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	)	

SURREBUTTAL

TESTIMONY AND EXHIBIT

OF

STEPHEN J. BARON

ON BEHALF OF

DOMTAR PAPER COMPANY, LLC

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 2024

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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**

SURREBUTTAL 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. Did you previously file Direct Testimony in this case?

A. Yes.

Q. What is the purpose of your Surrebuttal Testimony?

A. I provide Surrebuttal Testimony in response to the Rebuttal Testimony of Big Rivers witness Terry Wright, Jr. Mr. Wright opposes my proposal to implement a rate for backup and maintenance service based upon the Commission's long-approved Duke Energy Kentucky Rider GSS.

Q. Are there important issues presented by you and Domtar witness Steve Thomas in your respective Direct Testimonies that Mr. Wright did not contest in his Rebuttal Testimony?

A. Yes. Mr. Wright did not rebut the following:

- There are no standby service tariffs anywhere in the United States comparable to Big Rivers' proposed LICSS tariff.
- Other MISO utilities do offer standby service tariffs which reflect the principles incorporated in Duke Energy Kentucky's GSS standby rate.
- The annual rate increase to Domtar from Big Rivers' proposed tariff LICSS would be $6.48 million (45.5%).
- The annual rate increase to Domtar based on Duke Energy Kentucky's GSS standby rate design would be $2.53 million (17.8%).

Q. Before discussing the issues raised by Mr. Wright in his Rebuttal Testimony, would you summarize the key provisions of Big Rivers' LICSS tariff?

A. Yes. The LICSS tariff for standby service would charge Domtar and Kimberly-Clark:

1) The monthly standard large industrial demand charge for 100% of their plant load, without regard to the cogeneration used to serve part of the customer's load;

2) Plus, an energy charge on an hourly basis at the greater of the standard cost-based energy rate or the MISO market-based energy price;

3) Less, reimbursement from Big Rivers for Big Rivers selling the customer's cogeneration capacity into the MISO market.

Q. Please summarize your Surrebuttal Testimony.

A. There is no requirement by MISO for Big Rivers to plan on serving the total plant load of a customer with behind-the-meter generation. Nor is there such a requirement for Kentucky Integrated Resource Plan ("IRP") purposes. Historically, Big Rivers has planned on serving only Domtar's net plant load (total load less the capacity value of its generator). The planning change recommended by Mr. Wright to serve the total plant load appears to be an attempt to justify its LICSS standby rate. Domtar's behind-the-meter cogeneration plant is a Qualifying Facility ("QF") under PURPA. Big Rivers proposed standby rate violates the FERC PURPA regulations which specify that a standby rate "*shall not be based on an assumption*" that a QF will experience a forced outage "*during the system peak*" unless supported by factual data. MISO's Planning Reserve Margin is designed to sufficiently cover the possibility of a generation unit forced outage. Mr. Wright's argument is inconsistent with MISO Resource Adequacy standards. Its proposed standby rate also violates this Commission's PURPA regulations which require that backup and maintenance rates be priced separately. The "*greater of*" cost or market energy component of the proposed LICSS rate could unreasonably result in standby service customers paying more than customers on the standard industrial rate. Finally, the change in system planning to serve the total plant load will harm ratepayers by unnecessarily accelerating the need for expensive new generation.

Q. In his Rebuttal Testimony, how does Mr. Wright justify charging a standby service customer the standard large industrial demand charge applied to 100% of its load, instead of only on the customer's load net of its cogeneration facility capacity (its supplementary power requirement)?

A. Mr. Wright argues that Big Rivers must plan on serving the entire plant load (not the load net of the capacity value of the customer's cogeneration), and that charging for that service is therefore appropriate. He argues that Big Rivers must have capacity to serve all of the standby customer's load because no customer-owned cogeneration facility is 100% reliable and it may be forced out during critical peak hours, which could result in unacceptable reliability risks to the fifteen state MISO system. He stresses that "it is the *possibility* of forced outage, not *probability*, that is relevant when examining demand costs related to Backup Power Service."[1]

Q. Does MISO require utilities to plan on serving the full load of customers with behind-the-meter cogeneration facilities?

A. No. MISO does not require utilities to plan on serving the full load of customers with behind-the-meter cogeneration. The effect of MISO's treatment of customer behind-the-meter cogeneration is that Big Rivers will receive an offsetting capacity payment based on the accredited capacity value of the cogeneration. As such, with regard to MISO, Big Rivers will only be charged for a customer's net load, not its full load.

[1] Wright Rebuttal Testimony at 6 (emphasis in the original).

Q. How has Big Rivers historically planned on serving Domtar's load?

A. Since at least MISO planning year 2018-2019, the Big Rivers system peak load forecast submitted to MISO included only the net load of Domtar. This MISO peak load forecast determines Big Rivers' capacity obligation for purchases from the MISO market.[2] Therefore, since at least 2018-2019, Big Rivers was not required by MISO to pay for capacity associated with Domtar's load that was supplied by its cogeneration facility (about 49.6 MW of accredited capacity). For its own resource planning in Kentucky that is under the Commission's authority, as shown in Big Rivers' 2023 IRP, Big Rivers only included Domtar's firm demand (full load net of cogeneration) in its load forecasts prior to 2025. This meant that Big Rivers did not have to obtain physical capacity resources for the Domtar load served by its cogeneration facility.

Q. **Please describe the process that Big Rivers historically used to reduce its MISO peak load forecast by netting out the capacity value of Domtar's cogeneration facility.**

A. This process is addressed in Confidential Response to PSC 2-6 and the Confidential Attachment to PSC 1-1. According to Big Rivers, Domtar's cogeneration facility was accredited by MISO, thus reducing Big Rivers' peak load obligation for MISO planning years 2018-2019, 2019-2020, 2020-2021, 2021-2022 and 2022-2023.

[2] "A ZRC represents 1 MW-day of qualified Seasonal Accredited Capacity (SAC) from a Planning Resource for a specific Season of a Planning Year, tracked to the nearest tenth of a MW, pursuant to the applicable ZRC qualification procedures described herein." (MISO Business Practices Manual BPM-011 at page 75).

Because Domtar is not a member of MISO, all information regarding Domtar's behind-the-meter cogeneration facility was provided to MISO by Big Rivers.

Q. **In his Rebuttal Testimony, does Mr. Wright propose changing this historic practice**?

A. Yes. Mr. Wright now calls the practice of only planning to serve net load an "*artificial*" reduction in Big Rivers peak demand forecast.[3] Even though MISO allows this practice for its capacity planning, Mr. Wright claims that reducing Big Rivers peak demand forecast by the capacity value of behind-the-meter cogeneration could cause reliability problems for the fifteen states covered by MISO.[4,5] Mr. Wright's concern about the other utilities in MISO – at the expense of Domtar and Kimberly-Clark – is unjustified. MISO is fully capable of setting its own rules, and planning to serve net load complies with those rules. When applying the MISO peak load forecast rules as currently in effect, there is no basis to charge a standby service customer with behind-the-meter cogeneration the standard industrial demand charge on its full plant load.

[3] Wright Rebuttal Testimony at 4 and 7; Big Rivers Response to Joint Requests 3-2.

[4] Big Rivers Response to Intervenor Joint Request 3-5: "*When LSEs reduce their Peak Demand with unregistered generation, they are not giving MISO an accurate account of the load risk that exists. In that scenario, MISO, with visibility only of total forecasted Load, is deprived of relevant information and not aware that the Load could fluctuate significantly if a Behind-the-Meter-Generator experiences outages. LSEs, including Big Rivers, need to do their best to ensure that MISO has an accurate picture of the reliability risks that exist."*

[5] Wright Rebuttal Testimony at 5-6: *"If Big Rivers (and other load-serving utilities) undertake the burden of evaluating the anticipated capacity value of specific customer behind-the-meter generation in order to minimize MISO planning year capacity purchases (all within some undefined risk tolerance and is spite of true system peak demand), the risk of shortfall is all but assured. This instability is compounded by more load-serving utilities attempting to act as their own balancing authorities, instead of allowing MISO to have a clear and accurate picture of actual system load obligations."*

Q. **Is it reasonable to raise Domtar's rates by taking on obligations not imposed by MISO?**

A. No. Ratemaking in Kentucky should not voluntarily take on additional capacity planning obligations not imposed on MISO's other fourteen states. As discussed in Domtar witness Murray Hewitt's testimony, Domtar's Hawesville paper plant in Hancock County employs 460 people. The freesheet paper market is declining by 4%-6% per year. That is the equivalent of one Hawesville-sized mill being closed every seven months. In September 2023, Domtar announced the indefinite idling of its paper mill in Espanola, Canada that had, prior to its closing, employed 450 people. Big Rivers proposed LICSS standby tariff would raise Domtar's rates by 45.5% ($6.48 million per year). Under these circumstances, taking on additional obligations not imposed by MISO would not be reasonable.

Q. **Would planning to serve the entire load of Domtar and Kimberly-Clark instead of their net loads increase the costs of other ratepayers?**

A. Yes. Changing Big Rivers' historic practice of only planning to serve the net load of customers with cogeneration would increase costs to other ratepayers in the long-term by accelerating the need for new generating capacity. Later in my testimony I quantify this long-term generation cost.

Q. **Why would Big Rivers propose to change its system planning if it is not required by MISO or the Commission's IRP regulation and would increase its costs?**

A. It is the only way to justify charging Domtar and Kimberly-Clark the standard large industrial demand charge on their entire load. Instead of engaging in least cost planning and setting rates accordingly, Big Rivers proposes the opposite. It proposes to purposefully increase its costs in order to justify huge rate increases (45.5% to Domtar) to its standby service customers.

Q. Is Big Rivers' position that it must acquire capacity because there is a possibility that the customer's generator may be forced out at the time of a system peak in compliance with PURPA's backup power and maintenance power provisions, as adopted by FERC?

A. No. Domtar's behind-the-meter cogeneration facility which produces energy and steam from boilers fueled by tree bark, sawdust, wood chips and "*black liquor*" is a Qualifying Facility ("QF") under PURPA. As I discussed in my Direct Testimony, PURPA requires that backup and maintenance power rates "(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…" Contrary to this FERC rule, a central assumption of Mr. Wright's Rebuttal Testimony is that behind-the-meter QF cogeneration facilities could be out of service during the system peak. He has not supported this assumption with specific factual data. Therefore, Mr. Wright's attempt to justify charging the large industrial demand rate on Domtar's total plant load because there is a "*possibility*" that its QF could be forced out during a system peak violates this rule.

Q. Doesn't a Planning Reserve Margin provide resources to cover the "possibility" of a forced outage of generation during a critical load period?

A. Yes. Because no generator, utility owned or customer owned, is 100% reliable, MISO requires that utilities carry a reserve margin. A reserve margin requirement is not unique to MISO. It is a central planning element for all utilities. MISO's Business Practices Manual BPM-011, which addresses resource adequacy states as follows on page 14:

> The focus of Resource Adequacy is on the longer-term planning margins that are used to provide sufficient resources to reliably serve Load on a forward-looking basis. In the real-time operational environment, resources committed through the Resource Adequacy Requirements have a capacity obligation to be available to meet real-time customer demand and contingencies. Therefore, Planning Reserve Margins (PRMs) must be sufficient to cover:
>
> - Planned maintenance
> - ***Unplanned or forced outages of generating equipment*** *(emphasis added)*
> - Deratings in the capability of Generation Resources and Demand Response Resources
> - System effects due to reasonably anticipated variations in weather
> - Load Forecast Uncertainty

Q. Is Mr. Wright's recommendation in compliance with the Commission's PURPA regulations at 807 KAR 5:054?

A. No. Under the Commission's PURPA regulations, "*each electric utility shall provide supplementary, back-up power, maintenance and interruptible power.*" Supplementary power is defined as "*electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generated itself.*" The amount of capacity regularly used by Domtar in addition to that supplied by its cogeneration QF is its net load, or about 20.4 Mw (full plant load is approximately 70 Mw and the UCAP value of its QF cogeneration facility is 49.6 Mw). Therefore, Mr. Wright's proposal to charge the standard large industrial demand rate on Domtar's full plant load violates the Commission's PURPA regulations.[6] The Duke Energy Kentucky GSS standby rate that I recommend complies with this regulation.

Q. Does Mr. Wright's Rebuttal Testimony position that Big Rivers must have capacity to serve the full plant load because of the possibility of forced outages result in non-compliance with other aspects of the Commission's PURPA regulations?

A Yes. The assertion in Mr. Wright's Rebuttal Testimony that Big Rivers must have capacity to supply the full load because of the "*possibility*" of forced outages is his rationale for charging the same rate for maintenance service and backup service. "*So long as a forced outage is possible and the customer expects Big Rivers to deliver all required power during the forced outage, the costs to Big Rivers for capacity is established whether there are scheduled, unscheduled, or no outages during a month.*"[7] Contrary to Mr. Wright's position, the Commission's PURPA regulations define maintenance and backup service for QFs differently. Maintenance service is for scheduled outages and backup service is for unscheduled outages. When the Commission's PURPA rule was established in 1982, the

[6] All but about 20 MWs of the plant load is regularly supplied by Domtar's cogeneration facility.
[7] Wright Rebuttal Testimony at 7.

possibility of a QF forced outage was presumably understood. The possibility of QF forced outages has always existed. The Commission's Order establishing this case made it very clear that these two services are different and should be priced differently. The Duke Energy Kentucky GSS standby rate that I recommend complies with this regulation and the Commission's Order.

Q. Please discuss the LICSS tariff provision which provides the customer with a capacity credit based on the MISO market price of capacity if the customer's generator is registered and accredited by MISO.

A. This provision stems from Big Rivers' position that its standby service rate should reflect the market value of capacity to it, not Big Rivers' cost of providing standby service. Because Domtar is not a member of MISO, Big Rivers would sell the standby customer's generation capacity into the MISO market and credit back the revenue to the customer.

Q. **Please discuss the LICSS tariff provision regarding the price for energy.**

A. For energy, the LICSS tariff would charge the standby customer on an hourly basis at the "*greater of*" the cost-based standard large industrial energy charge or the MISO market cost of energy priced at the Locational Marginal Price ("LMP"). As I will explain below, this provision creates an energy penalty that offsets the MISO capacity credit provision of the LICSS tariff.

Q. **If the market value of capacity is low and the market cost of energy is high, could a standby customer on LICSS end up paying the same price (or more) for standby capacity as a standard service industrial customer?**

A. Yes. If the market value of capacity is low and the market price of energy is high, a customer with cogeneration could end up paying the standard industrial demand charge for load that is actually served by the customer's own generation. In Domtar's case, it's 49.6 MW of cogeneration capacity could end up having "0" capacity value to Domtar. If the market energy price is high enough, a standby customer under Big Rivers LICSS tariff could actually pay more to Big Rivers for demand to serve its load than a regular industrial customer without any generation. In this case, the capacity value of the customer's generation would be negative.

Q. **Have you quantified this effect on Domtar?**

A. Yes. Based on MISO market energy prices for the 12-month period ending September 30, 2023, the LICSS "*greater of*" energy charge penalty would nearly equal the MISO planning year capacity credit, essentially eliminating it.

Table 1-S calculates the additional LICSS energy charge penalty associated with the "greater of" provision.[8] Based on the most recent MISO accreditation, Domtar's generator has a UCAP value of 49,600 kW. At a 78.4% capacity factor[9], this means

[8] The "greater of" provision charges a standby and maintenance customer for replacement energy on an hourly basis at the greater of the standard LIC energy charge rate or MISO LMP.

[9] During 2021, 2022 and the first nine months of 2023, Domtar's capacity factor was 78.4%.

that 93,851 MWh of Domtar's energy usage would have been subject to "*greater of*" pricing in the 12-month period ending September 30, 2023 based on the LICSS tariff.

Table 1-S
Big Rivers' Proposed LICSS Tariff
Cost of Standby and Maintence Capacity
(including Energy Charge Impact)

LICSS Demand Charge for Standby/Maintence Capacity	$ 6,377,568	
Per kW Month	$ 10.715	
Assumed Capacity Factor of Generator*	78%	
MWh in which LICSS energy charge is applicable	93,851	
LMP Market Prices and LIC Energy Rate Assumptions - 12 Mo. Ending 9/30/2023		
1. Percent of the hours in year, LMP > LIC Energy Chg.		7.4%
2. Excess cost of LMP vs. LIC Energy rate during those hours ($/MWh)		$ 23.76
Adjusted Standby/Maintence Capacity Charge		
LICSS Energy Charge Penalty**		$ 164,992
2023/2024 PRA Based Capacity Credit		$ (167,462)
Net LICSS capacity credit***		$ (2,470)
Net LICSS capacity credit per kW		$ (0.004)
Effective Standby/Maintenance Capacity Rate Per kW		**$ 10.711**

* This is the average capacity factor for Domtar's generator during 2021, 2022 and .
for the first nine months of 2023.
** This is the excess charge over the standard LIC energy charge that is imposed under LICSS.
*** A negative credit means that the "greater of" energy charge penalty exceeds the MISO PRA capacity credit.

Out of 8,760 hours during this 12-month period, the MISO energy price exceeded the standard cost-based energy rate in 648 hours (7.4% of the time). Market-based energy exceeded cost-based energy by $23.76/MWh on average during these hours. This resulted in an energy penalty of $164,992. Using the current 2023-2024 PRA results, the market-based capacity credit for Domtar's cogeneration facility was only $167,462. Therefore, the net MISO market-based capacity credit under the LICSS tariff would be $2,470 or $0.004/kW. Effectively, Domtar would pay a standby capacity charge of $10.711/kW instead of the standard demand charge of $10.715/kW. A slightly higher MISO market energy price would result in a standby power demand charge that is actually higher than the standard industrial rate. This is not likely what the PURPA regulations had in mind for standby service for QFs.

Q. Are there longer-term consequences for Big Rivers' customers from its new planning approach to serve the full load of customers with cogeneration instead of their net load?

A. Yes. As shown in Big Rivers' 2023 IRP load forecast table that I attach as my Exhibit__(SJB-1S), prior to 2025, Big Rivers included only the firm portion of Domtar's load in its peak demand forecast. Beginning in 2025, Big Rivers is planning to obtain generating capacity to serve Domtar's total load. This is because of the possibility that its cogeneration facility could be out at a peak time due to a forced outage.

Q. What is the additional cost imposed on Big Rivers' customers as a result of the planning decision to acquire capacity to serve the Domtar and Kimberly-Clark load that is served by their own generation?

A. Based on Big Rivers' 2023 IRP, the next generating unit that is needed to serve its load is a 635 MW natural gas fired combined cycle unit ("NGCC") that would be added to the system in June 2029. Based on recent data from the Energy Information Administration ("EIA") presented in its 2023 Annual Energy Outlook ("AEO"), the overnight installed cost of a 2029 NGCC is $1,396/kW. For an NGCC with carbon sequestration, the estimated 2029 cost is $3,584/kW. Using this recent EIA data, the additional cost to Big Rivers' customers from ignoring the capacity benefit of the Domtar and Kimberly-Clark cogeneration facilities would range from $87.9 million to $225.7 million. Table 2-S below shows these calculations.

Table 2-S
Estimated Cost to Big Rivers' Customers of Ignoring Domtar and Kimberly-Clark BTMG Generation

Resource	Base overnight cost (2022$/kW*)	GDP Price Deflator 2022**	GDP Price Deflator 2029**	GDP Price Deflator Factor (2022 vs. 2029)	$2029 Cost	kW***	Total Cost
Combined-cycle—multi-shaft 2025	$1,176	1.26920	1.50691	1.187	$1,396	62,954	87,899,413
Combined-cycle with 90% CCS 2025	$3,019	1.26920	1.50691	1.187	$3,584	62,954	225,653,341

* Energy Information Administration, "Assumptions to the Annual Energy Outlook 2023: Electricity Module," Table 3.
** Energy Information Administration, Annual Energy Outlook 2023 "Macroeconomic Indicators," Table 20.
*** Domtar generator UCAP value (49,600 kW) plus Kimberly-Clark 14 MW ICAP generator adjusted for UCAP based on Domtar UCAP/ICAP ratio.

Q. Would adopting the Duke Energy Kentucky GSS standby service rate avoid the problems that you have described?

A. Yes. The Duke GSS rate does not include a "*greater of*" energy provision. Therefore, there is no chance of standby service being more expensive than regular service. The Duke GSS rate requires the standby customer to contract for Supplemental Power Service at the demand level not served by its own generation. Supplemental Power Service is charged at the standard rate. Therefore, the possibility of a utility intentionally acquiring excess capacity would be reduced or eliminated.

Q. What is your overall opinion of Mr. Wright's Rebuttal Testimony?

A. The LICSS rate supported by Mr. Wright is one of the more egregious proposals that I have seen in 40 years. It explains why no other utility in the United States has a standby rate that is similar to the one he supports. PURPA is intended to promote cogeneration. If adopted state-wide, his proposal would seriously undermine that policy.

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
14th day of March 2024.

Notary Public

RANDY A FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 26, 2024
COBB COUNTY, GEORGIA

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SURREBUTTAL EXHIBIT__(SJB-1S)

OF

STEPHEN J. BARON

Big Rivers
ELECTRIC CORPORATION

2023 INTEGRATED RESOURCE PLAN

BIG RIVERS TOTAL FORECAST										
RESIDENTIAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	99,724	99,871	100,257	100,954	101,506	102,118	102,864	103,563	104,147	104,633
SALES-MWH	1,491,338	1,410,779	1,359,904	1,395,391	1,430,495	1,438,426	1,446,158	1,445,944	1,450,553	1,454,971
USE PER CONSUMER-kWH	14,955	14,126	13,564	13,822	14,093	14,086	14,059	13,962	13,928	13,905
GENERAL C&I	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	17,482	17,749	18,262	18,502	18,815	19,096	19,124	19,302	19,505	19,702
SALES-MWH	618,143	589,282	548,908	573,487	579,464	591,349	596,736	597,500	602,749	607,821
USE PER CONSUMER-kWH	35,358	33,201	30,057	30,995	30,798	30,967	31,203	30,955	30,903	30,851
LARGE C&I	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	30	30	30	29	29	30	33	33	33	33
SALES-MWH	153,431	155,205	149,601	148,832	146,626	150,305	187,146	187,146	187,146	187,146
USE PER CONSUMER-kWH	5,114,366	5,130,733	4,986,683	5,102,807	5,056,063	5,095,086	5,671,098	5,671,098	5,671,098	5,671,098
IRRIGATION	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	5	5	5	5	5	5	5	5	5	5
SALES-MWH	70	114	50	84	130	93	93	93	93	93
USE PER CONSUMER-kWH	15,618	22,742	10,043	16,704	26,082	18,625	18,625	18,625	18,625	18,625
STREET & HIGHWAY	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	107	106	110	119	124	125	125	125	125	125
SALES-MWH	3,111	3,045	3,050	3,012	3,007	3,034	3,034	3,034	3,034	3,034
USE PER CONSUMER-kWH	28,965	28,640	27,662	25,332	24,202	24,272	24,272	24,272	24,272	24,272
RURAL TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	117,348	117,761	118,664	119,609	120,479	121,373	122,151	123,028	123,814	124,498
SALES-MWH	2,266,093	2,158,425	2,061,512	2,120,806	2,159,723	2,183,207	2,233,167	2,233,718	2,243,576	2,253,065
USE PER CONSUMER-kWH	19,311	18,329	17,373	17,731	17,926	17,988	18,282	18,156	18,120	18,097
OWNUSE-MWH	3,211	3,087	2,814	3,666	4,103	4,051	4,073	4,098	4,121	4,142
PURCHASES-MWH	2,366,988	2,261,069	2,164,868	2,219,380	2,269,586	2,291,062	2,343,506	2,344,105	2,354,461	2,364,427
DISTRIBUTION LOSSES-MWH	97,684	99,557	100,542	94,909	105,760	103,804	106,266	106,290	106,764	107,220
LOSSES (%)	4.1%	4.4%	4.6%	4.3%	4.7%	4.5%	4.5%	4.5%	4.5%	4.5%
DIRECT SERVE	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	21	21	19	16	16	17	18	18	18	18
SALES-MWH (SMELTERS AND DOMTAR REMOVED)	823,823	815,322	701,697	648,808	745,683	1,396,521	1,999,963	1,997,196	1,997,196	1,997,196
USE PER CONSUMER-kWH	39,543,509	38,824,859	36,294,688	40,762,820	45,422,312	80,957,713	111,109,034	110,955,311	110,955,311	110,955,311
AUX SALES-MWH	0	4,434	16,944	18,367	6,184	0	0	0	0	0
DOMTAR TAKE-MWH	240,369	273,974	240,564	242,657	229,274	227,932	227,932	227,932	227,932	227,932
DOMTAR UP TO TARIFF-MWH	129,999	130,718	122,998	132,751	173,674	172,657	172,657	227,932	227,932	227,932
SYSTEM TOTAL WITH DIRECT SERVE	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	117,369	117,782	118,684	119,625	120,496	121,391	122,169	123,046	123,832	124,516
SALES-MWH	3,219,916	3,104,465	2,886,207	2,902,364	3,079,080	3,752,384	4,405,787	4,458,845	4,468,703	4,478,193
USE PER CONSUMER-kWH	27,434	26,358	24,318	24,262	25,553	30,912	36,063	36,237	36,087	35,965
OWNUSE-MWH	3,211	3,087	2,814	3,666	4,103	4,051	4,073	4,098	4,121	4,142
TOTAL ENERGY REQUIREMENTS-MWH (NO TRANS. LOSSES)	3,320,811	3,211,544	3,006,507	3,019,306	3,195,127	3,860,240	4,516,125	4,569,232	4,579,589	4,589,554
DISTRIBUTION LOSSES-MWH	97,684	99,557	100,542	94,909	105,760	103,804	106,266	106,290	106,764	107,220
DISTRIBUTION LOSS (%)	2.9%	3.1%	3.3%	3.1%	3.3%	2.7%	2.4%	2.3%	2.3%	2.3%
TRANSMISSION LOSSES-MWH	86,858	82,848	77,120	71,125	74,851	92,323	108,209	109,482	109,730	109,969
TRANSMISSION LOSS (%)	2.6%	2.5%	2.5%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
TOTAL ENERGY REQUIREMENTS-MWH	**3,407,668**	**3,294,392**	**3,083,627**	**3,090,431**	**3,269,978**	**3,952,563**	**4,624,335**	**4,678,714**	**4,689,319**	**4,699,523**
ANNUAL PEAK	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
RURAL CP - kW	556,742	490,895	460,173	492,854	590,652	473,447	481,988	482,030	483,992	485,932
DIRECT SERVE CP - kW	80,530	102,931	90,992	81,513	64,682	241,127	318,288	318,288	318,288	318,288
AUX CP - kW	0	0	1,756	3,046	246	0	0	0	0	0
DOMTAR TAKE - kW	17,993	16,308	19,451	19,051	51,937	40,816	40,816	40,816	40,816	40,816
DOMTAR UP TO TARIFF - kW	15,000	15,000	15,000	15,000	35,000	20,000	20,000	40,816	40,816	40,816
TOTAL CP - kW	652,272	608,826	567,921	592,413	690,580	734,575	820,276	841,133	843,095	845,035
TRANSMISSION LOSSES - kW	16,382	15,995	14,562	13,822	16,185	17,601	19,654	20,154	20,201	20,248
TRANSMISSION LOSS (%)	2.6%	2.5%	2.5%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
TOTAL CP - kW (WITH TRANSMISSION LOSSES)	**668,654**	**624,821**	**582,483**	**606,235**	**706,765**	**752,176**	**839,930**	**861,287**	**863,296**	**865,283**
SUM OF COOP RURAL NCP - kW	561,382	517,109	497,373	522,923	604,578	520,744	530,273	530,229	532,427	534,316
SUM OF COOP DIRECT SERVE SUM OF INDIVIDUAL NCP - kW	892,945	940,172	889,584	897,274	992,296	742,991	778,571	826,013	826,013	826,013