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June 15, 2018

Mr. Walter L. Thomas, Jr.
Secretary
Alabama Public Service Commission
RSA Union Building
100 North Union Street, Suite 950
Montgomery, Alabama 36130

Re: **Docket No. U-4226, Rate Rider RGB (Supplementary, Back-Up, or Maintenance Power)**

Secretary Thomas:

On behalf of Alabama Power Company ("Alabama Power" or "Company"), and pursuant to Alabama Code § 37-1-81, we are submitting proposed modifications to Rate Rider RGB (Supplementary, Back-Up, or Maintenance Power), and specifically to Part B of the rate rider (Firm Back-Up Power). Along with the enclosed revised tariff sheets, the Company is including the testimony of Ms. Natalie Dean, Pricing Manager for Alabama Power.

Alabama Power is entitled under both federal and Alabama law to collect charges for back-up power service. *See, e.g.*, 18 C.F.R. § 292.305(b) & (c); Ala. Code § 37-4-140(c). Ms. Dean's testimony explains the design of Rate Rider RGB, and particularly the assessment of separate charges for Firm Back-Up Power to customers, taking service under certain rate schedules, who install and interconnect on-site generation to the Company's system (including, but not limited to, on-site solar generation). Ms. Dean's testimony also details the manner by which the Company calculated the updated charges being proposed with the modifications. To afford the Company sufficient time to adjust its billing systems to reflect the proposed modifications, if approved, the Company requests an effective date for the modifications that is sixty (60) days following entry of a Commission order.

We are tendering this submission to the Commission through its e-filing system, consistent with the applicable rules and practices. To this end, an original and one copy of this filing are being delivered to the Commission by overnight mail. To the extent additional information is required, please do not hesitate to contact the undersigned.

Sincerely,

Scott B. Grover

SBG:eb
Attachments

RATE RIDER RGB
SUPPLEMENTARY, BACK-UP, OR MAINTENANCE POWER

By order of the Alabama Public Service Commission dated XXX in Informal Docket # U-4226.

AVAILABILITY

Available in all areas served from the interconnected system of the Company.

APPLICABILITY

Required for any customer connected to the Company's system where the customer obtains any portion of its electric requirements from installed on-site, non-emergency electric generating capacity that operates in parallel with the Company's system, thus rendering the customer a partial requirements customer and requiring the Company to furnish Supplementary, Back-up, and/or Maintenance Power to the premises.

DEFINITIONS

Supplementary Power - Electric energy or capacity regularly used at the premises by a customer in addition to energy that is ordinarily generated by a customer's own generation equipment.

Back-up Power - Electric energy or capacity available to replace energy used at the premises and ordinarily generated by a customer's own generation equipment. Back-Up Power is not available when the customer requires Maintenance Power, but is available only during unscheduled outages, which can occur when a customer's own generation equipment is not producing energy or capacity, or is experiencing periods of intermittent generation.

Maintenance Power - Electric energy or capacity supplied for use at the premises during scheduled outages of the customer's own generation equipment.

RATE RIDER RGB
SUPPLEMENTARY, BACK-UP, OR MAINTENANCE POWER

By order of the Alabama Public Service Commission dated XXX in Informal Docket # U-4226.

RATES

GENERAL PROVISIONS

1. The Customer will pay any interconnection costs (costs of connection, switching, metering, transmission, distribution, transformation, and safety provisions) or any other costs directly related to the modification, installation and maintenance of physical equipment necessary for purposes of interconnected operations, to the extent such costs are in excess of the corresponding costs that the Company would have incurred if the Customer had been a full requirements customer with no generating capacity installed.

2. The Customer will also pay for that portion of the costs the Company would have incurred (if the Customer had been a full requirements customer) that exceed the Company's allowable investment as set forth in its general contract terms and conditions for customer service extensions.

3. Reference to the Company’s rates below shall include any revision or successor of such rates and any applicability requirements within those rates approved by the Alabama Public Service Commission.

4. Customers whose primary business is the production and sale of electric energy are not eligible for Supplementary, Back-Up, or Maintenance Power under Rate RTP.

SUPPLEMENTARY POWER

Available under the Rates BTA, BTAL, FD, HLF, LPL, LPLE, LPLM, LPM, LPME, LPS, LPSE, RTA, RTP, and SCH. Unless modified by this rate rider, all terms and conditions of such rates shall apply. Customers will be eligible to remain on their current rate when the nameplate capacity of the installed on-site, non-emergency generating capacity is no greater than the lesser of 6% of the maximum integrated fifteen (15) minute kW demand during the previous 11 months or 25 kW.

BACK-UP POWER

I. Firm – Electric energy or capacity intended to be available to the Customer at all times

A. Available under Rates BTA, BTAL, LPL, LPLE, LPLM, LPM, LPME, LPSE, and RTP. Unless modified by this rate rider, all terms and conditions of such rates shall apply.

B. Available for Customers on Rates FD, LPS, RTA, and SCH with the following modifications to the terms and conditions of such rates. Customers will be eligible to remain on their current rate, with the following modifications to the terms and conditions of such rate, when the nameplate capacity of the installed on-site, non-emergency electric generating capacity is no greater than the lesser of 6% of the maximum integrated fifteen (15) minute kW demand during the previous 11 months or 25 kW.

1. The Capacity Reservation Charge of $5.42/kW (secondary service) or $4.88/kW (primary service) shall be added to the applicable rate schedule. The Capacity Reservation Charge shall be applied to the nameplate capacity of the Customer's installed on-site, non-emergency electric generating capacity. The Customer may request the Company to calculate its actual capacity requirement to which the Capacity Reservation Charge shall be applied if the Customer believes the nameplate capacity of its installed on-site, non-emergency electric generating capacity exceeds its actual capacity needs. The monthly bill minimum shall be adjusted to include the Capacity Reservation Charge plus the Minimum Bill provisions of the applicable rate schedule. All other terms and conditions of the applicable rates shall continue to apply.

2. In lieu of the Capacity Reservation Charge in 1. above, qualifying customers may take service under Rate RTA with the following modification.

a. During the months of June through September, the energy charge shall be 71¢/kWh during the weekday hours of 3:00 pm – 5:00 pm, excluding holidays as outlined in Rate RTA. All other terms and conditions of Rate RTA shall continue to apply.

II. Short Term - Electric energy or capacity subject to availability and interruption

A. The furnishing of short term, back-up power is a non-standard service provided by the Company. Therefore, the Customer will pay for any facilities required to provide this service as outlined in paragraphs 1. and 2. of the "GENERAL PROVISIONS" above.

B. The Customer must request this service by contacting the Company approximately one (1) hour before each contemplated use. The request shall include the capacity desired and an estimate of the duration.

C. The Company will advise within one (1) hour whether power is available. The Company may withhold or withdraw this power for up to eight (8) hours per day or forty (40) hours per week whenever the Company determines, in its sole discretion, that it has insufficient capacity in plants, lines, or other equipment to provide the service requested.

D. This service is available under Rates LPL, LPM, and RTP with the following modifications to the terms and conditions of such rates:

1. The capacity for billing purposes shall be the measured maximum integrated fifteen-minute capacity during each service period. Contract capacity and previous capacities will not be considered in calculating the capacity for billing purposes. The demand minimums for the applicable rate shall apply for billing purposes.

2. If the service is used for less than a full billing month, the capacity requirement established (KW or KVA) and kilowatt hours consumed during the service period will be projected to a full billing month and the appropriate rate applied; this amount will then be prorated for the number of days the service is used, but the proration will not be for less than two (2) days.

3. Base rate capacity and energy charges (exclusive of Rate ECR charges) above will be multiplied by 1.25 for service during the months of June through September and by 1.15 for service during the months of October through May.

4. For service under Rate RTP, paragraphs II.D.2 and II.D.3 do not apply.

MAINTENANCE POWER

A. Available only during the months of March, April, October, and November. The furnishing of Maintenance Power is a non-standard service provided by the Company. Therefore, the Customer will pay for any facilities required to provide this service as outlined in paragraph 1. and 2. of the "GENERAL PROVISIONS" above.

B. The Customer must request this service in writing at least thirty (30) days in advance. The request shall include the capacity desired and the duration.

C. Maintenance Power will be provided if adequate service facilities are in place and if the Company determines, in its sole discretion, such power is available on its system. Once the Company commits to provide Maintenance Power, it shall be considered a firm power obligation for the specified maintenance period.

D. This service is available under Rates LPL, LPM, and RTP with the following modifications to the terms and conditions of such rates:

1. The capacity for billing purposes shall be the measured maximum integrated fifteen-minute capacity during each service period. Contract capacity and previous capacities will not be considered in calculating the capacity for billing purposes. The demand minimums for the applicable rate shall apply for billing purposes.

2. If the service is used for less than a full month, the capacity requirement established (KW or KVA) and kilowatt hours consumed during the service period will be projected to a full month and the appropriate rate applied; this amount will then be prorated for the number of days the service is used, but the proration will not be for less than seven (7) days.

3. For service under Rate RTP, paragraph D.2 does not apply

GENERAL

Service under this rate rider is subject to rules and regulations approved or prescribed by the Alabama Public Service Commission, including those Special Rules governing the application of this rate rider.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**	**In re Rate Rider RGB**
	)	**(Supplementary, Back-Up,**
Petitioner	**)**	**or Maintenance Power**
	)	**Docket No. U-4226**

TESTIMONY OF NATALIE DEAN
ON BEHALF OF ALABAMA POWER COMPANY

I. INTRODUCTION

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

A. My name is Natalie Dean. I currently serve as the Regulatory Pricing Manager for Alabama Power Company ("Alabama Power" or "Company"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q: Please describe your professional background.

A: I have a Bachelor of Mechanical Engineering degree from Auburn University as well as a Master's Degree in Business Administration from the University of Alabama at Birmingham. I have worked with Southern Company and Alabama Power for more than 17 years. I have experience in generation design engineering, generation development, construction, transmission customer service, and regulatory costing. I assumed the role of Pricing Manager in December 2017.

Q. Describe your professional responsibilities as Pricing Manager.

A: As the Pricing Manager, I am primarily responsible for the evaluation and monitoring of the Company's current rate offerings. Among my other responsibilities is the management of the design and analysis of any new rates or modifications to existing rates for electric service.

Q. What is the purpose of your testimony?

A: Alabama Power is filing proposed modifications to Rate Rider RGB (Supplementary, Back-Up or Maintenance Power) ("Rate Rider RGB"). This filing reflects a slight increase in the charges for Firm Back-Up Power service to customers with non-emergency on-site generation interconnected with the Company's electrical system, as set forth in Part B of the Firm Back-Up Power section of the rate rider. The Company proposes the increase to be effective beginning with billings in the second month following the entry by the Alabama Public Service Commission (the "Commission") of an order in this case. My testimony supports this filing.

Q: What has prompted Alabama Power to make this filing?

A: Recently, James Bankston, Ralph Pfeiffer and Gasp, Inc. filed a complaint against Alabama Power regarding Rate Rider RGB (the "Complaint"), claiming that it is unjust and unreasonable, and that the charges in the rate rider for Firm Back-Up Power are discriminatory and lack any cost basis. As my testimony here demonstrates, this is not the case. However, a defense of the current charges today, predicated on information from 2012, likely would have been questioned on grounds that such historical cost support is now "stale" and perhaps not reliable. Accordingly, the Company performed the analysis supporting the charges using currently available information. The results of that analysis showed that the Capacity Reservation Charge should be $5.42 per kilowatt ("kW") and the Rate RTA super-peak energy charge should be $0.71 per kilowatt hour ("kWh"). The modifications to the rate rider being filed reflect these figures.

Q: Would you please summarize your testimony?

A: Yes. Before doing so, I would note here that my testimony refers to several of the Company's rate schedules. When referring to these rates, I do so by their shortened name (e.g., Rate Rider RGB). The full name of each rate, along with the stated charges, terms and conditions, can be found on the Company's website, www.alabamapower.com, in the separate Residential and Business sections of the site.

In Part II of my testimony, I describe Rate Rider RGB, including the different service offerings under the rate rider and the general reasons why Alabama Power offers them. I then discuss when the currently effective provisions of the rate rider were placed into effect ("Revision Fifth"). Next, I discuss in more detail the Firm Back-Up Power section of the rate rider. As part of this discussion, I explain why the Company utilizes specific additional charges for Firm Back-Up Power in Part B for customers taking supplementary service on Rate FD, Rate LPS, Rate RTA or Rate SCH. I also explain why the Company does not need to utilize additional specific charges for customers who take supplementary service under the rates listed in Part A of the Firm Back-Up Power section. Then, in Part III, I explain the methodology used by the Company to calculate the Firm Back-Up Power charges set forth in Part B. Part IV of my testimony provides concluding remarks.

II. Rate Rider RGB

Q: Can you explain the various service offerings under Rate Rider RGB?

A: Rate Rider RGB applies to all customers with non-emergency on-site generation—regardless of type—interconnected and operating in parallel with Alabama Power's electrical system (i.e., partial requirements customers). The rate rider includes the rates, terms and conditions for three principal services: Supplementary, Back-Up and

Maintenance Power. Supplementary Power service applies to that portion of a partial requirements customer's electrical needs that ordinarily are not met by the customer's on-site generation. Supplementary Power service is made available through the rates specified in the rate rider (i.e., Rates BTA, BTAL, FD, HLF, LPL, LPLE, LPLM, LPM, LPME, LPS, LPSE, RTA, RTP, and SCH).

Back-Up Power service obligates Alabama Power to be ready to stand in the place of a partial requirements customer's on-site generation when that generation is not producing electricity. The rate rider provides for two forms of Back-Up Power service: Firm Back-Up Power and Short-Term Back-Up Power. Firm Back-Up Power is intended to be available at all times, including system peak times, without notice or request. Firm Back-Up Power is available under the rates listed in Parts A and B. Short-Term Back-Up Power is a non-standard service, and advanced arrangements between the Company and the customer are required before the service can be made available. The charges for Short-Term Back-Up Power are described in the rate rider.

Lastly, Maintenance Power service is offered to those customers that meet their electricity needs through on-site generation, but from time to time expect that generation to be unavailable (e.g., for maintenance of the generation), and thus require Alabama Power to serve the needs that otherwise would be served by the customer's generation. Like Short-Term Back-Up Power, Maintenance Power is a non-standard offering, and advanced arrangements between the Company and the customer are required before the service can be made available. The charges for Maintenance Power are described in the rate rider.

Q: Is Alabama Power required to offer these services?

A: As a general matter, Alabama Power has a duty under Alabama law to serve its customers. While I am not prepared to say that this duty alone translates to an obligation to provide the specific services offered through Rate Rider RGB, I am aware that the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the implementing regulations of the Federal Energy Regulatory Commission ("FERC"), specifically 18 C.F.R. § 292.305(b), obligate utilities such as Alabama Power to provide supplementary, back-up, maintenance and interruptible power to qualifying small power production facilities and co-generation facilities. In addition, I am aware that Title 37 of the Alabama Code, section 37-4-140(c)(1), authorizes the Commission to approve Alabama Power's rates, fees, and charges for services to on-site, interconnected generation, including those for supplementary power, back-up power and maintenance power.

In any event, a form of Rate Rider RGB consistent with both the existing Revision Fifth and the proposed modification has been on file with the Commission since early 1988.

Q: When was Revision Fifth placed on file with the Commission?

A: That revision was filed in December 2012. It was approved in January 2013, but did not go into effect until May 2013.

Q: Prior to the filing of the Complaint in May 2018, are you aware of any formal complaint having been lodged against Rate Rider RGB in the more than five years since Revision Fifth's approval in January 2013?

A: I am not.

Q: Do you know how many customers have begun taking service under Rate Rider RGB since the approval of Revision Fifth in January 2013?

A: As of the Revision Fifth effective date, approximately 79 customer accounts were subject to Rate Rider RGB. At present, the number of accounts subject to Rate Rider RGB is 155.

Q: Are all customers with interconnected, on-site generation subject to the provisions of Rate Rider RGB?

A: Yes. Effective with Revision Fifth, any customer that wants to interconnect and operate a non-emergency generator in parallel with the Company's electrical system is subject to the provisions of Rate Rider RGB.

Q: Are there situations where a customer can have non-emergency, on-site generation and not be subject to Rate Rider RGB?

A: Yes. If such a customer is not interconnected to the Company's system, then the customer would not be subject to Rate Rider RGB (as the customer does not require supplementary or back-up power service from Alabama Power). This means that the customer's on-site generation, as well as the load served by that generation, is not electrically connected to the Alabama Power system. An example of this is described in the affidavit of Gasp member Charles Scribner, included with the Complaint. As the affidavit explains, Mr. Scribner has invested in a battery-based system to provide the back-up for when his system is not producing electricity. In addition, Mr. Scribner has separated that generation and the battery back-up system (and the load served by them) from Alabama Power's system. He also explains that the remainder of his residence continues to be served solely by Alabama Power (and is not subject to Rate Rider RGB). *See* Complaint, Ex. 2, para. 7.

Q: Why does the Company require customers with on-site generation to comply with the provisions of Rate Rider RGB?

A: Foremost, Rate Rider RGB provides for the recovery of costs associated with providing the services offered through the rate rider to customers with interconnected, on-site generation. In addition, Rate Rider RGB includes a set of special rules that contain requirements relating to the interaction of the customer and the customer's on-site generation with the Company's system. These are necessary for various reasons, chief among them the protection of the Company's electrical system and its employees from potentially adverse impacts that could be caused by the operation of generation in parallel with the Company's system without the Company's knowledge.

Q: Does the Complaint object to the entirety of Rate Rider RGB?

A: No. The Complaint is focused on the charges for Firm Back-Up Power service, claiming them to be discriminatory and without any basis. The Complaint also alleges that Rate Rider RGB is unduly complicated and intended to confuse customers.

Q: Do you agree with the allegations of the Complaint?

A: I do not.

Q: Why?

A: First, the Firm Back-Up Power provisions of the rate rider targeted by the Complaint are not discriminatory; to the contrary, both the assessment of a Capacity Reservation Charge to the supplementary rates listed in Part B and the charging of an RTA super-peak charge are entirely reasonable. As I explain below, to forego these charges would result in these customers receiving the benefit of Back-Up Power service at the expense of other customers. In addition, it would be unreasonable to assess these charges in conjunction with the supplementary rates listed in Part A of the Firm Back-Up Power section of the rate rider, because those rates include design components that adequately provide for cost recovery of Back-Up Power service.

Moreover, and contrary to the allegations in the Complaint, the charges for Firm Back-Up Power service are cost-based and supported by comprehensive analysis undertaken by the Company. This is true for both for the existing Firm Back-Up Power charges in Revision Fifth as well as the updated charges I am supporting here. In this respect, and in support of those revisions, my testimony explains in detail how the Company calculated the charges. Finally, I would point out that the application of the Capacity Reservation Charge for Firm Back-Up Power is straightforward, based on values readily available to the customer, and certainly not intended to confuse. To the extent questions do arise, and from time to time they do, Alabama Power personnel are readily available to answer questions that a customer might have regarding Rate Rider RGB. I myself have responded to customer inquiries on such matters.

Q: Why does Alabama Power charge customers with interconnected, on-site generation for Firm Back-Up Power?

A: There are costs to Alabama Power to stand ready to provide Firm Back-Up Power to customers with such generation. Specifically, the Company has incurred and continues to incur fixed capacity costs—that is, those related to the infrastructure needed to provide Firm Back-Up Power service, including generation, transmission and distribution facilities that must be available to respond to the demands of customers with on-site generation who choose to rely on the Company to provide back-up power. Thus, just as there are costs to a customer self-providing back-up service (like Mr. Scribner’s battery-based system), there are costs to the Company when we provide this service, and in the absence of cost recovery for back-up power, the service would be provided at the expense of other customers.

Q: Why are the customers taking service under the rate schedules FD, RTA, SCH and LPS the only customers receiving a separate charge for Firm Back-Up Power service?

A: Recall that the Firm Back-Up Power service is segmented into Parts A and B. With the exception of Rate RTP, the eligible rates listed in Part A are referred to in the industry as ratcheted-demand rates. In essence, these rates include separate charges that a customer is required to pay to cover both its capacity and energy needs, and the respective fixed and variable costs of service corresponding to those needs. With respect to the capacity charge, or demand component, the rates recover fixed costs based on the customer's maximum or peak demand, utilizing a ratcheted-demand design. By that, I mean a customer is either billed for its monthly peak demand or a percentage of the peak demand in the prior eleven months, whichever is higher. This design provides for the fixed cost recovery of the customer's peak capacity needs for the entire year. Thus, while these rates were designed based on the needs of a full requirements customer, the ratcheted-demand component ensures that fixed cost recovery associated with peak capacity needs is being accomplished even in a partial requirements situation where the Company is required to provide Back-Up Power. And although Rate RTP does not include a ratcheted-demand component, the real-time pricing nature of the rate provides for automatic adjustments to the pricing during high cost periods. This affords the Company sufficient assurance of cost recovery in the event a customer under the rate requires back-up power service during such peaking periods. In summary, both the ratcheted-demand rates and Rate RTP provide the Company with a means to recover the peak capacity costs required to provide Firm Back-Up Power. For this reason, the Company does not need to utilize any additional specific back-up charges for customers who take supplementary service under the rates listed in Part A.

In contrast, the rates listed in Part B comprise either energy only rates (Rate FD and Rate LPS) or rates without a ratcheted-demand design (Rate RTA and Rate SCH). Rate FD and Rate LPS recover the Company's cost of service—both variable energy and fixed capacity costs—primarily through a kWh charge applied to the energy consumption of the customer. These rates were designed based on the energy consumption profiles for full requirements customers. These rates, as well as Rate RTA and Rate SCH, do not have a separate ratcheted-demand component, and thus do not provide a means for the Company to fully recover the fixed costs associated with providing Back-Up Power. Accordingly, an additional back-up charge is required for the service of partial requirements customers taking supplementary service under the rates listed in Part B.

Q: Why is there a different Firm Back-Up Power charge for customers on Rate RTA?

A: Rate RTA is a time-of-use rate, and is designed for customers who believe they can manage their usage more precisely, particularly during peak periods. The inclusion of this option as part of Revision Fifth extended that flexibility to those customers with interconnected, on-site generation. Being interconnected, however, meant that such customers could still require back-up power service. Thus, to send an appropriate price signal, while also providing for cost recovery when required, the Company included a summertime super-peak charge, applicable only during the hours of 3 p.m. to 5 p.m. on non-holiday weekdays. Customers on this rate can avoid the super-peak charge if they do not require service during this two-hour period.

III. The Methodology Used to Calculate the Charges for Firm Back-Up Power

Q: Earlier you stated that the Company employed a comprehensive analysis to determine the updated charges for Firm Back-Up Power service under Part B, correct?

A: That is correct.

Q: Is the methodology the Company used different than that employed to develop those charges set forth in Revision Fifth?

A: No. As I stated above, the Company used currently available cost data and customer load information, but the underlying methodology is the same as that employed to develop the charges set forth in Revision Fifth.

Q: Please describe that analysis.

A: While the Capacity Reservation Charge and the RTA super-peak charge both seek to recover the costs associated with providing Firm Back-Up Power service, they address the cost recovery through different rate designs. Even so, the underlying basis for the development of these charges is the same, as that development begins with the cost-of-service study required by the Company's Rate RSE. *See* Rate RSE, p. 3 ("Jurisdictional Allocations"). This study, commonly referred to as the jurisdictional separation study ("JSS"), is filed annually with the Commission. A copy of the JSS filing containing the cost information utilized in the development of the proposed updated charges for Firm

Back-Up Power service (the 2016 JSS, as filed with the Commission in April 2017) is included at Exhibit ND-1.

Q: What is the purpose of the JSS?

A: Generally speaking, the JSS seeks to equitably allocate the Company's costs of providing electric service among customers receiving that service so that the Company can implement recovery mechanisms consistent with the customers' corresponding cost responsibility.

Q: What is the informational basis for the JSS?

A: The JSS includes all of the Company's embedded costs of electric service, including all of the Company's plant-in-service (e.g., generating, transmission and distribution facilities) and operating expenses, as reflected in the Company's books and records for the year of the study. In addition, the JSS includes aggregated demand and energy data for all customers on a residential and non-residential basis (both being within the jurisdiction of the Commission) and on a wholesale basis (within the jurisdiction of FERC). This data is reflected at the specific demand level of service (e.g., transmission level, primary distribution level, secondary distribution level).

Q: Please describe the mechanics of the JSS.

The JSS undertakes to functionalize and classify the different components of the Company's embedded cost of service, consistent with standards prevailing in the industry and endorsed by the National Association of Regulatory Utility Commissioners. The JSS categorizes costs in terms of their function—with the primary functions being production, transmission and distribution. The JSS then classifies the functionalized costs based on the source of the costs incurred—i.e., demand, energy, and customer. Demand costs are classified as costs that vary with the kW demand imposed by the customer. Examples of these costs include investment in items such as generation and transmission facilities. Energy costs are costs that vary with the amount of energy, or kWh, that the Company provides. Examples of these costs include fuel and variable operating and maintenance expenses. The last classification, customer costs, includes costs that are directly related to the number of customers served. Examples of these costs include meters at and service drops to individual premises.

Q: How are the different functions classified?

A: Production costs generally are classified as demand and energy related. Transmission costs generally are classified as demand related. Distribution costs generally are classified as demand and customer related. Once this classification has been made, the JSS then allocates the costs of service to the customer classes I mentioned above (i.e., residential, non-residential and wholesale). This allocation is based on their contribution to each classification, which reflects both customer counts and their corresponding load profiles (i.e., energy usage and demand requirements).

Q: Is this information reflected on your Exhibit ND-1?

A: Yes. Page 1, Schedule 1.00 reflects the allocated costs by customer class.

Q: What did the Company do next to determine the charges for Firm Back-Up Power service in Part B?

A: With the cost of service for the classes identified, the Company then sought to determine a representative cost of service for the subset of the customer population likely to interconnect on-site generation and require Firm Back-Up Power subject to Part B. Rate FD customers were selected as an appropriate proxy for two reasons. First, relative to the rates subject to the Capacity Reservation Charge, the Company determined that Rate FD would serve as a conservative indication of the cost of service to customers under all of the Part B rates. Second, the vast majority of customers (more than 85 percent) subject to the Firm Back-Up Power service requirements under Part B are served under Rate FD.

The Company next determined an indicative load profile for this subgroup by utilizing the Rate FD customer sample load profiles. In cases where a rate population is small enough and can be expected to comprise a homogeneous group of customers (i.e., customers with comparable utilization), a simple random sample can be sufficient to determine a representative load profile. But for large rate populations like the customers taking service under Rate FD, simple random sampling is not applicable. Rather, it is necessary to stratify or break down the population into categories of similar customers, and then sample within those categories. For Rate FD, the standard sampling stratification employed by the Company comprises four categories, or strata, with sampling performed within each strata to obtain a representative load profile for the respective strata.

Q: What are the four strata used for Rate FD?

A: The four strata are based on levels of customer energy usage as follows: Strata 1 (low summer and low winter); Strata 2 (high summer and low winter); Strata 3 (low summer and high winter); and Strata 4 (high summer and high winter).

Q: How did the Company use the four Rate FD strata load profiles in its analysis?

A: The overall goal of the Company here was to determine the indicative load profile associated with the customer population subset likely to install and interconnect on-site generation requiring Firm Back-Up Power under Part B. To do this, the Company identified current Rate FD customers with such generation and determined the respective strata they occupied prior to the installation and interconnection of that generation. Then this information was used to determine an indicative weighted average load profile from the four Rate FD strata profiles, and hence a representative customer for use in the Company's analysis. The load profile for this representative customer is set forth at Exhibit ND-2.

With this load profile established, the Company then developed an indicative load profile for the same representative customer with installed rooftop solar generation. This form of on-site generation is the pre-dominant form used by current customers subject to the Firm Back-Up Power requirements of Part B, and was viewed as the most likely form of on-site generation to continue to be adopted by these type customers. To develop this load profile, the Company used the NREL PVWATTS tool, which is available at https://pvwatts.nrel.gov, to develop solar production profiles for 1 kW of installed fixed roof mount solar in each of the three weather zones representative of the Company's service territory (Birmingham, Montgomery, and Mobile). The Company then weighted each of these profiles, based on residential customer usage in the weather zones, to achieve a single 1 kW solar profile representative of the average in the Alabama Power service territory. This production profile is included at Exhibit ND-3. Next, the Company utilized this solar production profile to reduce the representative customer load profile I described earlier. In this way, the Company determined an indicative load profile for the same representative customer with 1 kW of on-site solar generation. This load profile also is included at Exhibit ND-3.

Q: What did the development of these two load profiles allow the Company to do?

A: By determining these two load profiles, the Company was able to develop the cost to serve each customer, and thereby compare the cost of service for the same representative customer with and without 1 kW of interconnected, on-site solar generation. Through this comparison, the Company was able to calculate the cost of service differentials—both from a variable energy cost perspective and a fixed capacity or demand cost perspective—and thus determine the cost of providing back-up power service to a customer with 1 kW of on-site solar generation.

Q: What do these two cost differentials represent?

A: The variable energy cost differential represents costs that are reduced by the 1 kW on-site generation and thus avoided by the Company (e.g., fuel and variable O&M). This differential is a savings that the Company, and in turn the customer, should realize as a result of energy being provided by the on-site generation. The fixed capacity cost differential represents the costs that would be reduced if the customer did not require Firm Back-Up Power service. These costs, however, are not reduced when the Company is required to maintain the same amount of capacity sufficient to back-up the customer's on-site generation.

Q: What variable energy and fixed capacity cost differentials did the Company identify?

A: From a variable energy cost perspective, the Company identified a savings of approximately $0.0253 per kWh produced by the customer's on-site generation. In terms of fixed capacity costs, the differential the Company identified is approximately $129 annually per kW of on-site generation requiring Firm Back-Up Power. These differentials are reflected on my Exhibit ND-4.

Q: Did the determination of the cumulative variable energy savings and fixed capacity cost differential complete the analysis?

A: No. The Company does not avoid the fixed capacity costs when a customer with on-site generation requires Firm Back-Up Power service, because the Company must remain prepared to serve the customer's peak load at any time and under any condition. That being said, FERC's PURPA implementing regulations do not permit rates for sales of back-up power to be based on the assumption that reductions in electric output by every on-site generator on the Company's system will occur simultaneously, or during the system peak, or both. The Company therefore determined that the customer should receive credit for a portion of the fixed cost differential due to the diversity of customer back-up power needs.

Q: How did the Company determine what portion should be credited?

A: The Company considered many factors, including customer diversification, the expected annual utilization and the incremental capacity equivalent of the on-site generator. Based on these factors, the Company determined that a credit of 35 percent of the fixed costs was a reasonable approximation of the benefits of customer generator diversity.

Q: So the Capacity Reservation Charge reflects the remaining fixed cost differential?

A: Yes, but it also includes consideration of the portion of those costs that may be covered by the provisions of the supplementary service rate (i.e., the customer and energy charge provided in Rate FD). In this way, the customer is not overcharged for Firm Back-Up Power service through the combination of both the existing charges in the supplementary rate and the Capacity Reservation Charge.

Q: Please explain.

A: The fixed capacity cost was determined to be the remaining 65 percent of the identified cost of $129 per kW annually or an equivalent monthly capacity reservation charge of $6.99 per kW of installed generation requiring back-up. Instead of relying just on this differential, however, the Company also performed calculations to determine how much of this cost would be recovered under Rate FD for the supplementary service of a representative customer with on-site generation. To do this, the Company took the representative customer load profiles I described earlier and calculated the expected annual cost recovery for each profile using the applicable charges under Rate FD. For this calculation, the Company assumed an installation of 4.3 kW of rooftop solar, which represents the average size of on-site generation for Residential customers with interconnection applications on file with Alabama Power. The load profile for this representative customer and the associated solar production profile are reflected on my Exhibit ND-5.

Q: What was the result of the Company's calculations?

A: The Company determined that the difference between the costs recovered from the full requirements customer and the costs recovered from providing supplemental service to the partial requirements customer was $610 annually. The Company then used the cost of service information derived earlier to determine the difference in the cost to serve these two customers. Consistent with the cost of service savings I discussed earlier, for the variable energy cost and a portion of the fixed costs, the Company determined that the cost to serve this partial requirements customer was reduced by $330 annually. The variable energy cost reduction associated with the installed generation was $136 annually, or $0.0253 per kWh multiplied by the calculated annual energy reduction associated with the 4.3 kW generator of 5,362 kWh. The fixed capacity cost reduction was $194 annually, or 35 percent of the $129/kW for 4.3 kW of on-site generation. Considering the reduction to the Company's costs versus the reduction to the cost recovery, the Company is left with an annual net unrecovered cost of $280. This amount represents the remaining cost of providing back-up service to the customer with on-site solar generation that is not otherwise recovered in the supplementary service rate (i.e., in either the energy or customer charge component of Rate FD). The information discussed here is reflected on my Exhibit ND-6.

Q: How would this annual net unrecovered cost translate into the calculation of a new Capacity Reservation Charge?

A: The $280 annual unrecovered cost would be divided by the size of the solar generator requiring back-up (i.e., 4.3 kW) and then by the 12 months in the year, to equal $5.42 per kW per month. Thus, for each kW of generation for which a customer required back-up power service, a monthly charge of $5.42 would be necessary. For the typical 4.3 kW facility, the monthly amount would be $23.30.

Q: Is the Company proposing to increase the Capacity Reservation Charge to $5.42?

A: Yes. In determining to do so, the Company recognized that the development of Revision Fifth actually yielded a monthly Capacity Reservation Charge of $5.23 per kW of installed generation. At the time, the Company believed that use of a whole number would more easily facilitate implementation. Accordingly, the charge was rounded down to $5.00. With this calculated increase approaching $5.50, the Company no longer believes rounding to be appropriate, and is modifying the rate to reflect a Capacity Reservation Charge of $5.42 for Firm Back-Up Power service at the secondary level (and

$4.88 for service at the primary level, as adjusted for the difference in voltage transformation costs).

Q: Was the RTA super-peak charge calculated in the same manner as the Capacity Reservation Charge?

A: Generally speaking, yes, although the rate predicate for the analysis is Rate RTA and the super-peak charge is limited to consumption under the rate during 3 p.m. to 5 p.m. on summertime weekdays (excluding holidays and Mondays following holidays).

Q: How does the rate calculation for the charge differ from that performed for the Capacity Reservation Charge?

A: The same cost of service differentials discussed earlier were utilized in the Company's determination of the net unrecovered cost to provide Firm Back-Up Power to a Rate RTA customer with interconnected, on-site solar generation. Because the super-peak energy charge would only apply to customers who take service under Rate RTA, the net unrecovered cost was calculated using the applicable Rate RTA charges. In addition, because the super-peak charge applies to consumption during a defined, super-peak period, the Company calculated the annual consumption (in kWh), during the hours of 3 p.m. to 5 pm on all non-holiday summer weekdays, by the representative customer without installed on-site solar generation. The annual net unrecovered cost of $262 was then converted to a cents/kWh energy charge for those hours by dividing the total annual net unrecovered cost by the total annual kWh used during the super-peak period of 535 kWh. This results in an unrecovered cost per kWh of $0.49. This cost, as an additional cost for providing back-up power service, is then added to the existing peak charge of

$0.221822 per kWh that is set forth in Rate RTA, resulting in a super-peak charge of $0.71/kWh. This information is reflected on my Exhibit ND-7.

Q: Is the Company proposing to increase the RTA super-peak charge?

A: Yes. The proposed modifications include this updated charge.

IV. Conclusion

Q: Do you have any closing remarks?

A: Yes. As evidenced by my testimony and the supporting information and analysis being provided with it, Rate Rider RGB is a just and reasonable rate and the charges for Firm Back-Up Power service are neither discriminatory nor lacking in support. Rather, these charges reflect efforts by the Company, employing standard rate design practices used in the normal course of the Company’s operations, to recover costs associated with the supply of Firm Back-Up Power to those customers who choose to install on-site generation on their premises, interconnect that generation and the load served by it with the Company’s electrical system, and continue to expect Alabama Power to meet all of the customer’s electric service needs, including any required firm back-up of the on-site interconnected generation. Charges for Firm Back-Up Power under Rate Rider RGB have been and continue to be fully appropriate. As also shown in my testimony, however, updated charges are now justified and the filed revisions should be approved and made effective as requested.

Q: Does this conclude your testimony?

A: Yes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	)	**In re Rate Rider RGB**
	)	**(Supplementary, Back-Up,**
Petitioner	)	**or Maintenance Power**
	)	**Docket No. U-4226**

TESTIMONY OF NATALIE DEAN
ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA)

COUNTY OF JEFFERSON)

Natalie Dean, being first duly sworn, deposes and says that she has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of her knowledge, information and belief.

Natalie Dean

Natalie Dean

Subscribed and sworn to before me
this 15th day of June, 2018.

Esther T. Howard

Notary Public

ALABAMA NOTARY PUBLIC
ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

1582114.1

Testimony of Natalie Dean

Exhibit ND-1

ALABAMA POWER COMPANY
RETAIL COST OF SERVICE
TWELVE MONTHS ENDED DECEMBER 31, 2016

INDEX

ALABAMA POWER COMPANY
RETAIL COST OF SERVICE
TWELVE MONTHS ENDED DECEMBER 31, 2016

SCHEDULE 1.00--SUMMATION OF INVESTMENT AND EXPENSE ALLOCATIONS

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)
	NET INVESTMENT					

1	ELECTRIC GROSS PLANT	$25,941,960,288	$12,173,648,717	$12,789,665,321	$24,963,314,038	$978,646,250
2	PROVISION FOR ACCUM DEPR & AMORT	9,792,475,348	4,598,759,019	4,823,366,866	9,422,125,885	370,349,463
3	NET PLANT	$16,149,484,940	$7,574,889,698	$7,966,298,455	$15,541,188,153	$608,296,787
	ADD:					
4	PLANT HELD FOR FUTURE USE	55,973,108	24,250,044	29,177,189	53,427,233	2,545,875
5	MATERIALS AND SUPPLIES	624,605,555	249,799,584	344,389,032	594,188,616	30,416,939
6	UNAMORTIZED LEASEHOLD IMPROVEMENTS	611,796	325,531	270,297	595,828	15,968
7	CONSTRUCTION WORK IN PROGRESS	491,341,197	211,081,091	257,601,559	468,682,650	22,658,547
8	AVERAGE DAILY BANK BALANCES	106,899,766	42,811,345	58,955,470	101,766,815	5,132,951
9	ELECTRIC PLANT ACQUISITION ADJUSTMENT	3,080,386	1,698,193	1,382,088	3,080,281	105
10	NUCLEAR FUEL	335,858,911	106,022,812	209,725,014	315,747,826	20,111,085
	DEDUCT:					
11	SEGCO/AEC DEPOSIT	36,778,679	11,610,170	22,966,218	34,576,388	2,202,291
12	CUSTOMER ADVANCES FOR CONSTRUCTION	328,418	0	328,418	328,418	0
13	CUSTOMER DEPOSITS	88,437,048	45,063,071	43,373,976	88,437,048	0
14	TOTAL NET INVESTMENT	$17,642,311,514	$8,154,205,057	$8,801,130,491	$16,955,335,548	$686,975,966
15	PERCENT OF TOTAL ELECTRIC SYSTEM	100.00%	46.22%	49.89%	96.11%	3.89%
16	**RETAIL ELECTRIC INVESTMENT FACTOR**				**96.11%**	
	EXPENSES					

17	OPERATION AND MAINTENANCE EXPENSES	$3,140,422,706	$1,257,680,191	$1,731,950,423	$2,989,630,615	$150,792,091
18	DEPRECIATION AND AMORTIZATION EXPENSE	724,205,225	341,671,763	356,555,764	698,227,527	25,977,698
19	OTHER AMORTIZATION AND ACCRETION	(13,658,640)	(5,003,851)	(7,831,535)	(12,835,386)	(823,254)
20	TAXES OTHER THAN INCOME TAXES	380,291,686	172,117,481	203,282,494	375,399,975	4,891,711
21	SALES TO NON-ASSOCIATED COMPANIES	(141,203,480)	(44,574,640)	(88,173,637)	(132,748,277)	(8,455,203)
22	OTHER ELECTRIC REVENUES	(111,267,023)	(63,008,531)	(40,358,540)	(103,367,071)	(7,899,952)
23	TOTAL EXPENSES	$3,978,790,474	$1,658,882,414	$2,155,424,969	$3,814,307,383	$164,483,091
24	PERCENT OF TOTAL ELECTRIC SYSTEM	100.00%	41.69%	54.17%	95.87%	4.13%
25	**RETAIL EXPENSE ALLOCATION FACTOR**				**95.87%**	
	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION					
	--					
25	TOTAL AFUDC	$38,892,695	$17,205,307	$20,000,930	$37,206,237	$1,686,458
26	PERCENT OF TOTAL ELECTRIC SYSTEM	100.00%	44.24%	51.43%	95.66%	4.34%
27	**RETAIL ELECTRIC AFUDC ALLOCATION FACTOR**				**95.66%**	

SCHEDULE 2.00--ANALYSIS OF GROSS PLANT

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
1	PRODUCTION	13,558,894,873	5,362,099,386	7,474,225,080	12,836,324,466	722,570,407	(A)
	TRANSMISSION						
	SUBSTATIONS						
2	LEVEL 2 COMMON	1,234,072,304	488,035,228	680,271,826	1,168,307,054	65,765,250	(B)
3	LEVEL 3 COMMON	13,608,653	7,402,578	6,205,618	13,608,196	457	(C)
4	TOTAL SUBSTATIONS	1,247,680,958	495,437,807	686,477,444	1,181,915,251	65,765,707	
	LINES						
5	LEVEL 2 COMMON	2,557,405,001	1,011,370,019	1,409,747,682	2,421,117,701	136,287,300	(B)
6	LEVEL 2 ASSIGNED	115,643,598	47,362,437	66,018,455	113,380,892	2,262,706	(D)
7	TOTAL LINES	2,673,048,600	1,058,732,457	1,475,766,137	2,534,498,594	138,550,006	
8	TOTAL TRANSMISSION	3,920,729,557	1,554,170,263	2,162,243,581	3,716,413,844	204,315,713	
	DISTRIBUTION						
	SUBSTATIONS						
	ACCOUNT 360						
9	LEVEL 2 COMMON	30,775	12,172	16,964	29,136	1,639	(B)
10	LEVEL 3 COMMON	42,896,867	23,334,229	19,561,197	42,895,426	1,441	(C)
11	LEVEL 4 COMMON	126,117	69,527	56,586	126,113	4	(E)
12	TOTAL COMMON	43,053,759	23,415,928	19,634,747	43,050,675	3,084	
13	SPECIFIC SUBSTATIONS	1,548,913	0	1,536,496	1,536,496	12,416	(F)
14	TOTAL ACCOUNT 360 SUBS	44,602,672	23,415,928	21,171,243	44,587,172	15,500	
	ACCOUNT 361						
15	LEVEL 2 COMMON	1,693,003	669,527	933,253	1,602,780	90,223	(B)
16	LEVEL 3 COMMON	80,198,312	43,624,764	36,570,852	80,195,616	2,696	(C)
17	LEVEL 4 COMMON	315,140	173,733	141,396	315,129	11	(E)
18	TOTAL COMMON	82,206,455	44,468,024	37,645,501	82,113,525	92,930	
19	SPECIFIC SUBSTATIONS	7,620,002	0	7,560,251	7,560,251	59,751	(F)
20	TOTAL ACCOUNT 361	89,826,457	44,468,024	45,205,752	89,673,776	152,681	
	ACCOUNT 362						
21	LEVEL 2 COMMON	46,225,013	18,280,478	25,481,145	43,761,623	2,463,390	(B)
22	LEVEL 3 COMMON	793,797,323	431,794,887	361,975,752	793,770,639	26,684	(C)
23	LEVEL 4 COMMON	5,562,834	3,066,749	2,495,896	5,562,645	189	(E)
24	TOTAL COMMON	845,585,170	453,142,114	389,952,793	843,094,907	2,490,263	
25	SPECIFIC SUBSTATIONS	188,154,269	0	185,660,048	185,660,048	2,494,222	(F)
26	TOTAL ACCOUNT 362	1,033,739,439	453,142,114	575,612,841	1,028,754,955	4,984,485	
27	TOTAL DISTRIBUTION SUBS	1,168,168,568	521,026,066	641,989,835	1,163,015,902	5,152,666	

SCHEDULE 2.00--ANALYSIS OF GROSS PLANT

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
	LINES						
28	ACCOUNT 360-CUST	3,897,327	3,341,521	555,801	3,897,322	5	(G)
29	ACCOUNT 364-CUST	831,450,224	712,875,163	118,573,925	831,449,088	1,136	(G)
30	ACCOUNT 364-DMND	353,964,980	195,138,202	158,814,732	353,952,934	12,046	(E)
31	TOTAL ACCOUNT 364	1,185,415,204	908,013,365	277,388,657	1,185,402,022	13,182	
32	ACCOUNT 365-CUST	887,016,866	760,517,316	126,498,338	887,015,654	1,212	(G)
33	ACCOUNT 365-DMND	363,183,086	200,220,072	162,950,654	363,170,726	12,360	(E)
34	TOTAL ACCOUNT 365	1,250,199,952	960,737,388	289,448,992	1,250,186,380	13,572	
35	ACCOUNT 366-CUST	7,343,487	6,296,215	1,047,262	7,343,477	10	(G)
36	ACCOUNT 366-DMND	39,104,882	21,558,223	17,545,328	39,103,551	1,331	(E)
37	TOTAL ACCOUNT 366	46,448,369	27,854,438	18,592,590	46,447,028	1,341	
38	ACCOUNT 367-CUST	101,704,143	87,199,877	14,504,127	101,704,004	139	(G)
39	ACCOUNT 367-DMND	505,484,769	278,669,909	226,797,658	505,467,567	17,202	(E)
40	TOTAL ACCOUNT 367	607,188,912	365,869,786	241,301,785	607,171,571	17,341	
41	TOTAL DISTRIBUTION LINES	3,093,149,765	2,265,816,499	827,287,825	3,093,104,324	45,441	
	ACCOUNT 368						
42	DEMAND	1,112,002,639	672,704,011	439,298,628	1,112,002,639	0	(H)
43	CUSTOMER	274,534,318	238,005,011	36,529,307	274,534,318	0	(I)
44	NETWORK PROTECTORS	21,800,016	0	21,800,016	21,800,016	0	(J)
45	ENCLOSURES	11,989,368	0	11,989,368	11,989,368	0	(K)
46	TOTAL ACCOUNT 368	1,420,326,341	910,709,022	509,617,319	1,420,326,341	0	
	ACCOUNT 369						
	UNSPECIFIED						
47	OVERHEAD	294,327,376	255,164,421	39,162,955	294,327,376	0	(I)
48	UNDERGROUND	158,498,737	137,409,028	21,089,709	158,498,737	0	(I)
49	TOTAL UNSPECIFIED	452,826,113	392,573,449	60,252,664	452,826,113	0	
	SPECIFIED						
50	HOUSEPOWER PANELS	849,998	849,998	0	849,998	0	(F)
51	BREAKER CENTERS	828,987	828,987	0	828,987	0	(F)
52	SPECIAL BREAKER CENTERS	6,921	0	6,921	6,921	0	(F)
53	TOTAL SPECIFIED	1,685,906	1,678,985	6,921	1,685,906	0	
54	TOTAL ACCOUNT 369	454,512,019	394,252,434	60,259,585	454,512,019	0	

SCHEDULE 2.00--ANALYSIS OF GROSS PLANT

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
	ACCOUNT 370--METERS						
55	KWH ONLY	147,009,588	137,475,301	9,534,287	147,009,588	0	(L)
56	DEMAND	55,435,539	271,562	55,162,806	55,434,368	1,171	(M)
57	PEDESTAL METERS	8,647,111	8,647,111	0	8,647,111	0	(F)
58	SUBTOTAL	211,092,237	146,393,973	64,697,093	211,091,066	1,171	
59	ACCESSORIES	124,006,619	85,999,475	38,006,456	124,005,931	688	(N)
60	TOTAL ACCOUNT 370	335,098,856	232,393,448	102,703,549	335,096,997	1,859	
61	ACCOUNT 373	231,318,764	0	231,318,764	231,318,764	0	(F)
62	TOTAL DISTRIBUTION	6,702,574,313	4,324,197,469	2,373,176,878	6,697,374,346	5,199,966	
	GENERAL PLANT						
63	ACCOUNT 389	39,674,065	21,110,273	17,528,330	38,638,603	1,035,462	(O)
64	ACCOUNT 399	18,891,990	7,471,165	10,414,048	17,885,213	1,006,777	(P)
65	POLLUTION CONTROL	4,341,792	1,717,037	2,393,376	4,110,413	231,379	(P)
66	OTHER GENERAL	1,400,787,247	745,348,387	618,879,416	1,364,227,803	36,559,444	(O)
67	TOTAL GENERAL PLANT	1,463,695,094	775,646,862	649,215,170	1,424,862,032	38,833,062	
68	INTANGIBLE PLANT	296,066,451	157,534,737	130,804,612	288,339,349	7,727,102	(O)
69	TOTAL GROSS PLANT	25,941,960,288	12,173,648,717	12,789,665,321	24,963,314,038	978,646,250	

NOTES FOR SCHEDULE 2.00

(A) Total allocated per Schedule 2.60, Demand--Level 1.
(B) Total allocated per Schedule 2.60, Demand--Level 2.
(C) Total allocated per Schedule 2.60, Demand--Level 3.
(D) Jurisdictional totals directly assigned. Within jurisdiction, allocated per Schedule 2.60, Demand--Level 2.
(E) Total allocated per Schedule 2.60, Demand--Level 4.
(F) Direct assignment.
(G) Total allocated per Schedule 2.60, Level 4 Customer Allocator.
(H) Total allocated per Schedule 2.60, Demand--Level 5.
(I) Total allocated per Schedule 2.60, Level 5 Customer Allocator.
(J) Total allocated per Schedule 2.60, Account 368--Network Protectors Allocator.
(K) Total allocated per Schedule 2.60, Account 368--Enclosures Allocator.
(L) Total allocated per Schedule 2.60, Customers with KWH Meters Only.
(M) Total allocated per Schedule 2.60, Customers with KW and KWH Meters.
(N) Total allocated per Subtotal of the balance of Account 370.
(O) Total allocated per Schedule 2.61, Total Salaries & Wages.
(P) Total allocated per Schedule 2.60, Demand--Level 1.

SCHEDULE 2.01--ANALYSIS OF PROVISION FOR
ACCUMULATED DEPRECIATION & AMORTIZATION

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
1	PRODUCTION	5,301,624,698	2,096,619,142	2,922,475,368	5,019,094,510	282,530,188	(A)
	TRANSMISSION						
2	TOTAL COMMON	1,237,619,712	490,095,384	681,805,764	1,171,901,148	65,718,564	(B)
3	LEVEL 2 ASSIGNED	10,619,878	4,338,276	6,047,120	10,385,396	234,482	(C)
4	TOTAL TRANSMISSION	1,248,239,590	494,433,660	687,852,884	1,182,286,544	65,953,046	
	DISTRIBUTION						
5	ACCT 360-SUBS	3,767,357	1,977,822	1,788,226	3,766,048	1,309	(D)
6	ACCT 360-LINES	329,187	282,241	46,946	329,187	0	(E)
7	TOTAL 360	4,096,544	2,260,063	1,835,172	4,095,235	1,309	
8	ACCT 361	28,266,039	13,992,925	14,225,069	28,217,994	48,045	(F)
9	ACCT 362	330,689,269	144,958,419	184,136,333	329,094,752	1,594,517	(G)
10	ACCT 364	497,827,403	381,329,625	116,492,242	497,821,867	5,536	(H)
11	ACCT 365	395,257,586	303,742,405	91,510,890	395,253,295	4,291	(I)
12	ACCT 366	18,630,540	11,172,475	7,457,527	18,630,002	538	(J)
13	ACCT 367	219,073,512	132,005,669	87,061,586	219,067,255	6,257	(K)
14	ACCT 368	489,151,221	313,642,307	175,508,914	489,151,221	0	(L)
15	ACCT 369	213,769,885	185,428,094	28,341,791	213,769,885	0	(M)
16	ACCT 370	168,807,228	117,069,019	51,737,273	168,806,292	936	(N)
17	ACCT 373	117,688,758	0	117,688,758	117,688,758	0	(O)
18	TOTAL DISTRIBUTION	2,483,257,985	1,605,601,001	875,995,555	2,481,596,556	1,661,429	
	GENERAL						
19	ACCOUNT 389	(14,117)	(7,512)	(6,237)	(13,749)	(368)	(P)
20	ACCOUNT 399	11,378,476	4,499,816	6,272,287	10,772,103	606,373	(Q)
21	POLLUTION CONTROL	2,827,255	1,118,087	1,558,501	2,676,588	150,667	(R)
22	OTHER GENERAL	591,053,252	314,495,002	261,132,225	575,627,227	15,426,025	(S)
23	TOTAL GENERAL	605,244,866	320,105,393	268,956,776	589,062,169	16,182,697	
24	TOTAL PROVISION FOR ACCUM DEPR	9,638,367,138	4,516,759,195	4,755,280,583	9,272,039,778	366,327,360	
25	PROVISION FOR AMORTIZATION OF LIMITED TERM ELECTRIC PLANT	154,108,210	81,999,824	68,086,283	150,086,107	4,022,103	(T)
26	TOTAL PROVISION FOR ACCUMULATED DEPRECIATION AND AMORTIZATION	9,792,475,348	4,598,759,019	4,823,366,866	9,422,125,885	370,349,463	

NOTES FOR SCHEDULE 2.01

(A) Total allocated per Schedule 2.00, Production.
(B) Total allocated per Schedule 2.00, Total Substations plus Level 2 Common Lines.
(C) Jurisdictional totals directly assigned. Within jurisdiction, allocated per Schedule 2.00, Level 2 Assigned Lines.
(D) Total allocated per Schedule 2.00, Distribution Substations Total Account 360 Subs.
(E) Total allocated per Schedule 2.00, Distribution Lines Account 360-Cust.
(F) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Substations Total Account 361.
(G) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Substations Total Account 362.
(H) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Lines Total Account 364.
(I) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Lines Total Account 365.
(J) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Lines Total Account 366.
(K) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Lines Total Account 367.
(L) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Total Account 368.
(M) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Total Account 369.
(N) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Total Account 370.
(O) See Supporting Workpapers Schedule 3.30 for total. Direct assignment.
(P) Total allocated per Schedule 2.00, General Plant Account 389.
(Q) Total allocated per Schedule 2.00, General Plant Account 399.
(R) Total allocated per Schedule 2.00, General Plant Pollution Control.
(S) Total allocated per Schedule 2.00, General Plant Other General.
(T) Total allocated per Schedule 2.00, Intangible Plant.

SCHEDULE 2.02--NET PLANT

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
1	PRODUCTION	8,257,270,175	3,265,480,244	4,551,749,712	7,817,229,956	440,040,219	(A)
2	TRANSMISSION	2,672,489,967	1,059,736,603	1,474,390,697	2,534,127,300	138,362,667	(B)
3	DISTRIBUTION	4,219,316,328	2,718,596,468	1,497,181,323	4,215,777,791	3,538,537	(C)
4	GENERAL	858,450,228	455,541,469	380,258,394	835,799,863	22,650,365	(D)
5	INTANGIBLE	141,958,241	75,534,913	62,718,329	138,253,242	3,704,999	(E)
6	TOTAL NET PLANT	16,149,484,940	7,574,889,698	7,966,298,455	15,541,188,153	608,296,787	

NOTES FOR SCHEDULE 2.02

(A) Schedule 2.00, Production minus Schedule 2.01, Production.
(B) Schedule 2.00, Total Transmission minus Schedule 2.01, Total Transmission.
(C) Schedule 2.00, Total Distribution minus Schedule 2.01, Total Distribution.
(D) Schedule 2.00, Total General Plant minus Schedule 2.01, Total General.
(E) Schedule 2.00, Intangible Plant minus Schedule 2.01, Provision for Amortization of Limited Term Electric Plant.

SCHEDULE 2.03--ANALYSIS OF MATERIALS & SUPPLIES

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
	PRODUCTION						
1	FUEL STOCK	230,064,086	72,625,857	143,662,092	216,287,949	13,776,137	(A)
2	PLANT M & S	221,787,197	87,709,582	122,258,299	209,967,881	11,819,316	(B)
3	TOTAL PRODUCTION	451,851,283	160,335,439	265,920,391	426,255,830	25,595,453	
	TRANSMISSION						
4	SUBSTATIONS	82,449,694	32,739,696	45,364,045	78,103,741	4,345,953	(C)
5	LINES	6,059,368	2,399,903	3,345,221	5,745,124	314,244	(D)
6	TOTAL TRANSMISSION	88,509,062	35,139,599	48,709,266	83,848,865	4,660,197	
	DISTRIBUTION						
7	ACCT 361	25,980	12,861	13,075	25,936	44	(E)
8	ACCT 362	16,535,906	7,248,555	9,207,619	16,456,174	79,732	(F)
9	ACCT 364	19,944,993	15,277,618	4,667,153	19,944,771	222	(G)
10	ACCT 365	25,471,664	19,574,134	5,897,254	25,471,388	276	(H)
11	ACCT 366	13,990	8,390	5,600	13,990	0	(I)
12	ACCT 367	6,829,679	4,115,315	2,714,169	6,829,484	195	(J)
13	ACCT 368	9,543,714	6,119,400	3,424,314	9,543,714	0	(K)
14	ACCT 369 H.P. PANELS	29,174	29,174	0	29,174	0	(L)
15	ACCT 369 OTHER	135,898	117,846	18,052	135,898	0	(M)
16	TOTAL ACCT 369	165,072	147,020	18,052	165,072	0	
17	ACCT 370	1,282,266	889,261	392,998	1,282,259	7	(N)
18	ACCT 373	2,427,405	0	2,427,405	2,427,405	0	(L)
19	TOTAL DISTRIBUTION	82,240,669	53,392,554	28,767,639	82,160,193	80,476	
20	CUSTOMER ACCOUNTING	80,551	69,095	11,454	80,549	2	(O)
21	CUSTOMER ASSISTANCE	7,948	2,448	5,500	7,948	0	(P)
22	SALES	85	65	20	85	0	(Q)
23	SUBTOTAL OF PLANT M & S ONLY	392,625,512	176,313,343	199,752,178	376,065,521	16,559,991	
24	UNCLASSIFIED M & S	1,915,519	860,187	974,540	1,834,727	80,792	(R)
25	UNDISTRIBUTED STORES	438	197	222	419	19	(R)
26	TOTAL MATERIALS AND SUPPLIES	624,605,555	249,799,584	344,389,032	594,188,616	30,416,939	

NOTES FOR SCHEDULE 2.03

(A) Total allocated per Schedule 2.60, Energy--Level 1.
(B) Total allocated per Schedule 2.60, Demand--Level 1.
(C) Total allocated per Schedule 2.00, Transmission Total Substations.
(D) Total allocated per Schedule 2.00, Transmission Total Lines.
(E) Total allocated per Schedule 2.00, Distribution Substations Total Account 361.
(F) Total allocated per Schedule 2.00, Distribution Substations Total Account 362.
(G) Total allocated per Schedule 2.00, Distribution Lines Total Account 364.
(H) Total allocated per Schedule 2.00, Distribution Lines Total Account 365.
(I) Total allocated per Schedule 2.00, Distribution Lines Total Account 366.
(J) Total allocated per Schedule 2.00, Distribution Lines Total Account 367.
(K) Total allocated per Schedule 2.00, Distribution Total Account 368.
(L) Direct assignment.
(M) Total allocated per Schedule 2.00, Distribution Total Account 369 minus Account 369--Housepower Panels.
(N) Total allocated per Schedule 2.00, Distribution Total Account 370.
(O) Total allocated per Schedule 2.20, Customer Accounting Subtotal.
(P) Total allocated per Schedule 2.20, Customer Assistance.
(Q) Total allocated per Schedule 2.20, Sales.
(R) Allocated per Subtotal of Plant M & S Only.

SCHEDULE 2.04--ANALYSIS OF OTHER RATE BASE ITEMS

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
	PLANT HELD FOR FUTURE USE						
1	PRODUCTION	42,821,952	16,934,681	23,605,236	40,539,917	2,282,035	(A)
2	TRANSMISSION	1,576,299	625,059	869,631	1,494,690	81,609	(B)
3	DISTRIBUTION	4,821,497	3,106,595	1,710,859	4,817,454	4,043	(C)
4	GENERAL	6,753,361	3,583,710	2,991,463	6,575,173	178,188	(D)
5	TOTAL PLANT HELD FUTURE USE	55,973,108	24,250,044	29,177,189	53,427,233	2,545,875	
6	SEGCO/AEC DEPOSIT	(36,778,679)	(11,610,170)	(22,966,218)	(34,576,388)	(2,202,291)	(E)
7	UNAMORT LEASEHOLD IMPROVEMENTS	611,796	325,531	270,297	595,828	15,968	(F)
	CONSTRUCTION WORK IN PROGRESS						
8	PRODUCTION	337,235,858	133,365,752	185,898,388	319,264,140	17,971,718	(G)
9	TRANSMISSION	67,233,763	26,651,344	37,078,756	63,730,100	3,503,663	(H)
10	DISTRIBUTION	42,810,776	27,619,574	15,157,989	42,777,563	33,213	(I)
11	GENERAL	44,060,799	23,444,420	19,466,426	42,910,846	1,149,953	(J)
12	TOTAL CONST WORK IN PROGRESS	491,341,197	211,081,091	257,601,559	468,682,650	22,658,547	
13	NUCLEAR FUEL	335,858,911	106,022,812	209,725,014	315,747,826	20,111,085	(E)
14	AVERAGE DAILY BANK BALANCES	106,899,766	42,811,345	58,955,470	101,766,815	5,132,951	(K)
15	ELECT PLANT ACQUISITION ADJ	3,080,386	1,698,193	1,382,088	3,080,281	105	(L)
16	CUSTOMER ADVANCES FOR CONST.	(328,418)	0	(328,418)	(328,418)	0	(M)
17	CUSTOMER DEPOSITS	(88,437,048)	(45,063,071)	(43,373,976)	(88,437,048)	0	(M)
18	TOTAL OTHER RATE BASE ITEMS	868,221,019	329,515,774	490,443,005	819,958,779	48,262,240	

NOTES FOR SCHEDULE 2.04

(A) Total allocated per Schedule 2.02, Production.
(B) Total allocated per Schedule 2.02, Transmission.
(C) Total allocated per Schedule 2.02, Distribution.
(D) Total allocated per Schedule 2.02, General.
(E) Total allocated per Schedule 2.60, Energy--Level 1.
(F) Total allocated per Schedule 2.61, Total Salaries & Wages.
(G) Total allocated per Schedule 2.00, Production.
(H) Total allocated per Schedule 2.00, Total Transmission.
(I) Total allocated per Schedule 2.00, Total Distribution.
(J) Total allocated per Schedule 2.00, Other General.
(K) Total allocated per Schedule 2.20, Total O&M Expense.
(L) Total allocated per Schedule 2.60, Demand--Level 4.
(M) Direct assignment.

SCHEDULE 2.10--ANALYSIS OF REVENUES

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
1	REVENUES FROM SALES	5,605,534,385	2,292,340,648	3,102,861,568	5,395,202,216	210,332,169	(A)
	NON-TERRITORIAL SALES FOR RESALE						
2	DEMAND	0	0	0	0	0	(B)
3	ENERGY	141,203,480	44,574,640	88,173,637	132,748,277	8,455,203	(C)
4	TOTAL NON-TERR SALES FOR RESALE	141,203,480	44,574,640	88,173,637	132,748,277	8,455,203	
	OTHER OPERATING REVENUES						
5	RENEW ENERGY CRED ALLOW--ACCT 411	385,533	121,704	240,743	362,447	23,086	(C)
6	TRANS TARIFF REFUND--ACCT 449	9,323,373	3,687,088	5,139,430	8,826,518	496,855	(D)
7	PROVISION FOR RATE REFUND APC--ACCT 449	(72,722,935)	(24,093,420)	(48,629,515)	(72,722,935)	0	(E)
8	MISC SERV REVENUES--ACCT 451	29,817,353	29,817,353	0	29,817,353	0	(A)
9	WATER & WATER RIGHTS--ACCT 453	777,757	257,674	520,083	777,757	0	(E)
	RENT FROM ELEC PROP--ACCT 454						
10	-100 POLE ATTACHMENT RENTS	26,243,386	22,500,755	3,742,595	26,243,350	36	(F)
11	-320 OFFICE BLDG RENT--ASSOC	8,932,971	3,532,697	4,924,224	8,456,921	476,050	(B)
12	-310 OFFICE BLDG RENT--FACILITIES	577,633	307,355	255,203	562,558	15,075	(G)
13	-321 OTHER BLDG RENTS--FAC ASSO	12,417,215	4,910,603	6,844,884	11,755,487	661,728	(B)
14	-400 MICROWAVE EQUIPMENT	6,924,034	3,684,226	3,059,096	6,743,322	180,712	(G)
15	-904 LEASED PROP (CUST PREM)	499,881	0	499,881	499,881	0	(A)
16	-510 JOINT USE FACIL--PROD	11,171,223	4,417,852	6,158,042	10,575,894	595,329	(B)
17	--TRAN	466,617	184,564	258,025	442,589	24,028	(H)
18	-906 MISC RENTS--ASSOC CO	0	0	0	0	0	(H)
19	-900 OTH MISC RENTS--PARKING	231,231	123,037	102,160	225,197	6,034	(G)
20	--PROJ LAND	1,538,452	608,407	848,059	1,456,466	81,986	(B)
21	TOTAL ACCOUNT 454	69,002,643	40,269,496	26,692,169	66,961,665	2,040,978	

SCHEDULE 2.10--ANALYSIS OF REVENUES

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
	OTHER ELEC REV--ACCT 456						
22	-300 PROFIT (LOSS)-M&S SALES -1	303,570	197,536	105,926	303,462	108	(I)
23	-305 PROFIT (LOSS)-M&S SALES -2	0	0	0	0	0	(B)
24	-306 PROFIT (LOSS)-M&S SALES -3	0	0	0	0	0	(B)
25	-530 TRANS OF AMEA ELECTRIC	764,287	302,250	421,307	723,557	40,730	(D)
26	-535 TRANS OF FPL ELECTRIC	0	0	0	0	0	(D)
27	-540 TRANS OF JEA ELECTRIC	0	0	0	0	0	(D)
28	-545 TRANS OF ENTERGY ELEC	0	0	0	0	0	(D)
29	-546 POINT-TO-POINT TRANS SERV AGREE	35,186,923	13,915,277	19,396,491	33,311,768	1,875,155	(D)
30	-547 POINT-TO-POINT TRANS SERV ANCILL	7,096,026	2,806,245	3,911,624	6,717,869	378,157	(D)
31	-548 TRANS FIRM	19,812,693	7,835,272	10,921,578	18,756,850	1,055,843	(D)
32	-549 REV - TRANSMISSION	1,975,175	781,117	1,088,798	1,869,915	105,260	(D)
33	-550 AMEA TRANS SERV	692,878	274,009	381,944	655,953	36,925	(D)
34	-600 OPERATION OF REC. FAC.	0	0	0	0	0	(B)
35	-700 PROFIT--NATL RESOURCES	0	0	0	0	0	(B)
36	-701 PROFIT--TIMBER SALES	1,124,863	444,846	620,071	1,064,917	59,946	(B)
37	-750 GOODYEAR STEAM	2,337,028	924,217	1,288,267	2,212,484	124,544	(B)
38	-751 OLIN STEAM	30,878,656	12,211,498	17,021,596	29,233,094	1,645,562	(B)
39	-900 MISC--NON-ASSOC	4,125,704	2,684,611	1,439,607	4,124,218	1,486	(I)
40	-905 MISC--AEC	405,772	215,908	179,273	395,181	10,591	(G)
41	-950 MISC--ASSOCIATED CO	(111,200)	(43,975)	(61,298)	(105,273)	(5,927)	(B)
42	-953 RETURNED CHECK CHARGE	956,204	827,888	128,316	956,204	0	(J)
43	-960 MISC FLEET SVC - GARAGE- MAINT SERV	408,157	217,177	180,327	397,504	10,653	(G)
44	-970 MISC - REMANUFACTURE	0	0	0	0	0	(G)
45	TOTAL ACCOUNT 456	105,956,736	43,593,876	57,023,827	100,617,703	5,339,033	
46	TOTAL OTHER OPERATING REVENUES	142,540,461	93,653,772	40,986,737	134,640,509	7,899,952	
47	TOTAL REVENUES	5,889,278,326	2,430,569,060	3,232,021,942	5,662,591,002	226,687,324	

NOTES FOR SCHEDULE 2.10

(A) Direct assignment.
(B) Total allocated per Schedule 2.60, Demand--Level 1.
(C) Total allocated per Schedule 2.60, Energy--Level 1.
(D) Total allocated per Schedule 2.60, Demand--Level 2.
(E) Total allocated per Schedule 2.60, Retail MWH Sales.
(F) Total allocated per Schedule 2.60, Level 4 Customer Allocator.
(G) Total allocated per Schedule 2.61, Total Salaries & Wages.
(H) Total allocated per Schedule 2.20, Total Transmission.
(I) Total allocated per Schedule 2.20, Total Distribution.
(J) Total allocated per Schedule 2.60, No. of RESI, COMM, and IND Customers.

SCHEDULE 2.20--ANALYSIS OF OPERATION AND MAINTENANCE EXPENSES

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
	PRODUCTION						
1	DEMAND	789,551,953	312,241,970	435,233,775	747,475,745	42,076,208	(A)
2	ENERGY	1,550,376,106	489,417,519	968,122,742	1,457,540,261	92,835,845	(B)
3	EPRI DUES	2,854,557	945,727	1,908,830	2,854,557	0	(C)
4	TOTAL PRODUCTION	2,342,782,615	802,605,215	1,405,265,347	2,207,870,562	134,912,053	
	TRANSMISSION						
5	SUBSTATIONS	23,377,880	9,283,050	12,862,573	22,145,623	1,232,257	(D)
6	LINES	57,567,676	22,799,205	31,779,791	54,578,996	2,988,680	(E)
7	EPRI DUES	1,020,672	338,152	682,520	1,020,672	0	(C)
8	TOTAL TRANSMISSION	81,966,228	32,420,407	45,324,884	77,745,291	4,220,937	
	DISTRIBUTION						
	OPERATION EXPENSE						
9	582 STATION EXP	2,597,829	1,138,765	1,446,539	2,585,304	12,525	(F)
	583 O.H. LINE EXP						
10	INSTALL & REMOVE TRANSFORMER	3,662,498	2,348,383	1,314,115	3,662,498	0	(G)
11	OTHER O.H. LINE EXP	961,374	747,955	213,409	961,364	10	(H)
12	TOTAL ACCT 583	4,623,872	3,096,338	1,527,524	4,623,862	10	
	584 UGRD LINE EXP						
13	INSTALL & REMOVE TRANSFORMER	816,236	523,368	292,868	816,236	0	(G)
14	OTHER UGRD LINE EXP	3,956,220	2,587,350	1,368,779	3,956,129	91	(I)
15	TOTAL ACCT 584	4,772,455	3,110,717	1,661,647	4,772,364	91	
16	585 STREET LIGHTING	6,139,138	0	6,139,138	6,139,138	0	(J)
17	586 METER EXP	13,126,645	9,103,422	4,023,150	13,126,572	73	(K)
18	587 CUST INST EXP	3,172,777	3,125,186	47,592	3,172,777	0	(J)
19	SUBTOTAL	34,432,716	19,574,427	14,845,590	34,420,017	12,699	
20	580 OPER,SUPERV,& ENGR	20,409,306	11,602,351	8,799,427	20,401,778	7,528	(L)
	588 MISC DIST EXP						
21	EPRI DUES	378,999	125,564	253,435	378,999	0	(C)
22	OTHER	18,879,082	10,732,445	8,139,674	18,872,119	6,963	(L)
23	TOTAL ACCT 588	19,258,081	10,858,009	8,393,109	19,251,118	6,963	
24	589 RENTS	17,754	10,092	7,655	17,747	7	(L)
25	TOTAL DIST OPERATION EXP	74,117,858	42,044,880	32,045,781	74,090,661	27,197	

SCHEDULE 2.20--ANALYSIS OF OPERATION AND MAINTENANCE EXPENSES

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
	MAINTENANCE EXPENSE						
26	591 MAINT OF STRUCTURES	306,679	151,820	154,338	306,158	521	(M)
27	592 MAINT OF STATION EQPT	6,680,173	2,928,269	3,719,694	6,647,963	32,210	(F)
28	593 MAINT OF O.H. LINES	72,013,780	56,027,245	15,985,829	72,013,074	706	(H)
29	594 MAINT OF UGRD LINES	5,175,711	3,384,892	1,790,700	5,175,592	119	(I)
30	595 MAINT OF LINE XFORMER	4,541,263	2,911,844	1,629,419	4,541,263	0	(N)
31	596 MAINT OF ST LIGHTS	3,775,367	0	3,775,367	3,775,367	0	(J)
32	597 MAINT OF METERS	1,971,267	1,367,088	604,168	1,971,256	11	(K)
33	SUBTOTAL	94,464,240	66,771,158	27,659,515	94,430,673	33,567	
34	590 MAINT SUPERV & ENGR	15,691,206	11,091,181	4,594,449	15,685,630	5,576	(O)
35	598 MAINT MISC DIST PLANT	2,493	1,762	730	2,492	1	(O)
36	TOTAL DIST MAINTENANCE EXP	110,157,939	77,864,101	32,254,694	110,118,795	39,144	
37	TOTAL DISTRIBUTION	184,275,797	119,908,980	64,300,475	184,209,456	66,341	
	CUSTOMER ACCOUNTING						
38	METER READING	3,049,836	2,664,207	385,538	3,049,745	91	(P)
39	CUST RECORDS/COLLECTIONS	76,073,133	65,205,951	10,864,948	76,070,899	2,234	(Q)
40	SUBTOTAL	79,122,969	67,870,158	11,250,486	79,120,644	2,325	
41	SUPERVISION	5,834,186	5,004,452	829,562	5,834,014	172	(R)
42	UNCOLLECTIBLE ACCOUNTS	9,986,242	8,688,031	1,298,211	9,986,242	0	(J)
43	TOTAL CUSTOMER ACCOUNTING	94,943,397	81,562,640	13,378,259	94,940,900	2,497	
	CUSTOMER ASSISTANCE						
44	EPRI DUES	427,160	141,519	285,641	427,160	0	(C)
45	OTHER	41,933,584	12,909,238	29,024,346	41,933,584	0	(J)
46	TOTAL CUSTOMER ASSISTANCE	42,360,744	13,050,757	29,309,987	42,360,744	0	
47	SALES	6,972,260	5,327,322	1,644,938	6,972,260	0	(J)

SCHEDULE 2.20--ANALYSIS OF OPERATION AND MAINTENANCE EXPENSES

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
	ADMINISTRATIVE & GENERAL EXP						
	924 PROPERTY INSURANCE						
48	PRODUCTION	6,581,953	2,602,946	3,628,246	6,231,192	350,761	(S)
49	TRANSMISSION	513,898	203,265	284,170	487,435	26,463	(T)
50	DISTRIBUTION	107,956	70,247	37,670	107,917	39	(U)
51	GENERAL	718,925	382,534	317,628	700,162	18,763	(V)
52	TOTAL PROPERTY INSURANCE	7,922,733	3,258,993	4,267,714	7,526,707	396,026	
	928 REG COMMISSION EXP						
53	WHOLESALE DOCKET	0	0	0	0	0	(W)
54	RETAIL DOCKET	53,148	22,581	30,567	53,148	0	(X)
	NON-DOCKET ITEMS:						
55	WHOLESALE	1,517,294	0	0	0	1,517,294	(Y)
56	RETAIL	9,686,407	4,115,609	5,570,798	9,686,407	0	(Z)
57	FERC FEE & CHARGES	2,719,386	1,075,428	1,499,039	2,574,467	144,919	(S)
58	TOTAL NON-DOCKET	13,923,087	5,191,037	7,069,837	12,260,874	1,662,213	
59	TOTAL REGULATORY COMM EXP	13,976,235	5,213,618	7,100,404	12,314,022	1,662,213	
60	EPRI DUES	0	0	0	0	0	(C)
61	SUBTOTAL	21,898,968	8,472,611	11,368,118	19,840,729	2,058,239	
62	OTHER A&G	365,222,697	194,332,259	161,358,414	355,690,673	9,532,024	(V)
63	TOTAL ADMIN & GENERAL	387,121,665	202,804,870	172,726,532	375,531,402	11,590,263	
64	TOTAL O&M EXPENSE	3,140,422,706	1,257,680,191	1,731,950,423	2,989,630,615	150,792,091	

NOTES FOR SCHEDULE 2.20

(A) Total allocated per Schedule 2.00, Production.
(B) Total allocated per Schedule 2.60, Energy--Level 1.
(C) Total allocated per Schedule 2.60, Retail MWH Sales.
(D) Total allocated per Schedule 2.00, Transmission Total Substations.
(E) Total allocated per Schedule 2.00, Transmission Total Lines.
(F) Total allocated per Schedule 2.00, Distribution Substations Total Account 362.
(G) Total includes Installing & Removing Transformers and First Cost of Installing Transformers. Total allocated per Schedule 2.00, Distribution Total Account 368.
(H) Total allocated per Schedule 2.60, Account 583-Other Allocator.
(I) Total allocated per Schedule 2.60, Account 584-Other Allocator.
(J) Direct assignment.
(K) Total allocated per Schedule 2.00, Distribution Total Account 370.
(L) Total allocated per Subtotal of Distribution Operation Expense.
(M) Total allocated per Schedule 2.00, Distribution Substations Total Account 361.
(N) Total allocated per Schedule 2.00, Distribution Total Account 368.
(O) Total allocated per Subtotal of Distribution Maintenance Expense.
(P) Total allocated per Schedule 2.60, Number of Metered Customers.
(Q) Total allocated per Schedule 2.60, Total Number of Customers.
(R) Total allocated per Subtotal of Customer Accounting.
(S) Total allocated per Production O&M Demand.
(T) Total allocated per Total Transmission O&M.
(U) Total allocated per Total Distribution O&M.
(V) Total allocated per Schedule 2.61, Total Salaries & Wages.
(W) Total allocated to wholesale customers only per Schedule 2.10, Revenues from Sales.
(X) Total allocated to retail customers only per Schedule 2.10, Revenues from Sales.
(Y) Total includes FERC Matters and Minor Federal Commission Expense. Total allocated to wholesale customers only per Schedule 2.10, Revenues from Sales.
(Z) Total includes APSC Matters, APSC Fee, and Minor State Commission Expense. Total allocated to retail customers only per Schedule 2.10, Revenues from Sales.

SCHEDULE 2.30--ANALYSIS OF DEPRECIATION AND AMORTIZATION EXPENSE

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
1	PRODUCTION	371,244,801	146,815,173	204,645,529	351,460,702	19,784,099	(A)
2	TRANSMISSION	88,015,729	34,889,279	48,539,805	83,429,084	4,586,645	(B)
	DISTRIBUTION						
3	ACCT 360-SUBS	34,643	18,188	16,443	34,631	12	(C)
4	ACCT 360-LINES	3,027	2,595	432	3,027	0	(D)
5	TOTAL ACCT 360	37,670	20,783	16,875	37,658	12	
6	ACCT 361	2,482,890	1,229,139	1,249,531	2,478,670	4,220	(E)
7	ACCT 362	29,928,338	13,119,157	16,664,872	29,784,029	144,309	(F)
8	ACCT 364	33,330,954	25,531,098	7,799,486	33,330,584	370	(G)
9	ACCT 365	36,642,056	28,158,210	8,483,448	36,641,658	398	(H)
10	ACCT 366	996,113	597,356	398,729	996,085	28	(I)
11	ACCT 367	17,506,706	10,548,899	6,957,307	17,506,206	500	(J)
12	ACCT 368	42,305,164	27,125,946	15,179,218	42,305,164	0	(K)
13	ACCT 369	12,779,758	11,085,407	1,694,351	12,779,758	0	(L)
14	ACCT 370	19,004,006	13,179,414	5,824,487	19,003,901	105	(M)
15	ACCT 373	14,606,695	0	14,606,695	14,606,695	0	(N)
16	TOTAL DISTRIBUTION	209,620,350	130,595,409	78,874,999	209,470,408	149,942	
17	GENERAL	30,325,265	16,070,079	13,450,631	29,520,710	804,555	(O)
18	TOTAL DEPRECIATION EXPENSE	699,206,146	328,369,941	345,510,964	673,880,905	25,325,241	
19	AMORTIZATION OF LIMITED TERM ELECTRIC PLANT	24,999,080	13,301,823	11,044,800	24,346,623	652,457	(P)
20	TOTAL DEPRECIATION & AMORTIZATION	724,205,225	341,671,763	356,555,764	698,227,527	25,977,698	

NOTES FOR SCHEDULE 2.30

(A) Total allocated per Schedule 2.00, Production.
(B) Total allocated per Schedule 2.00, Total Transmission.
(C) Total allocated per Schedule 2.00, Distribution Substations Total Account 360 Subs.
(D) Total allocated per Schedule 2.00, Distribution Lines Account 360-Cust.
(E) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Substations Total Account 361.
(F) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Substations Total Account 362.
(G) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Lines Total Account 364.
(H) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Lines Total Account 365.
(I) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Lines Total Account 366.
(J) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Lines Total Account 367.
(K) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Total Account 368.
(L) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Total Account 369.
(M) See Supporting Workpapers Schedule 3.30 for total. Total allocated per Schedule 2.00, Distribution Total Account 370.
(N) See Supporting Workpapers Schedule 3.30 for total. Direct assignment.
(O) Total allocated per Schedule 2.00, Total General Plant.
(P) Total allocated per Schedule 2.00, Intangible Plant.

SCHEDULE 2.40--ANALYSIS OF TAXES OTHER THAN INCOME TAXES

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
1	PAYROLL TAXES	31,065,944	16,631,739	13,643,666	30,275,405	790,539	(A)
2	REAL & PERSONAL PROPERTY TAXES	112,113,246	54,615,994	53,704,274	108,320,268	3,792,978	(B)
3	LOCAL & MISCELLANEOUS TAXES	6,247,634	2,927,264	3,083,843	6,011,107	236,527	(C)
4	CORPORATE FRANCHISE TAX	15,010	7,033	7,408	14,441	569	(C)
5	HYDRO GENERATION TAX	1,187,330	374,812	741,420	1,116,232	71,098	(D)
6	ENVIRONMENTAL TAX	0	0	0	0	0	(E)
	REVENUE TAXES						
7	STATE PUB UTIL LICENSE TAX	116,130,750	49,332,342	66,798,407	116,130,750	0	(F)
8	MUNI PUB UTIL LICENSE TAX	113,531,773	48,228,297	65,303,476	113,531,773	0	(F)
9	TOTAL REVENUE TAXES	229,662,523	97,560,640	132,101,883	229,662,523	0	
10	TOTAL TAXES OTHER THAN INC TAX	380,291,686	172,117,481	203,282,494	375,399,975	4,891,711	

NOTES FOR SCHEDULE 2.40

(A) Total allocated per Schedule 2.61, Salaries & Wages Excluding Fuel Handling.
(B) Total allocated per Schedule 2.60, Real & Personal Property Tax Allocator.
(C) Total allocated per Schedule 2.60, Gross Plant Less Intangible.
(D) Total allocated per Schedule 2.60, Energy--Level 1.
(E) Total allocated per Schedule 2.61, Total Salaries & Wages.
(F) Direct assignment.

SCHEDULE 2.50--ANALYSIS OF OTHER
AMORTIZATION AND ACCRETION

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
1	AMORTIZATION OF PLANT ACQUISITION ADJ	551,711	304,154	247,538	551,692	19	(A)
	AMORTIZATION OF PROPERTY LOSSES						
2	PRODUCTION	(87,896,757)	(34,760,292)	(48,452,337)	(83,212,629)	(4,684,128)	(B)
3	TRANSMISSION	(135,384)	(53,667)	(74,662)	(128,329)	(7,055)	(C)
4	DISTRIBUTION	1,321,574	852,621	467,928	1,320,549	1,025	(D)
5	GENERAL	(874,977)	(463,671)	(388,092)	(851,763)	(23,214)	(E)
6	TOTAL AMORT OF PROPERTY LOSSES	(87,585,544)	(34,425,009)	(48,447,163)	(82,872,172)	(4,713,372)	
	ACCRETION						
7	PRODUCTION	72,604,139	28,712,560	40,022,413	68,734,973	3,869,166	(B)
8	TRANSMISSION	106,052	42,039	58,487	100,526	5,526	(C)
9	DISTRIBUTION	86,817	56,012	30,738	86,750	67	(D)
10	GENERAL	578,185	306,393	256,452	562,845	15,340	(E)
11	TOTAL ACCRETION	73,375,192	29,117,003	40,368,090	69,485,093	3,890,099	
12	TOTAL OTHER AMORTIZATION AND ACCRETION	(13,658,640)	(5,003,851)	(7,831,535)	(12,835,386)	(823,254)	

NOTES FOR SCHEDULE 2.50

(A) Total allocated per Schedule 2.60, Demand--Level 4.
(B) Total allocated per Schedule 2.00, Production.
(C) Total allocated per Schedule 2.00, Transmission.
(D) Total allocated per Schedule 2.00, Distribution.
(E) Total allocated per Schedule 2.00, Total General Plant.

SCHEDULE 2.60--LISTING OF ALLOCATORS NOT SHOWN IN OTHER SCHEDULES

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
1	DEMAND--LEVEL 1	9,703,478	3,837,408	5,348,959	9,186,368	517,110	(A)
2	DEMAND--LEVEL 2	9,703,478	3,837,408	5,348,959	9,186,368	517,110	(A)
3	DEMAND--LEVEL 3	6,810,760	3,704,789	3,105,742	6,810,531	229	(A)
4	DEMAND--LEVEL 4	6,668,850	3,676,487	2,992,137	6,668,623	227	(A)
5	DEMAND--LEVEL 5	5,930,715	3,587,776	2,342,940	5,930,715	0	(A)
6	ENERGY--LEVEL 1	61,819,215	19,514,882	38,602,625	58,117,507	3,701,708	(B)
7	TOTAL NUMBER OF CUSTOMERS	1,464,553	1,255,339	209,171	1,464,510	43	(C)
8	LEVEL 4 CUSTOMER ALLOCATOR	1,464,144	1,255,339	208,803	1,464,142	2	(D)
9	LEVEL 5 CUSTOMER ALLOCATOR	1,448,010	1,255,339	192,671	1,448,010	0	(E)
10	ACCT 368 --NETWK PROT ALLOCATOR	194,191	0	194,191	194,191	0	(F)
11	ACCT 368 --ENCLOSURES ALLOCATOR	192,671	0	192,671	192,671	0	(G)
12	NO. OF RESI, COMM, & IND CUST	1,449,908	1,255,339	194,569	1,449,908	0	(C)
13	CUSTOMERS WITH KWH METERS ONLY	1,341,904	1,254,875	87,029	1,341,904	0	(H)
14	CUSTOMERS WITH KW & KWH METERS	94,719	464	94,253	94,717	2	(H)
15	NUMBER OF METERED CUSTOMERS	1,437,042	1,255,339	181,660	1,436,999	43	(H)
16	RETAIL MWH SALES	54,952,074	18,205,858	36,746,216	54,952,074	0	(I)
17	REAL & PERS PROP TAX ALLOCATOR	13,214,635,617	6,437,512,788	6,330,049,626	12,767,562,413	447,073,203	(J)
18	ACCOUNT 583--OTHER ALLOCATOR	2,729,942,533	2,123,915,175	606,000,604	2,729,915,779	26,754	(K)
19	ACCOUNT 584--OTHER ALLOCATOR	812,136,018	531,133,252	280,984,084	812,117,336	18,682	(L)
20	GROSS PLANT LESS INTANGIBLE	25,645,893,837	12,016,113,980	12,658,860,709	24,674,974,688	970,919,148	(M)

NOTES FOR SCHEDULE 2.60

(A) See Supporting Workpapers Schedule 3.61, Demand Line Allocator.
(B) See Supporting Workpapers Schedule 3.62, Energy Line Allocator.
(C) See Supporting Workpapers Schedule 3.40, Average Number of Customers.
(D) From Supporting Workpapers Schedule 3.40, Average Number of Customers: number of customers at Level 4, Level 5 Common, and Level 5 Customer Subs.
(E) From Supporting Workpapers Schedule 3.40, Average Number of Customers: number of customers at Level 5 Common excluding Street Lighting.
(F) From Supporting Workpapers Schedule 3.40, Average Number of Customers: number of Commercial and Industrial customers at Levels 4 and 5 Common.
(G) From Supporting Workpapers Schedule 3.40, Average Number of Customers: number of Commercial and Industrial customers at Level 5 Common.
(H) Direct assignment.
(I) See Supporting Workpapers Schedule 3.60, Energy and Demand Sales.
(J) Sum of Net Plant, Plant Held for Future Use, and Materials & Supplies excluding Fuel Stock, less Net Production Pollution Control Investment.
(K) From Schedule 2.00, Analysis of Gross Plant: sum of Account 364, Account 365, and Unspecified Overhead in Account 369.
(L) From Schedule 2.00, Analysis of Gross Plant: sum of Account 366, Account 367, and Unspecified Underground in Account 369.
(M) See Schedule 2.00.

SCHEDULE 2.61--ANALYSIS OF SALARIES & WAGES

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
1	PRODUCTION	141,631,208	56,010,511	78,072,994	134,083,505	7,547,703	(A)
2	TRANSMISSION	18,119,165	7,166,741	10,019,359	17,186,100	933,065	(B)
3	DISTRIBUTION	75,953,647	49,423,334	26,502,969	75,926,303	27,344	(C)
4	CUSTOMER ACCOUNTING	58,345,142	50,047,338	8,296,089	58,343,427	1,715	(D)
5	CUSTOMER ASSISTANCE	29,851,153	9,196,725	20,654,428	29,851,153	0	(E)
6	SALES	2,156,551	1,647,764	508,787	2,156,551	0	(F)
7	SUBTOTAL	326,056,865	173,492,412	144,054,626	317,547,038	8,509,827	
8	ADMIN & GENERAL	56,985,235	30,321,416	25,176,549	55,497,965	1,487,270	(G)
9	TOTAL SALARIES & WAGES	383,042,101	203,813,829	169,231,175	373,045,004	9,997,097	
10	FUEL HANDLING	8,970,305	3,547,463	4,944,803	8,492,266	478,039	(H)
11	S&W EXCLUDING FUEL HANDLING	374,071,796	200,266,366	164,286,372	364,552,738	9,519,058	

NOTES FOR SCHEDULE 2.61

(A) Total allocated per Schedule 2.20, Production Demand.
(B) Total allocated per Schedule 2.20, Total Transmission.
(C) Total allocated per Schedule 2.20, Total Distribution.
(D) Total allocated per Schedule 2.20, Customer Accounting Subtotal.
(E) Total allocated per Schedule 2.20, Total Customer Assistance.
(F) Total allocated per Schedule 2.20, Sales.
(G) Total allocated per Subtotal of Salaries & Wages.
(H) Total allocated per Schedule 2.20, Production Demand.

SCHEDULE 2.70--ANALYSIS OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

LINE (1)	LINE DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)	NOTES (8)
1	PRODUCTION	23,786,606	9,406,823	13,112,164	22,518,987	1,267,619	(A)
2	TRANSMISSION	4,278,752	1,696,090	2,359,690	4,055,780	222,972	(B)
3	DISTRIBUTION	4,427,715	2,856,561	1,567,719	4,424,280	3,435	(C)
4	GENERAL	5,720,590	3,031,477	2,537,341	5,568,818	151,772	(D)
5	NUCLEAR FUEL	679,032	214,356	424,016	638,372	40,660	(E)
6	TOTAL ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	38,892,695	17,205,307	20,000,930	37,206,237	1,686,458	

NOTES FOR SCHEDULE 2.70

(A) Total allocated per Schedule 2.00, Production.
(B) Total allocated per Schedule 2.00, Total Transmission.
(C) Total allocated per Schedule 2.00, Total Distribution.
(D) Total allocated per Schedule 2.00, Total General Plant.
(E) Total allocated per Schedule 2.60, Energy--Level 1.

ALABAMA POWER COMPANY
RETAIL COST OF SERVICE
TWELVE MONTHS ENDED DECEMBER 31, 2016

SCHEDULE 3.20--ANALYSIS OF PRODUCTION OPERATION & MAINTENANCE EXPENSE

LINE (1)	LINE DESCRIPTION (2)	MW-HOURS (3)	TOTAL (4)	ENERGY (5)	DEMAND (6)	OTHER (7)	NOTES (8)
	GENERATION						
1	STEAM FUEL (501)	32,285,272	894,249,632	894,249,632	0	0	
2	OTHER	0	377,625,172	215,931	377,409,241	0	
3	NUCLEAR FUEL (518)	13,687,256	106,527,079	106,527,079	0	0	
4	OTHER	0	240,284,984	0	240,284,984	0	
5	HYDRO (536)	3,200,018	419,857	419,857	0	0	
6	OTHER	0	38,661,485	0	38,661,485	0	
7	OTHER FUEL (547)	11,024,144	244,656,593	244,656,593	0	0	
8	OTHER	0	34,568,544	0	34,568,544	0	
9	TOTAL GENERATION EXPENSE	60,196,690	1,936,993,346	1,246,069,092	690,924,254	0	
	PURCHASED POWER (555)						
	ASSOCIATED COMPANIES						
10	FIXED PAYMENT	-----	461,381	0	461,381	0	
11	MONTH-END ADJUSTMENT	0	0	0	0	0	
12	INTERCHANGE ENERGY	3,742,065	112,205,760	112,205,760	0	0	
13	POOL ENERGY	0	0	0	0	0	
14	HYDRO REGULATION CHARGE	-----	0	0	0	0	
15	HYDRO OPTIMIZATION CHARGE	-----	0	0	0	0	
16	TRANS FACILITIES CHG & EMISSIONS ALLOW	-----	178,300	178,300	0	0	
17	SEGCO PURCHASES & HARRIS PPA	197,271	55,165,791	13,054,355	42,111,436	0	
18	TOTAL ASSOCIATED COMPANIES	3,939,336	168,011,231	125,438,415	42,572,817	0	
	OTHER NET TRANSACTIONS						
19	NON-ASSOCIATED COMPANIES	2,086,352	175,161,715	136,637,250	38,524,465	0	
20	INTERCHANGE TRANSACTIONS	887,086	0	0	0	0	(A)
21	SEPA--CARTER'S PUMPED STORAGE	33,438	0	0	0	0	(A)
22	PREF CUSTOMER STORAGE & LOSS	0	0	0	0	0	
23	CONSTRUCTION PRELIM TEST ENERGY	0	0	0	0	0	
24	AEC--NET TO (FROM) APCO	0	0	0	0	0	(A)
25	TOTAL OTHER NET TRANSACTIONS	3,006,876	175,161,715	136,637,250	38,524,465	0	
26	TOTAL PURCHASED POWER (555)	6,946,212	343,172,946	262,075,664	81,097,282	0	
27	TOTAL GENERATED PLUS PURCHASED	67,142,902	2,280,166,292	1,508,144,757	772,021,536	0	
28	SYSTEM CONTROL & LOAD DISPATCH (556)	-----	8,923,154	0	8,923,154	0	
29	OTHER EXPENSES (557) AND HEDGING (547)	-----	50,838,612	42,231,349	8,607,263	0	
30	TOTAL TERRITORIAL SUPPLY	67,142,902	2,339,928,058	1,550,376,106	789,551,953	0	
31	NON-ASSOCIATED NON-TERR	(5,323,688)	(141,203,480)	(141,203,480)	0	0	(B)
32	NET TERRITORIAL SUPPLY	61,819,214	2,198,724,579	1,409,172,626	789,551,953	0	(C)
33	EPRI DUES	-----	2,854,557	0	0	2,854,557	
34	TOTAL PRODUCTION O&M	-----	2,201,579,136	1,409,172,626	789,551,953	2,854,557	

NOTES FOR SCHEDULE 3.20

(A) Included to display MWH.
(B) Schedule E & Other Sales are credited to expense. MWH includes Schedule E, Barge Loading, and Construction Department.
(C) Excludes SEPA delivered.

SCHEDULE 3.30--ANALYSIS OF DISTRIBUTION DEPRECIATION

LINE (1)	LINE DESCRIPTION (2)	TOTAL (3)	LAND & LAND RIGHTS ACCT 360 (4)	STRUCTURES & IMPROVEMENTS ACCT 361 (5)	STATION EQUIPMENT ACCT 362 (6)	POLES, TOWERS, & FIXTURES ACCT 364 (7)	OVERHEAD COND. & DEV. ACCT 365 (8)	UNDERGROUND CONDUIT ACCT 366 (9)
1	INVESTMENT	6,702,574,313	48,499,998	89,826,457	1,033,739,439	1,185,415,204	1,250,199,952	46,448,369
	ACCUMULATED DEPRECIATION							
2	FROM DEPRECIATION STUDY	2,354,943,318	----	26,849,772	314,120,118	472,883,813	375,453,246	17,697,059
3	AVG DEPRECIATION RESERVE	2,483,257,985	4,096,544	28,266,039	330,689,269	497,827,403	395,257,586	18,630,540
4	NET PLANT	4,219,316,328	44,403,455	61,560,418	703,050,170	687,587,801	854,942,366	27,817,829
	DEPRECIATION EXPENSE							
5	DEPR STUDY RATES (PERCENT)	----	----	2.32%	2.43%	2.36%	2.46%	1.80%
6	EST (PER DEPR STUDY RATES)	175,909,846	----	2,083,974	25,119,868	27,975,799	30,754,919	836,071
7	DEPR EXPENSE BY ACCOUNT	209,620,350	37,670	2,482,890	29,928,338	33,330,954	36,642,056	996,113

SCHEDULE 3.30--ANALYSIS OF DISTRIBUTION DEPRECIATION

LINE	LINE DESCRIPTION	UNDERGROUND COND. & DEV. ACCT 367 (10)	LINE TRANSFORMERS ACCT 368 (11)	SERVICES ACCT 369 (12)	METERS ACCT 370 (13)	STREET LIGHTING ACCT 373 (14)	NOTES (15)
1	INVESTMENT	607,188,912	1,420,326,341	454,512,019	335,098,856	231,318,764	(A)
	ACCUMULATED DEPRECIATION						
2	FROM DEPRECIATION STUDY	208,096,857	464,642,351	203,058,967	160,349,160	111,791,975	(B)
3	AVG DEPRECIATION RESERVE	219,073,512	489,151,221	213,769,885	168,807,228	117,688,758	(C)
4	NET PLANT	388,115,400	931,175,120	240,742,134	166,291,628	113,630,006	(D)
	DEPRECIATION EXPENSE						
5	DEPR STUDY RATES (PERCENT)	2.42%	2.50%	2.36%	4.76%	5.30%	(B)
6	EST (PER DEPR STUDY RATES)	14,693,972	35,508,159	10,726,484	15,950,706	12,259,894	(E)
7	DEPR EXPENSE BY ACCOUNT	17,506,706	42,305,164	12,779,758	19,004,006	14,606,695	(F)

NOTES FOR SCHEDULE 3.30

(A) From Schedule 2.00, Gross Plant Distribution.
(B) From Depreciation Study.
(C) Account 360 assigned. Balance allocated per Line 2.
(D) Line 1 minus Line 3.
(E) Line 1 multiplied by Line 5.
(F) Account 360 assigned. Balance allocated per Line 6.

SCHEDULE 3.40--AVERAGE NUMBER OF CUSTOMERS

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)
	LEVEL					
1	1	0	0	0	0	0
2	2	227	0	186	186	41
3	3 - CS	138	0	138	138	0
4	3 - COMMON	44	0	44	44	0
5	4	1,522	0	1,520	1,520	2
6	5 - CS	10	0	10	10	0
7	5 - COMMON	1,462,612	1,255,339	207,273	1,462,612	0
8	AVERAGE CUSTOMERS	1,464,553	1,255,339	209,171	1,464,510	43

SCHEDULE 3.50--ENERGY & DEMAND SALES

MWH SALES

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)
	LEVEL					
1	1	0	0	0	0	0
2	2	11,746,647	0	8,150,066	8,150,066	3,596,580
3	3 - CS	9,018,396	0	9,018,396	9,018,396	0
4	3 - COMMON	718,135	0	718,135	718,135	0
5	4	4,170,187	0	4,169,107	4,169,107	1,080
6	5 - CS	58,176	0	58,176	58,176	0
7	5 - COMMON	32,838,192	18,205,858	14,632,334	32,838,192	0
8	TOTAL MWH SALES	58,549,734	18,205,858	36,746,216	54,952,074	3,597,661

TWELVE MONTHS' AVERAGE CP KW SALES

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)
	LEVEL					
1	1	0	0	0	0	0
2	2	1,415,884	0	916,872	916,872	499,011
3	3 - CS	1,132,769	0	1,132,769	1,132,769	0
4	3 - COMMON	89,878	0	89,878	89,878	0
5	4	568,513	0	568,291	568,291	222
6	5 - CS	8,496	0	8,496	8,496	0
7	5 - COMMON	5,786,648	3,500,622	2,286,027	5,786,648	0
8	TOTAL KW SALES	9,002,188	3,500,622	5,002,333	8,502,955	499,233

ALABAMA POWER COMPANY
RETAIL COST OF SERVICE
TWELVE MONTHS ENDED DECEMBER 31, 2016

SCHEDULE 3.61--DEMAND LINE ALLOCATOR

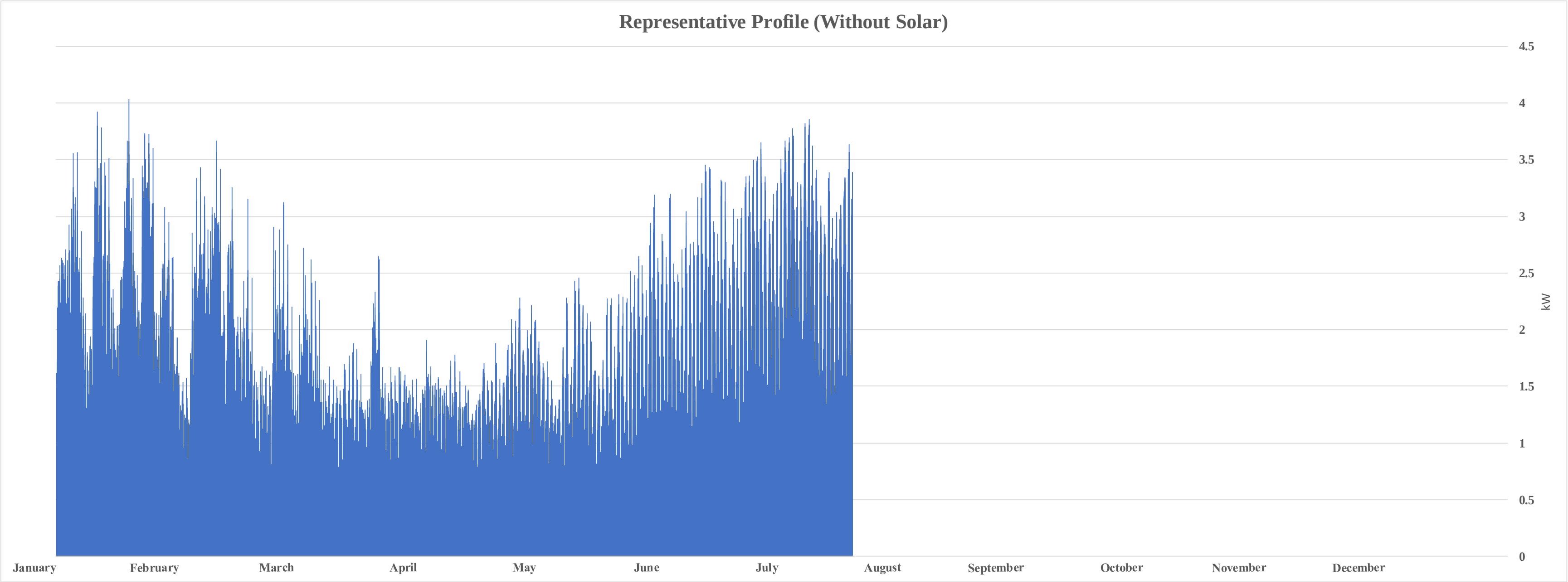
LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)
	LEVEL 5					
	COMMON					
1	SALES	5,786,648	3,500,622	2,286,027	5,786,648	0
2	LOSSES	144,067	87,154	56,913	144,067	0
3	INTO	5,930,715	3,587,776	2,342,940	5,930,715	0
	CUSTOMER SUBS					
4	SALES	8,496	0	8,496	8,496	0
5	LOSSES	212	0	212	212	0
6	INTO	8,708	0	8,708	8,708	0
	TOTAL LEVEL 5					
7	SALES	5,795,145	3,500,622	2,294,523	5,795,145	0
8	LOSSES	144,279	87,154	57,125	144,279	0
9	INTO	5,939,424	3,587,776	2,351,648	5,939,424	0
	LEVEL 4					
10	OUT	5,939,424	3,587,776	2,351,648	5,939,424	0
11	SALES	568,513	0	568,291	568,291	222
12	LOSSES	160,914	88,711	72,198	160,909	5
13	INTO	6,668,850	3,676,487	2,992,137	6,668,623	227
	LEVEL 3					
	COMMON					
14	OUT	6,668,850	3,676,487	2,992,137	6,668,623	227
15	SALES	89,878	0	89,878	89,878	0
16	LOSSES	52,031	28,302	23,727	52,029	2
17	INTO	6,810,760	3,704,789	3,105,742	6,810,531	229
	CUSTOMER SUBS					
18	SALES	1,132,769	0	1,132,769	1,132,769	0
19	LOSSES	8,720	0	8,720	8,720	0
20	INTO	1,141,489	0	1,141,489	1,141,489	0
	TOTAL LEVEL 3					
21	OUT	6,668,850	3,676,487	2,992,137	6,668,623	227
22	SALES	1,222,647	0	1,222,647	1,222,647	0
23	LOSSES	60,751	28,302	32,447	60,749	2
24	INTO	7,952,249	3,704,789	4,247,231	7,952,020	229
	LEVEL 2					
25	OUT	7,952,249	3,704,789	4,247,231	7,952,020	229
26	SALES	1,415,884	0	916,872	916,872	499,011
27	LOSSES	335,346	132,620	184,856	317,476	17,870
28	INTO	9,703,478	3,837,408	5,348,959	9,186,368	517,110
	LEVEL 1					
29	OUT	9,703,478	3,837,408	5,348,959	9,186,368	517,110

SCHEDULE 3.62--ENERGY LINE ALLOCATOR

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RESIDENTIAL (4)	NON - RESIDENTIAL (5)	TOTAL DIRECT SERVICE (6)	TOTAL ALL OTHER SERVICE (7)
	LEVEL 5					
	COMMON					
1	SALES	32,838,192	18,205,858	14,632,334	32,838,192	0
2	LOSSES	573,824	318,135	255,689	573,824	0
3	INTO	33,412,016	18,523,993	14,888,023	33,412,016	0
	CUSTOMER SUBS					
4	SALES	58,176	0	58,176	58,176	0
5	LOSSES	1,017	0	1,017	1,017	0
6	INTO	59,193	0	59,193	59,193	0
	TOTAL LEVEL 5					
7	SALES	32,896,368	18,205,858	14,690,510	32,896,368	0
8	LOSSES	574,841	318,135	256,706	574,841	0
9	INTO	33,471,209	18,523,993	14,947,216	33,471,209	0
	LEVEL 4					
10	OUT	33,471,209	18,523,993	14,947,216	33,471,209	0
11	SALES	4,170,187	0	4,169,107	4,169,107	1,080
12	LOSSES	669,856	329,648	340,189	669,837	19
13	INTO	38,311,253	18,853,641	19,456,513	38,310,154	1,099
	LEVEL 3					
	COMMON					
14	OUT	38,311,253	18,853,641	19,456,513	38,310,154	1,099
15	SALES	718,135	0	718,135	718,135	0
16	LOSSES	233,618	112,852	120,760	233,612	6
17	INTO	39,263,006	18,966,493	20,295,408	39,261,901	1,105
	CUSTOMER SUBS					
18	SALES	9,018,396	0	9,018,396	9,018,396	0
19	LOSSES	53,981	0	53,981	53,981	0
20	INTO	9,072,377	0	9,072,377	9,072,377	0
	TOTAL LEVEL 3					
21	OUT	38,311,253	18,853,641	19,456,513	38,310,154	1,099
22	SALES	9,736,532	0	9,736,532	9,736,532	0
23	LOSSES	287,599	112,852	174,741	287,593	6
24	INTO	48,335,384	18,966,493	29,367,785	48,334,278	1,105
	LEVEL 2					
25	OUT	48,335,384	18,966,493	29,367,785	48,334,278	1,105
26	SALES	11,746,647	0	8,150,066	8,150,066	3,596,580
27	LOSSES	1,737,185	548,389	1,084,774	1,633,163	104,022
28	INTO	61,819,215	19,514,882	38,602,625	58,117,507	3,701,708
	LEVEL 1					
29	OUT	61,819,215	19,514,882	38,602,625	58,117,507	3,701,708

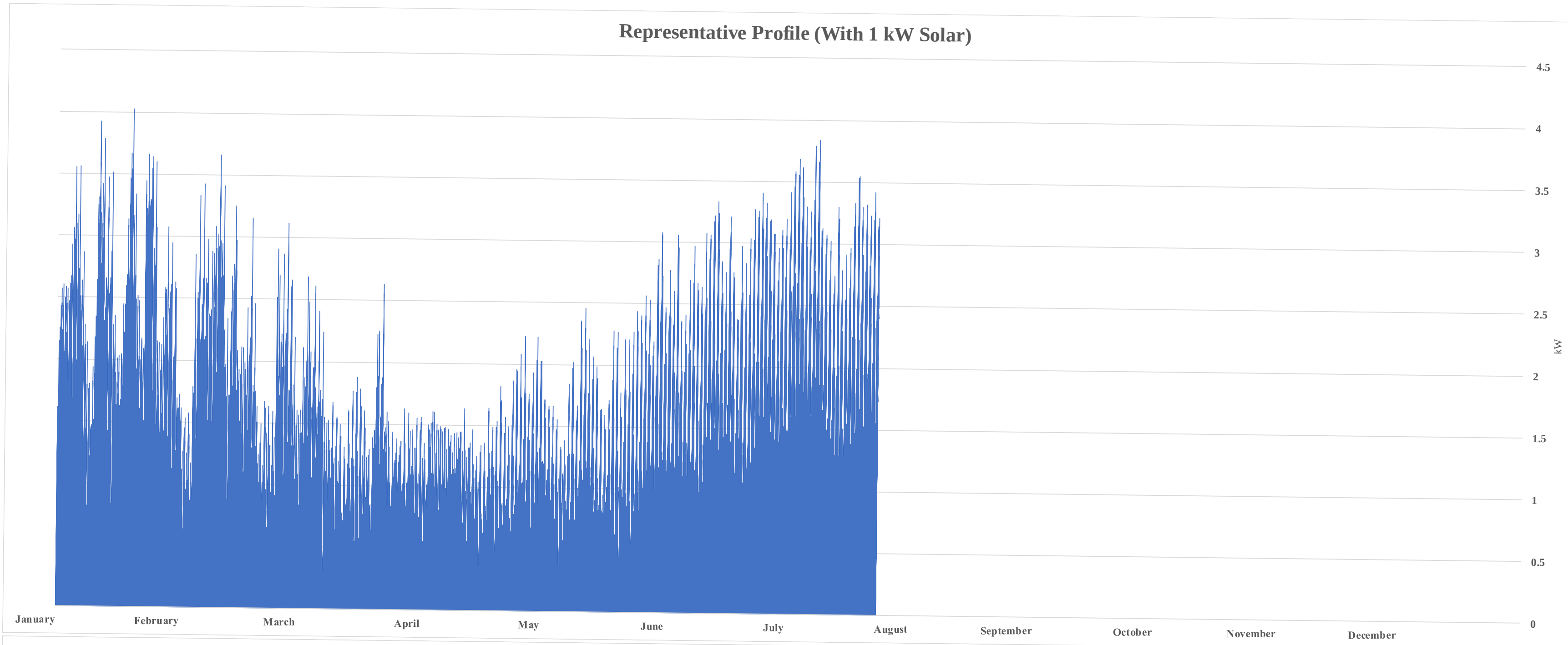
Testimony of Natalie Dean

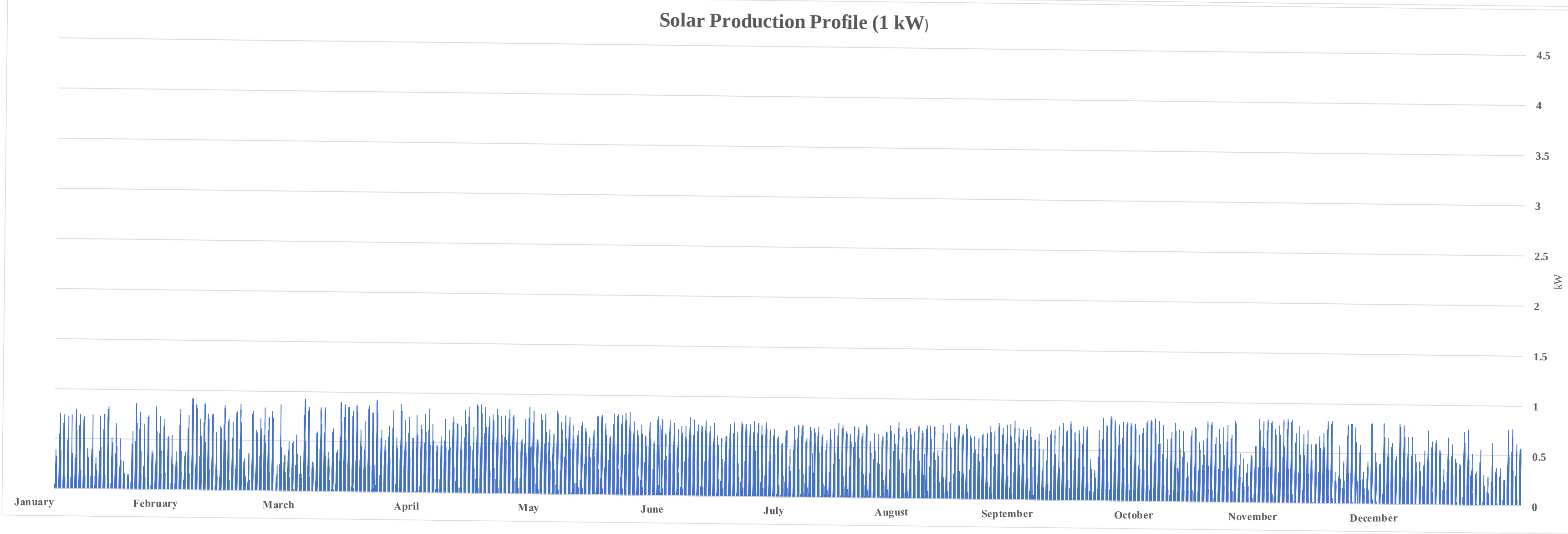
Exhibit ND-2


Representative Profile (Without Solar)
kW
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
January
February
March
April
May
June
July
August
September
October
November
December

Testimony of Natalie Dean

Exhibit ND-3


Representative Profile (With 1 kW Solar)
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
kW
January
February
March
April
May
June
July
August
September
October
November
December


Solar Production Profile (1 kW)
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
kW
January
February
March
April
May
June
July
August
September
October
November
December

Testimony of Natalie Dean

Exhibit ND-4

Cost of Service

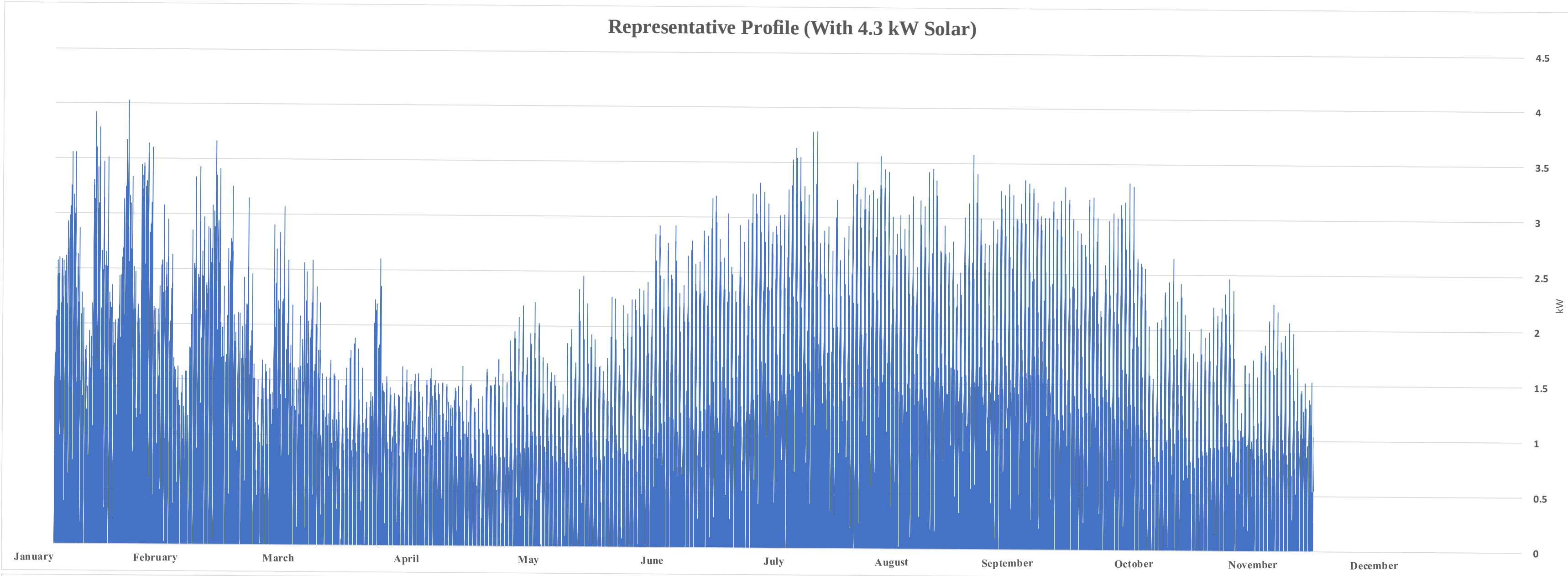
		Representative Profile (Without Solar)		Representative Profile (With 1 kW Solar)	Variable Energy Cost Differential
Variable Energy Cost Component					
Fuel Clause Expense	$	378	$	337	2.41 ¢/kWh
Variable O&M/Taxes	$	17	$	15	0.12 ¢/kWh
Total Energy Cost Component	$	395	$	352	**2.53 ¢/kWh**
Annual Energy (kWh)		15,485		13,787	

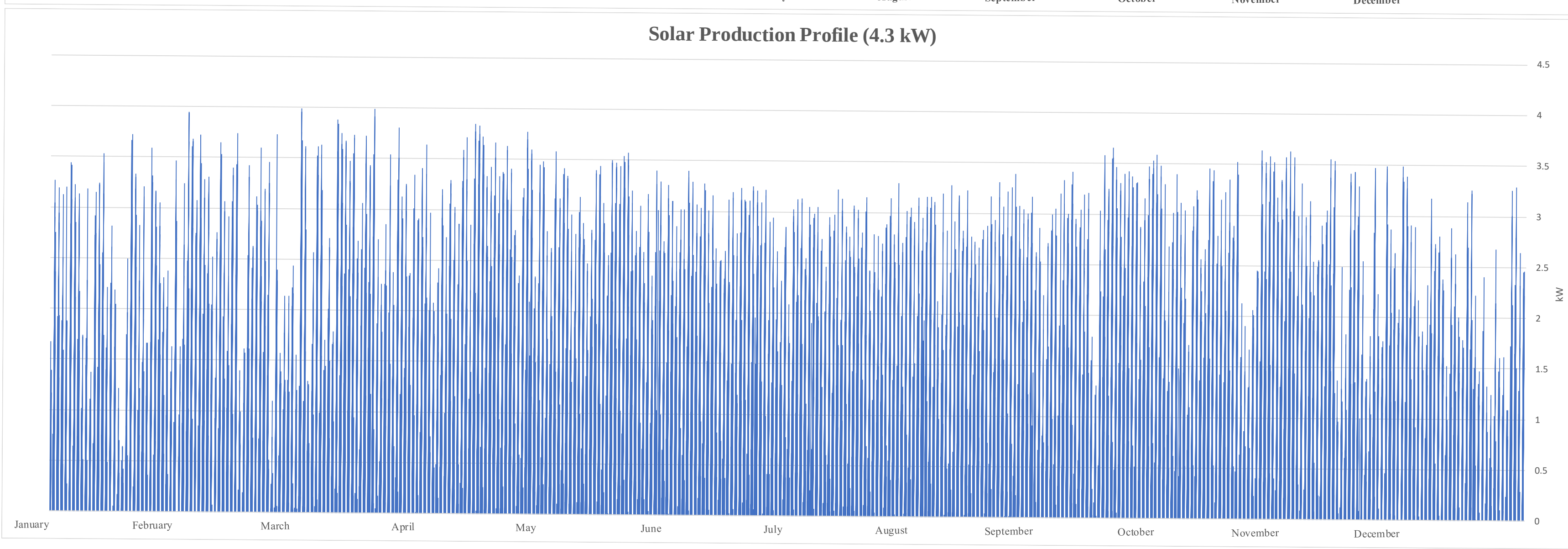
		Representative Profile (Without Solar)		Representative Profile (With 1 kW Solar)		Fixed Capacity Cost Differential
Fixed Capacity Cost Component						
Production	$	858	$	772	$	86/kW
Transmission	$	187	$	166	$	21/kW
Distribution	$	497	$	476	$	22/kW*
Total Fixed Cost Component	$	1,543*	$	1,414	**$**	**129/kW**

*Summation variances due to rounding approximations.

Testimony of Natalie Dean

Exhibit ND-5


Representative Profile (With 4.3 kW Solar)
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
kW
January
February
March
April
May
June
July
August
September
October
November
December


Solar Production Profile (4.3 kW)
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
kW
January
February
March
April
May
June
July
August
September
October
November
December

Testimony of Natalie Dean

Exhibit ND-6

Rate FD Cost Recovery Calculation

Month	Representative Profile (Without Solar) Billed kWh	FD Billing	Representative Profile (With 4.3 kW Solar) Billed kWh	FD Billing
January	1,635	$ 194.98	1,238	$ 153.70
February	1,235	$ 153.41	876	$ 116.06
March	971	$ 126.03	599	$ 85.38
April	872	$ 115.72	495	$ 73.21
May	1,071	$ 136.36	605	$ 86.07
June	1,500	$ 196.00	923	$ 125.72
July	1,772	$ 229.26	1,140	$ 152.10
August	1,679	$ 217.91	1,076	$ 144.29
September	1,452	$ 190.20	940	$ 127.79
October	990	$ 127.98	608	$ 86.48
November	965	$ 125.36	639	$ 90.07
December	1,343	$ 164.67	984	$ 127.34
Total	**15,485**	**$ 1,977.88**	**10,123**	**$ 1,368.21**

Energy Reduction (kWh)	**5,362**
Cost Recovery Difference (Rate FD)	**$ 610**

Capacity Reservation Charge Calculation

Cost Recovery Difference	**$ 610**	
Annual Cost Reduction		
Energy (2.53 ¢/kWh @ 5,362 kWh)	$ 136	
Demand ($129 /kW* 35% @ 4.3 kW)	$ 194	
Total Annual Cost Reduction	**$ 330**	
Annual Net Unrecovered Costs	**$ 280**	
Required for Monthly Recovery ($280/4.3 kW/12 months)	$ 5.42	
Capacity Reservation Charge	**$ 5.42**	**per kW**

Testimony of Natalie Dean

Exhibit ND-7

Rate RTA Cost Recovery Calculation

Month	Representative Profile (Without Solar) Billed kWh	Representative Profile (Without Solar) RTA Billing	Representative Profile (With 4.3 kW Solar) Billed kWh	Representative Profile (With 4.3 kW Solar) RTA Billing
January	1,635	$ 172.85	1,238	$ 136.61
February	1,235	$ 135.38	876	$ 102.47
March	971	$ 109.41	599	$ 74.87
April	872	$ 97.13	495	$ 63.26
May	1,071	$ 116.32	605	$ 74.23
June	1,500	$ 220.25	923	$ 140.79
July	1,772	$ 248.65	1,140	$ 165.30
August	1,679	$ 242.35	1,076	$ 160.75
September	1,452	$ 213.84	940	$ 143.95
October	990	$ 108.26	608	$ 74.11
November	965	$ 109.26	639	$ 79.09
December	1,343	$ 145.69	984	$ 112.44
Total	**15,485**	**$ 1,919.39**	**10,123**	**$ 1,327.87**

Energy Reduction (kWh)	**5,362**
Cost Recovery Difference (Rate RTA)	**$ 592**

Rate RTA Super-Peak Energy Charge Calculation

Cost Recovery Difference	**$**	**592**
Annual Cost Reduction		
Energy (2.53 ¢/kWh @ 5,362 kWh)	$	136
Demand ($129/kW* 35% @ 4.3 kW)	$	194
Total Annual Cost Reduction	**$**	**330**
Annual Net Unrecovered Costs	**$**	**262**
FD Energies (kWh) in 3:00-5:00PM Super-Peak Period		535
Required for Recovery during Super-Peak Period ($262/535 kWh)	$	0.49
Rate RTA Peak Period Charge (per kWh)	$	0.221822
Total Required for Recovery during Super-Peak Period ($0.49+$0.221822)	$	0.71
Rate RTA Super-Peak Energy Charge	**$**	**0.71 per kWh**