COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

ELECTRONIC TARIFF FILING OF BIG RIVERS	**)**	
ELECTRIC CORPORATION AND KENERGY	**)**	**Case No. 2023-00312**
CORP. TO REVISE THE LARGE INDUSTRIAL	**)**	
CUSTOMER STANDBY SERVICE TARIFF	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

DOMTAR PAPER COMPANY, LLC

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

December 2023

COMMONWEALTH OF KENTUCKY
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In the Matter of:

ELECTRONIC TARIFF FILING OF BIG RIVERS ELECTRIC CORPORATION AND KENERGY CORP. TO REVISE THE LARGE INDUSTRIAL CUSTOMER STANDBY SERVICE TARIFF	))))	**Case No. 2023-00312**

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background and experience.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida.

I have more than forty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis. I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, before the Federal Energy Regulatory Commission ("FERC"), and in the United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Exhibit___(SJB-1).

Q. Have you previously presented testimony before the Kentucky Public Service Commission?

A. Yes. I have testified before the Kentucky Public Service Commission ("Commission") in 34 cases over the past forty years, including six Big Rivers Electric Corporation ("Big Rivers") cases.

Q. Have you previously testified in electric utility proceedings in which you addressed standby and maintenance power rates?

A. Yes. I testified in an Arkansas Power and Light Company proceeding in 1988 (Docket No. 87-183-TF). I also authored an article on standby rate design that was published in Public Utilities Fortnightly.[1] In addition, I have testified in over 140 proceedings throughout the country on class cost of service and rate design issues that form the foundation for a cost-based standby service rate.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Domtar Paper Company, LLC ("Domtar"), a large industrial customer who takes generation and transmission service from Big Rivers and distribution service from Kenergy Corp. ("Kenergy"). Domtar owns a 52 MW cogeneration facility located onsite at its Hawesville mill, which uses the mill's wood waste as fuel to generate electricity used to meet a portion of Domtar's power needs.

[1] *A Realistic Approach to Standby Electric Rates*, Public Utilities Fortnightly, November 8, 1984.

Domtar's cogeneration facility is a Qualifying Facility ("QF") under the Public Utilities Regulatory Policy Act ("PURPA").

Q. What is the purpose of your testimony?

A. I provide testimony in response to Big Rivers' proposed Large Industrial Customer Standby Service ("LICSS") tariffs. I explain in detail why the proposed tariffs fail to provide a reasonable rate for standby service and therefore should be rejected. As I discuss, the proposed LICSS tariffs are fundamentally flawed in that they do not price backup power or maintenance power based upon the actual cost to Big Rivers of providing such services. Instead, the tariffs conflate backup and maintenance power, treating both as "Backup Power." The proposed tariff rates for "Backup Power" are likewise unreasonable, requiring standby customers to pay a cost/market hybrid rate for demand and a "higher of" market or cost rate for energy for "first through the meter" power up to the customer's entire Self-Supply Capacity. This design is fundamentally flawed in that it is not based upon Big Rivers' costs to provide standby service, but instead upon a flawed conception of the *benefits* that Big Rivers receives from the standby customer's generator, turning federal and state PURPA requirements inside out. This pricing approach stands in stark contrast to any other standby service tariffs of which I am aware. The proposed tariffs also include several unreasonable changes to the LICSS tariffs as they were approved on a pilot basis in Case No. 2021-00289.

In lieu of Big Rivers' proposed approach, I recommend that the Commission adopt the long-standing Commission-approved standby service rate used in the Duke Energy Kentucky, Inc, ("Duke Kentucky") service territory to price standby service in the Big Rivers service territory. That approach – contained in Duke Kentucky's Generation Support Service ("GSS") tariff – is cost-based, similar to approaches in other jurisdictions, and contains reasonable terms and conditions for standby service customers.

II. STANDBY SERVICE RATE DESIGN PRINCIPLES

Q. Please briefly describe standby service.

A. In simple terms, standby service is a type of service provided by an electric utility to customers that can self-generate electricity to meet part of their individual power needs. Standby service includes backup, maintenance, and supplementary power provided by an electric utility to a self-generating customer.

Backup power is electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.[2] Since all electric generators have a certain probability of being out of service during some hours of the year, a self-generating

[2] 807 KAR 5:054, Section 1 (2).

customer needs its electric utility to provide backup power when forced outages occur.[3]

Maintenance power is electric energy or capacity supplied by an electric utility during scheduled outages of a qualifying facility.[4] Unlike backup power, which can occur randomly over the year, maintenance power is provided on a scheduled basis and usually only during off-peak periods. Since it is scheduled during off-peak periods of the year, maintenance power does not place a requirement on an electric utility to plan and obtain generating capacity to meet a customer's load requirements, as long as it is scheduled and occurs in an off-peak season, in which case the maintenance load does not impact the utility's capacity need.

Supplemental power is the electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.[5] As such, supplemental power would always be required by the customer whether or not the customer's own generation is operating or is down for an unscheduled outage if the customer's self-generation is insufficient to meet the customer's entire load.

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[3] As described by Domtar's Mr. Thomas, many of the outages of Domtar's generator occurs because the paper production machinery is out, which means that the steam source for the generator is not available. However, in this case, Domtar's load is also reduced.
[4] 807 KAR 5:054, Section 1 (6).
[5] 807 KAR 5:054, Section 1 (11).

Q. How should standby service be priced?

A. For regulated utilities such as Big Rivers, standby service should be priced at cost in a manner consistent with the pricing of other electric services. While supplemental power is similar to the standard power used by customers that do not self-generate and can be priced accordingly, backup and maintenance power are not standard and their pricing should reflect the unique attributes of those services.

Backup power should be priced at cost and should reflect the probability that a given qualifying facility would experience a forced outage during a period that would impact a utility's need for capacity. For example, if a customer's generator has a capacity of 30 MW with a forced outage rate of 5% that would ordinarily supply half of the customer's load (60 MW), the customer would need to purchase 30 MW of standby capacity from its supplying utility. With a forced outage rate of 5% and applying a reasonable assumption that forced outages are random events, the expected value of the capacity that a utility would need to acquire to serve the standby load would be equivalent to a 1.5 MW load (5% of 30 MW). Under the principles of cost causation that generally underly utility ratemaking, the power supply cost to Big Rivers to meet this standby load would be equivalent to 1.5 MW under the standard tariff.

Maintenance power differs from backup power in that it is scheduled by the customer in coordination with the electric utility so that the maintenance power can be provided during off-peak seasons and periods. This coordinated scheduling means that the cost of providing maintenance generation capacity is essentially $0 because it does not factor into any resource acquisition decision nor would it impact the peak loads of the utility that drive generation resource costs. In the case of Big Rivers, maintenance would occur during periods that would also recognize Midcontinent Independent System Operator ("MISO") peak loads and the determination of Big Rivers' capacity obligations to MISO.

Q. Are you aware of any federal rules regarding the provision of backup and maintenance power?

A. Yes. The Federal Energy Regulatory Commission's ("FERC") rules governing sales of backup and maintenance power to Qualifying Facilities under PURPA state as follows:

> ***Rates for sales of back-up and maintenance power.*** The rate for sales of back-up power or maintenance power:
>
> (1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and
>
> (2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.[6]

[6] 18 CFR 292.305(c)

I am also aware that this Commission has adopted rules implementing federal PURPA requirements.[7]

III. BIG RIVERS' PROPOSED LICSS TARIFFS ARE UNREASONABLE AND SHOULD BE REJECTED

Q. Please describe the fundamental problem with Big Rivers' LICSS tariff proposal.

A. The fundamental problem with Big Rivers' proposal is that it did not design its LICSS rate based upon its costs to provide standby service, but instead based its proposal upon a flawed conception of the *benefit* it receives from the standby customer's generator. This turns the federal and state PURPA requirements inside out. This problem is addressed in the testimony of Big Rivers witness Nathan Berry, who states that "Big Rivers proposes that the credit be based on the applicable PRA price times the accredited capacity of the Standby Customer's generator. Regardless of Big Rivers' capacity position, Big Rivers must purchase all of the capacity needed for its Member load at the PRA price. Therefore, the *benefit* to Big Rivers from a Standby Customer's generator is the savings Big Rivers receives by purchasing less capacity in MISO equal to the accredited capacity of the customer's generator."[8]

Big Rivers is not purchasing generation capacity from a PURPA Qualifying Facility at MISO market prices, but instead is providing standby services at cost. If

[7] *See* 807 KAR 5:054.
[8] Berry Testimony at 5.

the utility was purchasing capacity from a QF at its avoided capacity cost, then the analysis would be much different. Big Rivers' 2023 IRP Base Case shows the addition of a 635 MW natural gas combined cycle ("NGCC") unit in June 2029.[9] Big Rivers' avoided capacity cost for a 635 MW NGCC in June 2029 is much different, and likely much higher, than the MISO PRA capacity price. The "*benefit*" to Big Rivers from Domtar's 52 MW QF generator is delaying the need for new generation. If Domtar's 52 MW QF did not exist, then the planned in-service date for Big Rivers' 635 MW NGCC would be moved up.

Q. Please describe the other problems with the LICSS proposal.

A. As proposed, the LICSS tariffs would separate standby service in the Big Rivers service territories into only two categories – Backup Power and Supplemental Power. The tariffs would not provide separate pricing for Maintenance Power.

With respect to "Backup Power," a standby customer's demand would be measured based upon that customer's Self-Supply Capacity (i.e. the amount of the customer's generating capacity accredited by MISO). Backup Power demand would be billed at Big Rivers' Standard Rate Schedule LIC – Large Industrial Customer ("LIC") tariff demand rate (currently $10.7150 per kW) less a credit equal to the MISO capacity auction clearing price for the Big Rivers' zone. Backup Power energy would be billed at the "higher of" the LIC tariff energy rate ($0.038050 per kWh) or

[9] Big Rivers Integrated Resource Plan, Case No. 2023-00310, at 141.

the MISO locational marginal price ("LMP") at the applicable node during each hour of the day at the time of delivery, plus any transmission charges, MISO fees, or other costs.

A standby customer's Supplemental Power demand would be measured as the level of metered demand or the level of demand set forth in a special contract after the Backup Power Self-Supply Capacity threshold is met. Supplemental Power energy would be measured as the actual energy sold to the standby customer in each month after the Self-Supply Capacity threshold is met. The demand and energy charges for Supplemental Power would be billed under the terms and charges of the LIC tariff.

Big Rivers' proposed LICSS tariffs are thus designed to charge standby customers cost/market hybrid rates for "first through the meter" power up to their total Self-Supply Capacity level regardless of the customer's actual standby generation needs. Only then would standard tariff rates apply.

Q. Do the proposed LICSS tariffs follow the standby service pricing principles you discussed earlier?

A. No. The proposed LICSS tariffs are not cost-based backup and maintenance power service rates. As discussed previously, Big Rivers priced its LICSS tariff on the erroneous assumption that it is buying generation capacity from a PURPA Qualifying Facility at the MISO market price, instead of supplying standby service at cost.

The tariffs unreasonably combine backup power and maintenance power service, failing to recognize that the cost to provide maintenance power – which can be limited to off-peak periods and scheduled in advance – is not the same as the cost to provide unscheduled backup power. Both federal PURPA rules and the Kentucky rules implementing PURPA expressly recognize that distinction. And no other standby service tariffs of which I am aware ignore that distinction. In its initial discovery, Commission Staff asked Big Rivers to provide backup and maintenance rates separately showing the embedded and incremental costs for each. Big Rivers refused to do so. Baron Exhibit__(SJB-2) is a copy of the Response to PSC DR 1-11. When Commission Staff again asked Big Rivers to provide such information in supplemental discovery, Big Rivers again refused. Baron Exhibit__(SJB-3) is a copy of the response to PSC DR 2-1.

Additionally, the proposed LICSS tariff fails to establish a cost-based rate that reflects the actual probability that a standby service customer's qualifying facility would experience forced outages and disregard the ability of the utility to coordinate scheduled maintenance outages with the standby customer. As I explained earlier, a customer's own generation reliability factor is a critical component in the determination of the cost of providing backup service. Big Rivers' tariff does not even consider this factor. The tariffs are also unduly punitive to standby service customers by forcing them to pay the "higher of" cost or market energy rates for "first through the meter" energy.

In discovery, Commission Staff asked Big Rivers to provide the cost support for the proposed LICSS rates. Big Rivers responded that there are "no quantified charges in the rate schedule for which Big Rivers can provide cost support." Baron Exhibit__(SJB-4) is a copy of the response to PSC DR 1-3. When asked if Big Rivers were aware of any other utilities in the country that have a standby service tariff similar to the proposed LICSS tariffs, Big Rivers could not provide an example despite reviewing several utility tariffs prior to filing the proposed LICSS tariffs. Baron Exhibit__(SJB-5) are copies of the responses to Domtar 1-5 and 1-6. Big Rivers likewise could not quantify the cost components included in its current LIC rates. Baron Exhibit__(SJB-6) are copies of the responses to Domtar 1-12 and 1-13.

Q. How do Big Rivers and Kenergy propose to change the LICSS tariffs as compared to the ones approved by the Commission on a pilot-only basis in Case No. 2021-00289?

A. The proposed tariffs make several major changes as compared to the Pilot LICSS tariff rates currently in effect as a result of the Commission's Order in Case No. 2021-00289. In addition to striking references to Maintenance Power throughout the Pilot LICSS tariff, the proposed tariffs:

- Require standby service customers to be accredited by MISO;

- Remove the current $150 administrative charge and require the standby customer to be responsible for "all costs (including charges from ACES) related to the standby customer's generator;"

- Change the demand credit to standby customers from \$3.80 per kW-month to the MISO auction clearing price for the Big Rivers zone;

- Bar standby customers with a non-dispatchable generation facility from receiving a capacity credit;

- Specify that Backup Power energy charges shall not be subject to the FAC, Non-FAC PPA, Environmental Surcharge or MRSM riders;

- Make standby customers "responsible for the cost of all facilities on the Standby Customer's site to meet and maintain eligibility as a MISO capacity resource, and the Standby Customer is subject to all non-performance costs levied by MISO or its successor, the Kentucky Public Service Commission, or other applicable entity related to nonperformance of its generating equipment;"

- Allow Big Rivers/Kenergy to charge standby customer for "[a]ny and all costs incurred by Big Rivers as a result of the Standby Customer's generator's failure to generate, including, without limitation, ancillary services necessary to maintain reliability on the Big Rivers system and MISO RSG charges;"

- Require standby customer to pay "all interconnection costs arising out of the Standby Customer's generator;"

- Require standby customers to "provide reasonable protection for Big Rivers' and the Member Cooperative's systems;"

- Require standby customers to "design, construct, install, own, operate, and maintain its generation equipment in accordance with all applicable codes, laws, regulations, and generally accepted utility practices."

- Require standby customers to "obtain insurance in the following minimum amounts for each occurrence: a. Public Liability for Bodily Injury - \$1,000,000.00 b. Property Damage - \$500,000.00;"

- Remove language allowing standby customers to enter into special agreements that may deviate from the provisions of the proposed LICSS tariffs;

- Allow Big Rivers to discontinue sales to a standby customer during system emergencies.

Q. Are these proposed LICSS tariff changes reasonable?

A. Several of them are not. For example, the revision to allow Big Rivers to discontinue sales to a standby customer during system emergencies would mean that standby service to the customer is potentially non-firm. The only other tariff that has a similar type of provision, or that even mentions system emergencies, is Big Rivers' "Standard Rate -QFP – Cogeneration/Small Power Production Purchase Tariff – Over 100 KW."[10] This provision does not appear in the standard LIC tariff.

While utilities such as Big Rivers can offer interruptible backup and maintenance power, this does not mean that they do not have to provide firm service for these products. Further, interruptible backup power and maintenance power would normally have a lower monthly demand reservation charge than the firm power equivalent standby rate.

The requirement that standby customer qualifying facilities must be accredited by MISO is also unreasonable. Big Rivers conceded that imposing such a requirement could be complex, costly, and could take years for intermittent resources owned by standby service customers. Baron Exhibit__(SJB-7) is a copy of the response to PSC 1-6. MISO accreditation would also require all standby service customers to make their Qualifying Facility available during MISO emergency conditions. Baron

[10] See BREC tariff sheet 41, Standard Rate QFP.

Exhibit__(SJB-8) is a copy of the response to PSC 1-14. In discovery, Big Rivers conceded that MISO does not require a behind-the-meter generator to register in the MISO market and receive capacity accreditation. Baron Exhibit__(SJB-9) is a copy of the Response to PSC 2-8. Hence, there is no need to impose an onerous requirement such as MISO accreditation on Big Rivers' standby customers.

The proposed replacement of an administrative fee with the requirement that standby customers must pay "all costs (including charges from ACES) related to the standby customer's generator" should also be rejected. This provision as well as other provisions listed above regarding standby customers' cost responsibility are vague, administratively burdensome, and could introduce the possibility of Big Rivers double recovering costs that are already recovered through Big Rivers' base rates or riders.

Finally, it is unreasonable to omit tariff language allowing standby service customers to enter into special contracts that may deviate from the terms of the proposed LICSS tariffs with Big Rivers. Customers like Domtar have operated under a special contract for standby service for decades. Including language in a standby service tariff allowing for special contracts is consistent with past practice and provides important clarity for standby customers.

Q. Based on your analysis of Big Rivers' LICSS tariff, should it be approved by the Commission?

A. No. For the reasons discussed above, the proposed LICSS tariffs should be rejected in their entirety.

IV. THE COMMISSION SHOULD ADOPT A DIFFERENT STANDBY SERVICE PRICING APPROACH

Q. Have you reviewed standby service rates offered by other electric utilities?

A. Yes. I have reviewed standby service tariffs offered by a number of electric utilities throughout the country. Table 1 below shows a list of the utilities and the standby/backup and maintenance rate or schedule name.

Table 1
Surveyed Utilities' Standby and Maintenance Power Tariffs

Utility	Tariff Name
Duke Energy Kentucky	GSS
Georgia Power Company	BU-11
Jacksonville Electric Authority	SS-1
Florida Power & Light Co.	SST-1
Entergy Louisiana, LLC	SMQ-G
Kingsport Power Co. (AEP)	S.B.S

Baron Exhibit__(SJB-10) contains a summary of the key provisions of each of these rates and copies of each of the tariffs that I surveyed. These tariffs generally base their standby service pricing on the underlying cost of service that supports each utility's firm power rate applicable to the customer's load.

With regard to backup power, the tariffs generally adjust the utility's firm service rates to reflect the much lower cost of service associated with standby power, recognizing the low probability of an unscheduled need for backup power due to a forced outage at the customer's generation facility.

With regard to maintenance power, the tariffs generally recognize the lower cost of providing scheduled maintenance power that is limited to usage during off-peak periods. For both unscheduled backup power and scheduled maintenance, the energy charges are generally based on the otherwise applicable standard tariff energy charges, including applicable riders and surcharges.

Q. Do you have a recommendation for a reasonable standby service tariff approach that the Commission should adopt in this proceeding?

A. Yes. I recommend that the Commission adopt the pricing approach used in the Duke Kentucky service territory under the Generation Support Service (GSS) tariff. Duke Kentucky's GSS tariff contains many characteristics that in my opinion, constitute a reasonable standby service rate.

Unlike the proposed LICSS tariffs, Duke Kentucky's GSS tariff properly distinguishes between backup, maintenance, and supplemental power service. The GSS tariff also establishes cost-based rates for those services that properly recognize the load characteristics of a standby customer. Under the GSS tariff approach, the standby customer contracts with the utility for a level of backup power and maintenance power demand that the customer will require in the event that the customer's generation plant is unavailable due to either an unscheduled or scheduled outage. The customer pays monthly reservation charges based upon the utility's cost-based standard generation and transmission tariff rates on the amount of the contracted backup power and maintenance power demand.

For backup power, the GSS customer pays the standard tariff generation demand rate prorated by the number of days that the backup power is taken. For maintenance power, the customer pays 50% of the standard tariff generation demand charge prorated by the number of days that maintenance power is taken. The GSS tariff also provides for coordination between the utility and the standby customer in scheduling maintenance outages. Maintenance power that is pre-scheduled to occur during off-peak periods is priced based on a pro rata percentage of the standard tariff demand charge. If, for example, the customer uses 5 days of maintenance power during a 30-day month, the standby customer would pay a demand charge equal to the total contractual demand for backup and maintenance power times 5/30th of the standard monthly large customer demand charge. If a customer uses maintenance power for even one hour, they pay the full daily prorated charge. For both backup power and maintenance power, the customer pays the standard tariff energy charge, including all energy-related riders and surcharges, for energy actually consumed during scheduled or unscheduled outages.

In addition to establishing a cost-based approach to standby service pricing, the GSS tariff contains more reasonable terms and conditions for standby customers as compared to the proposed LICSS tariffs. For example, there is no requirement for standby customers to be accredited by an RTO, no language stating that the utility does not have to provide firm service to the standby customer, and the tariff includes language clarifying that standby customers may enter into special contracts with the utility for standby service pricing.

Q. Have you calculated the rate impact to Domtar of adopting the Duke Kentucky standby service methodology?

A. Yes. Using the GSS approach, the backup power capacity rate for standby customers would be based on Big Rivers' current LIC billing demand charge, prorated for the number of days in the month in which backup power is used. The backup power energy charge would be the LIC energy charge. All applicable adjustment clauses would also be included. The maintenance power capacity rate would be the same, except that the demand charge would be 50% of the prorated backup power rate for each kW of maintenance power used during the month.

The appropriate transmission reservation charge would be Big Rivers' MISO network integrated transmission service ("NITS") charge. Based upon the September 2023 MISO Schedule 9 NITs rates, the charge would be $2.113/kW-month. That is the cost of providing firm transmission capacity under the assumption that the standby load (and maintenance load) requires firm transmission service, regardless of the likelihood that the customer's generator will be forced out. Since Big Rivers' Schedule 9 is recovered from customer's based on 12 CP demand, the standby generator on maintenance power would have to impose load on the system at the time of each of the Big Rivers zone's monthly peak.

Q. Have you estimated the cost to Domtar of adopting your recommended pricing approach?

A. Yes. Because the costs under the current Domtar contract rate, the LICSS tariff, and my recommended rate are driven by the load on Domtar's facilities, the operation of its generating unit, and market prices, I have developed a comparison using actual data for a five-year period (2018-2022). In this comparison, I use actual values for each of the inputs into each rate, with one exception. Since Duke Kentucky's GSS rate that I am recommending includes a transmission charge component based on Big Rivers' NITs rate, I have used the current BREC rate of $2.113/kW/month for each of the years. All of the other data (for example, MISO LMP, forced outage hours, FAC charge, etc.) are the actual values for the month being modeled. Table 2 below summarizes these results for each of the 5 years. The calculations supporting the development of the LICSS and Duke Kentucky GSS method charges for the year 2018 are shown in my Exhibits__(SJB-11) and (SJB-12), as an example of the components of the two rates. Domtar witness Mr. Thomas supports the actual Domtar charges under its contract with BREC in the years 2018-2022.

Table 2
Domtar Standby Service Rate Comparison

	Current Domtar Contract	Proposed LICSS Tariff	$ Change	% Difference	Recommended Rate Using DEK Methodology	$ Change	% Difference
2018	$ 13,214,109	$ 20,504,184	$ 7,290,075	55.2%	$ 16,120,138	$ 2,906,029	22.0%
2019	$ 13,132,940	$ 21,461,597	$ 8,328,658	63.4%	$ 17,346,682	$ 4,213,742	32.1%
2020	$ 11,277,928	$ 19,427,446	$ 8,149,518	72.3%	$ 15,955,034	$ 4,677,107	41.5%
2021	$ 13,624,513	$ 20,217,476	$ 6,592,964	48.4%	$ 15,455,424	$ 1,830,911	13.4%
2022	$ 20,044,343	$ 22,096,890	$ 2,052,547	10.2%	$ 19,113,694	$ (930,649)	-4.6%
5-Year Average Annual Charges	$ 14,258,767	$ 20,741,519	$ 6,482,752	45.5%	$ 16,798,195	$ 2,539,428	17.8%
Difference from Current Contract		$ 6,482,752			$ 2,539,428		
% Difference		45.5%			17.8%		

As can be seen, the increases to Domtar if Big Rivers' LICSS tariff is adopted would range from $2.1 million per year (10.2%) to $8.1 million (72.3%). Under the Duke Kentucky GSS methodology, these increases range from -$0.93 million per year (-4.6%) to $4.6 million (41.5%). The 5-year average increase from the LICSS tariff would be $6.5 million per year (45.5%), while the 5-year average increase under my recommended rate is $2.5 million per year (17.8%).

Q. What is your recommendation in this case?

A. My recommendation is to reject Big Rivers' proposed LICSS Tariff and adopt my proposed Backup, Maintenance and Supplemental Power rate design based on Duke Energy Kentucky's Rider GSS. However, the Commission should consider Mr.

Thomas's testimony in which he discusses the rate shock problems to Domtar's Kentucky plant, even under our recommended rate methodology. As he discusses, he proposes an alternative approach that would shift all of the risk for backup and maintenance power to Domtar and away from Big Rivers and its other customers.

Q. Does that complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this
30th day of November 2023.

Jessica K Inman

Notary Public

Jessica K Inman
NOTARY PUBLIC
Cherokee County, GEORGIA
My Commission Expires 07/31/2027

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EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

Professional Qualifications

Of

Stephen J. Baron

Mr. Baron graduated from the University of Florida in l972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, he received a Master of Arts Degree in Economics, also from the University of Florida. His areas of specialization were econometrics, statistics, and public utility economics. His thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which he received a grant from the Public Utility Research Center of the University of Florida. In addition, he has advanced study and coursework in time series analysis and dynamic model building.

Mr. Baron has more than forty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, he joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. His responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, he joined the Utility Rate Consulting Division of Ebasco Services, Inc.

as an Associate Consultant. In the seven years he worked for Ebasco, he received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. His responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

He joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity he was responsible for the operation and management of the Atlanta office. His duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, he specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, he joined the consulting firm of Kennedy and Associates as a Vice President and Principal. Mr. Baron became President of the firm in January 1991.

He has presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." His article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, he completed a detailed analysis entitled "Load Data

Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

Mr. Baron has presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, South Carolina, Ohio, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of his specific regulatory appearances follows.

Expert Testimony Appearances
of
Stephen J. Baron
As of November 2023

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air

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Date	Case	Jurisdict.	Party	Utility	Subject
					Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. And gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
09/00	00-1178-E-T	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Electric utility restructuring rate unbundling
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company (“Transco”). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
03/06	05-1278-E-PC -PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Retail cost of service, rate design.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design

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05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider

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6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost “ENEC” Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy’s Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.

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4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
7/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Cost of Service, Rate Design
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design
5/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
6/11	Docket No. 10-035-124	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/11	PUE-2011-00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
07/11	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues
07/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Provider of Last Resort Issues
08/11	PUE-2011-00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Rate Recovery of RPS Costs
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility	Louisville Gas & Electric Co. Kentucky Utilities Company	Environmental Cost Recovery
09/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Stipulation Support Testimony
10/11	11-0452 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery

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11/11	11-1272 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis
11/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Decoupling
12/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
3/12	Case No. 2011-00401	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Environmental Cost Recovery
4/12	2011-00036 Rehearing Case	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
5/12	2011-346 2011-348	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
6/12	PUE-2012 -00051	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
6/12	12-00012 12-00026	TN	Eastman Chemical Co. Air Products and Chemicals, Inc.	Kingsport Power Company	Demand Response Programs
6/12	Docket No. 11-035-200	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/12	12-0275-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider
6/12	12-0399-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/12	120015-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/12	2011-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Environmental Cost Recovery
8/12	Case No. 2012-00226	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Real Time Pricing Tariff
9/12	ER12-1384	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement, Cancelled Plant Cost Treatment
9/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/12	12-1238 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost Recovery Issues
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana	Purchased Power Contracts
12/12	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating	System Agreement Issues Related to off-system sales

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				Companies	Damages Phase
12/12	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Decoupling
1/13	12-1188 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Securitization of ENEC Costs
1/13	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
4/13	12-1571 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Generation Resource Transition Plan Issues
4/13	PUE-2012 -00141	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Generation Asset Transfer Issues
6/13	12-1655 E-PC/11-1775 -E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Generation Asset Transfer Issues
06/13	U-32675	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	MISO Joint Implementation Plan Issues
7/13	130040-EI	FL	WCF Health Utility Alliance	Tampa Electric Company	Cost of Service, Rate Design
7/13	13-0467-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost (“ENEC”)
7/13	13-0462-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
8/13	13-0557-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Ratemaking Policy Associated with Rural Economic Reserve Funds
10/13	13-0764-E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Clinch River Gas Conversion Project
11/13	R-2013-2372129	PA	United States Steel Corporation	Duquesne Light Company	Cost of Service, Rate Design
11/13	13A-0686EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Demand Side Management Issues
11/13	13-1064-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
4/14	ER-432-002	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Union Pacific Railroad Litigation Settlement
5/14	2013-2385 2013-2386	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues

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5/14	14-0344-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/14	14-0345-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
5/14	Docket No. 13-035-184	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
7/14	PUE-2014-00007	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
7/14	ER13-2483	FERC	Bear Island Paper WB LLC	Old Dominion Electric Cooperative	Cost of Service, Rate Design Issues
8/14	14-0546-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Mitchell Asset Transfer
8/14	PUE-2014-00026	VA	Old Dominion Committee	Appalachian Power Company	Biennial Review Case - Cost of Service Issues
9/14	14-841-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Electric Security Rate Plan Standard Service Offer
10/14	14-0702-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/14	14-1550-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
12/14	EL14-026	SD	Black Hills Power Industrial Intervenors	Black Hills Power, Inc.	Cost of Service Issues
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design transmission, lost revenues
2/15	14-1297 EI-SS0	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
3/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Interruptible load
5/15	15-0301-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/15	15-0303-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Co.	Energy Efficiency/Demand Response

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6/15	14-1580-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio	Energy Efficiency Rider Issues
7/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Off-System Sales and Bandwidth Tariff
8/15	PUE-2015 -00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
8/15	87-0669-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/15	D2015-6.51	MT	Montana Large Customer Group	Montana Dakota Utilities Co.	Class Cost of Service, Rate Design
11/15	15-1351-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
3/16	EL01-88 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Bandwidth Tariff
5/16	16-0239-E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
6/16	E-01933A-15-0322	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
6/16	16-00001	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Cost of Service, Rate Design
6/16	14-1297-EL-SS0-Rehearing	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
06/16	15-1734-E-T-PC	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Co.	Demand Response Rider
7/16	160021-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/16	16AL-0048E	CO	CF&I.Steel LP Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
7/16	16-0403-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Response
10/16	16-1121-E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
11/16	16-0395-EL-SSO	OH	Ohio Energy Group	Dayton Power & Light	Electric Security Rate Plan
11/16	EL09-61-004 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase

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12/16	1139	D.C.	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of Service, Rate Design
1/17	E-01345A-16-0036	AZ	Kroger	Arizona Public Service Co.	Cost of Service, Rate Design
2/17	16-1026-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Co.	Wind Project Purchase Power Agreement
3/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/17	16-1852	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
7/17	17-00032	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Vegetation Management Cost Recovery
8/17	17-0631-E-P	WV	West Virginia Energy Users Group	Monongahela Power Co.	Electric Energy Purchase Agreement
8/17	17-0296-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation Resource Asset Transfer
9/17	2017-0179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission cost recover.
9/17	17-0401 E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
12/17	17-0894-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Co.	Wind Project Asset Purchase
5/18	1150/ 1151	D.C.	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of Service, Rate Design Tax Cut and Jobs Act Issues
6/18	17-00143	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Storm Damage Rider Cost Recovery
7/18	18-0503-E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/18	18-0504-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Vegetation Management Cost Recovery
7/18	G.O.236.1	WV	West Virginia Energy Users Group	Appalachian Power Company	Tax Cut and Jobs Act Issues
7/18	G.O.236.1	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Tax Cut and Jobs Act Issues
10/18	18-0646-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design TCJA issues
10/18	18-00038	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Tax Cut and Jobs Act Issues

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11/18	18-1231- E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost (“ENEC”)
11/18	2018-00054	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Tax Cut and Jobs Act Issues
12/18	2018-00134	VA	Collegiate Clean Energy	Appalachian Power Company	Competitive Service Provider Issues
1/19	2018-00294 2018-00295	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
1/19	2018-00101	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service
2/19	UD-18-07	City of New Orleans	Crescent City Power Users Group	Entergy New Orleans	Cost of Service, Rate Design
4/19	42310	GA	Georgia Public Service Commission Staff	Georgia Power Company	2019 Integrated Resource Plan Optimal Reserve Margin Issues
7/19	19-0396 E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
10/19	19-0387 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Economic Development Fund
10/19	19-0564 E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Mitchell Generating Plant Surcharge
10/19	E-01933A- 19-0028	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
11/19	19-0785 E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost (“ENEC”)
11/19	2018-00101	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service
11/22	2019-00170 -UT	NM	COG Operating, LLC	Southwestern Public Service Co.	Cost of Service, Rate Design
12/19	19-1028 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	PURPA Contract Buy-out
4/20	20-00064	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Cooperative, Inc.	Rate Design
7/20	2019-226-E	SC	The South Carolina Office of Regulatory Staff	Dominion Energy South Carolina	2020 Integrated Resource Plan Load Forecasting, Reserve Margin Issue
7/20	2020-00015	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	2020 Triennial Review Case - Cost Allocation, Revenue Apportionment
8/20	E-01345A- 19-0236	AZ	Kroger Company	Arizona Public Service Co	Cost of Service, Rate Design

Expert Testimony Appearances
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Stephen J. Baron
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Date	Case	Jurisdict.	Party	Utility	Subject
10/20	2020-00174	KY	Kentucky Industrial Utility Customers, Inc., KY AG	Kentucky Power Company	Cost of service, net metering, transmission costs.
11/20	20-0665 E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Expanded Net Energy Cost ("ENEC")
2/21	2019-224-E 2019-225-E	SC	The South Carolina Office of Regulatory Staff	Duke Energy Carolinas Duke Energy Progress	2020 Integrated Resource Plan Load Forecasting, Reserve Margin Issue
3/21	2020-00349 2020-00350	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design. Net Metering issues
3/21	20AL-0432E	CO	Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
3/21	20-1476-	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
5/21	20-1040 E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Environmental CCN and Surcharge
5/21	20-1012 E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Infrastructure Investment Tracker and Surcharge
5/21	2020-00238 -UT	NM	COG Operating, LLC	Southwestern Public Service Co.	Cost of Service, Rate Design
6/21	2021-00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Coal Combustion Residuals Rider CCR Cost Allocation, Rate Design
7/21	20-1049 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Excess Accumulated. Def. Income Tax Rate Treatment
7/21	21-00339 E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Expanded Net Energy Cost ("ENEC")
9/21	2021-00058	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service 2020 Triennial Review Case - Cost Allocation, Revenue Apportionment
11/21	21-0658 E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Expanded Net Energy Cost ("ENEC")
2/22	2021-0481	KY	Kentucky Industrial Utility Customers, Inc., KY AG	Kentucky Power Company Liberty Utilities	Acquisition of Kentucky Power Co. by Liberty Utilities
2/22	21-0813- E-CS	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Solar Energy Rate Recovery
3/22	2021-00229	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Nuclear Plant Upgrade Rider SNL
3/22	21-00107	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Cost of Service, Rate Design
3/22	2021-00206	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	2021 RPS Plan

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5/22	44160	GA	Georgia Public Service Commission Staff	Georgia Power Company	2022 Integrated Resource Plan Optimal Reserve Margin Issues
6/22	2021-00156	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	2021 RPS Cost Allocation
9/22	22-00393 E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Expanded Net Energy Cost (“ENEC”) Coal Inventory Prudence Issues
10/22	44280	GA	Georgia Public Service Commission Staff	Georgia Power Company	2022 Rate Case
11/22	22-0793 E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Expanded Net Energy Cost (“ENEC”)
1/23	E-01933A-22-0107	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
2/23	21-00387	KY	Kentucky Industrial Utility Customers, Inc., Kentucky Attorney General	Kentucky Power Company	Special Contract.
3/23	2022-00166	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	2022 RPS Cost Recovery
4/23	22-00286 -UT	NM	COG Operating, LLC	Southwestern Public Service Company	Cost of Service, Rate Design
5/23	E-01345A-22-0144	AZ	Kroger Company	Arizona Public Service Co	Rate Design
6/23	23-23	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Transmission Rider Rate Design
7/23	2023-00002	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	2023 Triennial Review Case - Cost Allocation, Revenue Apportionment
8/23	23-0377 E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Expanded Net Energy Cost (“ENEC”) Coal Inventory Prudence Issues
10/23	23AL-0243E	CO	Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
10/23	2023-00002	VA	Virginia Committee For Fair Utility Rates	Virginia Electric Power Company (Dominion)	2023 Biennial Review Case - Cost Allocation, Revenue Apportionment
10/23	23-301 EL-SS0	OH	Ohio Energy Group	Ohio Edison, Toledo Edison	Electric Security Rate Plan

Expert Testimony Appearances
of
Stephen J. Baron
As of November 2023

Date	Case	Jurisdict.	Party	Utility	Subject

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

ELECTRONIC TARIFF FILING OF BIG RIVERS	**)**	
ELECTRIC CORPORATION AND KENERGY	**)**	**Case No. 2023-00312**
CORP. TO REVISE THE LARGE INDUSTRIAL	**)**	
CUSTOMER STANDBY SERVICE TARIFF	**)**	

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

IN THE MATTER OF:
ELECTRONIC TARIFF FILING OF BIG RIVERS ELECTRIC CORPORATION
AND KENERGY CORP. TO REVISE THE
LARGE INDUSTRIAL CUSTOMER STANDBY SERVICE TARIFF
CASE NO. 2023-00312

JOINT RESPONSE OF BIG RIVERS ELECTRIC CORPORATION AND KENERGY CORP.
TO COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION

REQUEST NO. 1-11: ***Refer to the Berry Direct Testimony, page 6. Also refer to the March 3, 2021 Order in Case No. 2021-00289, page 20.5 The Commission found BREC should not bundle LICSS Maintenance Power Service and Backup Power Service and the rates should be set so that the embedded and incremental costs of each are accounted for properly. Provide the maintenance and backup rates separately showing the embedded and incremental costs are accounted for properly. Include in the response each embedded and incremental cost for maintenance power and backup power.***

RESPONSE: As discussed in the Direct Testimony of Nathan Berry on pages 6-7, Big Rivers proposes in the instant case to remove Maintenance Power Service from the proposed tariff and to redefine Backup Power Service to apply in both scheduled and unscheduled outages. This approach is supported by the fact that Big Rivers is obligated to establish and maintain the capability to provide service at a Standby Customer's full demand level at all times during each and every month. The Standby Customer is charged the standard Commission-approved LIC demand rate for this service. Whether there are scheduled, unscheduled, or no outages during the month does not impact Big Rivers' costs to establish and maintain the capacity required by the Standby Customer.

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Also, because the energy charge for Back-up Power Service under the proposed LICSS tariff is the higher of the standard Commission-approved LIC energy rate or the LMP price, Big Rivers is held harmless whether outages are scheduled or unscheduled. Thus, there are not separate costs to Big Rivers for Maintenance Power Service and Backup Power Service, as those terms are used in the existing tariff. For that reason, the proposed tariff defines Backup Power Service to apply in both scheduled and unscheduled outages.

Witness: Nathanial A. Berry (Big Rivers)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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ELECTRIC CORPORATION AND KENERGY	**)**	**Case No. 2023-00312**
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CUSTOMER STANDBY SERVICE TARIFF	**)**	

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

IN THE MATTER OF:
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AND KENERGY CORP. TO REVISE THE
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JOINT RESPONSE OF BIG RIVERS ELECTRIC CORPORATION AND KENERGY CORP.
TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-1: ***Refer to BREC's response to Commission Staff's First Request for Information (Staffs First Request), Item 3. The March 3, 2023 Order in Case No. 2021-00289 made clear that Maintenance and Backup Services were different services and that BREC should provide cost support for the different services. Eliminating a service and effectively combining the two services is not responsive to the Order. Provide cost support for the different services in response to the previous Order.***

RESPONSE: Big Rivers' costs for providing Backup Power during planned outages is the same as during unplanned outages. If Big Rivers were its own Balancing Authority and responsible for balancing generation with its load, there could be a cost difference. However, from Big Rivers' perspective, since being fully integrated into MISO, the service provided to back up a customer generator during scheduled outages is the same service provided to back up a customer generator during unscheduled outages. In either case, Big Rivers will secure backup energy in the MISO energy market.

Under the previous tariff, there was a single demand charge for Maintenance and Backup Power Service, which was the demand charge under Big Rivers' Standard Rate Schedule LIC tariff, less a credit equal to \$3.80/KW-month. Maintenance and Backup energy were both billed

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at the higher of the LIC tariff energy rate or market prices. Utilizing the two terms caused confusion in Case No. 2021-00289.

Under the proposed LICSS tariff, the Standby Customer would pay the higher of LMP or the LIC tariff rate during an outage, so Big Rivers would have no exposure to the timing of a generator outage because even if the outage occurs when the LMP exceeds the LIC energy rate, then the LICSS Customer would be charged LMP just like Big Rivers pays LMP. Under all scenarios, Big Rivers still needs to maintain a sufficiently robust local transmission system to meet the LICSS Customer's needs under both a scheduled outage and unscheduled outage.

Furthermore, as was stated on pages 6 and 7 of the Direct Testimony of Nathanial A. Berry filed with the proposed LICSS Tariff:

> Big Rivers recognizes that the Commission's Mar. 3, 2022 Order stated that Maintenance Power Service and Backup Power Service, as those terms are used in the current Standby Service tariff, are different, and that bundling the pricing of the two service was inappropriate. However, Big Rivers respectfully disagrees that the difference between the two services results in a difference in cost. The Commission found in the Mar. 3, 2022 Order that
>
> > up until Kimberly-Clark began self-supplying a portion of its demand, it had been paying LIC Tariffed demand charges on its entire demand. It is not fair to the other customer for it to stop paying for that capacity even though it will be utilized on a temporary and incremental basis."
>
> The proposed Backup Power demand rate ensures that Standby Customers pay the LIC demand charges on their entire demand when their generator is on outage (less the demand credit). When a Standby Customer requests Backup Power

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> Service, the Standby Customer is purchasing a service whereby Big Rivers must make available the transmission service and power needed by the Standby Customer when the customer's generator is on outage or is not otherwise operating at its full accredited capacity. Because Big Rivers must have that capability available at all times in the event of an unscheduled outage, it does not change Big Rivers' cost if the customer also schedules some of its outages. And so long as the customer is paying for that capability, it should not be charged any different amounts for scheduled outages.
>
> In the Mar. 3, 2022 Order, the Commission noted, "In the event of an unplanned outage, regardless of when it occurs, Kimberly-Clark reverts to its historic demand level, and BREC is obligated to provide service at Kimberly-Clark's prior full demand level." This is also true of planned outages. In the event of a planned outage, Big Rivers is likewise obligated to provide service at a Standby Customer's full demand level. Thus, there are not separate costs to Big Rivers for Maintenance Power Service and Backup Power Service, as those terms are used in the existing Standby Service tariff. For that reason, the proposed tariff changes remove Maintenance Power Service and define Backup Power Service to apply in both scheduled and unscheduled outages. [Footnotes omitted.]

Witness: Terry Wright, Jr. (Big Rivers)

COMMONWEALTH OF KENTUCKY

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ELECTRIC CORPORATION AND KENERGY	**)**	**Case No. 2023-00312**
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CUSTOMER STANDBY SERVICE TARIFF	**)**	

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

IN THE MATTER OF:
ELECTRONIC TARIFF FILING OF BIG RIVERS ELECTRIC CORPORATION
AND KENERGY CORP. TO REVISE THE
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JOINT RESPONSE OF BIG RIVERS ELECTRIC CORPORATION AND KENERGY CORP.
TO COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION

REQUEST NO. 1-3: ***Refer to the March 3, 2023 Order in Case No. 2021-00289, ordering paragraph 3. Provide the cost support for the LICSS rates proposed in the tariff filing.***

RESPONSE: Since the March 3, 2023 Order, Big Rivers adopted an approach for the LICSS tariff that aligns with that in its proposed Rate QF – Qualified Cogeneration / Small Power Production Facility Tariff (for Qualifying Facilities or "QF" customers). This approach does not use a quantified, standalone rate, either for the relevant charges or for any credits. Instead, the proposed LICSS rate relies on the Commission-approved LIC demand rates for the demand charges to the customer, the MISO Planning Resource Auction ("PRA") Auction Clearing Prices ("ACP") for the credit passed back to the customer for the accredited capacity its generator provides, and the Commission-approved LIC energy rates or the actual locational marginal price ("LMP") for energy by MISO at the applicable load node for energy sold to the customer, plus incurred transmission charges, MISO fees, or other costs. Aside from the LIC rates that were set by the Commission, none of these are stated rates, per se, and thus there are no quantified charges in the rate schedule for which Big Rivers can provide cost support; instead, the justification for the amounts to be charged a LICSS customer are derived with transparency from other sources based on the actual costs and benefits.

Witness: John Wolfram

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EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

IN THE MATTER OF:
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JOINT RESPONSE OF BIG RIVERS ELECTRIC CORPORATION AND KENERGY CORP.
TO DOMTAR PAPER COMPANY, LLC'S FIRST REQUEST FOR INFORMATION

REQUESTNO.1-5: ***Please identify any utilities that BREC is aware of that has a standby and maintenance power tariff similar to BREC's proposed Rate LICSS. Include the name of the utility, the title of the rate or tariff and, if available to BREC, a copy of the rate or tariff.***

RESPONSE: Big Rivers is not aware of other utilities that have standby schedules similar to the proposed LICSS.

Witness: John Wolfram

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EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

IN THE MATTER OF:
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JOINT RESPONSE OF BIG RIVERS ELECTRIC CORPORATION AND KENERGY CORP.
TO DOMTAR PAPER COMPANY, LLC'S FIRST REQUEST FOR INFORMATION

REQUEST NO. 1-12: ***Refer to the Rate LIC kW demand charge. Please provide a breakdown of the generation and transmission components of the current LIC kW charge of $10.1750/kW (i.e., how much of the $10.175 charge is associated with generation/production demand and how much is associated with transmission demand). To the extent that the $10.175/kW charge includes a cost component for something other than generation/production and transmission, please identify such component(s) and state the amount of the $10.175/kW charge associated with such component/cost.***

RESPONSE: Please note that the LIC demand charge is $10.7150/kW per month. Because the current LIC demand charge was established by the Commission in a rate case without the Commission basing that charge entirely on the cost of service, the breakdown of generation and transmission components of the current charge is not precisely known. (The components are known within the cost of service studies, but those do not correspond exactly to the current rates.) Please also see the joint response of Big Rivers and Kenergy to Request Nos. 1-2 & 1-3 from Domtar Paper Company and Request Nos. 1-15 and 1-16 from Kimberly-Clark Corporation.

Witness: John Wolfram

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EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

IN THE MATTER OF:
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TO DOMTAR PAPER COMPANY, LLC'S FIRST REQUEST FOR INFORMATION

REQUEST NO. 1-6: ***In its development of Rate LICSS, did BREC review standby and maintenance power rates of other utilities? If so, identify each such utility and the name or title of the tariff.***

RESPONSE: As part of the effort to develop the LICSS rate schedule, Big Rivers reviewed tariffs of other utilities, including but not limited to standby and maintenance power rates. In 2019, these included an AEP backup and maintenance tariff from 2015 in West Virginia, as well as a standby schedule for Southern Company / Alabama Power. Big Rivers also researched standby schedules or contract offerings of the Ohio Power Company, Duke Energy (Ohio and North Carolina), Alliant, Vectren, and other parties. In early 2020, Big Rivers reviewed Commission-approved standby rates for Duke Energy Kentucky (Rider GSS) and Kentucky Utilities (Rider SS, which was canceled approximately 2016). Big Rivers also examined rate offerings by East Kentucky Power, KU, LG&E, and Kentucky Power related to self-supply pricing for non-industrial rate classes.

Witness: John Wolfram

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EXHIBIT__(SJB-8)

OF

STEPHEN J. BARON

IN THE MATTER OF:
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TO COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION

REQUEST NO. 1-14: ***Refer to the redline version of the proposed BREC Tariff, Third Revised Sheet No. 69.01, unnumbered at 14.***

a. Explain why the Self-Supply Capacity for a Standby Customer must be accredited by MISO.

b. Explain the implications for the Stand-By Customer of having its Self Supply capacity accredited by MISO.

RESPONSE:

a. The Self-Supply Capacity for a Standby Customer needs to be accredited by MISO because MISO is the primary reliability authority responsible for ensuring the grid is stable. MISO needs to have accurate information regarding the quantity of generation and load in the MISO footprint, and in each zone, so that it can notify market participants of potential shortages and send appropriate price signals to market participants to help avoid shortage scenarios. Because MISO performs the reliability function, and because capacity is a major contributor to reliability, MISO's accreditation of behind-the-meter capacity is appropriate. Further, by requiring the Standby Customer's Self- Supply capacity to be accredited by MISO, the Capacity Credit received by the customer under the proposed LICSS tariff is a more accurate pass-through of the credit Big Rivers

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receives from MISO, meaning the customer is reimbursed the Capacity Value that Big Rivers receives from the Customer's Self-Supply Capacity in the PRA.

b. By MISO accrediting the capacity, it has the ability to call on the capacity during Emergency Conditions, which could help alleviate shortages and thereby allow MISO to avoid calling for controlled power interruptions. The implication for the customer is that the customer would have to make the generating resource available during Emergency Conditions.

Witness: Terry Wright, Jr. (Big Rivers)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

ELECTRONIC TARIFF FILING OF BIG RIVERS	**)**	
ELECTRIC CORPORATION AND KENERGY	**)**	**Case No. 2023-00312**
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CUSTOMER STANDBY SERVICE TARIFF	**)**	

EXHIBIT__(SJB-9)

OF

STEPHEN J. BARON

IN THE MATTER OF:
ELECTRONIC TARIFF FILING OF BIG RIVERS ELECTRIC CORPORATION
AND KENERGY CORP. TO REVISE THE
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JOINT RESPONSE OF BIG RIVERS ELECTRIC CORPORATION AND KENERGY CORP.
TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-8: ***Refer to BREC's response to Staff's First Request, Item 14.***

a. If not answered above, confirm that MISO requires customers who self-supply a portion of their energy needs to have their self-supply capacity accredited.

b. If MISO does not require accreditation, explain why it is reasonable to require it now when it was not required previously.

RESPONSE:

a. MISO does not require a behind-the-meter generator to register in the MISO market and receive capacity accreditation.

b. Big Rivers believes that it is reasonable to require these resources to register in order to ensure Big Rivers accurately reports load values to MISO and that its LICSS tariff correctly passes through both credits and charges incurred as result of the LICSS customer's generation. As explained below, registration of the customer's resource permits Big Rivers to avoid the risk associated with the unit's continued operation.

MISO is the central authority that ensures that the power grid has adequate resources to meet its load requirements, not Big Rivers. When a behind-the-meter resource does not register with MISO, Big Rivers is forced to attempt to provide its own accreditation of the resource by submitting a lower total load value than would otherwise be submitted to MISO. For example, if Big Rivers' load were 700 MWs and the capacity of the customer's resource is 50 MWs, Big

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Rivers could consider reducing its load submission by 50 MWs, to 650 MWs. One of the first problems encountered is the 50 MW reduction does not assume any Forced Outage Rate, so by default, it is over-accredited at 50 MWs. The second problem is that any load reduction is amplified when the MISO PRM (%) is applied. For Planning Year 23-24, the MISO PRM (%) for the Winter Season was 25.5%, so a 50 MW resource would reduce Big Rivers' PRMR Requirement by 62.75 MWs (50 MWs * 1.255). This is a higher amount than the customer's resource can produce. Had the resource been a traditional resource, it would have received an accreditation less than 50 MWs, which implies that Big Rivers would be over-accrediting the resource by at least 12.75 MWs. While this does not seem like a lot of MWs, there are many BTMG facilities across MISO's footprint; consequently, MISO could be at risk of under-estimating its load due to the over-accreditation of these resources. As MISO becomes more and more capacity constrained due to base-load thermal units retiring and being replaced with intermittent wind and solar resources, capacity accreditation is becoming more important in MISO. In the past, there was significant excess capacity available across the footprint, while it is now becoming a tighter market with MISO predicting capacity shortfalls starting in Planning Year 25-26.

Attached to this response is a copy of MISO's " 2023 OMS-MISO Survey Results" dated July 14, 2023 for information on these forecasted shortfalls.

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Witness: Terry Wright, Jr. (Big Rivers)

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ELECTRONIC TARIFF FILING OF BIG RIVERS	**)**	
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EXHIBIT__(SJB-10)

OF

STEPHEN J. BARON

Description of Surveyed Utilities' Standby and Maintenance Power Tariffs

Utility	Tariff Name	Description of Key Provisions
Duke Energy Kentucky	GSS	Backup/Standby, Maintenance, Supplemental
		Admin charge: $50/month
		Monthly T&D reservation charge: $3.8408/kW
		Standby Demand Contact Level: lessor of transmission capacity needed for contracted load or capacity of customer's generating unit.
		Standby Charges: Standby load X standard rate billing kW charge prorated by days of standby usage in the month.
		Maintenance Charges: Standby load X Standard rate billing kW charge prorated by days of maintenance X 50%.
		Maintenance notification: 60 days prior to January 1; 30 days max per year; 2 consecutive days during June-September and only during off-peak periods, all subject to DEK approval.
Georgia Power Company	BU-11	Firm and Interruptible backup and maintenance power
		Backup power is calculated as MW > normal billing MW (kW prior to outage or prior month)
		Maintenance must be scheduled 14 days in advance, up to 6 occurances per year
		Standby rate based on outage hours (< 876; 876<>1,752; > 1,752). This is standby factor.
		Firm standby reservation charge $1.91/kW/mo. plus facilites charge of $1.50/kW/mo.
		No additional standby charge in month when outage occurs if outage < 2 days.
		If outage is greater than 2 days, pro-rate of standard industrial rate, adjusted for Standby Factor
Jacksonville Electric Authority	SS-1	Facilities charge of $0.93/kW/mo.
		Standby rate: Standard industrial rate X reliability factor (RAC)
		RAC: (.1)/(.7) - .1 is assumed forced outage rate; .7 is coincidence factor with system peak. For 5 MW or >, RAC is [1- (annual generator operating hours/8760/.7.
		Maintenance power is included based on annual operating hours provision.
Florida Power & Light Co.	SST-1	Customer charge: $591/mo.; $2,506/mo. For > 69 kV
		Standby demand charge: Distribution: 4.71/kW; Reservation $2.05/kW/mo.
		Daily standby charge during outage: $0.99/kW/day
		Standby charge shall be the greater of the reservation charge or the daily charge X days
		Maintenance is included in same charges.
		Additonal non-fuel energy charge of $0.99₵/kWh of standby or maintenance power used.
		Plus standard tariff energy charge.
Entergy Louisiana, LLC	SMQ-G	Reserved Standby Power: amount of standby demand required per contract or actual if contract exceeded.
		Standby demand: Difference between max demand in month and standard contract demand less scheduled maintenance demand.
		Daily Sta RSP: max standby load during each day during first 3 days; 0 beyond 3 days.
		Standby demand charge: $0.95* RSP + Standby service daily demand X 1.75 X (pro-rated standard rate)
		Maintenance: standard rate X maintenance kW X .667 [.667 is off-peak charge to on-peak charge ratio)
		Energy charge for all standby and maintenance power: standard rate energy charge.
Kingsport Power Co. (AEP)	S.B.S	Standby MW by contract
		Standby Monthly Rate: Customer selects reliability level based on the expected number of hours per year of outages (5%, 10%, 15%, 20%, 25%, 30%). For example, a 10% level would equate to 876 hours per year of expected outages.
		Standby demand charge: Distribution charge plus demand charges based on the reliability election X the production demand component of the standard rate.
		Energy Charge for standby and maintenance power: standard large customer rate energy charge.
		plus distribution energy charge (if primary or secondary voltage customer) of .596₵/kWh or .396₵/kWh.

RIDER GSS
GENERATION SUPPORT SERVICE

APPLICABILITY

Applicable to any general service customer having generation equipment capable of supplying all or a portion of its power requirements for other than emergency purposes and who requests supplemental, maintenance or backup power.

TYPE OF SERVICE

Service will be rendered in accordance with the specifications of the Company's applicable distribution voltage service or transmission voltage service tariff schedules.

NET MONTHLY BILL

The provisions of the applicable distribution service or transmission service tariff schedule and all applicable riders shall apply to Supplemental Power Service, Maintenance Power Service and Backup Power Service except where noted otherwise. The monthly Administrative Charge and the Monthly Reservation Charges as shown shall apply only to Maintenance Power Service and Backup Power Service.

1. Administrative Charge
   The Administrative Charge shall be $50 plus the appropriate Customer Charge.

2. Monthly Transmission and Distribution Reservation Charge

a. Rate DS - Secondary Distribution Service	$7.8593 per kW	(I)
b. Rate DT – Distribution Service	$10.3382 per kW	(I)
c. Rate DP – Primary Distribution Service	$7.8987 per kW	(I)
d. Rate TT – Transmission Service	$3.8408 per kW	(I)

3. Supplemental Power Service
   The customer shall contract with the Company for the level of demand required for Supplemental Power Service. All Supplemental Power shall be billed under the terms and charges of the Company's applicable full service tariff schedules. All power not specifically identified and contracted by the customer as Maintenance Power or Backup Power shall be deemed to be Supplemental Power.

4. Maintenance Power Service
   Requirements -
   The customer shall contract with the Company for the level of demand required for Maintenance Power. The contracted level of Maintenance Power shall be the lesser of: 1) the transmission and/or distribution capacity required to serve the contracted load; or, 2) the demonstrated capacity of the customer's generating unit(s) for which Maintenance Power is required. The customer's Maintenance Power requirements for each generating unit must be submitted to the Company at least sixty (60) days prior to the beginning of each calendar year. Within thirty (30) days of such submission, the Company shall respond to the customer either approving the Maintenance Power schedule or requesting that the customer reschedule those Maintenance Power requirements. For each generating unit, the customer may elect Maintenance Power Service for up to thirty (30) days in any twelve month period with no more than two (2) days consecutively

NET MONTHLY BILL (Contd.)

during the summer billing periods of June through September and those must be during the Company's off-peak periods. The customer may request an adjustment to the previously agreed upon Maintenance Power schedule up to three weeks prior to the scheduled maintenance dates. The adjusted dates must be within one (1) week of the previously scheduled dates and result in a scheduled outage of the same seasonal and diurnal characteristics as the previously scheduled maintenance outage. The Company shall respond to the customer's request for an adjustment within one (1) week of that request. The Company may cancel a scheduled Maintenance Power period, with reason, at any time with at least seven (7) days notice to the customer prior to the beginning of a scheduled maintenance outage if conditions on the Company's electrical system warrant such a cancellation. Any scheduled Maintenance Power period cancelled by the Company shall be rescheduled subject to the mutual agreement of the Company and the customer.

Billing –
All power supplied under Maintenance Power Service shall be billed at the applicable rate contained in the Company's full service tariff schedules except for the following modifications: 1) the demand ratchet provision of the Company's full service tariff schedules shall be waived; and 2) the demand charge for Generation shall be fifty (50) percent of the applicable full service tariff Generation demand charge prorated by the number of days that Maintenance Power is taken.

5. Backup Power Service
Requirements –
The customer shall contract with the Company for the level of demand required for Backup Power. The contracted level of Backup Power shall be the lesser of: 1) the transmission and/or distribution capacity required to serve the contracted load; or, 2) the demonstrated capacity of the customer's generating unit(s) for which Backup Power is required. The customer shall notify the Company by telephone within one-hour of the beginning and end of the outage. Within 48 hours of the end of the outage, the customer shall supply written notice to the Company of the dates and times of the outage with verification that the outage had occurred.

Billing –
All Backup Power will be billed at the applicable rate contained in the Company's full service tariff schedules except for the following modifications: 1) the demand ratchet provision, if any, of the Company's full service tariff schedules is waived; and 2) the demand charge for Generation shall be the applicable full service tariff schedule Generation demand charge prorated by the number of days that Backup Power is taken. (D)
(D)

6. Monthly Reservation Charges
The Monthly Distribution Reservation Charge, Monthly Transmission Reservation Charge and the Monthly Ancillary Services Charge items shown above shall be based on the greater of the contracted demand for Maintenance Power or Backup Power.

METERING

Recording meters, as specified by the Company, shall be installed where necessary, at the customer's expense. All metering equipment shall remain the property of the Company.

DEFINITIONS

Supplemental Power Service – a service which provides distribution and/or transmission capacity to the customer as well as the energy requirements for use by a customer's facility in addition to the electric power which the customer ordinarily generates on its own.

Maintenance Power Service – a contracted service which provides distribution and/or transmission capacity as well as the energy requirements for use by the customer during scheduled outages or interruptions of the customer's own generation.

Backup Power Service – a contracted service which provides distribution and/or transmission capacity as well as the energy requirements for use by the customer to replace energy generated by the customer's own generation during an unscheduled outage or other interruption on the part of the customer's own generation.

TERMS AND CONDITIONS

The term of contract shall be for a minimum of five (5) years.

The customer shall be required to enter into a written Service Agreement with the Company which shall specify the type(s) of service required, notification procedures, scheduling, operational requirements, the amount of deviation from the contract demand to provide for unavoidable generation fluctuations resulting from normal mechanical factors and variations outside the control of the customer and the level of demand and energy required.

The customer is required to adhere to the Company's requirements and procedures for interconnection as set forth in the Company's publication, "System Protection Requirements & Guidelines for Connection & Parallel Operation of Non-Utility Generators" which is provided to customers requesting service under this rider.

The cost of any additional facilities associated with providing service under the provisions of this rider shall be borne by the customer.

Changes in contracted demand levels may be requested by the customer once each year at the contract anniversary date. This request shall be made at least thirty (30) days in advance of the contract anniversary date.

The Company may enter into special agreements with customers which may deviate from the provisions of this rider. Such agreements shall address those significant characteristics of service and cost which would influence the need for such an agreement.

The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations currently in effect, as filed with the Kentucky Public Service Commission.

ELECTRIC SERVICE TARIFF:

BACK-UP SERVICE
SCHEDULE: "BU-11"

GEORGIA POWER
A SOUTHERN COMPANY

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AVAILABILITY:

Throughout the Company's service area from existing lines of adequate capacity.

APPLICABILITY:

Applicable upon request as a modification of the rate schedules for Power and Light, and Full Use Service to Governmental Institutions, if the customer is a PURPA qualifying facility, or has customer-owned generation that normally operates at least 6,000 hours per year.

DEFINITIONS:

A. STANDBY CAPACITY. The customer must designate and contract for the amount of firm and/or interruptible standby capacity to replace capacity from customer-owned generation when that generation is not in service. The sum of the firm and interruptible standby capacity shall not exceed the nameplate rating of the customer's own generation.

B. BACK-UP POWER. This is energy or capacity to replace energy generated by a customer's own equipment when that equipment is not in service, except during periods of maintenance power, or when the customer's actual metered demand is less than the normal Billing Demand on the Power and Light Rates or the Governmental Rate. Except during periods of approved maintenance power, any demand above the normal billing demand when the customer's generating equipment is not in service will be considered back-up power.

FIRM BACK-UP POWER. For billing under this schedule, the customer must notify the Company within 24 hours of taking firm back-up service.

INTERRUPTIBLE BACK-UP POWER. The customer shall request and receive permission from the Company before using interruptible back-up power, except if the customer has a forced outage. In such a case, back-up service may be started at the time of the outage, but the customer must notify the Company and request continued use of such service within 30 minutes. The Company shall have the right to deny or interrupt this service at any time solely at the option of the Company. If the Company denies or interrupts this service, the customer must cease such service within 30 minutes of receiving the notice from the Company.

C. MAINTENANCE POWER. This is energy or capacity supplied during scheduled outages of the customer's generation for the purpose of maintenance of his generation facility. The customer must schedule maintenance power with the Company not less than 14 days prior to its use. Maintenance power service shall be limited to not more than six occurrences and not more than sixty (60) total days during a calendar year (based on billing dates).

FIRM MAINTENANCE POWER. Firm maintenance power will be available during the months of March, April, October, November, and December, or at such other times as may be mutually acceptable. The firm maintenance power available shall not be greater than the firm back-up power reserved.

INTERRUPTIBLE MAINTENANCE POWER. This service will be available on an interruptible basis throughout the year. The Company shall have the right to deny or interrupt this service at any time solely at the option of the Company. If the Company denies or interrupts this service, the customer must cease such service within 30 minutes of receiving notice from the Company. The amount of interruptible maintenance power available shall be the total contracted standby capacity.

D. SUPPLEMENTARY POWER. The power supplied by the Company to the customer in addition to that which is normally supplied by customer-owned generation. Supplementary power will be supplied under the Power and Light Rates, or Governmental Rate.

SCHEDULE: "BU-11"

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E. STANDBY POWER DEMAND. Whenever back-up power or maintenance power, as specified in this tariff, is taken during a billing period, the standby power demand shall be equal to the maximum metered demand measured during the time standby service is being taken, less the maximum metered demand during the time intervals in the billing period (or the most recent month) when standby service is not being taken. When the customer is taking this schedule in conjunction with the Company's Off-Peak Service Rider, the standby power demand as determined herein will be calculated separately for on-peak and off-peak times, and the customer will be billed on the greater of the two calculations. The standby power demand cannot exceed the standby capacity contracted for.

During any time intervals when maintenance power is taken in conjunction with back-up power, the maintenance power demand shall be the amount of capacity scheduled for maintenance (not to exceed the total standby power demand). The back-up power demand during these time intervals shall be the total standby power demand less the maintenance power demand.

F. DETERMINATION OF NORMAL BILLING DEMAND. The highest 30-minute kW measurement, for the purpose of determining the normal billing demand for supplementary power as calculated under the provisions of either the Power and Light Rate or the Governmental Rate, shall be based on the greater of (1) the maximum measured demand during the time standby service is not being taken, or (2) the maximum measured demand during the time standby service is being taken, less the standby power demand times the standby demand adjustment factor, as defined in paragraph (G) below, for the applicable on-peak and off-peak periods.

G. STANDBY DEMAND ADJUSTMENT FACTOR. When the customer has required back-up service (firm or interruptible) for 876 hours or less during the most recent 12 month period, the standby demand adjustment factor is equal to 1.0.

When the customer has required back-up service (firm or interruptible) for more than 876 hours but less than 1,752 hours during the most recent 12 month period, the standby demand adjustment factor will be determined as follows:

SDAF = (2 - (NHU/876))

Where:

SDAF	=	standby demand adjustment factor
NHU	=	number of hours the back-up service has been required during the most recent 12 month period*

* The time that maintenance power is taken, as defined in this schedule, as well as time when the total metered demand is less than the normal billing demand under the Power and Light Rates or Governmental Rate schedule, shall not count toward NHU.

If the customer requests back-up service (firm or interruptible) when he has already used such service for 1,752 hours or more during the most recent 12 month period, the standby demand adjustment factor shall be equal to zero.

INTERCONNECTION:

The Company will interconnect to the customer's generating equipment in accordance with the Power Delivery Bulletin Number 18-8. The cost of such interconnection will be paid by the customer according to Company policies.

MONTHLY RATE:

Administrative Charge…………………………………………………………………..$196.00

Firm Standby Reserve Charge..$1.91 per kW of firm standby capacity plus Environmental Compliance Cost Recovery, plus Nuclear Construction Cost Recovery, plus Municipal Franchise Fee

Local Facilities Charge...$1.50 per kW of total standby capacity plus Environmental Compliance Cost Recovery, plus Nuclear Construction Cost Recovery, plus Municipal Franchise Fee

SCHEDULE: "BU-11"

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FIRM STANDBY CAPACITY CHARGE:

Firm standby power will have no additional capacity charge when either firm back-up, or firm maintenance, or a combination of both, has been used two days or less during the billing period. When used more than two days, the normal billing demand on the Power and Light Rates, or the Governmental Rate will be increased, based on the applicable days over two, as follows:

A. FIRM BACK-UP

ABDFB = BPDF x SDAF x (NDFBU/NBP) x 1.5

Where ABDFB	=	addition to normal billing demand-Firm Back-up
BPDF	=	back-up power demand-Firm
SDAF	=	standby demand adjustment factor (see paragraph "G" above)
NDFBU	=	number of applicable days firm back-up power is used in billing period
NBP	=	number of days in the billing period

B. FIRM MAINTENANCE:

ABDFM = MPDF x (NDFMU/NBP) x 0.6

Where ABDFM	=	addition to normal billing demand-Firm Maintenance
MPDF	=	maintenance power demand-Firm
NDFMU	=	number of applicable days firm maintenance power is used in billing period

INTERRUPTIBLE BACK-UP AND INTERRUPTIBLE MAINTENANCE CAPACITY CHARGE:

When interruptible standby power is used, the normal billing demand for that month on the Power and Light Rates or Governmental Rate will be increased as follows:

A. INTERRUPTIBLE BACK-UP:

ABDIB = BPDI x SDAF x (NDIBU/NBP) x 0.6

Where ABDIB	=	addition to normal billing demand-Interruptible back-up
BPDI	=	back-up power demand-Interruptible
NDIBU	=	number of days interruptible back-up power is used in billing period

B. INTERRUPTIBLE MAINTENANCE:

ABDIM = MPDI x (NDIMU/NBP) x 0.6

Where ABDIM	=	addition to normal billing demand-Interruptible maintenance
MPDI	=	maintenance power demand-Interruptible
NDIMU	=	number of days interruptible maintenance power is used in billing period

RESTRICTIONS ON SWITCHING SERVICES:

If a customer who has contracted for both firm and interruptible standby power is taking interruptible service, and is interrupted by the Company, he may not then switch interruptible service to firm service.

NOTIFICATION OF DOWN-TIME:

Within 24 hours of the end of each billing period, the customer will give to the Company a log of all down-time of the customer's generating equipment. If the customer fails to provide this log, the Company will assume the customer's generating equipment was down during the entire billing period.

TERM OF CONTRACT:

One (1) year.

GENERAL TERMS AND CONDITIONS

The charges calculated under this schedule are subject to change in such an amount as may be approved and/or amended by the Georgia Public Service Commission under the provisions of applicable riders. Service hereunder is subject to the Rules and Regulations for Electric Service on file with the Georgia Public Service Commission.

SS-1

RATE SCHEDULE SS-1

Standby and Supplemental Service

Available
In all territory served by JEA.

Applicable
To any service agreement, at a point of delivery, whose electric service requirements for the load are supplied or supplemented from the customer's generation equipment at that point of service and who requires standby and supplemental service from JEA. A service agreement is required to take service under this rate schedule if the customer's total generation capacity is 50 kW or greater and the full load requirement is 75 kW or greater four (4) or more months out of twelve (12) consecutive billing periods ending with the current billing period. For purposes of determining applicability of this rate schedule, the following definitions shall be used:

Standby Service: Electric energy or capacity supplied by JEA to replace energy or capacity ordinarily generated by the customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages of all or a portion of the customer's generation.

Supplemental Service: Electric energy or capacity supplied by JEA in addition to that which is normally provided by the customer's own generation equipment.

Full Load Requirement: The sum of the metered demand and the kW nameplate rating of the customer's generating unit(s).

Customers taking service under this rate schedule are required to execute an interconnection agreement. This rate schedule does not apply to existing customers who own generating capacity covered by JEA's Net Metering Policy. For the purposes of this rate schedule an existing customer is one who has physically connected to JEA and executed an interconnection agreement prior to the original effective date of this rate schedule (January 1, 2015).

Character of Service
JEA's primary and secondary voltage levels.

Rate per Month
The charge per month shall consist of the basic monthly, demand, energy, and fuel charges as follows:

Basic Monthly Charge: per the applicable time of day rate schedule.

Facilities Demand Charge: The applicable demand charge as provided below:

GSDT: $0.93 per kW of Contract Demand Primary
GSDT: $1.25 per kW of Contract Demand Secondary
GSLDT: $0.89 per kW of Contract Demand Primary
GSLDT: $0.96 per kW of Contract Demand Secondary

(Continued on Sheet No. 9.1)

(Continued from Sheet No. 9.0)

Standby Demand Charge: The sum of the on-peak demand charge less the Facilities Demand Charge above multiplied by the reliability adjustment factor which is equal to the assumed reliability factor set forth in the interconnection agreement but not less than 0.1, and divided by 0.7. For generators 5 MW and larger the reliability factor shall be one (1) minus the annual generating unit operating hours divided by the hours in the year (8760 for non-leap years and 8784 for leap years) divided by 0.7. The standby demand charge is applied to the kW nameplate rating of the generating unit(s).

The calculation for the Standby Demand Charge is:
SDC = (OPDC – FDC) * RAF / 0.7

Where:
SDC = Standby Demand Charge
OPDC = On Peak Demand Charge per the applicable time of day rate schedule
FDC = Facilities Demand Charge
RAF = Reliability Adjustment Factor
0.7 = System Peak Coincident Factor

Supplemental Demand Charge The on-peak demand charge per the applicable time of day rate schedule less the Facilities Demand Charge above. The supplemental demand charge is applied to the Metered Demand.

Excess Reactive Demand Charge: per applicable time of day rate schedule.

Energy Charge: per applicable time of day rate schedule.

Fuel Charge: as stated in the Fuel Charge (Sheet No. 20.0). Charge per applicable time of day rate schedule.

Primary Service Discount: A discount of 0.10 cent per kWh will be allowed for service taken at 4,160 volts or higher, when the customer provides all of the equipment required to take service at JEA's existing primary lines.
(Demand Discount is included in the rates charged above)

Minimum Bill: The Basic Monthly charge per the applicable time of day rate schedule.

Metered Demand: The maximum integrated 15-minute on peak and off-peak metered kW demand measured during the month.

Contract Demand: The kW demand as stated in the interconnection agreement.

Determination of Excess Reactive Demand: As stated in the Excess Reactive Demand (KVAR) Policy (Sheet No. 23.0).

Terms and Conditions

(a) Service is available under this rate schedule upon execution of an interconnection agreement accompanied by payment of deposit or bond as required by JEA and satisfaction of JEA Facility Interconnection Requirements.

(Continued on Sheet No. 9.2)

(Continued from Sheet No. 9.1)

(b) Service herein shall be subject to the Rules and Regulations of JEA.

(c) Customers receiving service under this rate schedule will be required to give JEA a written notice at least sixty (60) months prior to reclassification to any other standard JEA rate schedule unless it can be shown that such reclassification is in the best interests of the customer, JEA, and JEA's other ratepayers

STANDBY AND SUPPLEMENTAL SERVICE

RATE SCHEDULE: SST-1

AVAILABLE:

In all areas served. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

APPLICATION:

For electric service to any Customer, at a point of delivery, whose electric service requirements for the Customer's load are supplied or supplemented from the Customer's generation equipment at that point of service and require standby and/or supplemental service. For purposes of determining applicability of this rate schedule, the following definitions shall be used:

(1) "Standby Service" means electric energy or capacity supplied by the Company to replace energy or capacity ordinarily generated by the Customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages of all or a portion of the Customer's generation.

(2) "Supplemental Service" means electric energy or capacity supplied by the Company in addition to that which is normally provided by the Customer's own generation equipment.

A Customer is required to take service under this rate schedule if the Customer's total generation capacity is more than 20% of the Customer's total electrical load and the Customer's generators are not for emergency purposes only.

Customers taking service under this rate schedule shall enter into a Standby and Supplemental Service Agreement ("Agreement"); however, failure to execute such an agreement will not pre-empt the application of this rate schedule for service.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage. All service supplied by the Company shall be furnished through one metering point. Resale of service is not permitted hereunder.

Transformation Rider - TR, Sheet No. 8.820, does not apply to Standby Service.

MONTHLY RATE:

STANDBY SERVICE

Delivery Voltage:		Below 69 kV		69kV & Above
	SST-1(D1)	SST-1(D2)	SST-1(D3)	SST-1(T)
Contract Standby Demand:	Below 500 kW	500 to 1,999 kW	2,000 kW & Above	All Levels
Base Charge: Demand Charges:	$173.82	$173.82	$591.00	$2,506.23
Base Demand Charges:				
Distribution Demand Charge per kW of Contract Standby Demand	$4.17	$4.17	$4.17	N/A
Reservation Demand Charge per kW	$2.05	$2.05	$2.05	$1.88
Daily Demand Charge per kW for each daily maximum On-Peak Standby Demand	$0.99	$0.99	$0.99	$0.59

(Continued on Sheet No. 8.751)

(Continued from Sheet No. 8.750)

Delivery Voltage:	Below 69 kV			69 kV & Above
	SST-1(D1)	SST-1(D2)	SST-1(D3)	SST-1(T)
Contract Standby Demand:	Below 500 kW	500 to 1,999 kW	2,000 kW & Above	All Levels
Non-Fuel Energy Charges:				
Base Energy Charges:				
On-Peak Period charge per kWh	0.990¢	0.990¢	0.990¢	0.986¢
Off-Peak Period charge per kWh	0.990¢	0.990¢	0.990¢	0.986¢

Additional Charges:
See Billing Adjustments section, Sheet No. 8.030, for additional applicable charges.

Minimum: The Base Charge plus the Base Demand Charges.

DEMAND CALCULATION:

The Demand Charge for Standby Service shall be (1) the charge for Distribution Demand **plus** (2) the greater of the sum of the Daily Demand Charges **or** the Reservation Demand Charge times the maximum On-Peak Standby Demand actually registered during the month **plus** (3) the Reservation Demand Charge times the difference between the Contract Standby Demand and the maximum On-Peak Standby Demand actually registered during the month.

SUPPLEMENTAL SERVICE:

Supplemental Service shall be the total power supplied by the Company minus the Standby Service supplied by the Company during the same metering period. The charge for all Supplemental Service shall be calculated by applying the applicable retail rate schedule, excluding the Base charge.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. EST to 10 a.m. EST and 6 p.m. EST to 10 p.m. EST excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon EST to 9 p.m. EST excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

CONTRACT STANDBY DEMAND:

The level of Customer's generation requiring Standby Service as specified in the Agreement. This Contract Standby Demand will not be less than the maximum load actually served by the Customer's generation during the current month or prior 23-month period less the amount specified as the Customer's load which would not have to be served by the Company in the event of an outage of the Customer's generation equipment. For a Customer receiving only Standby Service as identified under Special Provisions, the Contract Standby Demand shall be maximum load actually served by the Company during the current month or prior 23-month period.

A Customer's Contract Standby Demand may be re-established to allow for the following adjustments:

1. Demand reduction resulting from the installation of FPL Demand Side Management Measures or FPL Research Project efficiency measures; or

(Continued on Sheet No. 8.752)

(Continued from Sheet No. 8.751)

2. Demand reductions resulting from the installation of other permanent and quantifiable efficiency measures, upon verification by FPL; or

3. Permanent changes to customer facilities that result in a permanent loss of electric load, including any fuel substitution resulting in permanently reduced electricity consumption, upon verification by FPL.

The re-established Contract Standby Demand shall be the higher of the actual Contract Standby Demand calculated in the next billing period following the Customer's written request or the prior Contract Standby Demand minus the calculated demand reduction. Requests to re-establish the Contract Standby Demand may be processed up to twice per calendar year when more than one efficiency measure is installed or where the same efficiency measure is installed in phases.

STANDBY DEMAND:

When the Customer's generation is less than the minimum normal operating level as specified in the Agreement, the Standby Demand is the lesser of (1) the Contract Standby Demand minus the Customer's load being served by the Customer's generation, but not less than zero, or (2) the level of Demand being supplied by the Company.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment and systems, for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than five years. The Customer shall give the Company at least five years written notice before the Customer may transfer from service under this rate schedule to an applicable retail rate schedule. Transfers, with less than five years written notice, to an applicable retail rate schedule may be permitted if it can be shown that such transfer is in the best interests of the Customer, the Company, and the Company's other ratepayers.

SPECIAL PROVISIONS:

The Customer will allow the Company to make all necessary arrangements to meter (1) the amounts of demand and energy supplied by the Company, (2) the gross demand and energy output of the Customer's generation equipment and, if the Customer is interconnected and operating electric generating equipment in parallel with the Company's system, (3) the capacity and energy supplied to the Company by the Customer's generation equipment. The Company shall provide and the Customer shall be required to pay the installation, operation and maintenance costs incurred by the Company for the metering equipment required in (2) and (3) described above. The Company shall retain ownership of all metering equipment.

Where the Customer and the Company agree that the Customer's service requirements are totally standby or totally supplemental, the Company shall bill the Customer accordingly and not require Company metering of the gross demand and energy output of the Customer's generation equipment provided that where only Standby Service is taken, (1) the Customer and the Company agree to the maximum amount of Standby Service to be provided by the Company and (2) the Customer agrees to and provides to the Company such data and information from the Customer's generating equipment from its own metering as is necessary to permit analysis and reporting of the load and usage characteristics of Standby and Supplemental Service.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service," the provision of this schedule shall apply.

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

RATE SCHEDULE: ISST-1

AVAILABLE:

In all areas served. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

LIMITATION OF AVAILABILITY:

This schedule may be modified or withdrawn subject to determinations made under Commission Rule 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

A Customer who is eligible to receive service under the Standby and Supplemental Service (SST-1) rate schedule may, as an option, take service under this rate schedule, unless the Customer has entered into a contract to sell firm capacity and/or energy to the Company, and the Customer cannot restart its generation equipment without power supplied by the Company, in which case the Customer may only receive Standby and Supplemental Service under the Company's SST-1 rate schedule.

Customers taking service under this rate schedule shall enter into an Interruptible Standby and Supplemental Service Agreement ("Agreement"). This interruptible load shall not be served on a firm service basis until service has been terminated under this rate schedule.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage.

A designated portion of the Customer's load served under this schedule is subject to interruption by the Company. Transformation Rider-TR, where applicable, shall only apply to the Customer's Contract Standby Demand for delivery voltage below 69 kV. Resale of service is not permitted hereunder.

MONTHLY RATE:
STANDBY SERVICE

Delivery Voltage:	Distribution Below 69 kV ISST-1(D)	Transmission 69 kV & Above ISST-1(T)
Base Charge:	$675.97	$2,764.83
Demand Charges:		
Base Demand Charges:		
Distribution Demand Charge per kW of Contract Standby Demand	$4.17	N/A
Reservation Demand Charge per kW of Interruptible Standby Demand	$0.36	$0.41
Reservation Demand Charge per kW of Firm Standby Demand	$2.05	$1.88
Daily Demand Charge per kW for each daily maximum On-Peak Interruptible Standby Demand	$0.17	$0.16
Daily Demand Charge per kW for each daily maximum On-Peak Firm Standby Demand	$0.99	$0.59
Non-Fuel Energy Charges: Base Energy Charges:		
On-Peak Period charge per kWh	0.990¢	0.986¢
Off-Peak Period charge per kWh	0.990¢	0.986¢

(Continued on Sheet No. 8.761)

(Continued from Sheet No. 8.760)

Additional Charges:

See Billing Adjustments section, Sheet No. 8.030, for additional applicable charges.

Minimum: The Base Charge plus the Base Demand Charges.

DEMAND CALCULATION:

The Demand Charge for Standby Service shall be:

Distribution - (1) the charge for Distribution Demand **PLUS**

Firm Service - (2) a) the greater of the sum of the Daily Firm Standby Demand Charges **OR** the Reservation Firm Standby Demand Charge times the maximum On-Peak Firm Standby Demand actually registered during the month **PLUS**

b) the Reservation Firm Standby Demand Charge times the difference between the Contract Firm Standby Demand and the maximum On-Peak Firm Standby Demand actually registered during the month **PLUS**

Interruptible Service - (3) a) the greater of the sum of the Daily Interruptible Standby Demand Charges **OR** the Reservation Interruptible Standby Demand Charge times the maximum On-Peak Interruptible Standby Demand actually registered during the month **PLUS**

b) the Reservation Interruptible Standby Demand Charge times the difference between the Contract Interruptible Standby Demand and the maximum On-Peak Interruptible Standby Demand actually registered during the month.

SUPPLEMENTAL SERVICE:

Supplemental Service shall be the total power supplied by the Company minus the Standby Service supplied by the Company during the same metering period. The charge for all Supplemental Service shall be calculated by applying the otherwise applicable rate schedule, excluding the Base charge.

If all or a portion of a Customer's Supplemental Service is Interruptible, then Supplemental Service will be provided pursuant to Rate Schedule CILC-1 or the General Service/Industrial Demand Reduction Rider.

INTERRUPTION:

Interruption Condition:

The Customer's interruptible load served under this rate schedule is subject to interruption when such interruption alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units orcombustion turbines above the continuous rated output, which may overstress the generators. These conditions will typically result in lessthan fifteen (15) interruption periods per year, will typically allow advance notice of four (4) hours or more prior to an interruption period and will typically result in interruption periods of four (4) hours' duration. The operating limits under this tariff are describedbelow.

Frequency: The frequency of interruption will not exceed twenty-five (25) interruption periods per year.

Notice: The Company will provide one (1) hour's advance notice or more to a Customer prior to interrupting the Customer's interruptible load.

Duration: The duration of a single period of interruption will not exceed six (6) hours.

(Continued on Sheet No. 8.762)

(Continued from Sheet No. 8.761)

In the event of an emergency, such as a Generating Capacity Emergency (See Definitions) or a major disturbance, greater frequency, less notice, or longer duration than listed above may occur. If such an emergency develops, the Customer will be given 15 minutes' notice. Less than 15 minutes' notice may only be given in the event that failure to do so would result in loss of power to firm service customers or the purchase of emergency power to serve firm service customers. The Customer agrees that the Company will not be liable for any damages or injuries that may occur as a result of providing no notice or less than one (1) hours' notice.

Customer Responsibility:

The Company will interrupt the interruptible portion of the Customer's service for a one-hour period, once per year at a mutually agreeable time and date for testing purposes. Testing purposes include the testing of the interruption equipment to ensure that the load is able to be interrupted within the agreed specifications. If the Customer's load has been successfully interrupted during the previous 12 months, this test obligation will have been met.

The Customer shall be responsible for providing and maintaining the appropriate equipment required to allow the Company to electrically interrupt the Customer's load, as specified in the Agreement.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. EST to 10 a.m. EST and 6 p.m. EST to 10 p.m. EST excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon EST to 9 p.m. EST excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment and systems, for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

CONTRACT STANDBY DEMAND:

The level of Customer's load requiring Standby Service as specified in the Agreement. This Contract Standby Demand will not be less than the maximum load actually served by the Customer's generation during the current month or prior 23-month period less the amount specified as the Customer's load which would not have to be served by the Company in the event of an outage of the Customer's generating equipment. For a Customer receiving only Standby Service as identified under Special Provisions, the Contract Standby Demand shall be the maximum load actually served by the Company during the current month or prior 23-month period.

A Customer's Contract Standby Demand may be re-established to allow for the following adjustments:

1. Demand reduction resulting from the installation of FPL Demand Side Management Measures or FPL Research Project efficiency measures; or
2. Demand reductions resulting from the installation of other permanent and quantifiable efficiency measures, upon verification by FPL; or
3. Permanent changes to customer facilities that result in a permanent loss of electric load, including any fuel substitution resulting in permanently reduced electricity consumption, upon verification by FPL.

The re-established Contract Standby Demand shall be the higher of the actual Contract Standby Demand calculated in the next billing period following the Customer's written request or the prior Contract Standby Demand minus the calculated demand reduction. Requests to re-establish the Contract Standby Demand may be processed up to twice per calendar year when more than one efficiency measure is installed or where the same efficiency measure is installed in phases.

STANDBY DEMAND:

When the Customer's generation is less than the minimum normal operating level as specified in the Agreement, the Standby Demand is the lesser of (1) the Contract Standby Demand minus the Customer's load being served by the Customer's generation, but not less than zero, or (2) the level of Demand being supplied by the Company.

FIRM STANDBY DEMAND:

The Customer's Firm Standby Demand shall be the lesser of the "Firm Standby Demand" level specified in the Customer's Agreement with the Company, or the highest Standby Demand. The level of "Firm Standby Demand" specified in the Agreement shall not be exceeded during the periods when the Company is interrupting the Customer's load.

(Continued on Sheet No. 8.763)

(Continued from Sheet No. 8.762)

INTERRUPTIBLE STANDBY DEMAND:

The Customer's Interruptible Standby Demand shall be the Customer's Standby Demand less the Customer's Firm Standby Demand.

INTERRUPTION PERIOD:

All hours established by the Company during a monthly billing period in which:

1. the Customer's load is interrupted, or
2. the Customer is billed pursuant to the Continuity of Service Provision.

EXCEPTIONS TO CHARGES FOR EXCEEDING FIRM DEMAND:

If the Customer exceeds the "Firm Standby Demand" during a period when the Company is interrupting load due to:

1. Force Majeure events (see Definitions) which are demonstrated to the satisfaction of the Company to have been beyond the Customer's control, or
2. maintenance of generation equipment necessary for interruption which is performed at a pre-arranged time and date mutually agreed to by the Company and the Customer (See Special Provisions), or
3. adding firm load that was not previously non-firm load to their facility, or
4. an event affecting local, state, or national security and space launch operations, within five (5) days prior to an impending launch,

then the Customer will not be required to pay the Charges for Exceeding Firm Demand during the period of such exceptions, but will be billed pursuant to the Continuity of Service Provision.

If the Company determines that the Customer has utilized one or more of the exceptions above in an excessive manner, then the Company will terminate service under this rate schedule as described in TERM OF SERVICE.

CHARGES FOR EXCEEDING FIRM STANDBY DEMAND:

If the Customer exceeds the "Firm Standby Demand" during a period when the Company is interrupting load for any reason other than those specified in Exceptions to Charges for Exceeding Firm Standby Demand, then the Customer will be:

1. billed the difference between the Reservation Demand Charge for Firm Standby Demand and the Reservation Demand Charge for Interruptible Standby Demand for the excess kw for the prior sixty (60) months or the number of months the Customer has been billed under the rate schedule, whichever is less, and
2. billed a penalty charge of $1.50 per kw of excess kw for each month of rebilling.

Excess kw for rebilling and penalty charges is determined by taking the difference between the maximum demand during the Interruption Period and the Customer's "Firm Standby Demand". The Customer will not be rebilled or penalized twice for the same excess kw in the calculation described above.

TERM OF SERVICE:

Service under this Rate Schedule shall continue, subject to Limitation of Availability, until terminated by either the Company or the Customer upon written notice given at least five (5) years prior to termination.

Transfers, with less than five (5) years' written notice, to any firm retail rate schedule for which the Customer would qualify may be permitted if it can be shown that such transfer is in the best interests of the Customer, the Company and the Company's other customers.

If the Customer no longer wishes to receive electric service in any form from the Company, the Customer may terminate the Agreement by giving thirty (30) days' advance written notice to the Company.

The Company may terminate service under this Rate Schedule at any time for the Customer's failure to comply with the terms and conditions of this Rate Schedule or the Agreement. Prior to any such termination, the Company shall notify the Customer at least ninety (90) days in advance and describe the Customer's failure to comply. The Company may then terminate this service under this Rate Schedule at the end of the 90-day notice period unless the Customer takes measures necessary to eliminate, to the Company's satisfaction, the compliance deficiencies described by the Company. Notwithstanding the foregoing, if, at any time during the 90-day period, the Customer either refuses or fails to initiate and pursue corrective action, the Company shall be entitled to suspend forthwith the monthly billing under this Rate Schedule and bill the Customer under the otherwise applicable firm service rate schedule.

In the even that:

a) service is terminated by the Company for any reason(s) specified in this section, or

b) the Customer transfers the interruptible portion of the Customer's load to "Firm Standby Demand" or to a firm or a curtailable service rate schedule without providing at least five (5) years' advance written notice, or

(Continued on Sheet No. 8.764)

(Continued from Sheet No. 8.763)

c) there is a termination of the Customer's existing service and, within twelve (12) months of such termination of service, the Company receives a request to re-establish service of similar character under a firm service or curtailable service rate schedule, or under this Rate Schedule with a shift from non-firm load to firm service,

i) at a different location in the Company's service area, or

ii) under a different name or different ownership, or

iii) under other circumstances whose effect would be to increase firm demand on the Company's system without the requisite five (5) years' advance written notice,

then the Customer will be:

1. rebilled under Rate Schedule SST-1 for the shorter of (a) the most recent prior sixty (60) months during which the Customer was billed for service under this Rate Schedule, or (b) the number of months the Customer has been billed under this Rate Schedule, and

2. billed a penalty charge of $1.50 per kW times the number of months rebilled in No. 1 above times the Contract Standby Demand.

Except as noted below:

If service under this schedule is terminated by the Customer for any reason, the Customer will not be rebilled as specified in paragraphs 1. and 2. above if:

a. it has been demonstrated to the satisfaction of the Company that the impact of such transfer of service on the economic cost-effectiveness of the Company's ISST-1 Schedule or is in the best interests of the Customer, the Company, and the Company's other customers, or

b. the Customer is required to transfer to another retail rate schedule as a result of Commission Rule 25-6.0438, F.A.C., or

c. the termination of service under this Rate Schedule is the result of either the Customer's ceasing operations at its facility without continuing or establishing similar operations elsewhere in the Company's service area, or,

d. any other Customer(s) with demand reduction equivalent to, or greater than, that of the existing Customer(s) agrees to take service under this Rate Schedule and the MW demand reduction commitment to the Company's Generation Expansion Plan has been met and the new replacement Customer(s) has(have) the equipment installed and is(are) available for interruption.

In the event the Customer pays the penalty charges because no replacement Customer(s) is(are) available as specified in paragraph d. above, but the replacement Customer(s) does(do) become available within 12 months from the date of termination of service under this Rate Schedule, then the Customer will be refunded all or part of the rebilling and penalty in proportion to the amount of MW obtained to replace the lost capacity less the additional cost incurred by the Company to serve those MW during any load control periods which occur before the replacement Customer(s) became available.

SPECIAL PROVISIONS:

1. Interruption of the Customer's load shall be accomplished through the Company's load management systems by use of control circuits connected directly to the Customer's switching equipment.

2. The Customer shall grant the Company reasonable access for installing, maintaining, inspecting, testing and/or removing Company-owned interruption equipment.

3. It shall be the responsibility of the Customer to determine that all electrical equipment to be interrupted is in good repair and working condition. The Company will not be responsible for the repair, maintenance or replacement of the Customer's electrical equipment.

4. The Company is not required to install interruption equipment if the installation cannot be economically justified.

5. Billing under this Rate Schedule will commence after the installation, inspection and successful testing of the interruption equipment.

6. Maintenance of the Customer’s generation equipment necessary for the implementation of load control will not be scheduled during periods where the Company projects that it would not be able to withstand the loss of its largest unit and continue to serve firm service customers.

(Continued on Sheet No. 8.765)

(Continued from Sheet No. 8.764)

The Customer will allow the Company to make all necessary arrangements to meter (1) the amounts of demand and energy supplied by the Company, (2) the gross demand and energy output of the Customer's generation equipment to the interruptible load served by the Customer and, if the Customer is interconnected and operating electric generating equipment in parallel with the Company's system, (3) the capacity and energy supplied to the Company by the Customer's generating equipment. The Company shall provide and the Customer shall be required to pay the installation, operation and maintenance costs incurred by the Company for the metering equipment required in (2) and (3) described above. The Company shall retain ownership of all metering equipment.

Where the Customer and the Company agree that the Customer's interruptible service requirements are totally standby or totally supplemental, the Company shall bill the Customer accordingly and not require Company metering of the gross demand and energy output of the Customer's generating equipment provided that where only Standby Service is taken, (1) the Customer and the Company agree to the maximum amount of interruptible standby service to be provided by the Company and (2) the Customer agrees to and provides to the Company such data and information from the Customer's generating equipment from its own metering as is necessary to permit analysis and reporting of the load and usage characteristics of Interruptible Standby and Supplemental Service.

CONTINUITY OF SERVICE PROVISION

In order to minimize the frequency and duration of interruptions requested under this rate schedule, the Company will attempt to obtain reasonably available additional capacity and/or energy during periods for which interruptions may be requested. The Company's obligation in this regard is no different than its obligation in general to purchase power to serve its Customers during a capacity shortage; in other words, the Company is not obligated to account for, or otherwise reflect in its generation planning and construction, the possibility of providing capacity and/or energy under this Continuity of Service Provision. Any non- firm customers so electing to receive capacity and/or energy which enable(s) the Company to continue service to the Customer's non-firm loads during these periods will be subject to the additional charges set forth below.

In the event a Customer elects not to have its non-firm load interrupted pursuant to this schedule, the Customer shall pay, in addition to the normal charges provided hereunder, a charge reflecting the additional costs incurred by the Company in continuing to provide service, less the applicable class fuel charge for the period during which the load would otherwise have been interrupted (see Sheet No.8.830). This incremental charge shall apply to the Non-Firm Customer for all consumption above the Customer's Firm Standby Demand during the time in which the non-firm load would otherwise have been interrupted. If, for any reason during such period, this capacity and/or energy is (are) no longer available or cannot be accommodated by the Company's system, the terms of this Continuity of Service Provision will cease to apply and interruptions will be required for the remainder of such period.

Any Customer served under this Rate Schedule may elect to minimize the interruptions through the procedure described above. The initial election must be made in the Agreement. Any adjustment or change to the election must be provided to the Company with at least 24 hours' written notice (not including holidays and weekends) and must be by mutual agreement, in writing, between the Customer and the Company. In such case, the written notice will replace any prior election with regard to this Continuity of Service Provision.

RULES AND REGULATIONS:

Service under this Rate Schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this Rate Schedule and said "General Rules and Regulations for Electric Service" the provision of this Rate Schedule shall apply.

DEFINITIONS:

Generating Capacity Emergency:

A Generating Capacity Emergency exists when any one of the electric utilities in the state of Florida has inadequate generating capability, including purchased power, to supply its firm load obligations.

Force Majeure:

Force Majeure for the purposes of this Rate Schedule means causes not within the reasonable control of the Customer affected and not caused by the negligence or lack of due diligence of the Customer. Such events or circumstances may include acts of God, strikes, lockouts or other labor disputes or difficulties, wars, blockades, insurrections, riots, environmental constraints lawfully imposed by federal, state, or local governmental bodies, explosions, fires, floods, lightning, wind, accidents to equipment or machinery, or similar occurrences.

I. AVAILABILITY

This Rate is available to Customers of Entergy Louisiana, LLC ("ELL" or the "Company"), for which the point of interconnection with ELL is located within the Legacy EGSL Service Area, or any qualifying Customers of ELL for which the point of interconnection is located outside of the Legacy EGSL Service Area. For a Customer having a point of interconnection outside of the Legacy EGSL Service Area to qualify to take Service under this schedule, the Customer must (1) have a minimum new firm load (or increase in firm load) of 500 kW; (2) execute a new Electric Service Agreement, or execute an amendment to an existing Electric Service Agreement to reflect the increase in firm load for billing purposes; and (3) in the case of an existing Customer increasing firm load under (1), above, that existing Customer must provide the Company with a notarized affidavit in conjunction with executing its new (or amended) Electric Service Agreement that contains (i) a statement that the existing Customer is adding at least 500 kW of new firm load, and (ii) a brief written description of the project(s) or process(es) causing that increase in firm load.

This Rate is available where facilities of adequate capacity and suitable phase and voltage are adjacent to the premises to be served, and Service is taken according to the Legacy EGSL Terms and Conditions (or, if otherwise agreed, the ELL Terms and Conditions) and Service Standards of the Company. Where facilities of adequate capacity and suitable phase and voltage are not adjacent to the premises to be served, Company may, at its option, require a contribution, higher minimum bill, facilities charge, or other compensation to make Service available.

Note: Generally, unless otherwise specified herein, capitalized terms used throughout this document are as defined in the Company's Terms and Conditions and Legacy EGSL Terms and Conditions, as applicable.

II. APPLICABILITY

This schedule is applicable to Qualifying Facilities (QFs) larger than 100 kW who contract for standby and/or maintenance Service from the Company. The Company is not obligated to provide Standby Service Power in excess of a QFs Reserve Standby Power and in no event more than 100 MW to each QF. A QF is defined as a small power production facility or cogeneration facility that qualifies under Subchapter K, Part 292, Subpart B, of the Federal Energy Regulatory Commission's regulations that implement Section 201 and 210 of the Public Utility Regulatory Policies Act of 1978.

III. MODIFICATION OF REGULAR RATE SCHEDULE

Service taken under this schedule may be in addition to Service provided by Company under other Rate Schedules. The other Rate Schedule in such case, if applicable, will be modified by the addition of § IV and V of this Schedule. In consideration of these modifications, when Service is taken under this schedule, Service under other Rate Schedules is permitted for auxiliary or supplementary Service to engines or other prime movers or to any other source of power.

IV. DETERMINATION OF BILLING DEMAND AND ENERGY QUANTITIES

A. Standby Service

1. The Reserved Standby Power in a Month shall be equal to the greater of: (a) the amount contracted for in kW for a consecutive 12-Month period or (b) the maximum 30-minute standby Service Demand during the 12-Month period ending with the prior Month. In the event that the maximum 30-minute standby Service Demand during the Month exceeds the existing Reserved Standby Power, that standby Service Demand shall constitute the Reserved Standby Power for the ensuing 12 Months unless subsequently exceeded. The QF must demonstrate if Company requests, that standby power was taken as the result of an unscheduled outage of a QF.

2. The Monthly Standby Service Billing Demand shall be equal to the sum of the Daily Standby Service Demands. The Daily Standby Service Demand shall be equal to:

   a. the maximum metered Demand registered in each calendar day during which the unscheduled outage occurs, less

   b. the greater of (1) the current Month's Billing Demand for firm or interruptible power or (2) the maximum metered 30-minute Demand for firm and interruptible power measured during the period of the Month when Service other than standby and/or maintenance Service is taken, less

   c. the amount of Reserved Standby Power. The amount of Reserved Standby Power for each of the first three or fewer consecutive calendar days of the unscheduled outage is its full amount. For the fourth and subsequent consecutive calendar days of the outage, the Reserved Standby Power shall be defined as zero. Should the Daily Standby Service Demand derived by applying the above formula be negative, that negative value should be taken to be zero for purposes of determining the Monthly Service Billing Demand. Should an unscheduled outage extend into a subsequent billing Month, the application of this paragraph to that Month should take into account the number of consecutive days in the prior Month in which that outage occurred. This § A.2.c is further limited by the provisions of § A.2.e, less

   d. the Scheduled Maintenance Billing Demand for Scheduled Maintenance Service taken simultaneously with the unscheduled outage,

   e. in applying § IV.A.2.c an unscheduled outage that commences within 8 hours of the preceding outage shall not constitute a distinct outage, but rather a continuation of the prior outage.

3. For QFs who have contracted for firm or for firm and interruptible power under other Rate Schedules, any Daily Standby Service Demand in excess of the Reserved Standby Power shall have no effect on the determination of subsequent levels of firm and interruptible power ratcheted Demand.

4. The QF is required to notify the Company of the time periods when standby Service is being taken. This notification must be made within 24 hours of the beginning and end of usage to avoid increasing the Customer's Contract Power for firm or for firm and interruptible load.

5. Regardless of whether a QF has contracted for firm or for firm and interruptible power under other Rate Schedules, the energy associated with the taking of standby Service shall not be distinguished from any other energy taken and shall be billed at the energy charge rate in accordance with the terms set forth in § V.B.

B. Unscheduled Maintenance Service

Unscheduled Maintenance Service is provided on an as available basis, only during such times and at such locations that, in Company's sole opinion, will not result in affecting adversely or jeopardizing firm Service to other Customers, prior commitments for Scheduled Maintenance Service to other Customers, or commitments to other utilities. For those QFs that have Reserved Standby Power pursuant to § IV.A.1, Unscheduled Maintenance Service shall be billed under the provisions of Standby Service as if the Unscheduled Maintenance is an unscheduled outage. The QF must demonstrate, if requested to do so by Company, that maintenance was performed on qualifying facilities for the period in which the unscheduled maintenance Service was taken.

1. The Monthly Unscheduled Maintenance Billing Demand charge shall be equal to the sum of the Daily Unscheduled Maintenance Demands. The Daily Unscheduled Maintenance Demand shall be equal to:

   a. the maximum metered Demand registered in each calendar day during which the unscheduled maintenance occurs, less

   b. the greater of (1) the current Month's Billing Demand for firm and interruptible power or (2) the maximum metered 30-minute Demand for firm and interruptible power measured during the period of the Month when Service other than standby and/or maintenance Service is taken, less

   c. the Scheduled Maintenance Billing Demand for Scheduled Maintenance Service taken simultaneously with Unscheduled Maintenance Service.

2. Those QFs who have not contracted for Reserved Standby Power and who purchase Unscheduled Maintenance Service under § IV.B shall thereby become subject to the terms of § IV.A.1.

3. For QFs who have contracted for firm or for firm and interruptible power under other Rate Schedules, any Daily Unscheduled Maintenance Service Demand shall have no effect on the determination of subsequent levels of firm or interruptible power ratcheted Demand.

4. The QF is required to notify the Company of the time periods when unscheduled maintenance Service is being taken. This notification must be made within 24 hours of the beginning and end of usage to avoid increasing the Customer's Contract Power for firm or for firm and interruptible load.

5. Regardless of whether a QF has contracted for firm or for firm and interruptible power under other Rate Schedules, the energy associated with the taking of unscheduled maintenance Service shall not be distinguished from any other energy taken and shall be billed at the energy charge rate in accordance with the terms set forth in § V.B.

C. Scheduled Maintenance Service

Scheduled Maintenance Service will be scheduled on not less than 24-hour prior notice by the QF and such Service shall be scheduled only during such times and at such locations that, in Company's sole opinion, will not result in affecting adversely or jeopardizing firm Service to other Customers, prior commitments for Scheduled Maintenance Service to other Customers, or commitments to other utilities. Arrangements and scheduling of Scheduled Maintenance Service will be agreed in writing in advance of use or confirmed in writing if arranged verbally. Where there are applications from more than one Customer, or Service applied for is more than Company has available, Company will allocate and schedule available Service, in its final judgment, and curtail or cancel application. Where Scheduled Maintenance Service stands requested, agreed and scheduled, but not taken, Customer will be obligated to pay for such Service as if taken, provided that: (a) the Company has refused to supply some other Customer similar Service in order to limit total Scheduled Maintenance Service to that which Company considers available or, (b) if in anticipation of providing such Scheduled Maintenance Service, Company has incurred Costs that would not otherwise have been incurred. The Company shall undertake all reasonable efforts in order to avoid or mitigate the loss of revenue incurred, and shall provide an explanation to a QF so charged upon request. Scheduled Maintenance Service will be scheduled for a continuous period of not less than one day. The QF must demonstrate if Company requests, that Scheduled Maintenance Service was not taken as the result of an unscheduled outage of a QF.

1. The Scheduled Maintenance Billing Demand shall be the product of the requested scheduled maintenance Service Demand and the number of days in the maintenance period. The Company is not obligated to furnish scheduled maintenance Service power in excess of that which is scheduled.

2. The Monthly Excess Scheduled Maintenance Service Billing Demand shall be equal to the sum of the Daily Excess Scheduled Maintenance Service Demands. The Daily Excess Scheduled Maintenance Service Demand shall be equal to:

   a. the maximum metered Demand registered in each calendar day during which the scheduled outage occurs, less

   b. the greater of (1) the current Month's Billing Demand for firm or interruptible power or (2) the maximum metered 30-minute Demand for firm or interruptible power measured during the period of the Month when Service other than standby and/or maintenance Service is taken, less

   c. the amount of Scheduled Maintenance Service Demand for those days for which the Demand was scheduled.

   In the case of multiple units where QF has contracted for Standby Service, any excess shall be determined in accordance with the terms and conditions of § IV.A including § IV.A.4.

3. For QFs who also contract for firm or for firm and interruptible power, scheduled maintenance Service in excess of the requested scheduled maintenance Service Demand shall have no effect on the determination of subsequent levels of firm or interruptible ratcheted Demand.

4. Any outage which occurs less than eight hours after the preceding Scheduled Maintenance Service outage shall be considered as a continuation of the preceding Scheduled Maintenance Service outage for purposes of quantifying the Monthly Excess Scheduled Maintenance Service Billing Demand per § IV.C.2.

5. Regardless of whether a QF has contracted for firm or for firm and interruptible power under other Rate Schedules the energy associated with the taking of Scheduled Maintenance Service shall not be distinguished from any other energy taken and shall be billed at the energy charge rate in accordance with the terms set forth in § V.B.

V. NET MONTHLY CHARGES

A.

1. The Demand charge for Standby Service shall be the sum of (a) and (b) below:

   a. The monthly Reserved Standby Power Demand charge shall be the product of $0.95 per kW and the monthly Reserved Standby Power Billing Demand as determined in § IV.A.1 and in accordance with § IV.A.2.

   b. The monthly standby Service Demand charge shall be the product of the daily proration of the applicable monthly Billing Load rate per kW set forth in the High Load Factor Service (HLFS-G) Rate Schedule, the monthly Standby Service Demand as determined in § IV.A.2 and the number 1.75.

2. The Demand charge for Scheduled Maintenance Service shall be the sum of (a) and (b) below:

   a. The monthly scheduled maintenance Service Demand charge shall be the product of the daily proration of the applicable monthly Billing Load rate per kW set forth in the HLFS-G rate, the monthly Scheduled Maintenance Billing Demand as determined in § IV.C.1 and the HLFS-G off-peak provision number 0.667.

   b. The excess scheduled maintenance Service charge shall be the product of the daily proration of the applicable monthly Billing Load rate per kW set forth in the HLFS-G rate, the monthly Excess Scheduled Maintenance Billing Demand as determined in § IV.C.2 and the number 1.75.

3. The Demand charge for Unscheduled Maintenance Service shall be:

   The product of the monthly Unscheduled Maintenance Service Billing Demand as determined in § IV.B.1, the daily proration of the applicable monthly Billing Load rate per kW set forth in the HLFS-G Rate Schedule, and the number 1.75. The off-peak provision shall not be applicable in the determination of Unscheduled Maintenance Service Billing Demand.

B. Energy Charge (All Services)

1. The energy charge for each kWh as determined in § IV.A.5, B.5 and C.5 shall be the energy rate plus the fuel adjustment charge plus other applicable adjustments based on either:

   a. The energy charge rate plus adjustments as contained in the tariff under which the QF is taking firm or interruptible Service, or

   b. If the QF is not taking firm or interruptible Service from Company, the energy charge rate plus adjustments as contained in the HLFS-G tariff.

VI. CONDITIONS OF SERVICE

A. The QF and Company will agree on operating procedures, and control and protective devices which will limit the taking of power from Company's system to amounts which will not adversely affect Service to Company's other Customers. When QF's generating equipment is operated in parallel with Company's, suitable relays, control and protective apparatus will be furnished and maintained by the QF in accordance with specifications agreed to by Company, and subject to inspection by Company's authorized representatives at all reasonable times.

B. The term of Service under § IV.A shall be such as may be agreed upon but not less than one Year.

C. Where a QF's power factor of total Service supplied by Company is such that 90% of measured monthly maximum kVA used during any 30-minute interval exceeds corresponding measured kW, Company will use 90% of such measured maximum kVA as the number of kW for all purposes that measured maximum kW Demand is specified herein. However, where a QF's power factor is regularly 0.9 or higher, Company may at its option omit kVA metering equipment or remove same if previously installed.

D. Schedule SMQ will normally be billed on a monthly basis or such other period as determined by Company. However, where use of Service includes recurring switching of load to Company's system, normally supplied from a QF's generating facilities, for intervals shorter than so stipulated above, Company may determine Billing Load by metering having shorter intervals.

VII. GROSS MONTHLY BILL AND PAYMENT

The gross monthly bill for Service furnished for which payment is not made within twenty days of the billing date shall be the Net Monthly Bill, including all adjustments under the Rate Schedule and applicable Riders, plus 5% of the first $50.00 and 2% of any additional amount of such gross monthly bill above $50.00. If the monthly bill is paid prior to such dates, the Net Monthly Bill, including all adjustments under the Rate Schedule and applicable Riders, shall apply.

TARIFF S.B.S.
(Standby Service)

MONTHLY CHARGES FOR STANDBY SERVICE

Supplemental Service

The customer shall contract for a specific amount of supplemental contract capacity according to the provisions of the applicable firm service Standard Tariff (hereinafter referred to as supplemental tariff). Any demand or energy not identified as backup or maintenance service shall be considered supplemental service and billed according to the applicable Standard Schedule.

Backup Service

1. Determination of Backup Contract Capacity

The backup contract capacity in kilowatts (kW) shall be initially established by mutual agreement between the customer and the Company for electrical capacity sufficient to meet the maximum backup requirements which the Company is expected to supply.

The customer shall specify the desired backup contract capacity to the nearest 50 kW as well as the desired service reliability as specified under the Monthly Backup Charge. Changes in the backup contract capacity are subject to the provisions set forth in the Term of Contract.

2. Backup Service Notification Requirement

Whenever backup service is needed, the customer shall verbally notify the Company within one (1) hour. Such notification shall be confirmed in writing within five (5) working days and shall specify the time and date such use commenced and termination date. If such notification is not received, the customer shall be subject to an increase in contract capacity in accordance with the provisions of the Standard Schedule under which the customer receives supplemental service and such backup demand shall be considered supplemental demand and billed accordingly.

3. Backup Demand Determination

Whenever backup service is supplied to the customer for use during forced outages, the customer's integrated kW demand shall be adjusted by subtracting the amount of backup contract capacity supplied by the Company. In no event shall the adjusted demand be less than zero (0). The monthly billing demand under the supplemental service schedule shall be the maximum adjusted integrated demand. If both backup and maintenance service are utilized during the same billing period, the customer's integrated demands will be adjusted for both in the appropriate period. Whenever the customer's maximum integrated demand at any time during the billing period exceeds the total of the supplemental service contract capacity and the specific request for backup and/or maintenance service, the excess demand shall be considered as supplemental demand in the determination of the billing demands under the appropriate supplemental service schedule.

4. Backup Service Energy Determination

Whenever backup service is utilized, backup energy shall be billed under the appropriate supplemental tariff.

TARIFF S.B.S.
(Standby Service)

MONTHLY CHARGES FOR STANDBY SERVICE (Cont'd)

5. Monthly Back-up Charge

Each kilowatt of demand billed is subject to all applicable riders.

Service Voltage	% Forced Outage Rate	Maximum Outage Hours	Demand Charge $/KW	
Service Reliability Level A	5	438		
Service Reliability Level B	10	876		
Service Reliability Level C	15	1,314		
Service Reliability Level D	20	1,752		
Service Reliability Level E	25	2,190		
Service Reliability Level F	30	2,628		
Secondary			4.70	I
Primary			3.13	I
Subtransmission/Transmission			0.00	

The total monthly backup charge is equal to the selected monthly backup demand charge times the backup contract capacity. Whenever the allowed outage hours for the respective reliability level selected by the customer are exceeded during the contract year, the customer's unadjusted integrated demands shall be used for billing purposes under the appropriate supplemental tariff for the remainder of the contract year.

Maintenance Service

1. Determination of Maintenance Contract Capacity

The customer may contract for maintenance service by giving at least six (6) months' advance written request as specified in the Term of Contract. Such notice shall specify the amount to the nearest fifty (50) kW not to exceed the customer's maximum maintenance service requirements during planned maintenance outages, and the effective date for the amount of contracted maintenance service.

2. Maintenance Service Notification Requirement

A major maintenance outage shall be considered as any maintenance service request greater than 5,000 kW and may be scheduled at a time consented to by the Company. Written notice shall be provided by the customer at least 180 days in advance of such scheduled outages or a lesser period by mutual agreement and shall specify the kW amount of maintenance service required, as well as the dates and times such use will commence and terminate. A major maintenance service request shall not exceed the kW capacity of the customer's power production facilities as listed in the customer's service contract.

A minor maintenance outage shall be considered as any maintenance service request of 5,000 kW or less and may be scheduled at a time consented to by the Company. Written notice shall be provided by the customer at least thirty (30) days in advance of such outage or a lesser period by mutual agreement.

If such notification is not received, the customer shall be subject to an increase in supplemental service contract capacity according to the provisions of the supplemental service schedule under which the customer is served and such maintenance service demand shall be considered as supplemental load in the determination of the billing demands.

TARIFF S.B.S.
(Standby Service)

MONTHLY CHARGES FOR STANDBY SERVICE (Cont'd)

3. Major Maintenance Service Limitation

The customer shall be limited to one major maintenance outage of 30-days duration for each generator listed in the customer's service contract in each contract year. Additional major maintenance outages or outages exceeding 30-days duration may be requested by the customer and shall be subject to approval by the Company. At the time in which any such additional or prolonged maintenance occurs, the customer shall provide to the Company notarized verification that energy provided under this provision is for maintenance use only.

4. Maintenance Service Demand Determination

Whenever a specific request for maintenance service is made by the customer, the customer's integrated demands will be adjusted by subtracting the maintenance service requested in the hours specified by the customer. The monthly billing demands under the supplemental service schedule shall be the maximum adjusted integrated demands.

If both backup and maintenance service are utilized during the same billing period, the customer's integrated demands will be adjusted for both in the appropriate hours. In no event shall the adjusted demand be less than zero (0).

Whenever the maximum integrated demand at any time during the billing period exceeds the total of the supplemental contract capacity and the specific request for maintenance and/or back-up service, the excess demand shall be considered as supplemental load in the determination of the billing demands.

5. Maintenance Service Energy Determination

Whenever maintenance service is used, maintenance energy shall be calculated as the lesser of a) the kW of maintenance service requested multiplied by the number of hours of maintenance use or b) total metered energy. Metered energy for purposes of billing under the appropriate supplemental service schedule shall be derived by subtracting the maintenance energy from the total metered energy for the billing period.

6. Monthly Maintenance Service Charge

In addition to the monthly charges established under the supplemental service schedule, the customer shall pay the Company for maintenance energy as follows:

For each kWh of maintenance energy taken:

Service Voltage	Energy Charge ¢/kWh
Secondary	0.596
Primary	0.396
Subtransmission/Transmission	0.000

Each kilowatt-hour of energy consumed is subject to all applicable riders.

TARIFF S.B.S.
(Standby Service)

MONTHLY CHARGES FOR STANDBY SERVICE (Cont'd)

Local Facilities Charge

Charges to cover interconnection costs (including but not limited to suitable meters, relays and protective apparatus) incurred by the Company shall be determined by the Company and shall be collected from the customer. Such charges shall include the total installed cost of all local facilities. In addition, the customer shall reimburse the Company for all state and federal income taxes associated with such charges. The customer shall make a one-time payment for the Local Facilities Charge at the time of the installation of the required additional facilities, or, at his option, up to thirty-six (36) consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit. This provision applies also to customers with Standby Contract capacities less than 100kW.

RIDERS

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved riders as contained herein. T

PROMPT PAYMENT DISCOUNT

A discount of 1.5 percent will be allowed if account is paid in full within 15 days of date of bill.

SPECIAL PROVISION FOR CUSTOMERS WITH STANDBY CONTRACT CAPACITIES OF LESS THAN 100 kW

Customers requesting standby service (backup and/or maintenance) with contract capacities of less than 100 kW shall execute a special contract form for a minimum of one (1) year. Contract standby capacity in kilowatts shall be set equal to the capacity of the customer's largest power production facility.

TERM

Contracts under this Schedule will be made for an initial period of not less than one (1) year and shall continue thereafter until either party has given six (6) months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for initial periods longer than one (1) year.

A 6-months' advance written request is required for any change in supplemental, backup, or maintenance service requirements, except for the initial standby service contract. All changes in the standby service contract shall be effective on the contract anniversary date. The Company shall either concur in writing or inform the customer of any conditions or limitations associated with the customer's request within sixty (60) days.

SPECIAL TERMS AND CONDITIONS

At its discretion, the Company may require that Company-owned metering be installed to monitor the customer's generation.

The Company reserves the right to inspect the customer's relays and protective equipment at all reasonable times.

Customers taking service under this Standard Schedule who desire to transfer to firm full requirements will be required to give the Company written notice of at least thirty-six (36) months. The Company reserves the right to reduce the notice period requirement dependent upon individual circumstances.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

ELECTRONIC TARIFF FILING OF BIG RIVERS	**)**	
ELECTRIC CORPORATION AND KENERGY	**)**	**Case No. 2023-00312**
CORP. TO REVISE THE LARGE INDUSTRIAL	**)**	
CUSTOMER STANDBY SERVICE TARIFF	**)**	

EXHIBIT__(SJB-11)

OF

STEPHEN J. BARON

Calculation of BREC LICSS Charges - 2018

Date	Standby Demand	Standby Demand - MISO PRA	Maint. Days	Outage Days	Forced Outage Hrs.	Maintenance Hrs.	Standby Demand Charges	MISO Capacity Credit
Jan-18	50,100	50,100	-	11	167	-	$ 578,141	$ 0.105850
Feb-18	50,100	50,100	-	8	133	-	$ 579,363	$ 0.105850
Mar-18	50,100	50,100	-	7	95	-	$ 566,042	$ 0.105850
Apr-18	50,100	50,100	-	4	65	-	$ 577,314	$ 0.105850
May-18	50,100	50,100	-	6	86	-	$ 575,231	$ 0.105850
Jun-18	50,100	50,100	-	1	2	-	$ 572,152	$ 0.304167
Jul-18	50,100	50,100	-	8	120	-	$ 567,563	$ 0.304167
Aug-18	50,100	50,100	-	4	76	-	$ 573,767	$ 0.304167
Sep-18	50,100	50,100	15	-	-	338	$ 557,947	$ 0.304167
Oct-18	50,100	50,100	2	1	9	29	$ 573,422	$ 0.304167
Nov-18	50,100	50,100	-	5	59	-	$ 573,584	$ 0.304167
Dec-18	50,100	50,100	-	-	-	-	$ 579,946	$ 0.304167
Total							$6,874,472	

Calculation of BREC LICSS Charges - 2018

Date	Stand-by Energy Rate	LIC Energy Rate	MISO BREC LMP	Generation Energy	Standby and Maintenance Energy	Standby and Maintenance Energy Charges	Supplemental Demand	Supplemental Demand Charges
Jan-18	$ 0.042277	$ 0.043587	$ 0.042277	24,119,927	13,154,473	$ 573,364	21,512.5	$ 250,526
Feb-18	$ 0.013493	$ 0.045083	$ 0.013493	22,967,189	10,700,011	$ 482,391	21,512.5	$ 251,050
Mar-18	$ 0.025803	$ 0.046015	$ 0.025803	32,814,164	4,460,236	$ 205,240	21,512.5	$ 245,331
Apr-18	$ 0.031687	$ 0.044425	$ 0.031687	33,044,236	3,027,764	$ 134,508	21,512.5	$ 250,170
May-18	$ 0.033472	$ 0.043685	$ 0.033472	30,236,356	7,038,044	$ 307,460	21,512.5	$ 249,276
Jun-18	$ 0.029592	$ 0.043627	$ 0.029592	30,828,252	5,243,748	$ 228,769	21,512.5	$ 252,221
Jul-18	$ 0.030333	$ 0.043185	$ 0.030333	27,799,569	9,474,831	$ 409,172	21,512.5	$ 250,250
Aug-18	$ 0.032728	$ 0.044440	$ 0.032728	21,840,745	15,433,655	$ 685,876	21,512.5	$ 252,914
Sep-18	$ 0.033772	$ 0.043530	$ 0.033772	17,834,794	17,497,490	$ 761,659	21,512.5	$ 246,121
Oct-18	$ 0.034417	$ 0.045260	$ 0.034417	32,532,009	4,742,391	$ 214,639	21,512.5	$ 252,766
Nov-18	$ 0.037857	$ 0.046750	$ 0.037857	32,433,737	3,638,263	$ 170,087	21,512.5	$ 252,835
Dec-18	$ 0.030766	$ 0.044200	$ 0.030766	37,495,072	-	$ -	21,512.5	$ 255,567
Total						$ 4,173,165		$ 3,009,027

Calculation of BREC LICSS Charges - 2018

Date	Total Plant Energy Usage	Supplemental Energy	Supplemental Energy Charges	Metering, Admin, Other Charges	As-Billed MRSM (for completeness)	Total
Jan-18	50,305,456	13,031,056	$ 567,984	$ 7,540	$ (11,259)	$ 1,966,295
Feb-18	42,825,009	9,157,809	$ 412,864	$ 7,761	$ (11,039)	$ 1,722,391
Mar-18	51,171,509	13,897,109	$ 639,482	$ 7,876	$ (9,952)	$ 1,654,018
Apr-18	49,938,989	13,866,989	$ 616,040	$ 7,890	$ (11,007)	$ 1,574,915
May-18	50,241,898	12,967,498	$ 566,491	$ 8,106	$ (10,907)	$ 1,695,658
Jun-18	49,193,523	13,121,523	$ 572,452	$ 8,031	$ (10,721)	$ 1,622,903
Jul-18	51,432,529	14,158,129	$ 611,420	$ 7,825	$ (10,605)	$ 1,835,625
Aug-18	51,000,583	13,726,183	$ 609,995	$ 8,289	$ (11,778)	$ 2,119,062
Sep-18	35,332,284	-	$ -	$ 7,477	$ (14,417)	$ 1,558,786
Oct-18	50,652,433	13,378,033	$ 605,486	$ 7,760	$ (14,641)	$ 1,639,433
Nov-18	49,953,637	13,881,637	$ 648,961	$ 7,899	$ (14,595)	$ 1,638,772
Dec-18	52,247,644	14,752,572	$ 652,067	$ 7,412	$ (18,666)	$ 1,476,327
Total			$ 6,503,243	$ 93,864	$ (149,586)	$ 20,504,184

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

ELECTRONIC TARIFF FILING OF BIG RIVERS	**)**	
ELECTRIC CORPORATION AND KENERGY	**)**	**Case No. 2023-00312**
CORP. TO REVISE THE LARGE INDUSTRIAL	**)**	
CUSTOMER STANDBY SERVICE TARIFF	**)**	

EXHIBIT__(SJB-12)

OF

STEPHEN J. BARON

Calculation of Recommended DEK GSS Method Charges - 2018

Date	Date	Days in Month	Standby Demand	Maint. Days	Outage Days	Forced Outage Hrs.	Maintenance Hrs.	Standby Demand Charges
Jan-18	Jan-18	31	50,100	-	11	167	-	$ 166,202
Feb-18	Feb-18	28	50,100	-	8	133	-	$ 134,106
Mar-18	Mar-18	31	50,100	-	7	95	-	$ 103,572
Apr-18	Apr-18	30	50,100	-	4	65	-	$ 62,363
May-18	May-18	31	50,100	-	6	86	-	$ 90,204
Jun-18	Jun-18	30	50,100	-	1	2	-	$ 15,719
Jul-18	Jul-18	31	50,100	-	8	120	-	$ 120,741
Aug-18	Aug-18	31	50,100	-	4	76	-	$ 61,013
Sep-18	Sep-18	30	50,100	15	-	-	338	$ -
Oct-18	Oct-18	31	50,100	2	1	9	29	$ 15,244
Nov-18	Nov-18	30	50,100	-	5	59	-	$ 78,784
Dec-18	Dec-18	31	50,100	-	-	-	-	$ -
	Total							

Calculation of Recommended DEK GSS Method Charges - 2018

Date	Maintenance Demand Charges	Transmission Charge	Supplemental Demand	Supplemental Demand Charges	Total Plant Energy Usage	Generation Energy	Energy Charges*
Jan-18	$ -	$ 115,055	21,513	$ 250,526	50,305,456	24,119,927	$ 1,141,348
Feb-18	$ -	$ 115,296	21,513	$ 251,050	42,825,009	22,967,189	$ 895,255
Mar-18	$ -	$ 112,669	21,513	$ 245,331	51,171,509	32,814,164	$ 844,722
Apr-18	$ -	$ 114,892	21,513	$ 250,170	49,938,989	33,044,236	$ 750,548
May-18	$ -	$ 114,482	21,513	$ 249,276	50,241,898	30,236,356	$ 873,950
Jun-18	$ -	$ 115,834	21,513	$ 252,221	49,193,523	30,828,252	$ 801,220
Jul-18	$ -	$ 114,929	21,513	$ 250,250	51,432,529	27,799,569	$ 1,020,592
Aug-18	$ -	$ 116,152	21,513	$ 252,914	51,000,583	21,840,745	$ 1,295,871
Sep-18	$ 230,077	$ 113,032	21,513	$ 246,121	35,332,284	17,834,794	$ 761,659
Oct-18	$ 30,489	$ 116,084	21,513	$ 252,766	50,652,433	32,532,009	$ 820,126
Nov-18	$ -	$ 116,116	21,513	$ 252,835	49,953,637	32,433,737	$ 819,049
Dec-18	$ -	$ 117,371	21,513	$ 255,567	52,247,644	37,495,072	$ 652,067
							$ 10,676,407

Calculation of Recommended DEK GSS Method Charges - 2018

Date	Metering, Admin, Other Charges	As-Billed MRSM (for completeness)	Total
Jan-18	$ 7,540	$ (11,259)	$ 1,669,411.72
Feb-18	$ 7,761	$ (11,039)	$ 1,392,430.00
Mar-18	$ 7,876	$ (9,952)	$ 1,304,217.60
Apr-18	$ 7,890	$ (11,007)	$ 1,174,856.79
May-18	$ 8,106	$ (10,907)	$ 1,325,111.69
Jun-18	$ 8,031	$ (10,721)	$ 1,182,302.89
Jul-18	$ 7,825	$ (10,605)	$ 1,503,731.61
Aug-18	$ 8,289	$ (11,778)	$ 1,722,460.49
Sep-18	$ 7,477	$ (14,417)	$ 1,343,948.23
Oct-18	$ 7,760	$ (14,641)	$ 1,227,828.01
Nov-18	$ 7,899	$ (14,595)	$ 1,260,088.26
Dec-18	$ 7,412	$ (18,666)	$ 1,013,751.18
	$ 93,864	$ (149,586)	$ 16,120,138