	$ 83,172
86	Transmission	-	-	-	-	-
87	Sub-Transmission	-	-	-	-	-
88	Railroad	-	-	-	-	-
89	Distribution Primary	-	-	-	-	-
90	Distribution Secondary	-	-	-	-	-
91	Customer	-	-	-	-	-
92	Customer Service	-	-	-	-	-
93	**Total**	$ 39,252,614	$ 135,098	$ 20,598	$ 48,217	$ 83,172
	Fuel					
94	Fuel Expenses	$ 322,936,621	$ 1,110,412	$ 169,302	$ 396,308	$ 992,040
95	**Total**	$ 322,936,621	$ 1,110,412	$ 169,302	$ 396,308	$ 992,040
96	**Total**	$ 1,545,815,189	$ 9,958,081	$ 733,281	$ 3,125,295	$ 5,194,960
	Total Revenue Requirement					
97	Demand	$ 1,092,193,354	$ 929,103	$ 398,729	$ 467,378	$ 4,118,405

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
98	Customer	91,432,600	63,172,286	79,823	12,339,395
99	Energy	39,252,614	11,270,140	34,418	5,149,627
100	Fuel	322,936,621	92,632,429	282,891	42,326,221
101	**Total**	$ 1,545,815,189	$ 615,434,091	$ 1,029,347	$ 223,402,588
102	Zero-Check	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
98	Customer	91,432,600	78,534	1,955,322	1,409,861
99	Energy	39,252,614	38,729	4,630,444	6,603,578
100	Fuel	322,936,621	318,327	38,058,912	54,276,650
101	**Total**	$ 1,545,815,189	$ 1,076,235	$ 164,533,201	$ 191,692,528
102	Zero-Check	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830
	(A)	(B)	(I)	(J)	(K)	(L)
98	Customer	91,432,600	94,905	873,355	681,428	388,554
99	Energy	39,252,614	306,559	3,380,955	5,134,850	2,252,452
100	Fuel	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530
101	**Total**	$ 1,545,815,189	$ 6,815,387	$ 112,712,618	$ 151,822,901	$ 52,665,216
102	Zero-Check	$ -	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Muni. Power Rate 841	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(M)	(N)	(O)
98	Customer	91,432,600	192,667	2,887	20,727
99	Energy	39,252,614	93,583	1,119	69,075
100	Fuel	322,936,621	769,185	9,197	567,744
101	**Total**	$ 1,545,815,189	$ 3,484,943	$ 32,525	$ 2,101,992
102	Zero-Check	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
98	Customer	91,432,600	7,783,468	144,652	2,213,392	1,343
99	Energy	39,252,614	135,098	20,598	48,217	83,172
100	Fuel	322,936,621	1,110,412	169,302	396,308	992,040
101	**Total**	$ 1,545,815,189	$ 9,958,081	$ 733,281	$ 3,125,295	$ 5,194,960
102	Zero-Check	$ -	$ -	$ -	$ -	$ -

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Billing Determinants				
103	Demand (KW) - Production	14,180,260	0	0	0
104	Demand (KW) - Other	21,213,001	0	0	0
105	Customer (Customer Bills or No. Customers * 12)	6,541,009	4,946,379	1,220	627,541
106	Energy (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398
107	Fuel (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398
	Unit Costs				
108	Demand - Production		$ -	$ -	$ -
109	Demand - Other		$ -	$ -	$ -
110	Customer		$ 103.42	$ 583.51	$ 280.34
111	Energy		$ 0.003257	$ 0.003256	$ 0.003256
112	Fuel		$ 0.026772	$ 0.026766	$ 0.026762
113	Demand Revenue		$ -	$ -	$ -
114	Customer Revenue		511,531,522	712,038	175,926,740
115	Energy Revenue		11,270,140	34,418	5,149,627
116	Fuel Revenue		92,632,429	282,891	42,326,221
117	Total Revenue		615,434,091	1,029,347	223,402,588
118	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Billing Determinants				
103	Demand (KW) - Production	14,180,260	0	4,003,187	4,659,514
104	Demand (KW) - Other	21,213,001	0	4,003,187	4,659,514
105	Customer (Customer Bills or No. Customers * 12)	6,541,009	1,640	44,986	5,466
106	Energy (kWh)	12,096,308,562	11,890,211	1,422,286,366	2,035,551,481
107	Fuel (kWh)	12,096,308,562	11,890,211	1,422,286,366	2,035,551,481
	Unit Costs				
108	Demand - Production		$ -	$ 18.48	$ 17.36
109	Demand - Other		$ -	$ 11.47	$ 10.41
110	Customer		$ 438.46	$ 43.46	$ 257.92
111	Energy		$ 0.003257	$ 0.003256	$ 0.003244
112	Fuel		$ 0.026772	$ 0.026759	$ 0.026664
113	Demand Revenue		$ -	$ 119,888,523	$ 129,402,439
114	Customer Revenue		719,179	1,955,322	1,409,861
115	Energy Revenue		38,729	4,630,444	6,603,578
116	Fuel Revenue		318,327	38,058,912	54,276,650
117	Total Revenue		1,076,235	164,533,201	191,692,528
118	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830
	(A)	(B)	(I)	(J)	(K)	(L)
	Billing Determinants					
103	Demand (KW) - Production	14,180,260	105,561	1,852,987	2,214,672	1,272,049
104	Demand (KW) - Other	21,213,001	105,561	1,852,987	9,247,414	1,272,049
105	Customer (Customer Bills or No. Customers * 12)	6,541,009	72	2,208	108	120
106	Energy (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124
107	Fuel (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124
	Unit Costs					
108	Demand - Production		$ 17.70	$ 28.44	$ 24.57	$ 19.46
109	Demand - Other		$ 19.19	$ 15.09	$ 5.34	$ 5.31
110	Customer		$ 1,318.12	$ 395.54	$ 6,309.52	$ 3,237.95
111	Energy		$ 0.003237	$ 0.003244	$ 0.003213	$ 0.003215
112	Fuel		$ 0.026610	$ 0.026664	$ 0.026405	$ 0.026429
113	Demand Revenue		$ 3,894,231	$ 80,669,297	$ 103,801,853	$ 31,510,680
114	Customer Revenue		94,905	873,355	681,428	388,554
115	Energy Revenue		306,559	3,380,955	5,134,850	2,252,452
116	Fuel Revenue		2,519,693	27,789,010	42,204,769	18,513,530
117	Total Revenue		6,815,387	112,712,618	151,822,901	52,665,216
118	Zero-Check		$ -	$ -	$ -	$ -

Line No.	Description	System Total	Muni. Power Rate 841	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(M)	(N)	(O)
	Billing Determinants				
103	Demand (KW) - Production	14,180,260	0	0	72,290
104	Demand (KW) - Other	21,213,001	0	0	72,290
105	Customer (Customer Bills or No. Customers * 12)	6,541,009	8,501	96	12
106	Energy (kWh)	12,096,308,562	28,753,903	343,541	21,456,529
107	Fuel (kWh)	12,096,308,562	28,753,903	343,541	21,456,529
	Unit Costs				
108	Demand - Production		$ -	$ -	$ 7.65
109	Demand - Other		$ -	$ -	$ 12.33
110	Customer		$ 308.47	$ 232.54	$ 1,727.29
111	Energy		$ 0.003255	$ 0.003257	$ 0.003219
112	Fuel		$ 0.026751	$ 0.026772	$ 0.026460
113	Demand Revenue		$ -	$ -	$ 1,444,446
114	Customer Revenue		2,622,174	22,209	20,727
115	Energy Revenue		93,583	1,119	69,075
116	Fuel Revenue		769,185	9,197	567,744
117	Total Revenue		3,484,943	32,525	2,101,992
118	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Billing Determinants					
103	Demand (KW) - Production	14,180,260	0	0	0	0
104	Demand (KW) - Other	21,213,001	0	0	0	0
105	Customer (Customer Bills or No. Customers * 12)	6,541,009	758,328	13,861	191,944	552
106	Energy (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
107	Fuel (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
	Unit Costs					
108	Demand - Production		$ -	$ -	$ -	$ -
109	Demand - Other		$ -	$ -	$ -	$ -
110	Customer		$ 11.49	$ 39.20	$ 13.97	$ 7,463.31
111	Energy		$ 0.003257	$ 0.003257	$ 0.003257	$ 0.003257
112	Fuel		$ 0.026772	$ 0.026772	$ 0.026772	$ 0.038851
113	Demand Revenue		$ -	$ -	$ -	$ -
114	Customer Revenue		8,712,571	543,381	2,680,770	4,119,748
115	Energy Revenue		135,098	20,598	48,217	83,172
116	Fuel Revenue		1,110,412	169,302	396,308	992,040
117	Total Revenue		9,958,081	733,281	3,125,295	5,194,960
118	Zero-Check		$ -	$ -	$ -	$ -

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Functionalized Revenue Requirement After Other Revenue Credit				
119	Other Rev as % of Functionalized Revenue	1.87%	1.75%	1.79%	2.10%
120	Ratio (Inverse of Percentage)	98.13%	98.25%	98.21%	97.90%
	Demand				
121	Production	$ 654,001,814	$ 275,427,683	$ -	$ 91,073,050
122	Transmission	156,775,723	41,323,873	108,954	18,302,697
123	Sub-Transmission	23,136,065	10,179,836	47,956	4,070,292
124	Railroad	669,777	-	-	-
125	Distribution Primary	172,608,654	81,533,284	384,093	32,117,568
126	Distribution Secondary	64,518,541	32,038,315	79,885	14,585,552
127	Customer	-	-	-	-
128	Customer Service	-	-	-	-
129	**Total**	$ 1,071,710,575	$ 440,502,990	$ 620,888	$ 160,149,160
	Customer				
130	Production	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-
132	Sub-Transmission	-	-	-	-
133	Railroad	-	-	-	-
134	Distribution Primary	-	-	-	-
135	Distribution Secondary	0	0	0	0
136	Customer	44,221,468	27,614,088	18,506	6,002,933
137	Customer Service	45,570,201	34,451,280	59,886	6,077,120
138	**Total**	$ 89,791,668	$ 62,065,368	$ 78,393	$ 12,080,053
			12.55		
	Energy				
139	Production	$ 39,252,614	$ 11,270,140	$ 34,418	$ 5,149,627
140	Transmission	-	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -
147	**Total**	$ 39,252,614	$ 11,270,140	$ 34,418	$ 5,149,627
	Fuel				
148	Fuel Expenses	$ 322,936,621	$ 92,632,429	$ 282,891	$ 42,326,221
149	**Total**	$ 322,936,621	$ 92,632,429	$ 282,891	$ 42,326,221
150	**Total**	$ 1,523,691,478	$ 606,470,927	$ 1,016,589	$ 219,705,061

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Functionalized Revenue Requirement After Other Revenue Credit				
119	Other Rev as % of Functionalized Revenue	1.87%	2.31%	1.81%	1.99%
120	Ratio (Inverse of Percentage)	98.13%	97.69%	98.19%	98.01%
	Demand				
121	Production	$ 654,001,814	$ -	$ 72,654,080	$ 79,263,613
122	Transmission	156,775,723	125,566	13,915,136	17,417,269
123	Sub-Transmission	23,136,065	45,233	2,480,588	3,062,795
124	Railroad	669,777	-	-	-
125	Distribution Primary	172,608,654	362,285	19,752,586	22,366,789
126	Distribution Secondary	64,518,541	92,792	8,920,279	4,711,496
127	Customer	-	-	-	-
128	Customer Service	-	-	-	-
129	**Total**	$ 1,071,710,575	$ 625,876	$ 117,722,670	$ 126,821,962
	Customer				
130	Production	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-
132	Sub-Transmission	-	-	-	-
133	Railroad	-	-	-	-
134	Distribution Primary	-	-	-	-
135	Distribution Secondary	0	0	0	0
136	Customer	44,221,468	27,154	1,007,124	235,080
137	Customer Service	45,570,201	49,569	912,873	1,146,666
138	**Total**	$ 89,791,668	$ 76,724	$ 1,919,998	$ 1,381,746
	Energy				
139	Production	$ 39,252,614	$ 38,729	$ 4,630,444	$ 6,603,578
140	Transmission	-	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -
147	**Total**	$ 39,252,614	$ 38,729	$ 4,630,444	$ 6,603,578
	Fuel				
148	Fuel Expenses	$ 322,936,621	$ 318,327	$ 38,058,912	$ 54,276,650
149	**Total**	$ 322,936,621	$ 318,327	$ 38,058,912	$ 54,276,650
150	**Total**	$ 1,523,691,478	$ 1,059,656	$ 162,332,023	$ 189,083,936

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830
	(A)	(B)	(I)	(J)	(K)	(L)
	Functionalized Revenue Requirement After Other Revenue Credit					
119	Other Rev as % of Functionalized Revenue	1.87%	1.63%	1.33%	2.64%	1.40%
120	Ratio (Inverse of Percentage)	98.13%	98.37%	98.67%	97.36%	98.60%
	Demand					
121	Production	$ 654,001,814	$ 1,837,733	$ 52,005,975	$ 52,978,943	$ 24,405,699
122	Transmission	156,775,723	484,827	10,412,782	47,682,985	6,171,396
123	Sub-Transmission	23,136,065	197,372	1,763,787	403,051	493,882
124	Railroad	669,777	-	-	-	-
125	Distribution Primary	172,608,654	1,105,834	12,473,497	(0)	-
126	Distribution Secondary	64,518,541	204,969	2,943,912	-	-
127	Customer	-	-	-	-	-
128	Customer Service	-	-	-	-	-
129	**Total**	$ 1,071,710,575	$ 3,830,734	$ 79,599,953	$ 101,064,978	$ 31,070,976
	Customer					
130	Production	$ -	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-	-
132	Sub-Transmission	-	-	-	-	-
133	Railroad	-	-	-	-	-
134	Distribution Primary	-	-	-	-	-
135	Distribution Secondary	0	0	0	-	-
136	Customer	44,221,468	2,335	74,819	390,398	89,677
137	Customer Service	45,570,201	91,022	786,959	273,063	293,454
138	**Total**	$ 89,791,668	$ 93,357	$ 861,778	$ 663,462	$ 383,132
	Energy					
139	Production	$ 39,252,614	$ 306,559	$ 3,380,955	$ 5,134,850	$ 2,252,452
140	Transmission	-	$ -	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -	$ -
147	**Total**	$ 39,252,614	$ 306,559	$ 3,380,955	$ 5,134,850	$ 2,252,452
	Fuel					
148	Fuel Expenses	$ 322,936,621	$ 2,519,693	$ 27,789,010	$ 42,204,769	$ 18,513,530
149	**Total**	$ 322,936,621	$ 2,519,693	$ 27,789,010	$ 42,204,769	$ 18,513,530
150	**Total**	$ 1,523,691,478	$ 6,750,344	$ 111,631,696	$ 149,068,059	$ 52,220,090

Line No.	Description	System Total	Muni. Power Rate 841	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(M)	(N)	(O)
	Functionalized Revenue Requirement After Other Revenue Credit				
119	Other Rev as % of Functionalized Revenue	1.87%	1.58%	6.42%	1.86%
120	Ratio (Inverse of Percentage)	98.13%	98.42%	93.58%	98.14%
	Demand				
121	Production	$ 654,001,814	$ 1,165,316	$ 10,981	$ 542,533
122	Transmission	156,775,723	274,725	2,482	127,787
123	Sub-Transmission	23,136,065	77,435	335	77,549
124	Railroad	669,777	-	-	669,777
125	Distribution Primary	172,608,654	620,198	2,680	-
126	Distribution Secondary	64,518,541	253,439	1,604	-
127	Customer	-	-	-	-
128	Customer Service	-	-	-	-
129	**Total**	$ 1,071,710,575	$ 2,391,113	$ 18,082	$ 1,417,647
	Customer				
130	Production	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-
132	Sub-Transmission	-	-	-	-
133	Railroad	-	-	-	-
134	Distribution Primary	-	-	-	-
135	Distribution Secondary	0	0	0	-
136	Customer	44,221,468	117,372	25	2,600
137	Customer Service	45,570,201	72,251	2,677	17,742
138	**Total**	$ 89,791,668	$ 189,623	$ 2,702	$ 20,343
	Energy				
139	Production	$ 39,252,614	$ 93,583	$ 1,119	$ 69,075
140	Transmission	-	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -
147	**Total**	$ 39,252,614	$ 93,583	$ 1,119	$ 69,075
	Fuel				
148	Fuel Expenses	$ 322,936,621	$ 769,185	$ 9,197	$ 567,744
149	**Total**	$ 322,936,621	$ 769,185	$ 9,197	$ 567,744
150	**Total**	$ 1,523,691,478	$ 3,443,504	$ 31,100	$ 2,074,808

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Functionalized Revenue Requirement After Other Revenue Credit					
119	Other Rev as % of Functionalized Revenue	1.87%	1.54%	2.01%	2.04%	0.20%
120	Ratio (Inverse of Percentage)	98.13%	98.46%	97.99%	97.96%	99.80%
	Demand					
121	Production	$ 654,001,814	$ -	$ 237,269	$ -	$ 2,398,939
122	Transmission	156,775,723	39,999	52,611	18,881	313,754
123	Sub-Transmission	23,136,065	64,884	7,416	32,873	130,783
124	Railroad	669,777	-	-	-	-
125	Distribution Primary	172,608,654	519,675	59,396	263,286	1,047,483
126	Distribution Secondary	64,518,541	290,249	34,008	142,796	219,243
127	Customer	-	-	-	-	-
128	Customer Service	-	-	-	-	-
129	**Total**	$ 1,071,710,575	$ 914,807	$ 390,701	$ 457,836	$ 4,110,202
	Customer					
130	Production	$ -	$ -	$ -	$ -	$ -
131	Transmission	-	-	-	-	-
132	Sub-Transmission	-	-	-	-	-
133	Railroad	-	-	-	-	-
134	Distribution Primary	-	-	-	-	-
135	Distribution Secondary	0	0	0	0	0
136	Customer	44,221,468	6,809,179	131,667	1,698,510	-
137	Customer Service	45,570,201	854,529	10,072	469,694	1,341
138	**Total**	$ 89,791,668	$ 7,663,707	$ 141,739	$ 2,168,204	$ 1,341
	Energy					
139	Production	$ 39,252,614	$ 135,098	$ 20,598	$ 48,217	$ 83,172
140	Transmission	-	$ -	$ -	$ -	$ -
141	Sub-Transmission	-	$ -	$ -	$ -	$ -
142	Railroad	-	$ -	$ -	$ -	$ -
143	Distribution Primary	-	$ -	$ -	$ -	$ -
144	Distribution Secondary	-	$ -	$ -	$ -	$ -
145	Customer	-	$ -	$ -	$ -	$ -
146	Customer Service	-	$ -	$ -	$ -	$ -
147	**Total**	$ 39,252,614	$ 135,098	$ 20,598	$ 48,217	$ 83,172
	Fuel					
148	Fuel Expenses	$ 322,936,621	$ 1,110,412	$ 169,302	$ 396,308	$ 992,040
149	**Total**	$ 322,936,621	$ 1,110,412	$ 169,302	$ 396,308	$ 992,040
150	**Total**	$ 1,523,691,478	$ 9,824,025	$ 722,340	$ 3,070,566	$ 5,186,755

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Total Revenue Requirement				
151	Demand	$ 1,071,710,575	$ 440,502,990	$ 620,888	$ 160,149,160
152	Customer	89,791,668	62,065,368	78,393	12,080,053
153	Energy	39,252,614	11,270,140	34,418	5,149,627
154	Fuel	322,936,621	92,632,429	282,891	42,326,221
155	**Total**	$ 1,523,691,478	$ 606,470,927	$ 1,016,589	$ 219,705,061
156	Zero-Check	-	-	-	-

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Total Revenue Requirement				
151	Demand	$ 1,071,710,575	$ 625,876	$ 117,722,670	$ 126,821,962
152	Customer	89,791,668	76,724	1,919,998	1,381,746
153	Energy	39,252,614	38,729	4,630,444	6,603,578
154	Fuel	322,936,621	318,327	38,058,912	54,276,650
155	**Total**	$ 1,523,691,478	$ 1,059,656	$ 162,332,023	$ 189,083,936
156	Zero-Check	-	-	-	-

Line No.	Description		System Total		Metal Melting Rate 825		Off-Peak Serv. Rate 826		Ind. Pwr Serv. - Large Rate 831		Ind. Pwr Serv. - Small Rate 830
	(A)		(B)		(I)		(J)		(K)		(L)
	Total Revenue Requirement										
151	Demand	$	1,071,710,575	$	3,830,734	$	79,599,953	$	101,064,978	$	31,070,976
152	Customer		89,791,668		93,357		861,778		663,462		383,132
153	Energy		39,252,614		306,559		3,380,955		5,134,850		2,252,452
154	Fuel		322,936,621		2,519,693		27,789,010		42,204,769		18,513,530
155	**Total**	$	1,523,691,478	$	6,750,344	$	111,631,696	$	149,068,059	$	52,220,090
156	Zero-Check		-		-		-		-		-

Line No.	Description	System Total	Muni. Power Rate 841	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(M)	(N)	(O)
	Total Revenue Requirement				
151	Demand	$ 1,071,710,575	$ 2,391,113	$ 18,082	$ 1,417,647
152	Customer	89,791,668	189,623	2,702	20,343
153	Energy	39,252,614	93,583	1,119	69,075
154	Fuel	322,936,621	769,185	9,197	567,744
155	**Total**	$ 1,523,691,478	$ 3,443,504	$ 31,100	$ 2,074,808
156	Zero-Check	-	-	-	-

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Total Revenue Requirement					
151	Demand	$ 1,071,710,575	$ 914,807	$ 390,701	$ 457,836	$ 4,110,202
152	Customer	89,791,668	7,663,707	141,739	2,168,204	1,341
153	Energy	39,252,614	135,098	20,598	48,217	83,172
154	Fuel	322,936,621	1,110,412	169,302	396,308	992,040
155	**Total**	$ 1,523,691,478	$ 9,824,025	$ 722,340	$ 3,070,566	$ 5,186,755
156	Zero-Check	-	-	-	-	-

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Billing Determinants				
157	Demand (KW) - Production	14,180,260	0	0	0
158	Demand (KW) - Other	21,213,001	0	0	0
159	Customer (Customer Bills or No. Customers * 12)	6,541,009	4,946,379	1,220	627,541
160	Energy (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398
161	Fuel (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398
162	Demand Unit Cost - Production		0.00	0.00	0.00
163	Demand Unit Cost - Other		0.00	0.00	0.00
164	Customer Unit Cost		101.60	573.06	274.45
165	Energy Unit Cost		0.0032572	0.0032564	0.0032561
166	Fuel Unit Cost		0.0267722	0.0267656	0.0267625
167	Demand Revenue		$ -	$ -	$ -
168	Customer Revenue		502,568,358	699,281	172,229,213
169	Energy Revenue		11,270,140	34,418	5,149,627
170	Fuel Revenue		92,632,429	282,891	42,326,221
171	Total Revenue		606,470,927	1,016,589	219,705,061
172	Zero-Check		$ -	$ -	$ -
	Grid Facility				
173	Grid Facility - Revenue Requirement	507,500,429	227,140,676	699,281	81,156,162
174	Grid Facility - Unit Costs	77.58748543	45.92	573.06	129.32

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Billing Determinants				
157	Demand (KW) - Production	14,180,260	0	4,003,187	4,659,514
158	Demand (KW) - Other	21,213,001	0	4,003,187	4,659,514
159	Customer (Customer Bills or No. Customers * 12)	6,541,009	1,640	44,986	5,466
160	Energy (kWh)	12,096,308,562	11,890,211	1,422,286,366	2,035,551,481
161	Fuel (kWh)	12,096,308,562	11,890,211	1,422,286,366	2,035,551,481
162	Demand Unit Cost - Production		0.00	18.15	17.01
163	Demand Unit Cost - Other		0.00	11.26	10.21
164	Customer Unit Cost		428.36	42.68	252.78
165	Energy Unit Cost		0.0032572	0.0032556	0.0032441
166	Fuel Unit Cost		0.0267722	0.0267590	0.0266643
167	Demand Revenue		$ -	$ 117,722,670	$ 126,821,962
168	Customer Revenue		702,600	1,919,998	1,381,746
169	Energy Revenue		38,729	4,630,444	6,603,578
170	Fuel Revenue		318,327	38,058,912	54,276,650
171	Total Revenue		1,059,656	162,332,023	189,083,936
172	Zero-Check		$ -	$ -	$ -
	Grid Facility				
173	Grid Facility - Revenue Requirement	507,500,429	702,600	46,988,587	48,940,095
174	Grid Facility - Unit Costs	77.58748543	428.36	1,044.51	8,953.13

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830
	(A)	(B)	(I)	(J)	(K)	(L)
	Billing Determinants					
157	Demand (KW) - Production	14,180,260	105,561	1,852,987	2,214,672	1,272,049
158	Demand (KW) - Other	21,213,001	105,561	1,852,987	9,247,414	1,272,049
159	Customer (Customer Bills or No. Customers * 12)	6,541,009	72	2,208	108	120
160	Energy (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124
161	Fuel (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124
162	Demand Unit Cost - Production		17.41	28.07	23.92	19.19
163	Demand Unit Cost - Other		18.88	14.89	5.20	5.24
164	Customer Unit Cost		1,296.63	390.30	6,143.16	3,192.77
165	Energy Unit Cost		0.0032375	0.0032441	0.0032126	0.0032155
166	Fuel Unit Cost		0.0266095	0.0266642	0.0264049	0.0264291
167	Demand Revenue		$ 3,830,734	$ 79,599,953	$ 101,064,978	$ 31,070,976
168	Customer Revenue		93,357	861,778	663,462	383,132
169	Energy Revenue		306,559	3,380,955	5,134,850	2,252,452
170	Fuel Revenue		2,519,693	27,789,010	42,204,769	18,513,530
171	Total Revenue		6,750,344	111,631,696	149,068,059	52,220,090
172	Zero-Check		$ -	$ -	$ -	$ -
	Grid Facility					
173	Grid Facility - Revenue Requirement	507,500,429	2,086,359	28,455,756	48,749,497	7,048,410
174	Grid Facility - Unit Costs	77.58748543	28,977.21	12,887.57	451,384.23	58,736.75

Line No.	Description	System Total	Muni. Power Rate 841	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(M)	(N)	(O)
	Billing Determinants				
157	Demand (KW) - Production	14,180,260	0	0	72,290
158	Demand (KW) - Other	21,213,001	0	0	72,290
159	Customer (Customer Bills or No. Customers * 12)	6,541,009	8,501	96	12
160	Energy (kWh)	12,096,308,562	28,753,903	343,541	21,456,529
161	Fuel (kWh)	12,096,308,562	28,753,903	343,541	21,456,529
162	Demand Unit Cost - Production		0.00	0.00	7.50
163	Demand Unit Cost - Other		0.00	0.00	12.11
164	Customer Unit Cost		303.59	217.61	1,695.24
165	Energy Unit Cost		0.0032546	0.0032572	0.0032193
166	Fuel Unit Cost		0.0267506	0.0267722	0.0264602
167	Demand Revenue		$ -	$ -	$ 1,417,647
168	Customer Revenue		2,580,736	20,783	20,343
169	Energy Revenue		93,583	1,119	69,075
170	Fuel Revenue		769,185	9,197	567,744
171	Total Revenue		3,443,504	31,100	2,074,808
172	Zero-Check		$ -	$ -	$ -
	Grid Facility				
173	Grid Facility - Revenue Requirement	507,500,429	1,415,420	9,802	895,457
174	Grid Facility - Unit Costs	77.58748543	166.51	102.63	74,621.42

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Billing Determinants					
157	Demand (KW) - Production	14,180,260	0	0	0	0
158	Demand (KW) - Other	21,213,001	0	0	0	0
159	Customer (Customer Bills or No. Customers * 12)	6,541,009	758,328	13,861	191,944	552
160	Energy (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
161	Fuel (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
162	Demand Unit Cost - Production		0.00	0.00	0.00	0.00
163	Demand Unit Cost - Other		0.00	0.00	0.00	0.00
164	Customer Unit Cost		11.31	38.41	13.68	7,448.45
165	Energy Unit Cost		0.0032572	0.0032572	0.0032572	0.0032572
166	Fuel Unit Cost		0.0267722	0.0267722	0.0267722	0.0388509
167	Demand Revenue		$ -	$ -	$ -	$ -
168	Customer Revenue		8,578,514	532,440	2,626,040	4,111,543
169	Energy Revenue		135,098	20,598	48,217	83,172
170	Fuel Revenue		1,110,412	169,302	396,308	992,040
171	Total Revenue		9,824,025	722,340	3,070,566	5,186,755
172	Zero-Check		$ -	$ -	$ -	$ -
	Grid Facility					
173	Grid Facility - Revenue Requirement	507,500,429	8,578,514	295,170	2,626,040	1,712,604
174	Grid Facility - Unit Costs	77.58748543	11.31	21.30	13.68	3,102.54

Line No.	Description	System Total	Residential Rate 811	C&GS Heat Pump Rate 820	GS Small Rate 821
	(A)	(B)	(C)	(D)	(E)
	Mitigated Revenue Requirement After Other Revenue Credit				
175	Other Rev as % of Functionalized Revenue	1.81%	1.71%	1.71%	2.04%
176	Ratio (Inverse of Percentage)	98.19%	98.29%	98.29%	97.96%
177	Mitigated Amount	(0)	(85,378,327)	(76,415)	32,883,469
	Total Revenue Requirement				
178	Demand	$ 1,080,992,976	$ 365,668,577	$ 553,039	$ 190,726,202
179	Customer	80,509,268	51,521,454	69,826	14,386,480
180	Energy	39,252,614	11,270,140	34,418	5,149,627
181	Fuel	322,936,621	92,632,429	282,891	42,326,221
182	**Total**	$ 1,523,691,478	$ 521,092,601	$ 940,174	$ 252,588,529
183	Zero-Check	-	-	-	-
	Billing Determinants				
184	Demand (KW) - Production	14,180,260	0	0	0
185	Demand (KW) - Other	21,213,001	0	0	0
186	Customer (Customer Bills or No. Customers * 12)	6,541,009	4,946,379	1,220	627,541
187	Energy (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398
188	Fuel (kWh)	12,096,308,562	3,460,022,773	10,569,193	1,581,552,398
189	Demand Unit Cost - Production		0.00	0.00	0.00
190	Demand Unit Cost - Other		0.00	0.00	0.00
191	Customer Unit Cost		84.34	510.43	326.85
192	Energy Unit Cost		0.0032572	0.0032564	0.0032561
193	Fuel Unit Cost		0.0267722	0.0267656	0.0267625
194	Demand Revenue		$ -	$ -	$ -
195	Customer Revenue		417,190,032	622,865	205,112,681
196	Energy Revenue		11,270,140	34,418	5,149,627
197	Fuel Revenue		92,632,429	282,891	42,326,221
198	Total Revenue		521,092,601	940,174	252,588,529
199	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Comml SH Rate 822	GS Medium Rate 823	GS Large Rate 824
	(A)	(B)	(F)	(G)	(H)
	Mitigated Revenue Requirement After Other Revenue Credit				
175	Other Rev as % of Functionalized Revenue	1.81%	2.19%	1.74%	1.90%
176	Ratio (Inverse of Percentage)	98.19%	97.81%	98.26%	98.10%
177	Mitigated Amount	(0)	186,884	25,195,342	37,427,166
	Total Revenue Requirement				
178	Demand	$ 1,080,992,976	$ 792,353	$ 142,513,683	$ 163,845,748
179	Customer	80,509,268	97,131	2,324,327	1,785,126
180	Energy	39,252,614	38,729	4,630,444	6,603,578
181	Fuel	322,936,621	318,327	38,058,912	54,276,650
182	**Total**	$ 1,523,691,478	$ 1,246,541	$ 187,527,365	$ 226,511,101
183	Zero-Check	-	-	-	-
	Billing Determinants				
184	Demand (KW) - Production	14,180,260	0	4,003,187	4,659,514
185	Demand (KW) - Other	21,213,001	0	4,003,187	4,659,514
186	Customer (Customer Bills or No. Customers * 12)	6,541,009	1,640	44,986	5,466
187	Energy (kWh)	12,096,308,562	11,890,211	1,422,286,366	2,035,551,481
188	Fuel (kWh)	12,096,308,562	11,890,211	1,422,286,366	2,035,551,481
189	Demand Unit Cost - Production		0.00	21.97	21.98
190	Demand Unit Cost - Other		0.00	13.63	13.19
191	Customer Unit Cost		542.29	51.67	326.57
192	Energy Unit Cost		0.0032572	0.0032556	0.0032441
193	Fuel Unit Cost		0.0267722	0.0267590	0.0266643
194	Demand Revenue		$ -	$ 142,513,683	$ 163,845,748
195	Customer Revenue		889,484	2,324,327	1,785,126
196	Energy Revenue		38,729	4,630,444	6,603,578
197	Fuel Revenue		318,327	38,058,912	54,276,650
198	Total Revenue		1,246,541	187,527,365	226,511,101
199	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Metal Melting Rate 825	Off-Peak Serv. Rate 826	Ind. Pwr Serv. - Large Rate 831	Ind. Pwr Serv. - Small Rate 830
	(A)	(B)	(I)	(J)	(K)	(L)
	Mitigated Revenue Requirement After Other Revenue Credit					
175	Other Rev as % of Functionalized Revenue	1.81%	1.51%	1.27%	2.51%	1.30%
176	Ratio (Inverse of Percentage)	98.19%	98.49%	98.73%	97.49%	98.70%
177	Mitigated Amount	(0)	769,741	(10,487,613)	0	818,467
	Total Revenue Requirement					
178	Demand	$ 1,080,992,976	$ 4,582,163	$ 69,224,667	$ 101,064,978	$ 31,879,474
179	Customer	80,509,268	111,670	749,451	663,462	393,101
180	Energy	39,252,614	306,559	3,380,955	5,134,850	2,252,452
181	Fuel	322,936,621	2,519,693	27,789,010	42,204,769	18,513,530
182	**Total**	$ 1,523,691,478	$ 7,520,085	$ 101,144,083	$ 149,068,059	$ 53,038,558
183	Zero-Check	-	-	-	-	-
	Billing Determinants					
184	Demand (KW) - Production	14,180,260	105,561	1,852,987	2,214,672	1,272,049
185	Demand (KW) - Other	21,213,001	105,561	1,852,987	9,247,414	1,272,049
186	Customer (Customer Bills or No. Customers * 12)	6,541,009	72	2,208	108	120
187	Energy (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124
188	Fuel (kWh)	12,096,308,562	94,691,415	1,042,183,440	1,598,370,614	700,499,124
189	Demand Unit Cost - Production		20.82	24.41	23.92	19.69
190	Demand Unit Cost - Other		22.58	12.95	5.20	5.38
191	Customer Unit Cost		1,550.98	339.43	6,143.16	3,275.84
192	Energy Unit Cost		0.0032375	0.0032441	0.0032126	0.0032155
193	Fuel Unit Cost		0.0266095	0.0266642	0.0264049	0.0264291
194	Demand Revenue		$ 4,582,163	$ 69,224,667	$ 101,064,978	$ 31,879,474
195	Customer Revenue		111,670	749,451	663,462	393,101
196	Energy Revenue		306,559	3,380,955	5,134,850	2,252,452
197	Fuel Revenue		2,519,693	27,789,010	42,204,769	18,513,530
198	Total Revenue		7,520,085	101,144,083	149,068,059	53,038,558
199	Zero-Check		$ -	$ -	$ -	$ -

Line No.	Description	System Total	Muni. Power Rate 841	Int WW Pumping Rate 842	Railroad Rate 844
	(A)	(B)	(M)	(N)	(O)
	Mitigated Revenue Requirement				
	After Other Revenue Credit				
175	Other Rev as % of Functionalized Revenue	1.81%	1.53%	6.11%	1.77%
176	Ratio (Inverse of Percentage)	98.19%	98.47%	93.89%	98.23%
177	Mitigated Amount	(0)	165,553	83,358	350,552
	Total Revenue Requirement				
178	Demand	$ 1,080,992,976	$ 2,544,502	$ 90,604	$ 1,763,240
179	Customer	80,509,268	201,787	13,537	25,302
180	Energy	39,252,614	93,583	1,119	69,075
181	Fuel	322,936,621	769,185	9,197	567,744
182	**Total**	$ 1,523,691,478	$ 3,609,057	$ 114,457	$ 2,425,360
183	Zero-Check	-	-	-	-
	Billing Determinants				
184	Demand (KW) - Production	14,180,260	0	0	72,290
185	Demand (KW) - Other	21,213,001	0	0	72,290
186	Customer (Customer Bills or No. Customers * 12)	6,541,009	8,501	96	12
187	Energy (kWh)	12,096,308,562	28,753,903	343,541	21,456,529
188	Fuel (kWh)	12,096,308,562	28,753,903	343,541	21,456,529
189	Demand Unit Cost - Production		0.00	0.00	9.33
190	Demand Unit Cost - Other		0.00	0.00	15.06
191	Customer Unit Cost		323.07	1,090.42	2,108.50
192	Energy Unit Cost		0.0032546	0.0032572	0.0032193
193	Fuel Unit Cost		0.0267506	0.0267722	0.0264602
194	Demand Revenue		$ -	$ -	$ 1,763,240
195	Customer Revenue		2,746,288	104,141	25,302
196	Energy Revenue		93,583	1,119	69,075
197	Fuel Revenue		769,185	9,197	567,744
198	Total Revenue		3,609,057	114,457	2,425,360
199	Zero-Check		$ -	$ -	$ -

Line No.	Description	System Total	Street Lighting Rate 850	Traffic Lighting Rate 855	Dusk-to-Dawn Rate 860	Interdepartmental Interdepartmental
	(A)	(B)	(P)	(Q)	(R)	(S)
	Mitigated Revenue Requirement After Other Revenue Credit					
175	Other Rev as % of Functionalized Revenue	1.81%	1.52%	1.94%	2.01%	0.20%
176	Ratio (Inverse of Percentage)	98.19%	98.48%	98.06%	97.99%	99.80%
177	Mitigated Amount	(0)	(1,720,778)	216,446	(398,121)	(35,723)
	Total Revenue Requirement					
178	Demand	$ 1,080,992,976	$ 731,304	$ 549,527	$ 388,426	$ 4,074,491
179	Customer	80,509,268	6,126,432	199,358	1,839,493	1,329
180	Energy	39,252,614	135,098	20,598	48,217	83,172
181	Fuel	322,936,621	1,110,412	169,302	396,308	992,040
182	**Total**	$ 1,523,691,478	$ 8,103,247	$ 938,785	$ 2,672,444	$ 5,151,032
183	Zero-Check	-	-	-	-	-
	Billing Determinants					
184	Demand (KW) - Production	14,180,260	0	0	0	0
185	Demand (KW) - Other	21,213,001	0	0	0	0
186	Customer (Customer Bills or No. Customers * 12)	6,541,009	758,328	13,861	191,944	552
187	Energy (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
188	Fuel (kWh)	12,096,308,562	41,476,293	6,323,787	14,802,974	25,534,520
189	Demand Unit Cost - Production		0.00	0.00	0.00	0.00
190	Demand Unit Cost - Other		0.00	0.00	0.00	0.00
191	Customer Unit Cost		9.04	54.03	11.61	7,383.73
192	Energy Unit Cost		0.0032572	0.0032572	0.0032572	0.0032572
193	Fuel Unit Cost		0.0267722	0.0267722	0.0267722	0.0388509
194	Demand Revenue		$ -	$ -	$ -	$ -
195	Customer Revenue		6,857,736	748,885	2,227,919	4,075,820
196	Energy Revenue		135,098	20,598	48,217	83,172
197	Fuel Revenue		1,110,412	169,302	396,308	992,040
198	Total Revenue		8,103,247	938,785	2,672,444	5,151,032
199	Zero-Check		$ -	$ -	$ -	$ -

Attachment JFW-16

- Assumptions for baseline technology energy efficiency levels after 2021 for residential and non-residential general service, reflector and specialty bulbs
- Measure participation forecasts after 2021
- Energy efficiency measures included in the 2019 to 2048 DSM Plan

GDS used Excel-based energy efficiency and demand response planning models to prepare this DSM savings update. These models are explained in more detail in Section 5.2.

1.2.1 Energy Efficiency

Table 1-1 shows the base case incremental annual energy efficiency MWH savings by sector and in total for the NIPSCO service area. The DSM Savings Update Report projections provided in this plan exclude commercial and industrial customers[1] who have opted out of NIPSCO's C&I sector energy efficiency programs. The DSM Plan base case incremental MWH and megawatt (MW) savings by sector and in total are presented as a percent of NIPSCO's electric load forecast for the period 2019 to 2048. The incremental annual energy efficiency MWH savings as a percent of forecast total MWH sales range from 1.5% to 1.8% annually over the thirty-year planning period.

The annual percent savings in the last column of Table 1-1 decline slightly in the years 2046 to 2048 due to rules for rounding of numbers. For example, in 2045 the percentage is 1.76% and it is rounded upward to 1.8% for presentation purposes. In 2048 the percentage is 1.73% and it is rounded down to 1.7%. The mathematical rule is if the number you are rounding is followed by 5, 6, 7, 8, or 9, round the number up. Otherwise your round down.

TABLE 1-1 NIPSCO DSM SAVINGS PLAN UPDATE, INCREMENTAL ANNUAL MWH SAVINGS BY SECTOR AND IN TOTAL

Year	Residential Sector Incremental Annual Energy Savings (MWH)	Savings As A Percent of Residential Sales Forecast	C&I Sector Incremental Annual Energy Savings (MWH)	Savings As A Percent of C&I Sector Sales Forecast	Total *(Res & C&I)* Incremental Annual Energy Savings (MWH)	Total *(Res & C&I Sectors)* Savings As A Percent of Total Sales Forecast
2019	50,974	1.5%	72,000	1.5%	122,974	1.5%
2020	50,947	1.5%	80,000	1.7%	130,947	1.6%
2021	50,918	1.5%	88,000	1.9%	138,918	1.7%
2022	46,240	1.4%	92,147	1.9%	138,387	1.7%
2023	46,887	1.4%	93,761	1.9%	140,648	1.7%
2024	47,503	1.4%	95,389	2.0%	142,892	1.7%
2025	48,178	1.4%	97,581	2.0%	145,759	1.7%
2026	48,716	1.4%	99,966	2.0%	148,683	1.8%
2027	49,287	1.4%	101,463	2.0%	150,750	1.8%
2028	49,744	1.4%	103,076	2.1%	152,820	1.8%
2029	50,231	1.4%	104,627	2.1%	154,858	1.8%
2030	50,686	1.4%	106,017	2.1%	156,703	1.8%
2031	51,166	1.4%	108,458	2.1%	159,625	1.8%
2032	51,645	1.4%	110,023	2.2%	161,669	1.8%

[1] Commercial and Industrial (C&I) refers to participating non-residential customers.

Year	Residential Sector Incremental Annual Energy Savings (MWH)	Savings As A Percent of Residential Sales Forecast	C&I Sector Incremental Annual Energy Savings (MWH)	Savings As A Percent of C&I Sector Sales Forecast	Total *(Res & C&I)* Incremental Annual Energy Savings (MWH)	Total *(Res & C&I Sectors)* Savings As A Percent of Total Sales Forecast
2033	52,173	1.4%	111,690	2.2%	163,863	1.8%
2034	52,411	1.4%	112,850	2.2%	165,261	1.8%
2035	52,659	1.4%	113,599	2.2%	166,258	1.8%
2036	53,050	1.4%	114,182	2.2%	167,231	1.8%
2037	53,050	1.3%	114,773	2.2%	167,823	1.8%
2038	53,050	1.3%	115,362	2.2%	168,412	1.8%
2039	53,050	1.3%	115,362	2.2%	168,412	1.8%
2040	53,050	1.3%	115,362	2.2%	168,412	1.8%
2041	53,050	1.3%	115,362	2.2%	168,412	1.8%
2042	53,050	1.3%	115,362	2.2%	168,412	1.8%
2043	53,050	1.3%	115,362	2.2%	168,412	1.8%
2044	53,050	1.2%	115,362	2.2%	168,412	1.8%
2045	53,050	1.2%	115,362	2.2%	168,412	1.8%
2046	53,050	1.2%	115,362	2.2%	168,412	1.7%
2047	53,050	1.2%	115,362	2.2%	168,412	1.7%
2048	53,050	1.2%	115,362	2.2%	168,412	1.7%

Table 1-2 shows the base case cumulative annual energy efficiency savings (MWH) by sector and in total for the NIPSCO service area. As previously noted, the updated DSM Plan base case excludes C&I customers who have opted out of NIPSCO's C&I sector energy efficiency programs. The cumulative annual MWH savings by sector and in total are shown as a percent of NIPSCO's electric load forecast for the period 2019 to 2048. The cumulative annual energy efficiency MWH savings as a percent of forecast total MWH sales is projected to be 14.7% by 2028, 21.2% by 2038 and 21.1% by 2048.

TABLE 1-2 NIPSCO DSM SAVINGS PLAN UPDATE, CUMULATIVE ANNUAL MWH SAVINGS BY SECTOR AND IN TOTAL

Year	Residential Sector Cumulative Annual Energy Savings (MWH)	Savings As A Percent of Residential Sales Forecast	C&I Sector Cumulative Annual Energy Savings (MWH)	Savings As A Percent of C&I Sector Sales Forecast	Total *(Res & C&I Sectors)* Cumulative Annual Energy Savings (MWH)	Total *(Res & C&I Sectors)* Savings As A Percent of Total Sales Forecast
2019	50,974	1.5%	72,000	1.5%	122,974	1.5%
2020	92,051	2.7%	152,000	3.2%	244,051	3.0%
2021	133,111	3.9%	240,000	5.1%	373,111	4.6%
2022	169,506	5.0%	325,796	6.8%	495,302	6.0%
2023	204,891	6.0%	419,550	8.7%	624,441	7.6%
2024	240,718	7.0%	510,798	10.5%	751,516	9.0%
2025	277,045	8.0%	602,907	12.3%	879,952	10.5%

Attachment JFW-17

Cause No. 45159
Northern Indiana Public Service Company LLC's
Objections and Responses to
Sierra Club's Set No. 2

Sierra Club Request 2-007:
Refer to the Direct Testimony of Paul Kelly, pages 13-14. a. Please define "fixed costs" as used on page 13, line 17. b. Identify examples of types of "fixed costs" that are being shifted from industrial customers to other customers as part of the Company's proposal in this case. c. Please identify the value of the "fixed costs" being shifted from industrial customers to other customers for the 2019 Forward Test Year. Provide all supporting workpapers.
Objections:
Response:
a. Fixed costs represent those costs that cannot be avoided or controlled in subsequent periods once the decision to perform that activity has been made; they are also not influenced by external factors like customer usage of the system, at least in the short term. Typical examples of fixed costs are investments in physical assets and the labor to operate that equipment. By contrast, variable costs represent those costs that an entity has some ability to control or shape in the short term or otherwise fluctuates (variable) on external factors like customer usage. Typical examples of variable costs include generation fuel and chemicals. b. Most notably the historical portion of return of and return on the net book value of the generating station investment NIPSCO has made to provide firm service to these largest customers that will now be served utilizing Tiers 2 and 3 of proposed Rate 831. c. Please see NIPSCO's response to OUCC Request 5-010.