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Attorney for Guam Power Authority

BEFORE THE GUAM PUBLIC UTILITIES COMMISSION

IN THE MATTER OF:	**GPA DOCKET NO. 25-14**
GUAM POWER AUTHORITY'S BASE RATE	**AMENDED PETITION OF THE GUAM POWER AUTHORITY TO ADJUST BASE RATE**

The Guam Power Authority (GPA) hereby submits its amended petition to the Guam Public Utilities Commission (PUC) for an adjustment in the base rate. The amended petition includes the following materials and testimony:

I. Background.

In April 2020, GPA entered into a court-approved consent decree with the U.S.

Department of Justice and U.S. Environmental Protection Agency to resolve alleged violations of the Clean Air Act in *United States v. Guam Power Authority*, District Court of Guam Civil Case No. 1:20-cv-00007. As part of the settlement, GPA agreed to install the Ukudu Power Plant, a 198-MW combined cycle baseload power plant, under a long-term energy conversion agreement with Guam Ukudu Power LLC. GPA has also been switching to cleaner fuel and installing renewable solar power as part of the consent decree.

The highly efficient Ukudu combined cycle power plant is expected to be 37 percent more efficient than Cabras 1 and 2 and 22 percent more efficient than Piti 8 and 9. By significantly reducing the amount of fuel required, the Ukudu Power Plant will help reduce fuel imports by over 900,000 barrels or 39 million gallons per year. The new plant has an expected commissioning date in mid-to-late September 2025. Within six months of commissioning the Ukudu plant, GPA must decommission Cabras 1 and 2.

At its regular meeting on February 25, 2025, the Consolidated Commission on Utilities approved a resolution to increase GPA's base rate. Attached to the resolution were the proposed rates and charges. The base rate adjustment will help GPA to service the debt for the new power plant, as well as continue funding capital improvement projects that promote operational efficiency and reliability. GPA submits the testimony of its General Manager, Chief Financial Officer, Utility Expert, and Assistant General Manager – Administration in support of the base rate adjustment.

The Ratepayers' Bill of Rights provides that ratepayers have the following fundamental rights:

(1) the right to receive clear and adequate notice of any proposed rate increase;
(2) the right to be fully informed about and to fully evaluate any proposed rate increase, as well as the finances of a Public Utility; and
(3) the right to give input and participate in any proposed rate increase.

12 GCA § 12102.1(b).

The Ratepayers' Bill of Rights imposes the following notice requirements:

(1) publish notice of a proposed rate increase in a newspaper of general circulation at least three months before submission to the PUC, stating the intention to submit a proposed change in rates in three months' time, the current utility rate, the proposed rate, the amount of increase and a justification for the increase;
(2) mail a notice to every ratepayer at least one month before submission to the PUC, stating the intention to submit a proposal to increase rates in one month's time, the current utility rate, the proposed rate, the amount of increase and a justification for the increase; and
(3) publish the required public notice information on the internet at least one month before submission to the PUC.

12 GCA § 12102.2(b), (c) & (e).

GPA has given ratepayers timely notice. GPA prepared a flyer containing the information required by the Ratepayers' Bill of Rights. On March 5, 2025, GPA published the required notice in an appropriate newspaper. On March 13, 2025, GPA published the notice on the internet. Throughout the month of April 2025, GPA issued and mailed notices to its customers. In addition, GPA undertook community outreach activities, including appearances on two local radio programs on April 15, and 18, 2025, respectively. GPA also sent SMS messages to prepaid customers on May 2, 2025.

II. Request For Approval.

The PUC's enabling legislation gives it the power to conduct regulatory oversight and supervision of rates over each public utility, investigate and examine any rates and charges charged by any utility, and establish and modify reasonable rates and charges for services. *See* 12 GCA § 12105(a), (c) & (e) (general powers and duties of the PUC). Before approving any rate change, the PUC must ensure that the utility has established that the change is necessary. 12 GCA § 12105(f). To that end, the PUC must conduct any investigation and hearings it deems necessary, using standards and financial criteria consistent with public utility generally accepted rate-making practices. 12 GCA § 12105(f)(1) & (2). For GPA specifically, the PUC must ensure that rate changes will be sufficient to enable GPA to meet its financial obligations, operating expenses, debt service and capital improvement needs. 12 GCA § 12105(f)(3).

When the PUC considers a rate change, Guam law requires the PUC to hold at least three public hearings in different locations in the north, center and south of Guam. 12 GCA § 12117(a) (governing public hearings). The hearing notices must list the proposed rates and their proposed effective date. *Id.* The law further requires the PUC to advertise the hearing date, time and place in a newspaper of general circulation on a specified timetable. 12 GCA § 12117(b). GPA also must notify ratepayers. 12 GCA § 12117(c).

The CCU has authorized GPA to seek a base rate adjustment as outlined in the attached exhibits. The proposed rates have been thoroughly studied for their reasonableness by a consultant. The base rate adjustment is necessary because GPA needs to finance the new power plant and continue to meet its responsibilities under the consent decree. The change in the base rate is prudent, because it supports GPA's new, more efficient power plant, with fuel savings that will more than offset the effect of the base rate increase on ratepayers.

III. Conclusion.

Based on the foregoing and the attached supporting documents, GPA requests the PUC to adjust the base rate, as it is reasonable, prudent and necessary.

Respectfully submitted this 8th day of August, 2025.

Attorney for Guam Power Authority

By: M. Woloschuk

Marianne Woloschuk
GPA Legal Counsel

CONSOLIDATED COMMISSION ON UTILITIES
Guam Power Authority | Guam Waterworks Authority
P.O. Box 2977 Hagatña, Guam 96932 | (671) 648-3002 | guamccu.org

GPA RESOLUTION NO.: FY2025-11

TO AUTHORIZE THE MANAGEMENT OF THE GUAM POWER AUTHORITY TO FILE A RATEPAYER'S BILL OF RIGHTS NOTICE IN ANTICIPATION OF THE FILING OF A PETITION FOR A BASE RATE ADJUSTMENT WITH THE GUAM PUBLIC UTILITIES COMMISSION

WHEREAS, Guam Power Authority (Authority) is a Public Corporation and an Enterprise fund of the Government of Guam;

WHEREAS, as a Public Corporation and an Enterprise fund it is expected that GPA will set its rates in a manner that will cover the costs of operation of the Authority; and

WHEREAS, the rates of the Authority are subject to regulation by the Public Utilities Commission (PUC); and

WHEREAS, Public Law 26-23 which was known as the Ratepayer's Bill of Right requires among other things, that a notice must be placed in a newspaper of general circulation at least three (3) months before an anticipated petition or a Base Rate increase which describes the rates for which the Authority is petitioning; and

WHEREAS, Public Law 26-23, Ratepayer's Bill of Right, also requires the Authority to mail a notice to every ratepayer at least one (1) month before submitting the proposed rate increase to the Public Utilities Commission; and

WHEREAS, GPA completed its Load study and Cost of Service study in order to ensure that costs of providing services to each rate class are being properly assigned to each rate class; and

WHEREAS, GPA's financial model developed by Utility Financial Solutions, LLC addresses the necessary base rate to cover payments for the upcoming 198-megawatt Combined Cycle Baseload Power Plant, the Ukudu Power Plant, under the long-term Energy Conversion Agreement with Guam Ukudu Power and necessary capital improvement projects to provide for continued operational efficiency and reliability while being financially stable to meet debt service coverage; and

WHEREAS, the Ukudu Power Plant will bring clean, highly fuel-efficient energy, and integrate well with renewable energy into Guam's power grid system. The Ukudu Power Plant is 37% more fuel efficient than Cabras 1 and 2 and 22% more efficient than Piti 8 and 9. This efficiency will help import 930,000 fewer barrels of fuel per annum or 39 million gallons. The fuel efficiency will more than offset the base rate adjustment and provide net savings to the ratepayers; and

WHEREAS, in early 2020, GPA, EPA and the Justice Department finalized a settlement to resolve the alleged violation of the Clean Air Act. The parties subsequently lodged a consent decree with the United States District Court of Guam, which approved the Consent Decree in April of 2020. In accordance with the terms of the settlement, GPA is completing the installation of a new, cleaner power plant, switching to cleaner fuel, and installing renewable solar power. In addition, the consent decree requires the decommissioning of Cabras 1 and 2 within six months of the new power plant being commissioned; and

WHEREAS, the proposed rates and charges are included as Appendix A to this filing; and

NOW, THEREFORE BE IT RESOLVED, by the Consolidated Commission on Utilities as follows:

1. The General Manager of the Guam Power Authority is authorized to finalize the rates and charges to be utilized for the Ratepayer's Bill of Rights Notice required by Public Law 26-23 in anticipation of the filing of a petition for a base rate increase. The rates and charges will be substantially the same as those reflected in Appendix A.

2. The General Manager and management of GPA are authorized to commence a public outreach program and comply with the required public notices requirements outlined in the Ratepayer's Bill of Rights.

3. The General Manager and management of GPA are authorized to engage the Public Utilities Commission in discussions regarding the advance submission, as needed, and to formally petition the Public Utilities Commission at the end of the three (3) months' notice for the base rate increase reflected in Appendix A.

RESOLVED, that the Chairman of the Commission certifies and the Secretary of the Commission attests to the adoption of this Resolution.

DULY AND REGULARLY ADOPTED, this 25th day of February, 2025.

Certified by:	Attested by:
FRANCIS E. SANTOS	**MELVIN F. DUENAS**
Chairperson	Secretary
Consolidated Commission on Utilities	Consolidated Commission on Utilities

SECRETARY'S CERTIFICATE

I, **Melvin F. Duenas**, Secretary of the Consolidated Commission on Utilities (CCU), as evidenced by my signature above, do hereby certify as follows:

The foregoing is a full, true and accurate copy of the resolution duly adopted at a regular meeting by the members of the Guam CCU, duly and legally held at a place properly noticed and advertised at which meeting a quorum was present and the members who were present voted as follows:

AYES:	4
NAYS:	1
ABSENT:	0
ABSTAIN:	0

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GPA RESOLUTION NO. FY2025-11 - To Authorize the Management of the Guam Power Authority to File a Ratepayer's Bill of Rights Notice in Anticipation of the Filing of a Petition for Base Rate Adjustment with the Guam Public Utilities Commission

APPENDIX A

Appendix A

BILL ILLUSTRATION RATE SCHEDULE R - RESIDENTIAL

	RATE SCHEDULE R		LEAC at $94.24 per barrel		LEAC at $100 per barrel			
	Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
KWH		**500**		500		500		
Monthly Charge	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 20.00	$ 20.00	$ 5.00	33.3%
Non-Fuel Energy Charge								
First 500 KWH	0.06955	34.78	0.06955	34.78	0.09239	46.20	0.02284	32.8%
Over 500 KWH	0.08687	-	0.08687	-	0.11540	-	0.02853	32.8%
Emergency Water-well charge	0.00279	-	0.00279	-	0.00279	-	-	0.0%
Self-Insurance Charge	0.00290	1.45	0.00290	1.45	0.00290	1.45	-	0.0%
Working Capital Fund Surcharge	0.00000	-	0.00000	-	0.00000	-		
Total Electric Charge before Fuel Recovery Charges		51.23		51.23		67.65		
Fuel Recovery Charge (LEAC)	**0.261995**	131.00	**0.208802**	104.40	**0.135840**	67.92	$(0.072962)	-34.9%
Total Electric Charge		$182.22		$ 155.63		$ 135.57		
Increase/(Decrease) in Total Bill		-		$ (26.60)		$ (20.06)		
% Increase/(Decrease) in Total Bill		-		**-14.60%**		**-12.89%**		
% Increase/(Decrease) in LEAC rate				**-20.30%**		**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE R - RESIDENTIAL

	RATE SCHEDULE R							
	Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
KWH		**1,000**		1,000		1,000		
Monthly Charge	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 20.00	$ 20.00	$ 5.00	33.3%
Non-Fuel Energy Charge								
First 500 KWH	0.06955	34.78	0.06955	34.78	0.09239	46.20	0.02284	32.8%
Over 500 KWH	0.08687	43.44	0.08687	43.44	0.11540	57.70	0.02853	32.8%
Emergency Water-well charge	0.00279	1.40	0.00279	1.40	0.00279	1.40	-	0.0%
Self-Insurance Charge	0.00290	2.90	0.00290	2.90	0.00290	2.90	-	0.0%
Working Capital Fund Surcharge	0.00000	-	0.00000	-	0.00000	-		
Total Electric Charge before Fuel Recovery Charges		97.52		97.52		128.19		
Fuel Recovery Charge (LEAC)	**0.261995**	262.00	**0.208802**	208.80	**0.135840**	135.84	$(0.072962)	-34.9%
Total Electric Charge		$359.52		$ 306.32		$ 264.03		
Increase/(Decrease) in Total Bill		-		$ (53.19)		$ (42.29)		
% Increase/(Decrease) in Total Bill		-		-14.80%		-13.81%		
% Increase/(Decrease) in LEAC rate				-20.30%		-34.94%		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE R - RESIDENTIAL

	RATE SCHEDULE R Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
KWH		**1,500**		1,500		1,500		
Monthly Charge	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 20.00	$ 20.00	$ 5.00	33.3%
Non-Fuel Energy Charge								
First 500 KWH	0.06955	34.78	0.06955	34.78	0.09239	46.20	0.02284	32.8%
Over 500 KWH	0.08687	86.87	0.08687	86.87	0.11540	115.40	0.02853	32.8%
Emergency Water-well charge	0.00279	2.79	0.00279	2.79	0.00279	2.79	-	0.0%
Self-Insurance Charge	0.00290	4.35	0.00290	4.35	0.00290	4.35	-	0.0%
Working Capital Fund Surcharge	0.00000	-	0.00000	-	0.00000	-		
Total Electric Charge before Fuel Recovery Charges		143.79		143.79		188.74		
Fuel Recovery Charge (LEAC)	**0.261995**	392.99	**0.208802**	313.20	**0.135840**	203.76	$(0.072962)	(0.3494)
Total Electric Charge		$536.78		$ 456.99		$ 392.50		
Increase/(Decrease) in Total Bill		-		$ (79.79)		$ (64.49)		
% Increase/(Decrease) in Total Bill		-		**-14.86%**		**-14.11%**		
% Increase/(Decrease) in LEAC rate				**-20.30%**		**-34.94%**		

Note:
- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE R - RESIDENTIAL

	RATE SCHEDULE R Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
KWH		**2,000**		2,000		2,000		
Monthly Charge	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 20.00	$ 20.00	$ 5.00	33.3%
Non-Fuel Energy Charge								
First 500 KWH	0.06955	34.78	0.06955	34.78	0.09239	46.20	0.02284	32.8%
Over 500 KWH	0.08687	130.31	0.08687	130.31	0.11540	173.10	0.02853	32.8%
Emergency Water-well charge	0.00279	4.19	0.00279	4.19	0.00279	4.19	-	0.0%
Self-Insurance Charge	0.00290	5.80	0.00290	5.80	0.00290	5.80	-	0.0%
Working Capital Fund Surcharge	0.00000	-	0.00000	-	0.00000	-		
Total Electric Charge before Fuel Recovery Charges		190.07		190.07		249.29		
Fuel Recovery Charge (LEAC)	**0.261995**	523.99	**0.208802**	417.60	**0.135840**	271.68	$(0.072962)	-34.9%
Total Electric Charge		$714.06		$ 607.67		$ 520.97		
Increase/(Decrease) in Total Bill		-		$ (106.39)		$ (86.70)		
% Increase/(Decrease) in Total Bill		-		**-14.90%**		**-14.27%**		
% Increase/(Decrease) in LEAC rate				**-20.30%**		**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE R - RESIDENTIAL

	RATE SCHEDULE R							
	Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
KWH		**2,500**		2,500		2,500		
Monthly Charge	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 20.00	$ 20.00	$ 5.00	33.3%
Non-Fuel Energy Charge								
First 500 KWH	0.06955	34.78	0.06955	34.78	0.09239	46.20	0.02284	32.8%
Over 500 KWH	0.08687	173.74	0.08687	173.74	0.11540	230.81	0.02853	32.8%
Emergency Water-well charge	0.00279	5.58	0.00279	5.58	0.00279	5.58	-	0.0%
Self-Insurance Charge	0.00290	7.25	0.00290	7.25	0.00290	7.25	-	0.0%
Working Capital Fund Surcharge	0.00000	-	0.00000	-	0.00000	-		
Total Electric Charge before Fuel Recovery Charges		236.35		236.35		309.83		
Fuel Recovery Charge (LEAC)	**0.261995**	654.99	**0.208802**	522.01	**0.135840**	339.60	$(0.072962)	-34.9%
Total Electric Charge		$891.33		$ 758.35		$ 649.43		
Increase/(Decrease) in Total Bill		-		$ (132.98)		$ (108.92)		
% Increase/(Decrease) in Total Bill		-		**-14.92%**		**-14.36%**		
% Increase/(Decrease) in LEAC rate				**-20.30%**		**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE D - CONDOMINIUM OR APARTMENT SERVICES

		RATE SCHEDULE D							
		Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
THREE PHASE									
KWH			101,400		101,400		101,400		
MINIMUM DEMAND	210								
Monthly Charge		$ 59.25	$ 59.25	$ 59.25	$ 59.25	$ 80.50	$ 80.50	$ 21.25	35.9%
Demand Charge ($/kW-month)	210	12.00	2,520.00	12.00	$ 2,520.00	16.00	3,360.00	4.00	33.3%
Energy Charge ($/kWh-month)									
All energy	101,400	0.06060	6,144.84	0.06060	$ 6,144.84	0.08086	8,199.20	0.02026	33.4%
Emergency Water-well charge	101,400	0.00279	282.91	0.00279	$ 282.91	0.00279	282.91	-	0.0%
Self-Insurance Charge	101,400	0.00290	294.06	0.00290	$ 294.06	0.00290	294.06	-	0.0%
WCF Surcharge	101,400	-	-	-	$ -	-	-		
Total Electric Charge before Fuel Recovery Charges			9,301.06		$ 9,301.06		12,216.67		
Fuel Recovery Charge (LEAC)	101,400	**0.261995**	26,566.29	**0.208802**	$ 21,172.52	**0.135840**	13,774.18	$ (0.072962)	-34.9%
Total Electric Charge			$ 35,867.35		$ 30,473.58		$ 25,990.85		
Increase/(Decrease) in Total Bill			-		$ (5,393.77)		$ (4,482.73)		
% Increase/(Decrease) in Total Bill			-		-15.04%		-14.71%		
% Increase/(Decrease) in LEAC rate					-20.30%		-34.94%		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE P - LARGE POWER SERVICE (THREE PHASE)

	kW/kWh Billed	RATE SCHEDULE P Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
THREE PHASE									
KWH			101,400		101,400		101,400		
MINIMUM DEMAND	210								
Monthly Charge		$ 59.25	$ 59.25	$ 59.25	$ 59.25	$ 80.50	$ 80.50	$ 21.25	35.9%
Demand Charge ($/kW-month)	210	8.94	1,877.40	8.94	1,877.40	11.90	2,499.00	2.96	33.1%
Energy Charge ($/kWh-month)									
First Block - First 55,000 kWh per month ($/kWh)	55,000	0.14170	7,793.50	0.14170	7,793.50	0.18869	10,377.95	0.04699	33.2%
Second Block - > 55,000 kWh per month ($/kWh)	46,400	0.06444	2,990.02	0.06444	2,990.02	0.08581	3,981.58	0.02137	33.2%
Emergency Water-well charge	101,400	0.00279	282.91	0.00279	282.91	0.00279	282.91	-	0.0%
Self-Insurance Charge	101,400	0.00290	294.06	0.00290	294.06	0.00290	294.06	-	0.0%
WCF Surcharge	101,400	-	-	-	-	-	-		
Total Electric Charge before Fuel Recovery Charges			13,297.13		13,297.13		17,516.00		
Fuel Recovery Charge (LEAC)	101,400	**0.261995**	26,566.29	**0.208802**	21,172.52	**0.135840**	13,774.18	$ (0.07296)	-34.9%
Total Electric Charge			$ 39,863.43		$ 34,469.65		$ 31,290.18		
Increase/(Decrease) in Total Bill			-		$ (5,393.77)		$ (3,179.48)		
% Increase/(Decrease) in Total Bill			-		**-13.53%**		**-9.22%**		
% Increase/(Decrease) in LEAC rate					**-20.30%**		**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE G - SMALL NON DEMAND (SINGLE PHASE)

		RATE SCHEDULE G (Single Phase)							
		Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
SINGLE PHASE									
KWH			5,000		5,000		5,000		
Monthly Charge		14.16	$ 14.16	14.16	$ 14.16	19.25	$ 19.25	$ 5.09	35.9%
Non-Fuel Energy Charge									
First 350 KWH per month	350	0.20086	70.30	0.20086	70.30	0.26574	93.01	0.06488	32.3%
Over 350 KWH per month	4,650	0.10861	505.04	0.10861	505.04	0.14369	668.16	0.03508	32.3%
Emergency Water-well charge	5,000	0.00279	13.95	0.00279	13.95	0.00279	13.95	-	0.0%
Self-Insurance Charge	5,000	0.00290	14.50	0.00290	14.50	0.00290	14.50	-	0.0%
WCF Surcharge	5,000	-	-	-	-	-	-		
Total Electric Charge before Fuel Recovery Charges			617.95		617.95		808.87		
Fuel Recovery Charge (LEAC)		**0.261995**	1,309.98	**0.208802**	1,044.01	**0.135840**	679.20	$ (0.07296)	-34.9%
Total Electric Charge			$ 1,927.92		$ 1,661.96		$ 1,488.07		
Increase(Decrease) in Total Bill			-		$ (265.97)		$ (173.89)		
% Increase/(Decrease) in Total Bill			-		**-13.80%**		**-10.46%**		
% Increase/(Decrease) in LEAC rate					**-20.30%**		**-34.94%**		

Note:
- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE G - SMALL NON DEMAND (THREE PHASE)

		RATE SCHEDULE G (Three Phase)							
		Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
THREE PHASE									
KWH			5,000		5,000		5,000		
Monthly Charge		$ 14.16	$ 14.16	$ 14.16	$ 14.16	19.50	$ 19.50	$ 5.34	37.7%
Non-Fuel Energy Charge									
First 500 KWH per month	500	0.19785	98.93	0.19785	98.93	0.26209	131.05	0.06424	32.5%
Over 500 KWH per month	4,500	0.10608	477.36	0.10608	477.36	0.14052	632.34	0.03444	32.5%
Emergency Water-well charge	5,000	0.00279	13.95	0.00279	13.95	0.00279	13.95	-	0.0%
Self-Insurance Charge	5,000	0.00290	14.50	0.00290	14.50	0.00290	14.50	-	0.0%
WCF Surcharge	5,000	-	-	-	-	-	-		
Total Electric Charge before Fuel Recovery Charges			618.90		618.90		811.34		
Fuel Recovery Charge (LEAC)		**0.261995**	1,309.98	**0.208802**	1,044.01	**0.135840**	679.20	$ (0.07296)	-34.9%
Total Electric Charge			$ 1,928.87		$ 1,662.91		$ 1,490.54		
Increase(Decrease) in Total Bill			-		$ (265.97)		$ (438.34)		
% Increase/(Decrease) in Total Bill			-		**-13.79%**		**-10.37%**		
% Increase/(Decrease) in LEAC rate			-		**-20.30%**		**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE J - SMALL DEMAND (SINGLE PHASE)

		RATE SCHEDULE J (Single Phase)							
		Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
SINGLE PHASE									
KWH			25,000		25,000		25,000		
DEMAND (kW Billed)	35								
Monthly Charge		$ 38.33	$ 38.33	$ 38.33	$ 38.33	$ 52.00	$ 52.00	$ 13.67	35.7%
Demand Charge ($/kW-month)	35	6.16	215.60	6.16	215.60	8.18	286.30	2.02	32.8%
Energy Charge									
First Block - First 2,000 kWh per month ($kWh)	2,000	0.19676	393.52	0.19676	393.52	0.26136	522.72	0.06460	32.8%
Second Block - > 2,000 kWh per month ($kWh)	23,000	0.06554	1,507.42	0.06554	1,507.42	0.08706	2,002.38	0.02152	32.8%
Emergency Water-well charge	25,000	0.00279	69.75	0.00279	69.75	0.00279	69.75	-	0.0%
Self-Insurance Charge	25,000	0.00290	72.50	0.00290	72.50	0.00290	72.50	-	0.0%
WCF Surcharge	25,000	-	-	-	-	-	-		
Total Electric Charge before Fuel Recovery Charges			2,297.12		2,297.12		3,005.65		
Fuel Recovery Charge (LEAC)		**0.261995**	6,549.88	**0.208802**	5,220.05	**0.135840**	3,396.00	$ (0.07296)	-34.9%
Total Electric Charge			$ 8,847.00		$ 7,517.17		$ 6,401.65		
Increase(Decrease) in Total Bill			-		$ (1,329.83)		$ (1,115.52)		
% Increase/(Decrease) in Total Bill			-		**-15.03%**		**-14.84%**		
% Increase/(Decrease) in LEAC rate					**-20.30%**		**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE J - SMALL DEMAND (THREE PHASE)

		RATE SCHEDULE J (Three Phase)							
		Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
THREE PHASE									
KWH			117,200		117,200		117,200		
DEMAND (kW Billed)	163								
Monthly Charge		$ 38.33	$ 38.33	$ 38.33	$ 38.33	$ 52.10	$ 52.10	$ 13.77	35.9%
Demand Charge ($/kW-month)	163	5.80	945.40	5.80	945.40	7.71	1,256.73	1.91	32.9%
Energy Charge									
First Block - First 5,000 kWh per month ($/kWh)	5,000	0.19437	971.85	0.19437	971.85	0.25850	1,292.50	0.06413	33.0%
Second Block - > 5,000 kWh per month ($/kWh)	112,200	0.06484	7,275.05	0.06484	7,275.05	0.08623	9,675.01	0.02139	33.0%
Emergency Water-well charge	117,200	0.00279	326.99	0.00279	326.99	0.00279	326.99	-	0.0%
Self-Insurance Charge	117,200	0.00290	339.88	0.00290	339.88	0.00290	339.88	-	0.0%
WCF Surcharge	117,200	-	-	-	-	-	-		
Total Electric Charge before Fuel Recovery Charges			9,897.50		9,897.50		$ 12,943.20		
Fuel Recovery Charge (LEAC)		**0.261995**	30,705.81	**0.208802**	24,471.59	**0.135840**	$ 15,920.45	$ (0.07296)	-34.9%
Total Electric Charge			$40,603.31		34,369.09		$ 28,863.65		
Increase(Decrease) in Total Bill			-		(6,234.22)		$ (5,505.44)		
% Increase/(Decrease) in Total Bill			-		**-15.35%**		**-16.02%**		
% Increase/(Decrease) in LEAC rate					**-20.30%**		**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE L - LARGE GOVT SERVICE (THREE PHASE)

			RATE SCHEDULE L							
			Prior Rate		Current		Proposed			
		kW/kWh Billed	Eff 08-01-24		Eff 02-01-25		Eff 09-01-2025			
THREE PHASE										
KWH				634,200		634,200		634,200		
MINIMUM DEMAND	200	1,158								
Monthly Charge			$ 59.25	$ 59.25	$ 59.25	59.25	$ 80.50	$ 80.50	$ 21.25	35.9%
Demand Charge ($/kW-month)		1,158	8.94	10,352.52	8.94	10,352.52	11.88	13,757.04	2.94	32.9%
Energy Charge ($/kWh-month)										
First Block - First 38,000 kWh per month ($/kWh)		38,000	0.16495	6,268.10	0.16495	6,268.10	0.21922	8,330.36	0.05427	32.9%
Second Block - > 38,000 kWh per month ($/kWh)		596,200	0.08090	48,232.58	0.08090	48,232.58	0.10752	64,103.42	0.02662	32.9%
Emergency Water-well charge		634,200	0.00279	1,769.42	0.00279	1,769.42	0.00279	1,769.42	-	0.0%
Self-Insurance Charge		634,200	0.00290	1,839.18	0.00290	1,839.18	0.00290	1,839.18	-	0.0%
WCF Surcharge		634,200	-	-	-	-	-	-		
Total Electric Charge before Fuel Recovery Charges				68,521.05		68,521.05		89,879.92		
Fuel Recovery Charge (LEAC)		634,200	**0.261995**	166,157.23	**0.208802**	132,422.23	**0.135840**	86,149.73	$ (0.07296)	-34.9%
Total Electric Charge				$234,678.28		200,943.28		176,029.65		
Increase/(Decrease) in Total Bill				-		($33,735.00)		($24,913.63)		
% Increase/(Decrease) in Total Bill				-		**-14.37%**		**-12.40%**		
% Increase/(Decrease) in LEAC rate						**-20.30%**		**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE S - SMALL GOVT SERVICE (SINGLE PHASE)

		RATE SCHEDULE S (Single Phase)							
		Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
SINGLE PHASE									
KWH			5,000		5,000		5,000		
Monthly Charge		14.16	$ 14.16	14.16	$ 14.16	19.50	$ 19.50	$ 5.34	37.7%
Non-Fuel Energy Charge									
First 300 KWH per month	300	0.23097	69.29	0.23097	69.29	0.34740	104.22	0.11643	50.4%
Over 300 KWH per month	4,700	0.12786	600.94	0.12786	600.94	0.16870	792.89	0.04084	31.9%
Emergency Water-well charge	5,000	0.00279	13.95	0.00279	13.95	0.00279	13.95	-	0.0%
Self-Insurance Charge	5,000	0.00290	14.50	0.00290	14.50	0.00290	14.50	-	0.0%
WCF Surcharge	5,000	-	-	-	-	-	-		
Total Electric Charge before Fuel Recovery Charges			712.84		712.84		945.06		
Fuel Recovery Charge (LEAC)		**0.261995**	1,309.98	**0.208802**	1,044.01	**0.135840**	679.20	$ (0.07296)	-34.9%
Total Electric Charge			$ 2,022.82		$ 1,756.85		$ 1,624.26		
Increase(Decrease) in Total Bill			-		$ (265.97)		$ (132.59)		
% Increase/(Decrease) in Total Bill			-		-13.15%		-7.55%		
% Increase/(Decrease) in LEAC rate					-20.30%		-34.94%		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE S - SMALL GOVT SERVICE (THREE PHASE)

		RATE SCHEDULE S (Three Phase)							
		Prior Rate		Current		Proposed			
		Eff 08-01-24		Eff 02-01-25		Eff 09-01-2025			
THREE PHASE									
KWH			5,000		5,000		5,000		
Monthly Charge		$ 14.16	$ 14.16	$ 14.16	$ 14.16	19.50	$ 19.50	$ 5.34	37.7%
Non-Fuel Energy Charge									
First 500 KWH per month	500	0.22945	114.73	0.22945	114.73	0.30410	152.05	0.07465	32.5%
Over 500 KWH per month	4,500	0.12095	544.28	0.12095	544.28	0.16030	721.35	0.03935	32.5%
Emergency Water-well charge	5,000	0.00279	13.95	0.00279	13.95	0.00279	13.95	-	0.0%
Self-Insurance Charge	5,000	0.00290	14.50	0.00290	14.50	0.00290	14.50	-	0.0%
WCF Surcharge	5,000	-	-	-	-	-	-		
Total Electric Charge before Fuel Recovery Charges			$ 701.61		$ 701.61		$ 921.35		
Fuel Recovery Charge (LEAC)		**0.261995**	$ 1,309.98	**0.208802**	$ 1,044.01	**0.135840**	$ 679.20	$ (0.07296)	-34.9%
Total Electric Charge			$ 2,011.59		$ 1,745.62		$ 1,600.55		
Increase(Decrease) in Total Bill			-		$ (265.97)		$ (411.04)		
% Increase/(Decrease) in Total Bill			-		**-13.22%**		**-8.31%**		
% Increase/(Decrease) in LEAC rate					**-20.30%**		**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE K - SMALL DEMAND (SINGLE PHASE)

		RATE SCHEDULE K (Single Phase)							
		Prior Rate		Current		Proposed			
		Eff 08-01-24		Eff 02-01-25		Eff 09-01-2025			
SINGLE PHASE									
KWH			25,000		25,000		25,000		
DEMAND (kW Billed)	35								
Monthly Charge		$ 38.33	$ 38.33	$ 38.33	$ 38.33	$ 52.00	$ 52.00	$ 13.67	35.7%
Demand Charge ($/kW-month)	35	7.25	253.75	7.25	253.75	9.61	336.35	2.36	32.6%
Energy Charge									
First Block - First 1,600 kWh per month ($kWh)	1,600	0.18065	289.04	0.18065	289.04	0.23945	383.12	0.05880	32.5%
Second Block - > 1,600 kWh per month ($kWh)	23,400	0.08970	2,098.98	0.08970	2,098.98	0.11889	2,782.03	0.02919	32.5%
Emergency Water-well charge	25,000	0.00279	69.75	0.00279	69.75	0.00279	69.75	-	0.0%
Self-Insurance Charge	25,000	0.00290	72.50	0.00290	72.50	0.00290	72.50	-	0.0%
WCF Surcharge	25,000	-	-	-	-	-	-		
Total Electric Charge before Fuel Recovery Charges			$ 2,822.35		$ 2,822.35		$ 3,695.75		
Fuel Recovery Charge (LEAC)		**0.261995**	$ 6,549.88	**0.208802**	$ 5,220.05	**0.135840**	$ 3,396.00	$ (0.07296)	-34.9%
Total Electric Charge			$ 9,372.23		$ 8,042.40		$ 7,091.75		
Increase(Decrease) in Total Bill			-		$ (1,329.83)		$ (950.65)		
% Increase/(Decrease) in Total Bill			-		-14.19%		-11.82%		
% Increase/(Decrease) in LEAC rate					-20.30%		-34.94%		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE K - SMALL DEMAND (THREE PHASE)

		RATE SCHEDULE K (Three Phase)							
		Prior Rate Eff 08-01-24		Current Eff 02-01-25		Proposed Eff 09-01-2025			
THREE PHASE									
KWH			117,200		117,200		117,200		
DEMAND (kW Billed)	163								
Monthly Charge		$ 38.33	$ 38.33	$ 38.33	$ 38.33	$ 52.00	$ 52.00	$ 13.67	35.7%
Demand Charge ($/kW-month)	163	8.43	1,374.09	8.43	1,374.09	11.19	1,823.97	2.76	32.7%
Energy Charge									
First Block - First 7,000 kWh per month ($/kWh)	7,000	0.17960	1,257.20	0.17960	1,257.20	0.23843	1,669.01	0.05883	32.8%
Second Block - > 7,000 kWh per month ($/kWh)	110,200	0.08365	9,218.23	0.08365	9,218.23	0.11105	12,237.71	0.02740	32.8%
Emergency Water-well charge	117,200	0.00279	326.99	0.00279	326.99	0.00279	326.99	-	0.0%
Self-Insurance Charge	117,200	0.00290	339.88	0.00290	339.88	0.00290	339.88	-	0.0%
WCF Surcharge	117,200	-	-	-	-	-	-		
Total Electric Charge before Fuel Recovery Charges			12,554.72		12,554.72		16,449.56		
Fuel Recovery Charge (LEAC)		**0.261995**	30,705.81	**0.208802**	24,471.59	**0.135840**	15,920.45	$ (0.07296)	-34.9%
Total Electric Charge			$43,260.53		37,026.31		$ 32,370.01		
Increase(Decrease) in Total Bill			-		(6,234.22)		$ (4,656.31)		
% Increase/(Decrease) in Total Bill			-		**-14.41%**		**-12.58%**		
% Increase/(Decrease) in LEAC rate					**-20.30%**		**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE N-NAVY (Alternative Navy Rate)

			RATE SCHEDULE N					
			Current Eff 02-01-25		Proposed Eff 09-01-2025			
Customer Charge			$ 10,990.00	$ 131,880.00	$ 12,000.00	$ 144,000.00	$ 1,010.00	9.2%
Demand Charge	44,077	kW	34.48	1,519,774.96				
Charge per contract capacity	47,000	kW			43.36	2,037,920.00		
Charge per kW above contract capacity	-	kW			520.34	-		
Non Fuel Enegy Charge	28,625,019	kWh	0.00495	141,693.84	0.00495	141,693.84	-	0.0%
Insurance Charge	-	kWh	0.00070	-	0.00070	-		
WCF Surcharge			-	-		-		
Wheeling	703,294	kWh	0.02000	14,065.88	0.02000	333,212.16		
Total Electric Charge before Fuel Recovery Charges				1,675,534.68		2,512,826.00		
Fuel Recovery Charge (LEAC)	28,625,019	kWh	**0.208802**	5,976,961.22	**0.135840**	3,888,422.58	$ (0.07296)	-34.9%
Total Electric Charge				$ 7,652,495.90		$ 6,401,248.59		
Increase/(Decrease) in Total Bill						$ (1,251,247)		
% Increase/(Decrease) in Total Bill						**-16.35%**		
% Increase/(Decrease) in LEAC rate						**-34.94%**		

Note:
- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.
- Monthly bill is fixed based on contract capacity at the time of contract. The Navy is required to provide three years of capacity need. Rate equivalent of 12 times the contract capacity will be assessed each month the capacity is exceeded.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE H - PRIVATE OUTDOOR LIGHTING

	Current		Proposed			
HIGH INDENSITY DISCHARGE	Eff 02-01-25		Eff 09-01-2025			
WATTAGE		400		400		
KWHR PER MONTH		163		163		
Monthly Facility Charge	$ 29.50	$ 29.50	$ 38.51	$38.51	$ 9.01	30.5%
Monthly Energy charge						
per kwh	0.10784	17.58	0.14655	23.89	0.03871	35.9%
Insurance Charge	0.00290	0.47	0.00290	0.47	-	0.0%
Working Capital Fund(WCF) Surcharge	0.00000	-	-	-		
Fuel Recovery Charge (LEAC)	**0.208802**	34.03	**0.135840**	22.14	$ (0.07296)	-34.9%
Total Electric Charge		$ 81.59		$85.01		
Increase/(Decrease) in Total Bill		-		$ 3.43		
% Increase/(Decrease) in Total Bill				**4.20%**		
% Increase/(Decrease) in LEAC rate				**-34.94%**		

Note:
- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE H - PRIVATE OUTDOOR LIGHTING

HIGH PRESSURE SODIUM (Lucalox)	Current Eff 02-01-25		Proposed Eff 09-01-2025			
WATTAGE		250		250		
KWHR PER MONTH		101		101		
Monthly Facility Charge	$ 26.15	$ 26.15	$ 34.14	$34.14	$ 7.99	30.6%
Monthly Energy charge						
per kwh	0.10784	10.89	0.14655	14.80	0.03871	35.9%
Insurance Charge	0.00290	0.29	0.00290	0.29	-	0.0%
Working Capital Fund(WCF) Surcharge	0.00000	-	-	-		
Fuel Recovery Charge (LEAC)	**0.208802**	21.09	**0.135840**	13.72	$ (0.07296)	-34.9%
Total Electric Charge		$ 58.42		$62.95		
Increase/(Decrease) in Total Bill		-		$ 4.53		
% Increase/(Decrease) in Total Bill				**7.75%**		
% Increase/(Decrease) in LEAC rate				**-34.94%**		

Note:
- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE H - PRIVATE OUTDOOR LIGHTING

HIGH PRESSURE SODIUM (HPS)	**Current**		**Proposed**			
	Eff 02-01-25		**Eff 09-01-2025**			
WATTAGE		150		150		
KWHR PER MONTH		54		54		
Monthly Facility Charge	$ 19.10	$ 19.10	$ 24.94	$24.94	$ 5.84	30.6%
Monthly Energy charge						
per kwh	0.10784	5.82	0.14655	7.91	0.03871	35.9%
Insurance Charge	0.00290	0.16	0.00290	0.16	-	0.0%
Working Capital Fund(WCF) Surcharge	0.00000	-	-	-		
Fuel Recovery Charge (LEAC)	**0.208802**	11.28	**0.135840**	7.34	$ (0.07296)	-34.9%
Total Electric Charge		$ 36.36		$40.35		
Increase/(Decrease) in Total Bill		-		$ 3.99		
% Increase/(Decrease) in Total Bill				**10.98%**		
% Increase/(Decrease) in LEAC rate				**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE H - PRIVATE OUTDOOR LIGHTING

	Current		**Proposed**			
LED (250W)	**Eff 02-01-25**		**Eff 09-01-2025**			
		120		120		
		43.2		43.2		
Monthly Facility Charge	$ 26.15	$ 26.15	$ 34.14	$34.14	$ 7.99	30.6%
Monthly Energy charge						
per kwh	0.10784	4.66	0.14655	6.33	0.03871	35.9%
Insurance Charge	0.00290	0.13	0.00290	0.13	-	0.0%
Working Capital Fund(WCF) Surcharge	0.00000	-	-	-		
Fuel Recovery Charge (LEAC)	**0.208802**	9.02	**0.135840**	5.87	$ (0.07296)	-34.9%
Total Electric Charge		$ 39.95		$46.46		
Increase/(Decrease) in Total Bill		-		$ 6.51		
% Increase/(Decrease) in Total Bill				**16.29%**		
% Increase/(Decrease) in LEAC rate				**-34.94%**		

Note:
- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE H - PRIVATE OUTDOOR LIGHTING

	Current		Proposed			
LED (150W)	Eff 02-01-25		Eff 09-01-2025			
WATTAGE		67		67		
KWHR PER MONTH		24.1		24.1		
Monthly Facility Charge	$ 19.10	$ 19.10	$ 24.94	$24.94	$ 5.84	30.6%
Monthly Energy charge						
per kwh	0.10784	2.60	0.14655	3.53	0.03871	35.9%
Insurance Charge	0.00290	0.07	0.00290	0.07	-	0.0%
Working Capital Fund(WCF) Surcharge	0.00000	-	-	-		
Fuel Recovery Charge (LEAC)	**0.208802**	5.03	**0.135840**	3.27	$ (0.07296)	-34.9%
Total Electric Charge		$ 26.80		$31.82		
Increase/(Decrease) in Total Bill		-		$ 5.01		
% Increase/(Decrease) in Total Bill				**18.71%**		
% Increase/(Decrease) in LEAC rate				**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE F - PUBLIC OUTDOOR LIGHTING

HIGH INDENSITY DISCHARGE	Current		Proposed			
	Eff 02-01-25		Eff 09-01-2025			
WATTAGE		400		400		
KWHR PER MONTH		163		163		
Monthly Facility Charge	$ 29.50	$ 29.50	$ 38.67	$ 38.67	$ 9.17	31.1%
Monthly Energy charge per kwh	0.05245	8.55	0.07128	11.62	0.01885	35.9%
Insurance Charge	0.00290	0.47	0.00290	0.47	-	0.0%
Working Capital Fund(WCF) Surcharge	0.00000	-	-	-		
Fuel Recovery Charge (LEAC)	**0.208802**	34.03	**0.135840**	22.14	$ (0.07296)	-34.9%
Total Electric Charge		$ 72.56		$ 72.91		
Increase/(Decrease) in Total Bill		-		$ 0.35		
% Increase/(Decrease) in Total Bill				**0.48%**		
% Increase/(Decrease) in LEAC rate				**-34.94%**		

Note:
- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A
BILL ILLUSTRATION RATE SCHEDULE F - PUBLIC OUTDOOR LIGHTING

	Current		Proposed			
HIGH PRESSURE SODIUM (Lucalox)	Eff 02-01-25		Eff 09-01-2025			
WATTAGE		250		250		
KWHR PER MONTH		101		101		
Monthly Facility Charge	$ 26.15	$ 26.15	$ 34.28	$ 34.28	$ 8.13	31.1%
Monthly Energy charge per kwh	0.05245	5.30	0.07128	7.20	0.01883	35.9%
Insurance Charge	0.00290	0.29	0.00290	0.29	-	0.0%
Working Capital Fund(WCF) Surcharge	0.00000	-	-	-		
Fuel Recovery Charge (LEAC)	**0.208802**	21.09	**0.135840**	13.72	$ (0.07296)	-34.9%
Total Electric Charge		$ 52.83		$ 55.49		
Increase/(Decrease) in Total Bill		-		$ 2.66		
% Increase/(Decrease) in Total Bill				**5.04%**		
% Increase/(Decrease) in LEAC rate				**-34.94%**		

Note:
- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE F - PUBLIC OUTDOOR LIGHTING

	Current		Proposed			
HIGH PRESSURE SODIUM (HPS)	Eff 02-01-25		Eff 09-01-2025			
WATTAGE		150		150		
KWHR PER MONTH		54		54		
Monthly Facility Charge	$ 19.10	$ 19.10	$ 25.04	$ 25.04	$ 5.94	31.1%
Monthly Energy charge per kwh	0.05245	2.83	0.07128	3.85	0.01883	35.9%
Insurance Charge	0.00290	0.16	0.00290	0.16	-	0.0%
Working Capital Fund(WCF) Surcharge	0.00000	-	-	-		
Fuel Recovery Charge (LEAC)	**0.208802**	11.28	**0.135840**	7.34	$ (0.07296)	-34.9%
Total Electric Charge		$ 33.36		$ 36.38		
Increase/(Decrease) in Total Bill		-		$ 3.02		
% Increase/(Decrease) in Total Bill				**9.04%**		
% Increase/(Decrease) in LEAC rate				**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE F - PUBLIC OUTDOOR LIGHTING

	Current		Proposed			
	Eff 02-01-25		Eff 09-01-2025			
LED (250W)		120		120		
		43.2		43.2		
Monthly Facility Charge	$ 26.15	$ 26.15	$ 34.28	$ 34.28	$ 8.13	31.1%
Monthly Energy charge per kwh	0.05245	2.27	0.07128	3.08	0.01883	35.9%
Insurance Charge	0.00290	0.13	0.00290	0.13	-	0.0%
Working Capital Fund(WCF) Surcharge	0.00000	-	-	-		
Fuel Recovery Charge (LEAC)	**0.208802**	9.02	**0.135840**	5.87	$ (0.07296)	-34.9%
Total Electric Charge		$ 37.56		$ 43.35		
Increase/(Decrease) in Total Bill		-		$ 5.79		
% Increase/(Decrease) in Total Bill				**15.42%**		
% Increase/(Decrease) in LEAC rate				**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

Appendix A

BILL ILLUSTRATION RATE SCHEDULE F - PUBLIC OUTDOOR LIGHTING

LED (150W)	**Current Eff 02-01-25**		**Proposed Eff 09-01-2025**			
WATTAGE		67		67		
KWHR PER MONTH		24.1		24.1		
Monthly Facility Charge	$ 19.10	$ 19.10	$ 25.04	$ 25.04	$ 5.94	31.1%
Monthly Energy charge per kwh	0.05245	1.26	0.07128	1.72	0.01883	35.9%
Insurance Charge	0.00290	0.07	0.00290	0.07	-	0.0%
Working Capital Fund(WCF) Surcharge	0.00000	-	-	-		
Fuel Recovery Charge (LEAC)	**0.208802**	5.03	**0.135840**	3.27	$ (0.07296)	-34.9%
Total Electric Charge		$ 25.47		$ 30.10		
Increase/(Decrease) in Total Bill		-		$ 4.64		
% Increase/(Decrease) in Total Bill				**18.20%**		
% Increase/(Decrease) in LEAC rate				**-34.94%**		

Note:

- The proposed LEAC rate may increase or decrease depending on the market price of fuel. The estimated LEAC is based on $100 per barrel fuel cost.

PUBLIC NOTICE

Proposed Base Rate Increases by Rate Classes

Schedule D - Condominium or Apartment Services	Current	Proposed	Proposed Increase
Monthly Charge	59.25	80.50	21.25
Demand Charge $/kW-month	12.00	16.00	4.00
Energy Charge $/kW-month			
All Energy	0.06060	0.08086	0.02026

Schedule G - Small Non Demand (Single Phase)	Current	Proposed	Proposed Increase
Monthly Charge	14.16	19.25	5.09
Non Fuel Energy Charge			
First 350 KWH per month	0.20086	0.26574	0.06488
Over 350 KWH per month	0.10861	0.14369	0.03508

Schedule J - Small Demand (Single Phase)	Current	Proposed	Proposed Increase
Monthly Charge	38.33	52.00	13.67
Demand Charge $/kW-month	6.16	8.18	2.02
Energy Charge $/kW-month			
1st Block - 2.000 kWh per mo.	0.19676	0.26136	0.06460
2nd Block - > 2,000 kWh per mo.	0.06554	0.08706	0.02152

Schedule L - Large Govt. Service (Three Phase)	Current	Proposed	Proposed Increase
Monthly Charge	59.25	80.50	21.25
Demand Charge $/kW-month	8.94	11.88	2.94
Energy Charge $/kW-month			
1st Block - 38,000 kWh per mo.	0.16495	0.21922	0.05427
2nd Block - > 38,000 kWh per mo.	0.08090	0.10752	0.02662

Schedule S - Small Govt. Service (Three Phase)	Current	Proposed	Proposed Increase
Monthly Charge	14.16	19.50	5.34
Non Fuel Energy Charge			
First 500 kWh per month	0.22945	0.30410	0.07465
Over 500 kWh per month	0.12095	0.16030	0.03935

Schedule K - Small Demand (Three Phase)	Current	Proposed	Proposed Increase
Monthly Charge	38.33	52.00	13.67
Demand Charge $/kW-month	8.43	11.19	2.76
Energy Charge			
1st Block - 7,000 kWh per mo.	0.17960	0.23843	0.05883
2nd Block - > 7,000 kWh per mo.	0.08365	0.11105	0.02740

Schedule F - Public Outdoor Lighting	Current	Proposed	Proposed Increase
High-Intensity Discharge	29.50	38.67	9.17
High Pressure Sodium (Lucalox)	26.15	34.28	8.13
High Pressure Sodium (HPS)	19.10	25.04	5.94
Llght Emitting Diode (LED 250)	26.15	34.28	8.13
Llght Emitting Diode (LED 150)	19.10	25.04	5.94
Monthly Energy Charge per kWh	0.05245	0.07128	0.01883

This notice is hereby published in compliance with 12 GCA Chapter 12 § 12102.1 and § 12102.2. For more information, visit: www.guampowerauthority.com

Schedule R - Residential	Current	Proposed	Proposed Increase
Monthly Charge	15.00	20.00	5.00
Non Fuel Energy Charge			
First 500 kWh	0.06955	0.09239	0.02284
Over 500 kWh	0.08687	0.11540	0.02853

Schedule P - Large Power Service (Three Phase)	Current	Proposed	Proposed Increase
Monthly Charge	59.25	80.50	21.25
Demand Charge $/kW-month	8.94	11.90	2.96
Energy Charge $/kW-month			
1st Block - 55,000 kWh per mo.	0.14170	0.18869	0.04699
2nd Block - > 55,000 kWh per mo.	0.06444	0.08581	0.02137

Schedule G - Small Non Demand (Three Phase)	Current	Proposed	Proposed Increase
Monthly Charge	14.16	19.50	5.34
Non Fuel Energy Charge			
First 500 kWh per month	0.19785	0.26209	0.06424
Over 500 kWh per month	0.10608	0.14052	0.03444

Schedule J - Small Demand (Three Phase)	Current	Proposed	Proposed Increase
Monthly Charge	38.33	52.10	13.77
Demand Charge $/kW-month	5.80	7.71	1.91
Energy Charge $/kW-month			
1st Block - 5,000 kWh per mo.	0.19437	0.25850	0.06413
2nd Block - > 5,000 kWh per mo.	0.06484	0.08623	0.02139

Schedule S - Small Govt. Service (Single Phase)	Current	Proposed	Proposed Increase
Monthly Charge	14.16	19.50	5.34
Non Fuel Energy Charge			
First 300 kWh per month	0.23097	0.34740	0.11643
Over 300 kWh per month	0.12786	0.16870	0.04084

Schedule K - Small Demand (Single Phase)	Current	Proposed	Proposed Increase
Monthly Charge	38.33	52.00	13.67
Demand Charge $/kW-month	7.25	9.61	2.36
Energy Charge			
1st Block - 1600 kWh per mo.	0.18065	0.23945	0.05880
2nd Block - > 1600 kWh per mo.	0.08970	0.11889	0.02919

Schedule H - Private Outdoor Lighting	Current	Proposed	Proposed Increase
High-Intensity Discharge	29.50	38.51	9.01
High Pressure Sodium (Lucalox)	26.15	34.14	7.99
High Pressure Sodium (HPS)	19.10	24.94	5.84
Llght Emitting Diode (LED 250)	26.15	34.14	7.99
Light Emitting Diode (LED 150)	19.10	24.94	5.84
Monthly Energy Charge per kWh	0.10784	0.14655	0.03871

Schedule N	Current	Proposed	Proposed Increase
Customer Charge	10,990.00	12,000.00	1,010.00
Demand Charge $/kW-month will change to: Charge per contract capacity	34.48	43.36	8.88
Charge per kW above contract capacity	—	520.34	520.34
Non Fuel Energy Charge per kWh	0.00495	0.00495	—
Wheeling Rate per kWh	0.02000	0.02000	—

**The rates for Schedule N have been revised to reflect changes in billing structure.*

Investing in Reliability

Guam Power Authority (GPA) is committed to providing reliable and affordable energy on a sustained basis for Guam's families and businesses. As part of this effort, GPA has received authorization from the Consolidated Commission on Utilities (CCU) to petition the Guam Public Utilities Commission (PUC) for a base rate adjustment and intends to request approval for a reduction to the Fuel Recovery Charge (LEAC) in May/June 2025. If approved, both adjustments will take effect on **September 1, 2025**.

These changes are designed to work together to lower energy costs for customers. The **base rate adjustment** will ensure GPA can continue to invest in modern, efficient infrastructure, including the **Ukudu Power Plant**, which will replace aging generators and significantly reduce fuel costs. At the same time, the LEAC reduction — made possible by the plant's improved efficiency—will lower fuel charges, **mitigating the impact of the base rate adjustment** and resulting in an **overall reduction in energy bills.**

GPA's goal is to build a more resilient and cost-effective power system while reducing dependence on expensive fossil fuels. Customers can review a detailed FAQ section and a chart outlining the proposed base rate increase schedule by customer rate class for reference.

Lower Bills Already in Effect

The average monthly residential bill lowered by

$53

Based on 1000 kWh residential consumption.

Effective as of February 1, 2025

More Savings on the Way

Additional decrease on average monthly power bills of

$42

Effective September 1, 2025 (proposed)

Smarter Energy, Bigger Benefits

The Ukudu Power Plant will replace aging generators and save

+900,000

Barrels of Oil annually.

RESIDENTIAL POWER BILL BASED ON $100/BBL FUEL

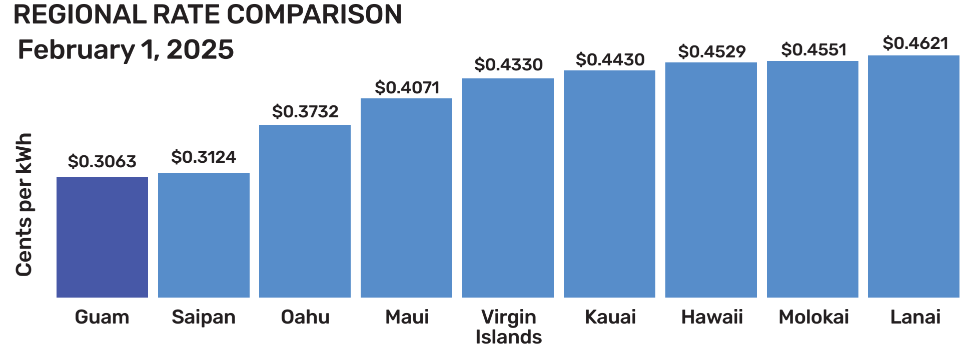
Based on 1000 kWh residential consumption

January 2025 **$359**

February 2025 **$306**

September 2025 **$264** (proposed)

REGIONAL RATE COMPARISON
February 1, 2025



Notes:
1. Rates for Guam effective February 1, 2025
2. Rates for Saipan effective February 1, 2025
3. Rates for Virgin Islands effective March 1, 2022 and remains unchanged
4. Rates for Kauai, Oahu, Hawaii, Maui, Molokai, Lanai effective February 1, 2025
5. All rates were based on 1000 kWh consumption

SCAN HERE to learn more about the proposed rate changes and how they may affect your bill

(671) 647-5787/8/9 • guampowerauthority.com • customersfirst@gpagwa.com • businessfirst@gpagwa.com

General Questions

What is GPA requesting, and how does it affect my bill?
GPA has been working diligently to lower power bills for its customers. As part of this effort, GPA is petitioning the Guam Public Utilities Commission (PUC) for a base rate increase to cover the costs of the Ukudu Power Plant while simultaneously petitioning PUC during the next LEAC period to reduce the Fuel Recovery Charge (LEAC). The LEAC, if approved by the PUC would mean a reduction to approximately 13-14 cents per kilowatt-hour (kWh) resulting in additional savings. For residential customers using about 1000 kWh of power, the net savings is estimated to be $42.

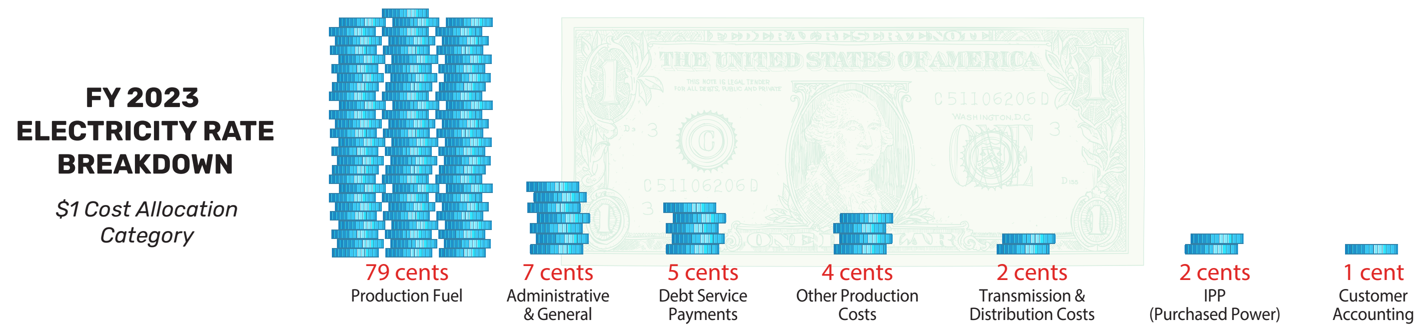
The goal is to provide reliable and affordable power on a sustained basis, and this adjustment will bring much-needed relief to customers by reducing fuel costs and stabilizing long-term energy pricing.

When will these changes take effect?
Pending PUC approval, the new rates would take effect on September 1, 2025. The proposed LEAC reduction is also being requested by GPA to be implemented at the same time to ensure customers see immediate savings on their bills.

How does the Ukudu Power Plant contribute to reducing fuel costs?
The Ukudu Power Plant is a highly efficient combined-cycle plant that significantly reduces the amount of fuel required to generate electricity. By replacing older, inefficient generators and transitioning to highly fuel-efficient units and cleaner energy, GPA will lower fuel imports per year, resulting in reduced LEAC rate. The Ukudu Power Plant is 37% more fuel efficient than Cabras 1 and 2 and 22% more efficient than Piti 8 and 9. This efficiency will help reduce fuel imports by over 900,000 barrels per annum or 39 million gallons. The fuel efficiency of the Ukudu Power Plant will more than offset the base rate adjustment and provide net savings to our customers.

The current Energy Conversion Agreement (ECA) with GPA's partner Guam Ukudu Power LLC, allows for the Ukudu Power Plant to be turned over to GPA in 25 years once the contract is completed.

Without Ukudu, the savings on fuel could not be extended to customers. Without Ukudu, GPA will not be able to comply with USEPA/GPA consent decree potentially resulting in $350 million in USEPA fines. Without Ukudu, Guam will continue to be susceptible to volatile oil prices.



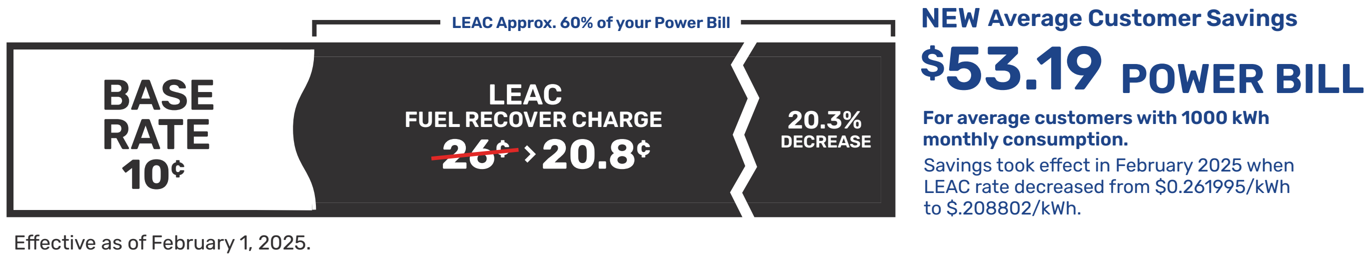
Customer Impact

When will the new rates go into effect?
Pending PUC approval, the new rates would be expected to take effect September 1, 2025.
The base rate can only be changed by the PUC.

The proposed rates will be published in newspapers, mailed to individual ratepayers, and posted on GPA's webpage. The Ratepayer's Bill of Rights (12GCA Ch. 12 § 12102.1 and § 12102.2) requires GPA to publish in a newspaper of general circulation, notice of the proposed rates and justification at least three (3) months before petitioning the PUC. Every current ratepayer will be mailed a notice of the proposed rate changes one (1) month before petitioning the PUC.

The new base rate will pay for the Ukudu Plant, similar to a mortgage payment. The new LEAC adjustment will account for the start of a total reduction in fuel imports by over 900,000 barrels per year according to GPA's most recent calculations. The fuel efficiency of the Ukudu Power Plant will more than offset the base rate adjustment and provide net savings to our customers.

How will customers benefit from the LEAC reduction?
The current LEAC represents approximately 68% of customers' average power bills. The proposed reduction to 13-14 cents means customers will pay less on their overall energy costs.



Reasons & Justification

How does GPA determine when a base rate adjustment is necessary?
GPA assesses financial obligations, power generation needs, and infrastructure investments. Over the years, GPA has implemented operational efficiencies, leveraging Smart Grid and AI technology to optimize grid operations and reduce unnecessary costs. These advancements have helped minimize expenses related to labor costs. By implementing cost-saving measures and efficiency improvements, GPA has worked to reduce the overall impact of the base rate adjustment for Ukudu. Additionally, the base rate has not increased since 2013, making this adjustment necessary to account for inflation, capital improvement, to cover the costs (similar to a mortgage payment) of the Ukudu Power Plant, and the transition to newer, more efficient energy infrastructure.

How does this adjustment support Guam's energy future?
The combination of the Ukudu Power Plant and increased renewable energy integration aligns with GPA's Clean Energy Master Plan. By reducing reliance on expensive fuel and modernizing infrastructure, GPA is ensuring more sustainable, affordable, and reliable power for Guam in the long term by reducing our dependency on imported fuel.

Transparency & Accountability
How can customers review and provide feedback on these changes?
Customers can review GPA's full petition and supporting documents on its website and through the Guam Public Utilities Commission. Public hearings will be held where customers can ask questions, voice concerns, and provide input. Customers may also submit feedback via email or GPA's website (guampowerauthority.com/rateadjustment).

This FAQ is designed to help customers understand how GPA's base rate adjustment and LEAC reduction work together to minimize financial impact. For more details, visit www.guampowerauthority.com or contact GPA directly at 671 648-3225 or 671 648-3145.

JOHN M. BENAVENTE, P.E.
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Guam Power Authority
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Telephone: (671) 648-3203
Fax No. (671) 648-3290
Email: mwoloschuk@gpagwa.com

BEFORE THE GUAM PUBLIC UTILITIES COMMISSION

IN THE MATTER OF:	**GPA DOCKET NO. 25-14**
GUAM POWER AUTHORITY'S BASE RATE	**TESTIMONY OF GENERAL MANAGER IN SUPPORT OF PETITION OF THE GUAM POWER AUTHORITY TO ADJUST BASE RATE**

I. Introduction and Background.

Q1. Please state your name, occupation and business address.

A1. My name is John M. Benavente. I am a registered professional engineer on Guam, and I am the General Manager of the Guam Power Authority, located at the Gloria B. Nelson Public Service Building, Route 15, Fadian, Mangilao, Guam.

Q2. Please describe your educational and professional history.

A2. I am a licensed Professional Engineer on Guam. I hold a Master of Science degree in Engineering Management from the University of Missouri (Rolla) and a Bachelor of Science Mechanical Engineering degree from the University of Dayton.

My expertise spans over four decades of technical, engineering, operations and executive leadership in the power and water utility-related fields across both the government and private sectors. I have held the position of General Manager serving Guam's utilities for over 29 years during this period.

I am the immediate past Director of the American Public Power Association, representing Guam, CNMI, American Samoa, Virgin Islands, Puerto Rico, and Canada. I am the recipient of the Professor John M. Phillips Excellence in Government Accountability Award and the American Public Power Association's James D. Donovan Individual Achievement Award.

Q3. Please describe your responsibilities as General Manager of GPA.

A3. As General Manager, I am responsible for the overall management of GPA, including its operations, regulatory compliance, and financial management. I provide leadership and develop and implement strategic plans to ensure that GPA is responsive to its ratepayers, employees and other stakeholders. I ensure that the conduct of GPA's business adheres to the values, sound financial management practices, policies, and objectives established by the Consolidated Commission on Utilities (CCU).

I directly supervise the department heads, including the Assistant General Manager of Operations, Assistant General Manager of Administration, Assistant General Manager of Engineering and Technical Services, Chief Financial Officer, Staff Attorney, Internal Auditor, and Communications Manager. I oversee the technical expertise of the departments and guide, monitor and review the activities of department heads to ensure their capability. With recommendation from our staff, I make decisions relating to the Island Wide Power System (IWPS), purchasing, staffing, and administrative policies.

I report to the five-member CCU and am responsible for keeping the CCU informed of GPA's financial health, personnel matters, and system reliability, as well as important and relevant industry issues locally and in the region. I regularly attend CCU meetings and submit items of business for their consideration. I administer the CCU's policies and carry out its directives. I educate or have my staff educate CCU members on subjects of importance to GPA, particularly financial matters. I recommend short- and long-term plans to maintain adequate power supply, sufficient physical plant, and a qualified, appropriately compensated staff.

I oversee all phases of the budget process for GPA, working with my direct reports to prepare departmental budget planning and overall budget planning, execution and presentation to the CCU to ensure that GPA is fiscally responsible. I also act as the chief procurement officer of GPA, reviewing and approving formal construction bids, specifications and engineering drawings, contract purchases for goods, materials, and services.

I develop and maintain positive working relationships with appropriate officials in all branches of local and federal government, the military, and the local community to promote GPA's needs and objectives. I oversee GPA's communications programs to ensure that GPA effectively communicates with and is responsive to the needs of Guam's population. I provide written and oral testimony to the Guam Legislature and the Guam Public Utilities Commission on proposed legislation and regulatory matters that affect GPA and its ratepayers.

Q4. Has the testimony you are providing been prepared by you or under your direction?

A4. Yes.

II. Scope and Purpose of Testimony.

Q5. What is the purpose of your testimony in this proceeding?

A5. I am testifying in support of GPA's petition to approve a one-time adjustment in the base rate in order to support the financing of the Ukudu Power Plant. The base rate funds GPA's fixed costs, including operations, maintenance, infrastructure improvements, and debt service. As a result of this infrastructure investment, GPA needs to adjust the base rate portion of the ratepayers' power bills.

Q6. How does GPA determine when a base rate adjustment is necessary?

A6. GPA regularly assesses its financial obligations, power generation needs, and infrastructure investments. Over the years, GPA has implemented operational efficiencies, leveraging Smart Grid and AI technology to optimize grid operations and reduce unnecessary costs. These advancements have helped minimize expenses related to labor costs. By implementing cost-saving measures and efficiency improvements, GPA has worked to reduce the overall impact of the base rate adjustment for Ukudu. Additionally, the base rate has not increased since 2013, making this adjustment necessary to account for inflation, capital improvement, to cover the costs of the Ukudu Power Plant, and the transition to newer, more efficient energy infrastructure.

Q7. Why is a base rate increase needed now?

A7. The Ukudu Power Plant's financial obligations begin in September 2025, requiring GPA to ensure stable funding. Additionally, GPA must comply with bond covenants to maintain financial stability and sufficient revenue to meet debt obligations. Delaying or denying this adjustment could impact GPA's ability to provide reliable service. Without Ukudu, the savings on fuel could not be extended to customers. Without Ukudu, GPA will not be able to comply with the consent decree with the USEPA (U.S. Environmental Protection Agency), potentially resulting in millions in penalties. Without Ukudu, Guam will continue to be susceptible to volatile oil prices.

Q8. What is the purpose of the Ukudu Power Plant?

A8. The new Ukudu Power Plant will allow the retirement of the Cabras 1&2 units in compliance with the consent decree between GPA and the USEPA. The Ukudu Power Plant is a new, highly efficient, combined cycle 198 megawatt power plant under an independent power producer (IPP) contract with KEPCO/EWP (Korea Electric Power Corporation/Korea East West Power Co., Ltd.). Its purpose is to bring increase power generation capacity to Guam and to support GPA's commitment to delivering safe, reliable, and cost-effective power. Commissioning the Ukudu Plant will reduce fuel dependence and enhance system resilience, an integral part of GPA's Clean Energy Master Plan. The Plant includes 25MW battery energy storage to supply immediate backup power.

Q9. Why is the Ukudu Power Plant necessary?

A9. The new Ukudu Power Plant will allow the retirement of the Cabras 1&2 units in compliance with the consent decree between GPA and the USEPA. The Ukudu Plant represents a major step toward modernizing Guam's power infrastructure, stabilizing energy cost, and supporting long-term sustainability goals. System demand has grown increasingly higher. On May 9, 2025, demand spiked to 265 MW, the highest level yet since Typhoon Mawar in May 2023 and approximately 10 MW higher compared to the same time one year earlier. The Ukudu Power Plant will allow GPA to meet that level of demand, even when key units are offline for maintenance, without the need to resort to measures such as load-shedding.

Without the Ukudu Power Plant, the cost savings on fuel could not be extended to customers. Without the Ukudu Power Plant, GPA will not be able to comply with USEPA/GPA consent decree potentially resulting in hundreds of million in USEPA fines. Without the Ukudu Power Plant, Guam will continue to be susceptible to volatile oil prices.

Q10. What impacts will the Ukudu Power Plant have on levels of service for GPA ratepayers?

A10. In addition to increased power generation capacity to meet customer demand, the Ukudu Power Plant's higher thermal efficiency produces fuel-cost savings which translate to net savings for ratepayers. Operating the new power plant will deliver higher efficiency and the subsequent savings are being factored into GPA's current LEAC reduction proposal to provide swift direct cost relief to customers. The retirement of Cabras and the adoption of more efficient generation methods using less expensive fuel will result in over 900,000 fewer barrels of fuel imports annually.

Q11. Does the Ukudu Power Plant take into consideration the current U.S. district court order and future regulatory priorities?

A11. In addition to lowering ratepayer costs and reducing fuel consumption through efficient machine technology, the new Ukudu Power Plant will bring GPA into compliance with environmental regulations. GPA entered into a consent decree on April 20, 2020, with the United States Government through the U.S. Department of Justice and the U.S. Environmental Protection Agency in *United States v. Guam Power Authority*, District Court of Guam Civil Case No. 20-00007. As part of the consent decree, GPA was ordered to enter into a contract to construct and operate 180 MW of new generation utilizing ultra-low sulfur diesel (ULSD) fuel and capable of burning natural gas by April 30, 2024. *See* Order Approving Modifications to Consent Decree at 5 (Jan. 14, 2022) (ECF No. 7).

In May 2023, Typhoon Mawar caused significant damage to the project. GPA notified USDOJ and USEPA of the force majeure event and its deleterious effect on project milestones. Productive dialogue between the parties ensued. The United States Government ultimately granted GPA an extension of time to September 30, 2025, for commissioning the Ukudu Power Plant.

Q12. What regulatory issues will need to be addressed in the future?

A12. Part and parcel with the commissioning of the Ukudu Power Plant comes the decommissioning of the Cabras 1&2 baseload plants, which utilize low sulfur residual fuel oil (RFO). GPA will permanently retire Cabras 1&2 by March 31, 2026. In addition, by treating waste water for cooling instead of sea water under the requirement of the Clean Water Act, the new Plant will reduce sewer water ocean outfall, as well as water drawn from the aquifer.

Q13. What significant operational changes are anticipated in the future?

A13. The Ukudu Plant coupled with renewables production will generate the majority of energy demand. The next dispatched unit will be Piti 8&9. The substantial production from reserve units will be drastically reduced and basically reserve units will operate under emergency conditions. The current Energy Conversion Agreement (ECA) with GPA's partner Guam Ukudu Power LLC, allows for the option of turning over the Ukudu Power Plant to GPA in 25 years once the contract is completed.

Q14. What significant changes are anticipated in operational and maintenance expenses for the future?

A14. Operation and maintenance costs will increase upon commissioning of Ukudu. However, the total cost for Ukudu, including capacity fee, fixed and variable operation and maintenance, is offset by the efficiency of Ukudu, resulting in net savings to ratepayers. The new Ukudu Power Plant is expected to reduce Guam's carbon footprint by cutting oil imports by more than 900,000 barrels (39 million gallons) annually.

Q15. Do the proposed improvements and operational changes you have described above justify the rate increases over that same period?

A15. Yes. The fuel savings only occurs with the Ukudu Plant. However, as noted, the fuel savings is significant and able to offset all Ukudu costs, resulting in lower power bills to ratepayers. The Ukudu Power Plant is 37 percent more fuel efficient than Cabras 1&2 and 22 percent more efficient than Piti 8 and 9. The fuel efficiency of the Ukudu Power Plant will more than offset the base rate adjustment and provide net savings to our customers.

Q16. Does this conclude your testimony?

A16. Yes.

I aver under penalty of perjury that the foregoing is true and accurate.

Executed on July 10, 2025.

John M. Benavente, P.E.
General Manager

BEFORE THE GUAM PUBLIC UTILITIES COMMISSION

IN THE MATTER OF: **GUAM POWER AUTHORITY'S BASE RATE**	**GPA DOCKET NO. 25-14** **TESTIMONY OF JOHN J.E KIM IN SUPPORT OF PETITION OF THE GUAM POWER AUTHORITY TO ADJUST BASE RATE**

Table of Contents

I. Introduction and Background.

Q1. Please state your name, occupation, and business address.

A1. My name is John J.E. Kim. I am the Chief Financial Officer with Guam Power Authority. My business address is 688 Route 15, Mangilao, Guam 96913.

Q2. Please describe your educational and professional history.

A2. I joined the Authority as Chief Financial Officer in 2015. As CFO, I worked on rates, including Schedule D – Condominium or Apartment Services, and pole attachments. Other projects that I worked on, which were reviewed by PUC, include the Ukudu power plant, Solar plants (Phase II and Phase IV), a 40MW battery storage facility, LEAC, merchant banking, bill and print solutions, accounting system upgrades and migrations, bond refinancing in 2017, 2022, and 2024, and NEM.

Prior to joining the Authority, I spent 11 years working in the telecommunications field. My projects included privatization of the last government-owned telecommunication company, mergers and acquisitions, and financing. I also worked at Deloitte & Touche LLP for eight years and have industry audit experience in utilities, construction, hospitality, retail, wholesale, and government. I hold a Bachelor of Science degree in Accounting from the University of Southern California. I am a certified public accountant.

Q3. Have you ever testified before the Public Utilities Commission of Guam?

A3. Yes. I have provided testimony before the Guam Public Utilities Commission (GPUC) on occasion on behalf of the Guam Power Authority.

Q4. Did anyone assist you with this testimony?

A4. Yes. Maripaz Perez, Assistant CFO, helped with the Exhibit GPA-1. The financial projection for the target year 2026 was assisted by Utility Financial Solutions, a GPA rate consultant.

II. Scope and Purpose of Testimony.

Q5. What is the purpose of your testimony in this proceeding?

A5. I am sponsoring the following exhibits:

i. Exhibit GPA 1: Proposed Rates

ii. Exhibit GPA 2: Standard Filing Requirements

Q6. What were the factors that led GPA to petition for a rate increase?

A6. On August 31, 2015, Cabras 3 and 4 experienced an explosion and fire, which reduced the island's power capacity by 78 MW, resulting in a capacity shortage that led to load shedding. GPA updated its Integrated Resource Plan (IRP) in 2016 and presented it to the CCU and PUC for approval, which included remedies to address the shortfall in generation capacity. The IRP included plans to install 180 MW of dual-fired combined-cycle generation units, retire Cabras 1 & 2, expand the renewable energy portfolio, and install energy storage. The PUC approved GPA's generation plan in October 2016, with procurement finished in 2019.

KEPCO entered into a build-operate-transfer agreement for the new generation, which was scheduled to be commissioned by September 30, 2025. For GPA, combined-cycle generation offers characteristics such as improved fuel efficiency, reduced capital costs when compared to installing emission control systems in existing plants, supports fuel diversity, and meets USEPA requirements.

In addition, the United States, on behalf of the United States Environmental Protection Agency (EPA), filed its complaint under the Clean Air Act. The United States' complaint sought injunctive relief and civil penalties for the alleged violations of the emission limits and performance testing requirements in the National Emission Standard for Hazardous Air Pollutants (NESHAP) regulations that govern the operation of stationary reciprocating internal combustion engines and electric utility steam generating units at GPA's Cabras and Piti power plants.

In early 2020, GPA, EPA, and the Justice Department finalized a settlement to resolve the alleged violations. The parties subsequently lodged a consent decree with the United States District Court in Guam, which approved the Consent Decree in April 2020.

Under the terms of the settlement, GPA will build and operate a new power plant burning ultralow sulfur diesel (USLD) and capable of burning liquified natural gas (LNG), convert the fuel delivery system from residual fuel oil to ULSD, build 100MW of solar power, install and operate a new energy storage system, and pay a civil penalty of $400,000 to resolve the United States' allegations.

Q7. When would the proposed rates become effective under GPA's proposed rate plan?

A7. The new rate will take effect on October 1, 2025.

Q8. Is this a one-time adjustment in the base rate?

A8. Yes. GPA is requesting a single adjustment of 31%. The Navy is a 27.9%.

III. Review of Rate Filing Schedules.

Q9. What is the test year?

A9. The test year is Fiscal Year 2026

Q10. Please describe the actions taken by GPA to lessen its need for additional revenue.

A10. GPA refunded revenue bond 2012 and 2014 to reduce cash outflow and reduce the impact of the base rate. The refunding saved $10.3 million in annual cash payments. Additionally, GPA will be retiring Cabras 1 & 2, resulting in a $4.7 million reduction in operating expenses. With the retirement of Cabras, we can expect to see some savings in property insurance. Since GPA will be using a single fuel type, we will utilize tanks 1934 and 1935, which will result in a $5 million reduction in the tank rental fee. By decreasing the utilization of Piti 8 & 9, expenditures on cylinder oil and emulsifier are projected to decrease by $2.2 million. At a minimum, the GPA will reduce the outflow of funds by $22.2 million.

Q11. How much additional revenue will GPA collect in fiscal year 2026 under this rate increase proposal?

A11. GPA estimates an additional revenue of $50.7 million.

Q12. How was the revenue forecasted?

A12. GPA consultant, Utility Financial Solutions, did the base revenue forecasting. They analyzed revenues for fiscal years 2022 and 2023, as well as actual and budgeted figures for 2024, and the 2025 budget. However, the debt service coverage ratio is 1.11 with IPP. There is a risk that GPA credit rating will be downgraded. The debt service coverage ratio at 1.3 is ideal.

Q13. What has GPA done to reduce fuel costs?

A13. The Ukudu power plant is a highly efficient combined cycle plant that consumes significantly less fuel than current GPA generations. The new power plant is 37 percent more fuel-efficient than Cabras 1 and 2, and 22 percent more fuel-efficient than Piti 8 and 9.

In January 2025, an average residential customer using 1,000 kWh of electricity saw a power bill of $359.52. With the LEAC adjustment in February 2025, the customer's power bill was $306.32. With the recent adoption of the LEAC rate of $0.155495, effective August 1, 2025. The same customer will see a power bill of $283.69, despite a 31% increase in the base rate, effective October 1, 2025.

Q14. Does GPA anticipate issuing new revenue bonds in the future?

A14. GPA anticipates future bond issuance to replace aging infrastructure, providing a reliable system to its customers. GPA is currently working on a list of projects to be funded by a bond. However, the current request at 31% will not be able to pay for the additional bond payment.

Q15. Did GPA conduct a staffing study?

A15. Yes. GPA witness Beatrice Limtiaco, AGMA, will address the study.

Q16. What level of staffing is included in the budget?

A16. GPA included full funding of 490 positions in its FY 2026 budget. GPA's current headcount is 454, and 36 vacant positions. Vacant positions are those where an employee has retired, left the agency, or passed away.

Q17. Does this conclude your testimony?

A17. Yes.

I aver under penalty of perjury of the laws of Guam that the foregoing testimony in support of GPA's petition to adjust the base rate is true and accurate.

Executed on August 8, 2025.

John Kim

John J.E, Kim
CFO, Guam Power Authority

TARRIFF RATES

Proposed Changes Effective 10-01-2025

GPA Exhibit 1

RATE SCHEDULE R - Residential	Current Rate	Proposed Rate - Effective 09-01-2025	$ Change	% Change
R - Base Rate				
R - Non-fuel Energy Charge - 0 to 500 kWh	$ 0.069550	$ 0.092390	$ 0.022840	32.8%
R - Non-fuel Energy Charge - > 500 kWh	$ 0.086870	$ 0.115400	$ 0.028530	32.8%
R - Customer Monthly Charge	$ 15.00	$ 20.00	$ 5.00	33.3%

RATE SCHEDULE D - Condominium or Apartment Services	Current Rate	Proposed Rate - Effective 09-01-2025	$ Change	% Change
D - Base Rate				
D - Energy Charge (All Energy) $/kW-month	$ 0.060600	$ 0.080860	$ 0.020260	33.4%
D - Customer Monthly Charge	$ 59.25	$ 80.50	$ 21.25	35.9%
D - Demand Charge $/kW-month	$ 12.00	$ 16.00	$ 4.00	33.3%

RATE SCHEDULE G - General Small Non-Demand Single & Three Phase	Current Rate	Proposed Rate - Effective 09-01-2025	$ Change	% Change
G1 - Base Rate (Single Phase)				
G1 - Non-Fuel Energy Charge - First 350 kWh	$ 0.200860	$ 0.265740	$ 0.064880	32.3%
G1 - Non-Fuel Energy Charge - > 350 kWh	$ 0.108610	$ 0.143690	$ 0.035080	32.3%
G1 - Customer Monthly Charge	$ 14.16	$ 19.25	$ 5.09	35.9%
G3 - Base Rate (Three Phase)				
G3 - Non-Fuel Energy Charge - First 500 kWh	$ 0.197850	$ 0.262090	$ 0.064240	32.5%
G3 - Non-Fuel Energy Charge - > 500 kWh	$ 0.106080	$ 0.140520	$ 0.034440	32.5%
G3 - Customer Monthly Charge	$ 14.16	$ 19.50	$ 5.34	37.7%

RATE SCHEDULE J - General Small Demand Single & Three Phase	Current Rate	Proposed Rate - Effective 09-01-2025	$ Change	% Change
J1 - Base Rate (Single Phase)				
J1 - Energy Charge First Block - First 2,000 kWh	$ 0.196760	$ 0.261360	$ 0.064600	32.8%
J1 - Energy Charge Second Block - > 2,000 kWh	$ 0.065540	$ 0.087060	$ 0.021520	32.8%
J1 - Customer Monthly Charge	$ 38.33	$ 52.00	$ 13.67	35.7%
J1 - Demand Charge $/kW-month	$ 6.16	$ 8.18	$ 2.02	32.8%
J3 - Base Rate (Three Phase)				
J3 - Energy Charge First Block - First 5,000 kWh	$ 0.194370	$ 0.258500	$ 0.064130	33.0%
J3 - Energy Charge Second Block - > 5,000 kWh	$ 0.064840	$ 0.086230	$ 0.021390	33.0%
J3 - Customer Monthly Charge	$ 38.33	$ 52.10	$ 13.77	35.9%
J3 - Demand Charge $/kW-month	$ 5.80	$ 7.71	$ 1.91	32.9%

RATE SCHEDULE P - Large Power Service Three Phase	Current Rate	Proposed Rate - Effective 09-01-2025	$ Change	% Change
P - Base Rate				
P - Energy Charge First Block - First 55,000 kWh	$ 0.141700	$ 0.188690	$ 0.046990	33.2%
P - Energy Charge Second Block - > 55,000 kWh	$ 0.064440	$ 0.085810	$ 0.021370	33.2%
P - Customer Monthly Charge	$ 59.25	$ 80.50	$ 21.25	35.9%
P - Demand Charge $/kW-month	$ 8.94	$ 11.90	$ 2.96	33.1%

RATE SCHEDULE H - Private Outdoor Lighting (Streetlighting)	Current Rate	Proposed Rate - Effective 09-01-2025	$ Change	% Change
H1 - High Indensity Discharge 400 Wattage				
H1 - Energy Charge per kWh	$ 0.107840	$ 0.146550	$ 0.038710	35.9%
H1 - Monthly Facility Charge	$ 29.50	$ 38.51	$ 9.01	30.5%
H2 - High Pressure Sodium (Lucalox) 250 Wattage				
H2 - Energy Charge per kWh	0.107840	0.146550	$ 0.038710	35.9%
H2 - Monthly Facility Charge	$ 26.15	$ 34.14	$ 7.99	30.6%
H3 - High Pressure Sodium (HPS) 150 Wattage				
H3 - Energy Charge per kWh	0.107840	0.146550	$ 0.038710	35.9%
H3 - Monthly Facility Charge	$ 19.10	$ 24.94	$ 5.84	30.6%
H4 - Light Emitting Diode (LED) 250 Wattage				
H4 - Energy Charge per kWh	0.107840	0.146550	$ 0.038710	35.9%
H5 - Monthly Facility Charge	$ 26.15	$ 34.14	$ 7.99	30.6%
H5 - Light Emitting Diode (LED) 150 Wattage				
H5 - Energy Charge per kWh	0.107840	0.146550	$ 0.038710	35.9%
H5 - Monthly Facility Charge	$ 19.10	$ 24.94	$ 5.84	30.6%

RATE SCHEDULE S - Small Government Service Non-Demand	Current Rate	Proposed Rate - Effective 09-01-2025	$ Change	% Change
S1 - Base Rate (Single Phase)				
S1 - Non-Fuel Energy Charge - First 300 kWh	$ 0.230970	$ 0.347400	$ 0.116430	50.4%
S1 - Non-Fuel Energy Charge - > 300 kWh	$ 0.127860	$ 0.168700	$ 0.040840	31.9%
S1 - Customer Monthly Charge	$ 14.16	$ 19.50	$ 5.34	37.7%

S3 - Base Rate (Three Phase)				
S3 - Non-Fuel Energy Charge - First 500 kWh	$ 0.229450	$ 0.304100	$ 0.074650	32.5%
S3 - Non-Fuel Energy Charge - > 500 kWh	$ 0.120950	$ 0.160300	$ 0.039350	32.5%
S3 - Customer Monthly Charge	$ 14.16	$ 19.50	$ 5.34	37.7%

RATE SCHEDULE K - Small Government Demand Single & Three Phase	**Current Rate**	**Proposed Rate - Effective 09-01-2025**	**$ Change**	**% Change**
K1 - Base Rate (Single Phase)				
K1 - Energy Charge First Block - First 1,600 kWh	$ 0.180650	$ 0.239450	$ 0.058800	32.5%
K1 - Energy Charge Second Block - > 1,600 kWh	$ 0.089700	$ 0.118890	$ 0.029190	32.5%
K1 - Customer Monthly Charge	$ 38.33	$ 52.00	$ 13.67	35.7%
K1 - Demand Charge $/kW-month	$ 7.25	$ 9.61	$ 2.36	32.6%
K3 - Base Rate (Three Phase)				
K3 - Energy Charge First Block - First 7,000 kWh	$ 0.179600	$ 0.238430	$ 0.058830	32.8%
K3 - Energy Charge Second Block - > 7,000 kWh	$ 0.083650	$ 0.111050	$ 0.027400	32.8%
K3 - Customer Monthly Charge	$ 38.33	$ 52.00	$ 13.67	35.7%
K3 - Demand Charge $/kW-month	$ 8.43	$ 11.19	$ 2.76	32.7%

RATE SCHEDULE L - Large Government Service Three Phase	**Current Rate**	**Proposed Rate - Effective 09-01-2025**	**$ Change**	**% Change**
L - Base Rate				
L - Energy Charge First Block - First 38,000 kWh	$ 0.164950	$ 0.219220	$ 0.054270	32.9%
L - Energy Charge Second Block - > 38,000 kWh	$ 0.080900	$ 0.107520	$ 0.026620	32.9%
L - Customer Monthly Charge	$ 59.25	$ 80.50	$ 21.25	35.9%
L - Demand Charge $/kW-month	$ 8.94	$ 11.88	$ 2.94	32.9%

RATE SCHEDULE F - Public Outdoor Lighting (Streetlighting)	**Current Rate**	**Proposed Rate - Effective 09-01-2025**	**$ Change**	**% Change**
F1 - High Indensity Discharge 400 Wattage				
F1 - Energy Charge per kWh	$ 0.052450	$ 0.071280	$ 0.018830	35.9%
F1 - Monthly Facility Charge	$ 29.50	$ 38.67	$ 9.17	31.1%
F2 - High Pressure Sodium (Lucalox) 250 Wattage				
F2 - Energy Charge per kWh	$ 0.052450	$ 0.071280	$ 0.018830	35.9%
F2 - Monthly Facility Charge	$ 26.15	$ 34.28	$ 8.13	31.1%
F3 - High Pressure Sodium (HPS) 150 Wattage				
F3 - Energy Charge per kWh	$ 0.052450	$ 0.071280	$ 0.018830	35.9%
F3 - Monthly Facility Charge	$ 19.10	$ 25.04	$ 5.94	31.1%
F4 - Light Emitting Diode (LED) 250 Wattage				
F4 - Energy Charge per kWh	$ 0.052450	$ 0.071280	$ 0.018830	35.9%
F4 - Monthly Facility Charge	$ 26.15	$ 34.28	$ 8.13	31.1%
F5 - Light Emitting Diode (LED) 150 Wattage				
F5 - Energy Charge per kWh	$ 0.052450	$ 0.071280	$ 0.018830	35.9%
F5 - Monthly Facility Charge	$ 19.10	$ 25.04	$ 5.94	31.1%

RATE SCHEDULE N - Navy	**Current Rate**	**Proposed Rate - Effective 09-01-2025**	**$ Change**	**% Change**
N - Base Rate				
N - Customer Monthly Charge	$ 10,990.00	$ 12,000.00	$ 1,010.00	9.2%
N - Demand Charge (Will Change to - Charge per Contract Capacity)	$ 34.48	$ 43.36	$ 8.88	25.8%
N - Charge per kW Above Contract Capacity	$ -	$ 520.34	$ 520.34	100.0%

Guam Power Authority
Summary of Revenue Requirement

Exhibit GPA 2
Schedule A
Page 1 of 2

Test year: 2026

Row #	Description	Audited FY 2024	Budget FY 2025	Projected FY 2026	With Request FY 2026	Difference	Reference
1	% Increase on Total Bill						
2							
3	**Proforma Income Statement:**						
4	Existing Base Rate Revenues:	$ 157,015,973	$ 159,857,437	$ 163,667,200	214,404,031	50,736,831	Schedule B
5	Fuel Revenue	385,761,787	359,503,192	241,974,098	241,974,098	-	Schedule B
6	Miscellaneous Revenue	4,796,752	8,715,177	7,082,201	7,082,201	-	Schedule B
7	Bad Debt Expense	(1,245,504)	(1,295,000)	(1,295,324)	(1,295,324)	-	
8	Revenue from Allowed Rate Change						
9	% of Base Rate Revenue				31%		
10	Number of Months Rate Change Effective				12		
11	Requested Revenue	-	-	-	50,736,831	-	
12	Total Revenues	$ 546,329,008	$ 526,780,806	$ 411,428,175	$ 462,165,006	$ 50,736,831	
13							
14	Production Fuel	385,761,787	359,503,192	241,974,098	241,974,098	-	Schedule C
15	IPP Costs	13,843,588	22,307,747	59,685,566	59,685,566	-	Schedule C
16							
17	Production (non-fuel)	22,856,995	22,824,779	16,892,057	16,892,057	-	Schedule C
18	Transmission and distribution	13,791,473	17,358,000	14,598,095	14,598,095	-	
19	Customer Accounting	7,061,383	7,926,000	7,610,655	7,610,655	-	
20	Administrative and General	47,360,409	46,649,221	46,692,945	46,692,945	-	
21	**Total O&M Expenses**	91,070,260	94,758,000	85,793,752	85,793,752	-	Schedule D
22	Depreciation Expense	35,021,336	40,110,000	45,002,856	45,002,856	-	
23							
24	Total Operating Expenses	525,696,971	516,678,938	432,456,272	432,456,272	-	
25	Earnings From Operations	20,632,037	10,101,868	(21,028,097)	29,708,734	50,736,831	
26							
27	Other Revenues (Expenses):						
28	Interest Income	5,114,054	5,316,949	6,357,510	6,357,510	-	
29	Interest Expense	(22,951,049)	(21,295,000)	(51,861,750)	(51,861,750)	-	
30	Other Income (Expenses)	(5,337,679)	(1,200,000)	-	-	-	
31							
32	Net Earnings/ (Loss)	$ (2,542,637)	$ (7,076,183)	$ (66,532,337)	$ (15,795,506)	$ 50,736,831	

Guam Power Authority
Debt Service Coverage

Exhibit GPA 2
Schedule A
Page 2 of 2

Row #	Description	Audited FY 2024	Budget FY 2025	Projected FY 2026	With Request FY 2026	Difference	Reference
1	**DEBT SERVICE COVERAGE CALCULATION**						
2							
3	**Bond Method:**						
4	Earnings From Operations	$ 20,632,037	$ 10,101,868	$ (21,028,097)	$ 29,708,734	50,736,831	
5	Add Interest Income	5,114,054	5,316,949	6,357,510	6,357,510	-	
6	Add Depreciation	35,021,336	40,110,000	45,002,856	45,002,856	-	
7	**Balance Available for Debt Serivce**	60,767,427	55,528,817	30,332,269	81,069,100	50,736,831	
8	**Debt Service:**						
9	Bont Interest Expense	21,887,718	21,088,250	20,262,000	20,262,000	-	Schedule E
10	Bond Principal	15,855,000	16,525,000	17,350,000	17,350,000	-	Schedule E
11	Total Debt Service	37,742,718	37,613,250	37,612,000	37,612,000	-	
12	**Debt Service Coverage (Bond Method)**	1.61	1.48	0.81	2.16		
13							
14	**DEBT SERVICE COVERAGE CALCULATION WITH IPP ACCOUNTING CHANGE**						
15							
16	**Rating Agency Method:**						
17	Earnings From Operations	20,632,037	10,101,868	(21,028,097)	29,708,734	50,736,831	
18	Add Interest Income	5,114,054	5,316,949	6,357,510	6,357,510	-	
19	Add Depreciation	35,021,336	40,110,000	45,002,856	45,002,856	-	
20	Less IPP Interest and Principal	-	-	(39,387,665)	(39,387,665)	-	
21	**Balance Available for Debt Service**	60,767,427	55,528,817	(9,055,396)	41,681,435	50,736,831	
22	**Debt Service:**						
23	Bont Interest Expense	21,887,718	21,088,250	20,262,000	20,262,000	-	Schedule E
24	Bond Principal	15,855,000	16,525,000	17,350,000	17,350,000	-	Schedule E
25	Total Debt Service	$ 37,742,718	$ 37,613,250	$ 37,612,000	$ 37,612,000	-	
26	**Debt Service Coverage (Rating Agency Method)**	1.61	1.48	(0.24)	1.11	1.35	

Row #	Description	Audited FY 2024	Budget FY 2025	Projected FY 2026	With Request FY 2026	Difference	Reference
1							
2	**Cash Generated From**						
3	Net Income	$ (2,542,637)	$ (7,076,183)	$ (66,532,337)	$ (15,795,506)	$ 50,736,831	
4	Add Depreciation	$ 35,021,336	$ 40,110,000	$ 45,002,856	$ 45,002,856	-	
5	Demand Side Management	$ 1,581,841	$ 1,483,928	$ 1,528,445	$ 1,528,445	-	Schedule D
6	Internally Funded Projects	(29,494,281)	(24,509,619)	(21,000,000)	(21,000,000)	-	
7	Principal Payments	(28,800,000)	(16,650,000)	(25,337,665)	(25,337,665)	-	Schedule E
8	Working Capital	-	-	-	-	-	
9		-	-	-	-	-	
10	Surplus (Deficit)	$ (24,233,741)	$ (6,641,875)	$ (66,338,700)	$ (15,601,869)	$ 50,736,831	

Guam Power Authority
Revenues

Test year: 2026

Row #	Description	Audited FY 2024	Budget FY 2025	Projected FY 2026	With Request FY 2026	Difference	Reference
1	**Base Rate Revenue**						
2	R Residential	$ 51,023,839	$ 52,275,354	$ 53,186,875	$ 69,674,807	$ 16,487,932	
3	D Residential - Apt & Condo	672,065	682,825	706,424	925,415	218,991	
4	G Small Gen. Non Demand	10,136,454	9,956,034	10,529,224	13,793,283	3,264,059	
5	J Small Gen. Demand	24,439,339	24,389,362	25,498,712	33,403,312	7,904,600	
6	P Large General	23,802,932	24,974,227	25,037,715	32,799,407	7,761,692	
7	I Independent PowerProducer	117,094	128,502	-	-	-	
8	H Private St. Lights	234,757	233,693	237,060	310,548	73,488	
9	S Small Non Demand	1,915,546	1,702,539	2,005,555	2,627,277	621,722	
10	K Small Demand	13,155,390	13,625,707	13,915,164	18,228,864	4,313,700	
11	L Large	7,143,400	6,768,645	7,676,780	10,056,581	2,379,801	
12	F Street Lighting	4,299,599	4,346,945	4,339,573	5,684,841	1,345,268	
13	Total Civilian	136,940,414	139,083,831	143,133,081	187,504,335	44,371,254	
14							
15	U. S. Navy	20,075,559	20,773,606	20,534,119	26,899,696	6,365,577	
16							
17	Subtotal	$ 157,015,974	$ 159,857,437	$ 163,667,200	$ 214,404,031	$ 50,736,831	
18							
19	**Fuel Revenue**						
20	R Residential	$ 133,839,143	$ 125,332,899	$ 81,692,174	$ 81,692,174	-	
21	D Residential - Apt & Condo	1,827,000	1,824,244	1,110,286	1,110,286	-	
22	G Small Gen. Non Demand	17,861,417	15,934,115	10,995,086	10,995,086	-	
23	J Small Gen. Demand	54,371,093	47,041,657	33,423,019	33,423,019	-	
24	P Large General	58,093,066	56,501,869	36,013,244	36,013,244	-	
25	I Independent PowerProducer	251,508	267,709	-	-	-	
26	H Private St. Lights	89,814	83,639	56,603	56,603	-	
27	S Small Non Demand	3,076,335	2,373,893	1,925,286	1,925,286	-	
28	K Small Demand	24,865,466	23,997,634	15,543,930	15,543,930	-	
29	L Large	14,615,677	12,364,969	9,580,796	9,580,796	-	
30	F Street Lighting	1,365,840	1,251,632	835,884	835,884	-	
31	Total Civilian	310,256,359	286,974,259	191,176,308	191,176,308	-	
32							
33	U. S. Navy	75,505,428	72,528,933	50,797,790	50,797,790	-	
34							
35	Subtotal	$ 385,761,787	$ 359,503,192	$ 241,974,098	$ 241,974,098	-	
36							
37	**Other Revenues**						
38	Miscellanoues Revenues	$ 4,796,752	$ 8,715,177	$ 7,082,201	$ 7,082,201	-	
39							
40	**Total Revenues**	$ 547,574,512	$ 528,075,806	$ 412,723,499	$ 463,460,330	50,736,831	

Guam Power Authority
Production Fuel

Row #	Description	Actual FY 2024 Barrel	Actual FY 2024 Amount	Budget FY 2025 Barrel	Budget FY 2025 Amount	With Requested FY 2026 Barrel	With Requested FY 2026 Amount
1	GPA Conventional						
2	Ukudu New 198 MW			56,007	$ 5,488,658	1,453,015	$ 145,301,463
3	Cabras 1&2 0.2% LSRFO	1,087,204	$ 145,786,980	1,119,427	$ 150,003,190	79,715	$ 9,087,510
4	Piti 8&9 ULSD	845,425	$ 95,852,572	692,429	$ 69,242,898	513,324	$ 51,332,351
5	Total Baseload	1,932,629	$ 241,639,552	1,867,862	$ 224,734,746	2,046,053	$ 205,721,324
6	Total Non-Baseload Units	897,133	$ 103,068,721	1,022,815	$ 101,188,773	24,923	$ 2,492,274
7							
8	GPA Renewables						
9	GlidePath PV		$ 9,760,724		$ 9,861,194		$ 9,958,830
10	KEPCO PV		$ 12,561,822		$ 12,780,157		$ 12,906,693
11	Total GPA Renewables		$ 22,322,546		$ 22,641,351		$ 22,865,523
12							
13	Total Conventional		$ 344,708,273		$ 325,923,519		$ 208,213,598
14	Adjustment		-$ 87,065		$ -		$ -
15	Deferred Fuel Cost		$ 7,923,056		$ -		$ -
16	Fuel handling		$ 10,894,977		$ 10,938,322		$ 10,894,977
17	System Production Cost		$ 385,761,787		$ 359,503,192		$ 241,974,098
18							
19	Average Fuel Cost Per Barrel		$ 122		$ 113		$ 101

Guam Power Authority
IPP - Energy Conversion Cost

Row #	Description	Audited FY 2024	Budget FY 2025	Projected FY 2026	With Request FY 2026	Difference
1						
2	Energy Conversion Costs:					
3	MEC	$ 10,312,797	$ 10,622,180	$ 10,500,000	$ 10,500,000	$ -
4	Agrekko	3,530,791	10,622,180	8,205,634	8,205,634	-
5	Ukudu Power Plant	-	-	39,279,932	39,279,932	-
6	Water and Heated Water Disposal	-	1,063,386	1,700,000	1,700,000	-
7		$ 13,843,588	$ 22,307,747	$ 59,685,566	$ 59,685,566	$ -

Guam Power Authority
Production (non-fuel)

Row #	Description	Audited FY 2024	Budget FY 2025	Projected FY 2026	With Request FY 2026	Difference
1	CABRAS 1 & 2	14,385,873	14,247,244	5,663,196	5,663,196	
2	DEDEDO CT	910,837	938,162	1,228,149	1,228,149	-
3	MACHECHE CT	2,330,568	2,400,485	3,142,477	3,142,477	-
4	YIGO CT	1,214,247	1,250,674	1,637,259	1,637,259	-
5	MDI DIESEL	406,795	418,999	548,512	548,512	-
6	TALOFOFO	463,497	329,681	431,586	431,586	-
7	TENJO VISTA	1,234,065	1,271,087	1,663,982	1,663,982	-
8	TEMES Piti 7	1,093,420	1,126,222	1,474,339	1,474,339	-
9	Agrekko/Yigo Diesel	817,694	842,225	1,102,557	1,102,557	-
10		22,856,995	22,824,779	16,892,057	16,892,057	-

Guam Power Authority
Production (non-fuel)

Row #	Description	Audited FY 2024	Budget FY 2025	Projected FY 2026	With Request FY 2026	Difference
1	Number of Employee	443	453	490	490	
2						
3	Labor:					
4	Regular	$ 29,769,042	$ 37,205,086	$ 38,144,270	$ 38,144,270	$ -
5	Workforce Intern	1,732,205	2,437,519	1,566,134	1,566,134	-
6	Grants	34,442	-		-	-
7	Overtime	4,463,890	4,393,792	2,000,000	2,000,000	-
8	Premium	341,743	388,997	225,621	225,621	-
9	Medical & Dental Benefits	3,799,203	4,207,209	4,517,121	4,517,121	-
10	Sub-Total Labor	40,140,525	48,632,603	46,453,146	46,453,146	-
11						
12	Capitalize labor & benefits	(4,310,440)	(3,286,583)	(6,310,440)	(6,310,440)	-
13	Fuel Labor	(176,246)	(185,058)	(194,311)	(194,311)	-
14	Other Production Labor	(11,418,654)	(11,989,587)	(10,406,920)	(10,406,920)	-
15	Pension Retirement	12,192,592	10,406,499	8,215,702	8,215,702	-
16	OPEB Adjustment	2,776,134	-	-	-	-
17		39,203,911	43,577,874	37,757,177	37,757,177	-
18						
19	Insurance	9,158,423	9,288,262	8,688,262	8,688,262	-
20	Contract	6,984,741	6,578,590	9,775,948	9,775,948	-
21	Retiree healthcare and other bene	4,397,432	5,947,322	5,948,000	5,948,000	-
22	Utilities	280,627	149,503	153,988	153,988	-
23	Other administrative expenses	285,166	487,502	502,127	502,127	-
24	Travel	306,236	250,459	257,973	257,973	-
25	Miscellaneous	309,665	29,251	30,129	30,129	-
26	Trustee fee	131,242	111,636	114,985	114,985	-
27	Operating supplies	759,489	731,244	753,182	753,182	-
28	Training	198,164	118,139	121,683	121,683	-
29	Office supplies	112,111	74,101	76,324	76,324	-
30	Overhead allocations	1,838,037	-	-	-	-
31	Lease expense	170,644	170,000	170,000	170,000	-
32	Completed work orders	7,847	381,125	392,559	392,559	-
33	Collection Fee	2,178,935	2,255,789	2,323,462	2,323,462	-
34	Demand-side management progra	1,581,841	1,483,928	1,528,445	1,528,445	-
35	Communication	308,754	298,496	307,451	307,451	-
36	Total Non-Labor	29,009,354	28,355,347	31,144,518	31,144,518	-
37						-
38	Total Operating & Maintenance	$ 68,213,265	$ 71,933,221	$ 68,901,695	$ 68,901,695	$ -

Guam Power Authority
Debt Service

Exhibit GPA 2
Schedule E
Page 1 of 1

Row #	Description	Audited FY 2024	Budget FY 2025	Projected FY 2026	With Request FY 2026
1	**Debt Service Components"**				
2	Principal				
3	2014 Series Revenue Bond	$ 1,845,000	$ -	$ -	$ -
4	2017 Series Revenue Bond	4,245,000	4,460,000	4,680,000	4,680,000
5	2022 Series Revenue Bond	9,765,000	10,255,000	10,765,000	10,765,000
6	2024 Series Revenue Bond	-	1,810,000	1,905,000	1,905,000
7		$ 15,855,000	$ 16,525,000	$ 17,350,000	$ 17,350,000
8	Interest				
9	2014 Series Revenue Bond	2,575,936	200,000	200,000	200,000
10	2017 Series Revenue Bond	7,199,500	6,987,250	6,764,250	6,764,250
11	2022 Series Revenue Bond	11,647,750	11,159,500	10,646,750	10,646,750
12	2024 Series Revenue Bond	464,532	2,741,500	2,651,000	2,651,000
13		21,887,718	21,088,250	20,262,000	20,262,000
14					
15	Total	$ 37,742,718	$ 37,613,250	$ 37,612,000	$ 37,612,000
16					
17	**IPP Cost - Ukudu Power Plant**				
18	Principal	-	-	$ 7,987,665	$ 7,987,665
19	Interest	-	-	31,400,000	31,400,000
20	Total	-	-	$ 39,387,665	$ 39,387,665

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BEFORE THE GUAM PUBLIC UTILITIES COMMISSION

IN THE MATTER OF: **GUAM POWER AUTHORITY'S BASE RATE**	**GPA DOCKET NO. 25-14** **TESTIMONY OF MARK BEAUCHAMP IN SUPPORT OF PETITION OF THE GUAM POWER AUTHORITY TO ADJUST BASE RATE**

Table of Contents

I. Introduction and Background.

Q1. Please state your name, occupation and business address.

A1. My name is Mark C. Beauchamp. My business address is 185 Sun Meadow Ct., Holland, Michigan 49424. I am the president and owner of Utility Financial Solutions, LLC

Q2. Please describe your educational and professional history.

A2. I hold degrees in Water Purification Technology, a Bachelor's degree in Accounting, and a Master's degree in Business. My utility career began at the Holland Board of Public Works, where I served from 1981 to 1998 in several key roles, including Cost and Rate Specialist, Billing and Rates Manager, Financial Planning Manager, and Strategic Planning Manager.

In 1998, I helped establish the National Consulting Group of Baker Tilly and served as a consultant until 2001. That same year, I founded Utility Financial Solutions (UFS), a consulting firm specializing in utility rate studies and financial planning for public utilities.

Since its inception, UFS has completed projects in 44 U.S. states as well as internationally in Barbados, Bermuda, Guam, and the Cayman Islands. Over the past ten years, UFS has provided consulting services to 339 electric utilities and currently serves approximately 24% of American Public Power Association (APPA) member utilities. A full list of UFS electric utility clients is included in Appendix A.

Q3. What professional society and industry research projects enhance your qualifications to offer testimony in this case?

A3. I have contributed to the advancement of utility financial planning and rate design through numerous published articles, ongoing research efforts, and frequent industry presentations. Many of these works are available on the Utility Financial Solutions (UFS) website at www.ufsweb.com. These contributions reflect leadership in addressing key challenges facing the utility industry, including emerging rate design practices, financial sustainability, and long-term strategic planning.

Representative publications include:

- *Balancing Act: Redesigning Electric Rates for a Complex World*
- *Michigan's Public Power Edge: MMEA's Data-Backed Insights*
- *Rate Design Trends in an Evolving Industry*
- *Managing New Electric Loads in a Changing Industry*
- *Live Local: Supporting Municipal Electric Utilities Starts with Understanding*
- *Opportunities and Transformative Financial Planning*
- *The Importance of Minimum Cash*
- *Direction for a New Age in Energy*
- *How Public Power Sets Electricity Rates*
- *Finance Fundamentals Are Key to COVID Recovery*
- *What a Long-Term Rate Strategy Should Address*

These works have helped shape utility policies and practices across the U.S. and internationally.

In addition to published research, I am actively involved in professional education and training. UFS serves as the primary instructor for the American Public Power Association (APPA) in the areas of financial planning, strategic rate design, and cost of service studies. Our firm is also a frequent speaker at both national and regional utility conferences.

Selected industry engagements over the past year include:

- Taught two courses and presented in two sessions at APPA's National Conference (June 2025)
- Delivered three courses over four days for APPA's Education Institute (May 2025)

- Conducted the Strategic Rate Design course for NEPPA in Littleton, MA (May 2025)
- Presented two sessions on financial planning and electric rate design at FMEA's Annual Conference (July 2024)
- Speaker at the MMEA Annual Conference (September 2024)

These activities underscore a deep and ongoing commitment to utility education, innovation, and leadership in the public power industry.

Q4. Have you ever testified before the Public Utilities Commission of Guam?

A4. UFS has provided services in 2019 for Guam and the Public Utilities Commission on modifications to the electric rates for apartment buildings. We have meet with the PUC to discuss long term strategies on electric rates including time based rates and current industry challenges.

Q5. Did anyone assist you with this testimony?

A5. No.

II. Scope and Purpose of Testimony.

Q6. What is the purpose of your testimony in this proceeding?

A6. UFS completed the determination of the revenue requirements, cost of service study, and rate designs for this rate study process. UFS is providing the following with this testimony:

1. A PDF report titled "GPA Electric COS Report"
2. Excel spreadsheet models titled "GPA Rate Study Model" and "GPA Dispatch Model"
3. Appendix A: A PDF file listing "UFS electric clients"

Q7. When would the proposed rates become effective under GPA's proposed rate plan?

A7. Planned data for implementation in October 1, 2025.

Q8. Is this a one-time adjustment in the base rate?

A8. Yes.

III. Review of Rate Filing Schedules.

Q9. How were revenues forecasted?

A9. To determine revenue requirements, UFS analyzed revenues and expenses for fiscal years 2022, 2023, the actual and budgeted figures for 2024, and the 2025 budget. Adjustments were made to reflect projected changes in operating characteristics, cost structure, and known future conditions. Please refer to Excel model titled "GPA Rate

Study Model" a green tab titled "Billing Details" for detailed financial data and assumptions.

Growth assumptions were applied to estimate changes in energy sales and customer counts between the preliminary 2024 figures and the projected test year of 2026. The following assumptions were used in the modeling:

- A 1% annual growth rate in energy sales, based on anticipated economic activity, including potential increases from the Navy base expansion.
- No rate increases were assumed in the baseline forecast; however, when isolating the impact of external factors such as lower fuel costs from the Ukudu generating unit, revenues are anticipated to decline.

These projections formed the basis for estimating revenues under existing rates and assessing the need for potential adjustments to maintain the financial sustainability of Guam Power Authority. The table below outlines the assumed growth rates by class between 2024 and 2026.

Customer Class	Customer Growth	Additional Energy Growth	Demand Growth
Residential (R)	0.00%	1.00%	
Small General (G 1ϕ)	0.00%	2.00%	
Small General (G 3ϕ)	0.00%	2.00%	
Small Govt. (S 1ϕ)	0.00%	2.00%	
Small Govt. (S 3ϕ)	0.00%	2.00%	
Private Outdoor Lighting (H)	0.00%	2.00%	
Public Street Lights (F)	0.00%	2.00%	
General Service (J 1ϕ)	0.00%	2.00%	2.00%
General Service (J 3ϕ)	0.00%	2.00%	2.00%
Large Power (P)	0.00%	2.00%	2.00%
Small Govt. (K 1ϕ)	0.00%	2.00%	2.00%
Small Govt. (K 3ϕ)	0.00%	2.00%	2.00%
Large Govt. (L)	0.00%	2.00%	2.00%
Standyby (M)	0.00%	2.00%	2.00%
Condo/Apartment (D)	0.00%	2.00%	2.00%
Navy (N)	0.00%	2.00%	2.00%

In reviewing historical growth rates between 2017 and 2024, actual energy sales declined by approximately **1%** over the seven-year period. However, based on discussions with staff and consideration of potential future load growth particularly related to planned Navy base expansion, UFS incorporated an annual growth rate of approximately 1% in the five-year projection.

Q10. Why are revenues projected to decrease between 2024 and 2026?

A10. Revenues, without any rate changes, are projected to decline from $550 million in 2024 to $438 million in 2026. This decrease is primarily due to a reduction in LEAC

(Levelized Energy Adjustment Clause) charges, which are directly tied to fuel costs. The expected operation of the Ukudu generating unit in 2026 will significantly lower fuel expenses, driving this reduction in LEAC charges. Specifically, LEAC-related costs are projected to fall from $400 million in 2024 to $269 million in 2026.

The table below outlines the projected change in revenues:

	Preliminary 2024	Projected 2025	Projected 2026	Change 2024 - 2026
Total	$ 550,370,238	$ 548,070,105	$ 438,452,525	$ (111,917,713)
Projected Fuel Costs	$ 399,920,099	$ 385,761,787	$ 268,948,628	$ (130,971,471)

Q11. Please describe GPA's forecast of operations and maintenance expenses?

A11. UFS reviewed the historical trial balance and projected expenses for 2025, 2026, and 2027. This projection covers Administrative and General, Transmission, Distribution, and Customer Accounting. A more detailed analysis was conducted for production costs due to the addition of the Ukudu Generating Station. The figures below reflect the trial balance projections, with the green numbers being used in the financial model. Other expenses were projected as indicated.

Year	2022	2023	2024	2025	2026
Production Fuel	315,770,815	399,920,099	385,761,787		-
Other Production	22,559,180	19,742,775	21,232,555	21,626,198	22,274,983
Energy Conversion Costs	9,355,771	10,185,615	13,843,588	11,462,174	11,806,040
Administrative and General	38,538,405	34,072,427	39,350,567	39,048,851	40,452,523
Depreciation Expense	34,249,020	35,215,950	34,971,592	35,856,553	35,856,553
Transmission	6,788,231	5,803,448	6,298,479	6,362,473	6,687,617
Distribution	6,978,634	5,233,205	7,463,034	7,512,028	7,910,478
Customer Accounting	7,330,537	6,637,622	7,043,273	7,327,264	7,610,655

The trial balance projections incorporated assumptions about cost changes. UFS assumed inflation and changes in production costs and payroll as listed below.

	2025	2026
Production Costs	3.0%	3.0%
Payroll	5.5%	5.5%
Inflation	3.0%	3.0%

Key Assumptions for Production Costs:

- Closing of Cabras 1 & 2 and the reallocation of labor-related expenses to other generating units.
- Changes in energy conversion costs resulting from the operation of Aggreko and MEC.
- Ukudu lease, debt service and O&M expenses.

These adjustments are detailed in the green tabs of the Rate Study Spreadsheet. Key areas in these tabs are discussed below.

Ongoing Labor Costs and Aggreko Energy Conversion:

It is anticipated that Aggreko Energy Conversion costs will end in July 2026, and the labor costs associated with Cabras 1 & 2 will be reallocated to other generating units. Below is the key assumption related to ongoing labor costs after the closure of Cabras 1 & 2.

Projected		
Labor for Cabras 1&2	$	1,800,000
Benefits Adder		33.0%
Total	$	2,394,000

O&M Production Costs:

The Ukudu cost projections were developed based on discussions with GPA and a review of the Ukudu operations contract. The projected costs for 2026 are summarized below.

		2026
Ukudu Lease O&M	$	39,279,932
Ukudu Water Costs		1,700,000
Debt Service		39,387,665
Total Cost before Fuel and Fuel Handling	**$**	**80,367,597**

- Ukudu Lease O&M Costs were based on the 2019 operation costs. The operations contract specifies that the base amount would be adjusted annually according to the inflation rate, as shown below.
- Ukudu Water Costs were provided by GPA.
- Debt Service figures were provided by GPA.
- Fuel Costs were projected based on a dispatch model. The 2024 fuel costs were used in the projection, and the generating units were dispatched to meet the island's electricity needs. UFS assumed the Ukudu generating station would have 85% availability and produce 20.4 kWh per gallon of fuel.

Q12. How was available cash determined

A12. GPA maintains both restricted and unrestricted cash reserves. In coordination with GPA staff, UFS reviewed and identified available fund balances as of the end of Fiscal Year 2024. These balances were categorized based on their restrictions to determine the level of cash available for general utility operations and financial planning. Funds such as the Energy Sense Fund is only available for energy efficiency programs and cannot be used to fund GPA operations or capital improvements.

The table below provides a summary of the unrestricted cash reserves available at the end of FY 2024:

	8/31/2024	Available	Unrestricted	Restricted
Cathay Bank-TCD				
BG-2010 Sr. Bond Const Fund	492,878	No		492,878
2014 B Construction Fund	1,748,755	No		1,748,755
US Bank-2022 Bond Res Fund	47,940,991	No		47,940,991
BOG-2024 Bonds COI Fund	11		11	
BOG- Working Capital Fund	15,904,385	Yes	15,904,385	
Self Insurance Fund	14,475,502	For Typhoons	14,475,502	
1999 Series -BOG Rev Fund	9,792,000	Yes	9,792,000	
1999 Series A Surplus Fund	26,480,804	Yes	26,480,804	
Fund G BG 601-024961	349,462	Yes	349,462	
Fund N BG 601-007290	5,684	Yes	5,684	
Fund D BH 38-010042	14,111	Yes	14,111	
Bank of Hawaii - Merchant	3,928,117	Yes	3,928,117	
Fund F FHB 02-00024	17,531	Yes	17,531	
Fund K Bank Pacific S	3,458	Yes	3,458	
Community First	12,827	Yes	12,827	
Coast 360	3,507	Yes	3,507	
USB - 2014 Bond Fund	1,813,893	Debt Service Fund		1,813,893
USB - 2017 Bond Fund	6,902,449	Debt Service Fund		6,902,449
USB - 2022 Bond Fund	15,199,227	Debt Service Fund		15,199,227
USB - 2024 Bond Fund	232,266	Debt Service Fund		232,266
Insurance Proceeds	52,576,525	Yes	52,576,525	
Change Fund	6,000	Yes	6,000	
Petty Cash Fund	3,000	Yes	3,000	
Payroll Acct B 601-00	15,546	Yes	15,546	
BOG - Disbursement Ac	4,217,631	Yes	4,217,631	
Operating Fund - 03-0	(61,614)	Yes	(61,614)	
Payroll Account -03-0	41,770	Yes	41,770	
BOG - Energy Sense Fund	6,121,819	Restricted		6,121,819
Letter of Credit - BOH	24,672	Yes	24,672	
Total	**$ 208,263,208**		**127,810,929**	**80,452,278**

This analysis is essential for evaluating GPA's actual cash reserves compared to the its working capital needs.

Q13 – What load research information did you receive?

A13. Load research data for most rate studies in the United States can present challenges. However, GPA provided excellent load research data from its database. UFS used two years of load data, covering FY 2023 and FY 2024. Load data from 2020 to 2022 was excluded due to the temporary disruptions caused by the COVID-19 pandemic. A summary of the load research by rate class is provided below, with additional details available on the red tabs in the Excel spreadsheet.

Load Factor	"EGEN-G"	"EGEND-J"	"EIPP-I"	"ELGS-L"	"ELPS-P"	"ENVS-N"	"ERES-D"	"ERES-R"	"ESGS-S"	"ESGSD-K"
High	61%	71%	0%	67%	77%	65%	77%	63%	70%	76%
Low	62%	73%	0%	65%	78%	65%	76%	64%	72%	77%

Coincidence Peak	"EGEN-G"	"EGEND-J"	"EIPP-I"	"ELGS-L"	"ELPS-P"	"ENVS-N"	"ERES-D"	"ERES-R"	"ESGS-S"	"ESGSD-K"
High	72%	82%	0%	70%	88%	79%	94%	98%	79%	80%
Low	73%	84%	0%	67%	89%	84%	92%	99%	86%	84%

Q14. Did the Rate Design include modifications toward cost of service results?

A14. UFS made adjustments toward cost of service results, primarily related to the fixed monthly customer charges. A uniform rate increase was applied to each customer class, with the exception of the Navy Base, which received a 27.9% increase in base rates.

Customer Class	Proposed Percentage Change in Base Rates
Residential (R)	31.44%
Small General (G 1ϕ)	31.44%
Small General (G 3ϕ)	31.44%
Small Govt. (S 1ϕ)	31.44%
Small Govt. (S 3ϕ)	31.44%
Private Outdoor Lighting (H)	31.44%
Public Street Lights (F)	31.44%
General Service (J 1ϕ)	31.44%
General Service (J 3ϕ)	31.44%
Large Power (P)	31.44%
Small Govt. (K 1ϕ)	31.44%
Small Govt. (K 3ϕ)	31.44%
Large Govt. (L)	31.44%
Condo/Apartment (D)	31.44%
Navy (N)	27.90%
Totals	**31.00%**

The Navy Base accounts for approximately 21% of the electric usage on Guam. The base has projected substantial increases in its future electricity needs, which have been factored into the capacity planning of GPA. Reliability of the power supply is the most critical factor, and GPA has included the Navy Base's future requirements in its long-term planning horizon. However, because current costs, which account for the Navy's projected future energy needs, are allocated based on the Navy's current usage, this results in an unfair subsidy to the Navy from other ratepayers of GPA.

To address this issue, UFS has proposed two alternative rate structures for the Navy Base:

1. Rate adjustment using the current rate structure.
2. Rate adjustment based on the contracted capacity needs of the Navy Base.

The proposed rate designs for all rate classes are included in the red tabs of the Rate Study spreadsheet.

Q 15. Does this conclude your testimony?

A 15. Yes.

I swear under penalty of perjury of the laws of Guam that the foregoing testimony in support of GPA's petition to adjust the base rate is true and accurate.

Executed on June 29, 2025.

DocuSigned by:
Mark Beauchamp
90B9A9A408554A7...

Mark Beauchamp, CPA, CMA, MBA
President, Utility Financial Solutions, LLC

6/29/2025

Guam Power Authority

Electric Cost of Service Study and Financial Projection

June 2025

Corporate location:
Utility Financial Solutions, LLC
185 Sun Meadow Court
Holland, MI USA 49424
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Submitted Respectfully by:
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June 2025

John Kim
Guam Power Authority
PO Box 21868
Barriganda, Guam 96921

Dear John:

We are pleased to present the Report for the electric cost of service study and financial projection for the Guam Power Authority (GPA). This report was prepared to provide GPA with a comprehensive examination of its existing rate structure by an outside party.

The specific purposes of this rate study are:

- Determine electric utility's revenue requirements for fiscal year 2026
- Identify cross-subsidies that may exist between rate classes
- Recommend rate adjustments needed to meet targeted revenue requirements
- Identify the appropriate monthly customer charge for each customer class

This report includes results of the electric cost of service study and financial projection and recommendations on future rate designs.

This report is intended for information and use by the utility and management for the purposes stated above and is not intended to be used by anyone except the specified parties.

Sincerely,

Utility Financial Solutions, LLC
Mark Beauchamp
CPA, MBA, CMA
185 Sun Meadow Ct
Holland, MI 49424

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1. Introduction

This report was prepared to provide Guam Power Authority (GPA) with an electric cost of service study and financial projection, and a comprehensive examination of its existing rate structure by an outside party.

The specific purposes of the study are identified below:

1) ***Determine electric utility's revenue requirements for fiscal year 2026.*** GPA's revenue requirements were projected for the period from 2026 – 2030 and included adjustments for the following:

    a. Projected power costs
    b. Projected changes in staffing levels
    c. Capital improvement plan projected over next five years

2) ***Identify if cross-subsidies exist between rate classes.*** Cross-subsidies exist when certain customer classes subsidize the electric costs of other customers. The rate study identifies if cross-subsidies exist and practical ways to reduce the subsidies. The cost of service study was completed using 2026 projected revenues and expenses. The financial projections are for the period from 2026 – 2030.

3) ***Identify cost-based power supply and distribution rates.*** The cost of providing electricity to customers consists of several components, including power generation, distribution, customer services, transmission, and transfers to the general fund. Electric unbundling identifies the cost of each component to assist the utility in preparing for electric restructuring and understanding its cost structure.

4) ***Identify the appropriate monthly customer charge for each customer class.*** The monthly customer charge consists of fixed costs to service customers that do not vary based on the amount of electricity used.

5) ***Recommend rate adjustments needed to meet targeted revenue requirements.*** The primary purpose of this study is to identify appropriate revenue requirements and the rate adjustments needed to meet targeted revenue requirements. The report includes a long-term rate track for GPA to help ensure the financial stability of the utility in future years.

2. Cost of Service Summary

Utility Rate Process

GPA retained Utility Financial Solutions, LLC to review utility rates and cost of service and make recommendations on the appropriate course of action. This report includes results of the electric cost of service and unbundling study and recommendations on future rate designs.

Utility Revenue Requirements

To determine revenue requirements, the revenues and expenses for fiscal years 2022, 2023, 2024, and 2025 budget were analyzed, with adjustments made to reflect projected operating characteristics. ***The projected financial statements are for cost of service purposes only.***

Table 1 is the projected financial statement for the Electric Department from 2026 – 2030.

The following pages review cash flow, debt coverage ratio, and rate of return which are important indicators of financial health.

Table 1 – Financial Statements (without rate adjustments)

Description	Projected 2026	Projected 2027	Projected 2028	Projected 2029	Projected 2030
Operating Revenues:					
Electric Sales					
Residential (R)	$ 53,186,875	$ 53,718,744	$ 54,255,932	$ 54,798,491	$ 55,346,476
Small General (G 1ϕ)	5,257,033	5,309,603	5,362,699	5,416,326	5,470,489
Small General (G 3ϕ)	5,272,191	5,324,913	5,378,162	5,431,944	5,486,263
Small Govt. (S 1ϕ)	952,653	962,180	971,802	981,520	991,335
Small Govt. (S 3ϕ)	1,052,901	1,063,431	1,074,065	1,084,805	1,095,654
Private Outdoor Lighting (H)	237,060	239,430	241,825	244,243	246,685
Public Street Lights (F)	4,339,573	4,382,969	4,426,799	4,471,067	4,515,777
General Service (J 1ϕ)	1,511,135	1,526,246	1,541,508	1,556,923	1,572,493
General Service (J 3ϕ)	23,987,577	24,227,453	24,469,727	24,714,425	24,961,569
Large Power (P)	25,037,715	25,288,092	25,540,973	25,796,383	26,054,347
Small Govt. (K 1ϕ)	271,269	273,982	276,722	279,489	282,284
Small Govt. (K 3ϕ)	13,643,894	13,780,333	13,918,136	14,057,318	14,197,891
Large Govt. (L)	7,676,780	7,753,547	7,831,083	7,909,394	7,988,488
Condo/Apartment (D)	706,424	713,488	720,623	727,829	735,108
Navy (N)	20,534,119	20,739,460	20,946,855	21,156,323	21,367,887
Miscellaneous Revenue	7,082,201	7,153,023	7,224,553	7,296,799	7,369,767
Bad Debt Expense	(1,295,324)	(1,308,277)	(1,321,360)	(1,334,574)	(1,347,920)
LEAC Revenues	267,384,672	270,143,684	272,931,998	275,749,942	278,597,846
Total Operating Revenues	**$ 436,838,749**	**$ 441,292,302**	**$ 445,792,102**	**$ 450,338,646**	**$ 454,932,438**
Operating Expenses:					
Purchases					
Renewables & Closings	$ 23,681,990	$ 23,918,810	$ 24,157,998	$ 24,399,578	$ 24,643,573
Fuel Costs	235,270,464	237,623,169	239,999,400	242,399,394	244,823,388
Other Fuel Handling	8,432,218	8,601,706	8,774,600	8,950,969	9,130,884
Production					
Other Production	11,228,861	11,565,727	11,912,699	12,270,080	12,638,182
Energy Conversion Costs	18,705,634	10,815,000	11,139,450	11,473,634	11,817,843
Ukudu Water Costs	1,700,000	1,751,000	1,803,530	1,857,636	1,913,365
Ukudu Lease O&M	39,279,932	40,458,330	41,672,080	42,922,242	44,209,909
Distribution					
Transmission	6,687,617	6,888,246	7,094,893	7,307,740	7,526,972
Distribution	7,910,478	8,147,792	8,392,226	8,643,993	8,903,313
Other Operating Expenses (Revenues)					
Customer Accounting	7,610,655	7,838,974	8,074,144	8,316,368	8,565,859
Administrative and General	40,452,523	41,666,098	42,916,081	44,203,564	45,529,671
Depreciation Expense	45,002,856	53,877,856	40,398,009	54,402,856	40,923,009
Total Operating Expenses	$ 445,963,228	$ 453,152,708	$ 446,335,110	$ 467,148,053	$ 460,625,969
Operating Income	$ (9,124,479)	$ (11,860,406)	$ (543,008)	$ (16,809,407)	$ (5,693,531)
Other Income & Expense					
Interest Income	$ 6,357,510	$ 3,474,704	$ 1,889,557	$ 191,913	$ (1,624,393)
Interest Expense	(51,861,750)	(50,329,843)	(48,721,290)	(47,032,198)	(45,258,838)
Non Operating Income/Expense	**$ (45,504,240)**	**$ (46,855,138)**	**$ (46,831,734)**	**$ (46,840,284)**	**$ (46,883,231)**
Net Income	**$ (54,628,719)**	**$ (58,715,545)**	**$ (47,374,742)**	**$ (63,649,691)**	**$ (52,576,762)**
Adjusted Operating Income	**$ (9,124,479)**	**$ (11,860,406)**	**$ (543,008)**	**$ (16,809,407)**	**$ (5,693,531)**

Projected Cash Flow

Table 2 is the projected cash flow for 2026 – 2030, including projections of capital improvements as provided by GPA. Changes in the capital improvement plan can greatly affect the cash balance and recommended minimum cash reserve target. The cash balance for 2026 is projected at $35.37M and $-199.33M in 2030. The recommended minimum cash reserve level for 2026 is $107.61M and $110.76M for 2030.

Table 2 – Projected Cash Flows (without rate adjustments)

Description	Projected 2026	Projected 2027	Projected 2028	Projected 2029	Projected 2030
Projected Cash Flows					
Net Income	$ (54,628,719)	$ (58,715,545)	$ (47,374,742)	$ (63,649,691)	$ (52,576,762)
Depreciation Expense/Amortization	45,002,856	53,877,856	40,398,009	54,402,856	40,923,009
Subtract Debt Principal	(25,467,665)	(27,000,572)	(28,611,374)	(30,296,717)	(32,073,327)
Add Bond Sale Proceeds	628,000,000	-	-	-	-
Cash Available from Operations	$ 592,906,472	$ (31,838,260)	$ (35,588,107)	$ (39,543,552)	$ (43,727,080)
Estimated Annual Capital Additions	689,000,000	21,000,000	21,000,000	21,000,000	21,000,000
Net Cash From Operations	$ (96,093,528)	$ (52,838,260)	$ (56,588,107)	$ (60,543,552)	$ (64,727,080)
Beginning Cash Balance	$ 131,464,732	$ 35,371,205	$ (17,467,056)	$ (74,055,163)	$ (134,598,715)
Ending Cash Balance	$ 35,371,205	$ (17,467,056)	$ (74,055,163)	$ (134,598,715)	$ (199,325,795)
Total Cash Available	**$ 35,371,205**	**$ (17,467,056)**	**$ (74,055,163)**	**$ (134,598,715)**	**$ (199,325,795)**
Recommended Minimum	**$ 107,606,754**	**$ 107,609,033**	**$ 108,640,594**	**$ 109,689,636**	**$ 110,757,713**

Cash balances are decreasing throughout the projection period.

Minimum Cash Reserve

Table 3 details the minimum level of cash reserves required to help ensure timely replacement of assets and to provide financial stability of the utility. The methodology used to establish this target is based on an assessment of working capital needs to fund operating expenses, capital improvements, annual debt service payments, and utility's exposure to risks related to catastrophic events, exposure to market risks, changes in fuel costs, loss of major customers, and utility's ability to timely recover changes in power supply expenses. Based on these assumptions, GPA should maintain a minimum of $107.61M in cash reserves for 2026 and $110.76M in 2030.

Table 3 – Minimum Cash Reserves (without rate adjustments)

Description	Projected 2026	Projected 2027	Projected 2028	Projected 2029	Projected 2030
Minimum Cash Reserve Levels Determinants					
Operation & Maintenance Less Depreciation Expense	$ 133,575,700	$ 129,131,168	$ 133,005,103	$ 136,995,256	$ 141,105,114
Fuel Expense	267,384,672	270,143,684	272,931,998	275,749,942	278,597,846
Historical Rate Base	1,874,296,543	1,895,296,543	1,916,296,543	1,937,296,543	1,958,296,543
Current Portion of Debt Service Payment	77,329,415	77,330,415	77,332,665	77,328,915	77,332,165
Five Year Capital Improvements - Net of bond proceed	145,000,000	105,000,000	109,000,000	113,000,000	117,000,000
Minimum Cash Reserve Allocation					
Operation & Maintenance Less Depreciation Expense	12.3%	12.3%	12.3%	12.3%	12.3%
Fuel Expense	12.3%	12.3%	12.3%	12.3%	12.3%
Historical Rate Base	1%	1%	1%	1%	1%
Current Portion of Debt Service Payment	8.3%	8.3%	8.3%	8%	8%
Five Year Capital Improvements - Net of bond proceed	20%	20%	20%	20%	20%
% Plant Depreciated	45%	47%	49%	51%	52%
Calculated Minimum Cash Level					
Operation & Maintenance Less Depreciation Expense	$ 16,468,237	$ 15,920,281	$ 16,397,889	$ 16,889,826	$ 17,396,521
Fuel Expense	32,965,234	33,305,386	33,649,150	33,996,568	34,347,680
Historical Rate Base	18,742,965	18,952,965	19,162,965	19,372,965	19,582,965
Current Portion of Debt Service Reserve	6,444,118	6,444,201	6,444,389	6,444,076	6,444,347
Five Year Capital Improvements - Net of bond proceed	32,986,200	32,986,200	32,986,200	32,986,200	32,986,200
Minimum Cash Reserve Levels	**$ 107,606,754**	**$ 107,609,033**	**$ 108,640,594**	**$ 109,689,636**	**$ 110,757,713**
Projected Cash Reserves	**$ 35,371,205**	**$ (17,467,056)**	**$ (74,055,163)**	**$ (134,598,715)**	**$ (199,325,795)**

Projected cash balances fall below the recommended minimums during the projection period.

Debt Coverage Ratio

Table 4 is the projected debt coverage ratios with capital additions as provided by GPA. Debt coverage ratio is a measurement of debt affordability and measures the cash flow from operations in that fiscal year. A ratio of 1, indicates there was enough cash flow from operations to pay the debt payment one time. The minimum recommended debt coverage ratio for prudent financial planning purposes is 1.40.

Maintaining a 1.40 debt coverage ratio is good business practice and helps to achieve the following:

a. Helps to ensure debt coverage ratios are met in years when sales are low due to cold or wet summers or loss of a major customer(s).

b. When debt coverage ratios are consistently met, it may help obtain a higher bond rating if revenue bonds are sold in the future, to lower interest cost.

Table 4 – Projected Debt Coverage Ratios (without rate adjustments)

Description	Projected 2026	Projected 2027	Projected 2028	Projected 2029	Projected 2030
Debt Coverage Ratio					
Net Income	$ (54,628,719)	$ (58,715,545)	$ (47,374,742)	$ (63,649,691)	$ (52,576,762)
Add Depreciation/Amortization Expense	45,002,856	53,877,856	40,398,009	54,402,856	40,923,009
Add Interest Expense	91,671,697	90,139,790	88,531,238	86,842,145	85,068,785
Cash Generated from Operations	$ 82,045,834	$ 85,302,102	$ 81,554,505	$ 77,595,310	$ 73,415,033
Debt Principal and Interest	$ 77,329,415	$ 77,330,415	$ 77,332,665	$ 77,328,915	$ 77,332,165
Projected Debt Coverage Ratio (Covenants)	**1.06**	**1.10**	**1.05**	**1.00**	**0.95**
Minimum Debt Coverage Ratio	**1.40**	**1.40**	**1.40**	**1.40**	**1.40**

Debt coverage falls below the minimum debt coverage ratio throughout the projection without changes in rates.

Fixed Cost Coverage Ratio

The Fixed Cost Coverage ratio (FCC) is an assessment used by bond rating agencies when determining bond ratings. The FCC calculation varies by rating agency and considers “take or pay” provisions of power supply contracts as debt service. For purposes of our estimate, we consider 26% of the power supply costs as “take or pay”, the percentage often used when direct “take or pay” is not clearly identified.

Table 5 – Projected Fixed Cost Coverage Ratios (without rate adjustments)

Description	Projected 2026	Projected 2027	Projected 2028	Projected 2029	Projected 2030
Fixed Cost Coverage Ratio					
Cash Available for Debt Service	$ 82,045,834	$ 85,302,102	$ 81,554,505	$ 77,595,310	$ 73,415,033
Off System Debt	57,985,566	51,273,330	52,811,530	54,395,876	56,027,752
Total Available	$ 140,031,401	$ 136,575,432	$ 134,366,035	$ 131,991,185	$ 129,442,785
Debt Service Including Off System Debt	$ 135,314,981	$ 128,603,745	$ 130,144,195	$ 131,724,790	$ 133,359,917
Fixed Costs Coverage Ratio	**1.03**	**1.06**	**1.03**	**1.00**	**0.97**
Minimum Fixed Costs Coverage Ratio	**1.40**	**1.40**	**1.40**	**1.40**	**1.40**

Fixed cost coverage ratio is projected to fall below the minimum throughout the projection.

Rate of Return

The optimal target for setting rates is the establishment of a target operating income to help ensure the following:

A. Funding of interest expense on the outstanding principal on debt. Interest expense is below the operating income line and needs to be recouped through the operating income balance.

B. Funding of the inflationary increase on the assets invested in the system. The inflation on the replacement of assets invested in the utility should be recouped through the Operating Income.

C. Funding of depreciation expense.

D. Adequate rate of return on investment to help ensure current customers are paying their fair share of the use of the infrastructure and not deferring the charge to future generations.

E. The rate of return identifies the target operating income and is used to identify the appropriate funding for replacement of existing infrastructure to recover in rates charged to customers.

As improvements are made to the system, the optimal operating income target will increase unless annual depreciation expense is greater than yearly capital improvements. The revenue requirements for the study are set on the utility basis. Table 6 identifies the utility basis target established for 2026 is $36.64M and increases to $59.80M in 2030.

Table 6 – Rate of Return Calculation

Description	Projected 2026	Projected 2027	Projected 2028	Projected 2029	Projected 2030
Target Operating Income Determinants					
Net Book Value/Working Capital	$ 1,037,439,688	$ 1,004,561,832	$ 985,163,822	$ 951,760,966	$ 931,837,957
Outstanding Principal on Debt	860,852,328	824,964,636	787,020,285	745,986,425	708,609,145
System Equity	$ 176,587,360	$ 179,597,196	$ 198,143,537	$ 205,774,541	$ 223,228,812
Debt:Equity Ratio	83%	82%	80%	78%	76%
Target Operating Income Allocation					
Interest on Debt	6.02%	6.10%	6.19%	6.30%	6.39%
System Equity	-8.62%	5.85%	6.03%	6.31%	6.51%
Target Operating Income					
Interest on Debt	$ 51,861,750	$ 50,329,843	$ 48,721,290	$ 47,032,198	$ 45,258,838
System Equity	(15,216,897)	10,504,170	11,948,018	12,984,390	14,542,866
Target Operating Income	**$ 36,644,853**	**$ 60,834,013**	**$ 60,669,308**	**$ 60,016,588**	**$ 59,801,704**
Projected Operating Income	**$ (9,124,479)**	**$ (11,860,406)**	**$ (543,008)**	**$ (16,809,407)**	**$ (5,693,531)**
Rate of Return in %	**3.5%**	**6.1%**	**6.2%**	**6.3%**	**6.4%**

Operating income is projected to be below the target each year.

Projected Rate Track

Adjusting system revenue requires balancing the financial health of the utility with the financial impact on customers and cost of service results. Table 7 is the summary financial projection without any rate changes. Cash balances, operating income, debt coverage ratio, and fixed cost coverage ratio fall to critical levels.

Table 7 – Summary of Financials without Rate Adjustment

Fiscal Year	Distribution Rate Adjustment	Rate Impact (after fuel savings)	Debt Coverage Ratio	Fixed Coverage Ratio	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2026	0.0%	-22.4%	1.06	1.03	$ (9,124,479)	$ 36,644,853	$ 35,371,205	$ 107,606,754
2027	0.0%	0.0%	1.10	1.06	(11,860,406)	60,834,013	(17,467,056)	107,609,033
2028	0.0%	0.0%	1.05	1.03	(543,008)	60,669,308	(74,055,163)	108,640,594
2029	0.0%	0.0%	1.00	1.00	(16,809,407)	60,016,588	(134,598,715)	109,689,636
2030	0.0%	0.0%	0.95	0.97	(5,693,531)	59,801,704	(199,325,795)	110,757,713

The study identifies an increase of 31% in 2026 to work towards the minimum financial targets. Table 8 is a summary of the financial results detailing the recommended revenue adjustments.

Table 8 – Projected Revenue Adjustments

Fiscal Year	Distribution Rate Adjustment	Rate Impact (after fuel savings)	Debt Coverage Ratio	Fixed Coverage Ratio	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2026	31.0%	-13.3%	1.72	1.41	$ 41,612,353	$ 36,644,853	$ 86,108,037	$ 107,606,754
2027	0.0%	0.0%	1.79	1.47	39,383,794	60,834,013	86,036,082	107,609,033
2028	0.0%	0.0%	1.76	1.45	51,213,634	60,669,308	84,309,711	108,640,594
2029	0.0%	0.0%	1.74	1.43	35,464,802	60,016,588	80,791,313	109,689,636
2030	0.0%	0.0%	1.72	1.41	47,103,420	59,801,704	75,322,886	110,757,713

This rate track ensures operating income and cash balances increase through 2030 while working towards the targets. Due to cost changes, inflationary factors, and growth, financial projections should be reviewed on an annual basis. Depending on the system improvement timetable, additional changes may be needed throughout the projection period.

Debt to Equity Ratio

Debt to equity identifies the amount of existing infrastructure financed through debt and is used to determine the amount the system is leveraged in debt. For distribution systems, the debt to equity ratio is normally between 30% and 35%. Table 9 details the debt/equity ratio.

Table 9 – Debt/Equity Ratio

Description	Projected 2026	Projected 2027	Projected 2028	Projected 2029	Projected 2030
Target Operating Income Determinants					
Net Book Value/Working Capital	$ 1,037,439,688	$ 1,004,561,832	$ 985,163,822	$ 951,760,966	$ 931,837,957
Outstanding Principal on Debt	860,852,328	824,964,636	787,020,285	745,986,425	708,609,145
System Equity	$ 176,587,360	$ 179,597,196	$ 198,143,537	$ 205,774,541	$ 223,228,812
Debt:Equity Ratio	83%	82%	80%	78%	76%

Age of Infrastructure

GPA is currently 45% depreciated. Average infrastructure is approximately 50% to 55% depreciated, indicating GPA has not consistently funded replacement of infrastructure. Replacement of infrastructure tends to indicate the utility's ability to consistently provide a reliable system to customers, its ability to withstand catastrophic weather events, and unexpected replacement of system infrastructure. GPA's system age increases through the projection and indicates it will increase to the average range of infrastructure age. Table 10 identifies the depreciated plant.

Table 10 – Age of Infrastructure

Description	Projected 2026	Projected 2027	Projected 2028	Projected 2029	Projected 2030
Historical Rate Base	$ 1,874,296,543	$ 1,895,296,543	$ 1,916,296,543	$ 1,937,296,543	$ 1,958,296,543
Net Book Value/Working Capital	1,037,439,688	1,004,561,832	985,163,822	951,760,966	931,837,957
% Plant Depreciated	45%	47%	49%	51%	52%

Cost of Service Summary Results

A cost of service study was completed to determine the cost of providing service to each class of customers and to assist in design of electric rates for customers. A cost of service study consists of the following general steps:

1) Determine utility revenue requirement for test year 2026.
2) Classify utility expenses into common cost pools.
3) Allocate costs to customer classes based on the classes' contribution to utility expenses.
4) Compare revenues received from each class to the cost of service.

The cost of service summary is included as Table 11 which compares the projected cost to serve each class with the revenue received from each class. The "% change" column is the revenue adjustment necessary to meet projected cost of service requirements. The cost of service summary uses the current rates, including any adjustment factors.

No utility charges 100% cost of service-based rates because retail rates are based on customers usage patterns that are largely driven by variations in weather. Due to these variations, it is recommended that rates move toward cost of service slowly with a general tolerance of a 10% variation between projected revenue and cost of service. The cost of service summary "% change" column indicates a variance exists for certain rate classes.

Table 11 – Cost of Service Summary

Customer Class	Cost of Service	Projected Revenues	% Change
Residential (R)	$ 192,151,535	$ 144,279,507	33.2%
Small General (G 1ϕ)	11,525,603	11,133,050	3.5%
Small General (G 3ϕ)	13,376,443	11,646,477	14.9%
Small Govt. (S 1ϕ)	1,760,724	1,878,493	-6.3%
Small Govt. (S 3ϕ)	2,491,150	2,270,538	9.7%
Private Outdoor Lighting (H)	339,774	299,282	13.5%
Public Street Lights (F)	5,009,297	5,369,792	-6.7%
General Service (J 1ϕ)	3,374,791	3,559,664	-5.2%
General Service (J 3ϕ)	59,899,424	59,185,323	1.2%
Large Power (P)	64,418,298	65,078,335	-1.0%
Small Govt. (K 1ϕ)	538,199	577,589	-6.8%
Small Govt. (K 3ϕ)	28,851,696	30,655,041	-5.9%
Large Govt. (L)	15,320,491	18,300,724	-16.3%
Condo/Apartment (D)	2,159,633	1,961,581	10.1%
Navy (N)	82,135,602	76,420,434	7.5%
Total	$ 483,352,660	$ 432,615,828	11.7%

Cost of Service Results

Table 12 shows the average cost of service per kWh and compares the cost to the average revenue per kWh for each customer class. This table is for information purposes only and is not used in the setting of rates. Average cost per kWh varies due to fixed cost recoveries such as meter costs and infrastructure needs of the customer. In general customer classes that use energy consistently have a lower average kWh cost to serve compared with customer classes that use energy only part of the day or year.

Table 12 – Average Cost per kWh vs. Average Revenue per kWh

Customer Class	Cost of Service $/kWh	Projected Revenues $/kWh
Residential (R)	$ 0.3576	$ 0.2685
Small General (G 1ϕ)	0.3325	0.3212
Small General (G 3ϕ)	0.3558	0.3098
Small Govt. (S 1ϕ)	0.3224	0.3440
Small Govt. (S 3ϕ)	0.3469	0.3161
Private Outdoor Lighting (H)	0.9258	0.8155
Public Street Lights (F)	0.8243	0.8837
General Service (J 1ϕ)	0.2793	0.2946
General Service (J 3ϕ)	0.2885	0.2851
Large Power (P)	0.2728	0.2755
Small Govt. (K 1ϕ)	0.2979	0.3197
Small Govt. (K 3ϕ)	0.2875	0.3055
Large Govt. (L)	0.2445	0.2920
Condo/Apartment (D)	0.2917	0.2650
Navy (N)	0.2492	0.2318

Cost differences result from usage patterns of customers and how efficiently each class of customer use facilities based on load data provided by GPA.

Distribution Costs

Separation of distribution cost helps identify distribution charges for each customer class and the fixed monthly customer charge. Distribution rates include separation of the following costs:

- Operation and maintenance of distribution & transmission system
- Contributions to general fund
- Customer service
- Customer accounting
- Meter reading
- Billing
- Meter operation & maintenance
- Administrative expenses

The distribution rates consist of two components:

- Monthly customer charge to recover the costs of meter reading, billing, customer service, and a portion of maintenance and operations of the distribution system.
- Distribution rate based on billing parameters (kW or kWh) to recover the cost to operate and maintain the distribution system. Table 13 identifies the cost-based distribution rates for customer classes.

Table 13 – Distribution Costs by Customer Class (COS)

Customer Class	Monthly Customer Charge	Distribution Rate	Billing Basis
Residential (R)	$ 27.85	$ 0.0454	kWh
Small General (G 1ϕ)	27.85	0.0437	kWh
Small General (G 3ϕ)	55.14	0.0438	kWh
Small Govt. (S 1ϕ)	27.83	0.0384	kWh
Small Govt. (S 3ϕ)	55.18	0.0384	kWh
Private Outdoor Lighting (H)	39.23	0.0474	kWh
Public Street Lights (F)	235.43	0.1871	kWh
General Service (J 1ϕ)	132.88	11.13	kW
General Service (J 3ϕ)	134.81	11.74	kW
Large Power (P)	277.83	14.00	kW
Small Govt. (K 1ϕ)	132.91	9.69	kW
Small Govt. (K 3ϕ)	134.84	12.84	kW
Large Govt. (L)	276.72	12.59	kW
Condo/Apartment (D)	189.97	13.48	kW
Navy (N)	676.62	8.85	kW

The cost of service based monthly customer charge for residential customers recovers 38.5% of the fixed cost of delivery of electricity. UFS averages across the United States show 40% to 60% fixed cost recovery in the residential customer charge.

Power Supply Costs

Table 14 identifies the average cost of providing power supply to customers of GPA.

Table 14 – Power Supply Costs by Customer Class

Customer Class	Demand	Billing Basis	Energy	Billing Basis
Residential (R)	$ 0.1123	kWh	$ 0.1714	kWh
Small General (G 1ϕ)	0.0906	kWh	0.1713	kWh
Small General (G 3ϕ)	0.1104	kWh	0.1712	kWh
Small Govt. (S 1ϕ)	0.0803	kWh	0.1713	kWh
Small Govt. (S 3ϕ)	0.1181	kWh	0.1709	kWh
Private Outdoor Lighting (H)	0.0965	kWh	0.1712	kWh
Public Street Lights (F)	0.0783	kWh	0.1707	kWh
General Service (J 1ϕ)	20.69	KW	0.1713	kWh
General Service (J 3ϕ)	28.86	KW	0.1712	kWh
Large Power (P)	32.96	KW	0.1713	kWh
Small Govt. (K 1ϕ)	25.25	KW	0.1713	kWh
Small Govt. (K 3ϕ)	34.32	KW	0.1713	kWh
Large Govt. (L)	17.46	KW	0.1713	kWh
Condo/Apartment (D)	36.27	KW	0.1714	kWh
Navy (N)	44.06	KW	0.1628	kWh

Demand recovers costs for power supply and transmission fixed demand related costs. Energy is cost recovery for variable power supply costs.

Combined Cost Summary

Table 15 identifies the cost of service rates for each customer class. Charging these rates would directly match the cost of providing service to customers identified in this study.

Table 15 – Total Costs by Customer Class

Customer Class	Current Average Customer Charge	COS Customer Charge	Demand	Energy
Residential (R)	$ 15.00	$ 27.85	$ -	$ 0.3291
Small General (G 1ϕ)	14.16	27.85	-	0.3055
Small General (G 3ϕ)	14.16	55.14	-	0.3253
Small Govt. (S 1ϕ)	14.16	27.83	-	0.2900
Small Govt. (S 3ϕ)	14.16	55.18	-	0.3275
Private Outdoor Lighting (H)	-	39.23	-	0.3152
Public Street Lights (F)	-	235.43	-	0.4361
General Service (J 1ϕ)	38.33	132.88	31.83	0.1713
General Service (J 3ϕ)	38.33	134.81	40.60	0.1712
Large Power (P)	59.25	277.83	46.95	0.1713
Small Govt. (K 1ϕ)	38.33	132.91	34.93	0.1713
Small Govt. (K 3ϕ)	38.33	134.84	47.16	0.1713
Large Govt. (L)	59.25	276.72	30.05	0.1713
Condo/Apartment (D)	59.25	189.97	49.75	0.1714
Navy (N)	10,990.00	676.62	52.91	0.1628

Residential Customer Charge

The customer charge consists of expenses related to, 1) providing a minimum amount of electricity to the residential customer, and 2) expenses related to servicing a meter on the customer's premises; together they reflect the cost to deliver a single kWh of electricity to the customer. The methodology used in this study is consistent with methodologies and practices used in the electric industry.

The customer charge includes two types of charges called minimum system charges and direct charges.

Minimum System Charges:

The cost to provide the minimum level of service. GPA provides wires to connect the transmission system to customer homes and businesses. This wire is required to provide even the minimal amount of service to a customer. For cost of service purposes, the total cost of the distribution infrastructure is broken into two components: 1) the minimum system costs, in effect to provide a customer with a single kWh of electricity which should be recovered through the customer charge, and 2) demand related costs to recover the additional infrastructure costs for when a customer uses more than a single kWh, which should be recovered through the usage component. The distribution system is sized to handle the customers' peak demands and the cost above the minimum system is recovered through the usage component (for residential customers this is included in the kWh charge).

The first step in identifying the cost related to the minimum system is obtaining information on the number and current replacement costs of GPA distribution system. For example: UFS used information on the number and size of all the poles and the cost to replace the poles. The minimum size pole was identified and the cost to construct GPA's system at the minimum sizing was determined. This process was completed for all GPA's distribution system, including overhead and underground conductors and devices, line transformers, etc. Based on this methodology, 61.5% of GPA's total distribution costs should be recovered by the usage component and 38.5% recovered in the fixed customer charge component.

Direct Charges

Costs related to maintaining a customer's account. These costs include the cost to operate and maintain the meter, including meter installation, meter repair and replacement costs, the cost to read the meter, billings and collections, customer service personnel to assist with questions and maintain the account, and the cost of the "service drop" to connect the home to the distribution line. These costs are direct costs of serving a residential account.

3. Functionalization of Costs

Delivery of electricity consists of many components that bring electricity from the power supply facilities to the communities and eventually into customer facilities. The facilities consist of four major components: transmission, distribution, customer-related services, and administration. Following are general descriptions of each of these facilities and the sub-breakdowns within each category.

Transmission

The transmission system is comprised of four types of subsystems that operate together:

1) Backbone and inter-tie transmission facilities are the network of high voltage facilities through which a utility's major production sources are integrated.
2) Generation set-up facilities are the substations through which power is transformed from a utility's generation voltages to its various transmission voltages.
3) Sub-transmission plant consists of lower voltage facilities to transfer electric energy from convenient points on a utility's backbone system to its distribution system.
4) Radial transmission facilities are those that are not networked with other transmission lines but are used to serve specific loads directly.

Operation of the transmission system also consists of providing certain services that ensure a stable supply of power. These services are typically referred to as ancillary services. The Federal Energy Regulatory Commission (FERC) has defined six ancillary service charges for the use of transmission facilities. For GPA, these charges will be passed-through charges by the control area operator. Ancillary services consist of the following:

- **Mandatory Ancillary Service Charges:**
  Reactive Supply and Voltage Control
  Regulation and Frequency Response Service
  Energy Imbalance Charges
  Operating Reserves Spinning
  Operating Reserves Supplemental
  Reactive Power Supply
  Power losses from use of transmission system

Terminology of Cost of Service

FUNCTIONALIZATION – Cost data arranged by functional category (e.g., power supply, transmission, distribution

CLASSIFICATION – Assignment of functionalized costs to cost components (e.g., demand, energy and customer related).

ALLOCATION – Allocating classified costs to each class of service based on each class's contribution to that specific cost component.

DEMAND COSTS – Costs that vary with the maximum or peak usage. Measured in kilowatts (kW)

ENERGY COSTS – Costs that vary over an extended period of time. Measured in kilowatt-hours (kWh)

CUSTOMER COSTS – Costs that vary with the number of customers on the system (e.g. metering costs).

DIRECT ASSIGNMENT – Costs identified as belonging to a specific customer or group of customers.

Distribution

The distribution facilities connect the customer with the transmission grid to provide the customer with access to the electrical power that has been generated and transmitted. The distribution plant includes substations, primary and secondary conductors, poles, and line transformers that are jointly used and in the public right-of-way.

Substations typically separate the distribution plant from the transmission system. The substation power transformer "steps down" the voltage to a level that is more practical to install on and under city streets.

Distribution circuits are divided into primary and secondary voltages with the primary voltages usually ranging between 35 kV and 4 kV and the secondary below 4 kV.

Distribution Customer Types

Sub-transmission customers are served directly from the substation feeder and bypass both the secondary and primary distribution lines. The charges for this type of customer should reflect the cost of the substation and not include the cost of primary or secondary line charges.

Primary customers are typically referred to as customers who have purchased, owned, and maintained their own transformers that convert the voltage to the secondary voltage level. The rates for these customers should reflect the cost of substations and the cost of primary distribution lines and not include the cost of secondary line extensions.

Secondary customers have the services provided by the utilities directly into their facilities. The utility provides the customer with the transformer and the connection on the customers' facilities.

Customer-Related Services

Certain administrative-type services are necessary to ensure customers are provided service connections and disconnections in a timely manner and the facilities are in place to read meters and bill for customer usages. These services typically consist of the following components:

- Customer Services – The cost of providing personnel to assist customers with questions and dispatch personnel to connect and disconnect meters.
- Billing and Collections – The cost of billing and collections personnel, postage, and supplies.
- Meter Reading – The cost of reading customers' meters.
- Meter Operation and Maintenance – The cost of installing and maintaining customer meters.

Administrative Services

These costs are sometimes referred to as overhead costs and relate to functions that cannot be directly-attributed to any service. These costs are spread to the other services through an allocator such as labor, expenses, or total rate base. These costs may consist of City Commission expenses, property insurance, and wages for higher level management of the utility.

System Losses

As energy moves through each component of the transmission and distribution system, some of the power is lost and cannot be sold to customers. Losses vary based on time of day and season. Typically, as system usage increases or ambient temperature increases, the percentages of losses that occur also increase. These losses are recovered from distribution customers through an analysis of the losses that occur in the system. The average system losses and unaccounted energy for GPA are approximately 5.5%. (Typical municipal system losses are approximately 5.4%)

4. Unbundling Process

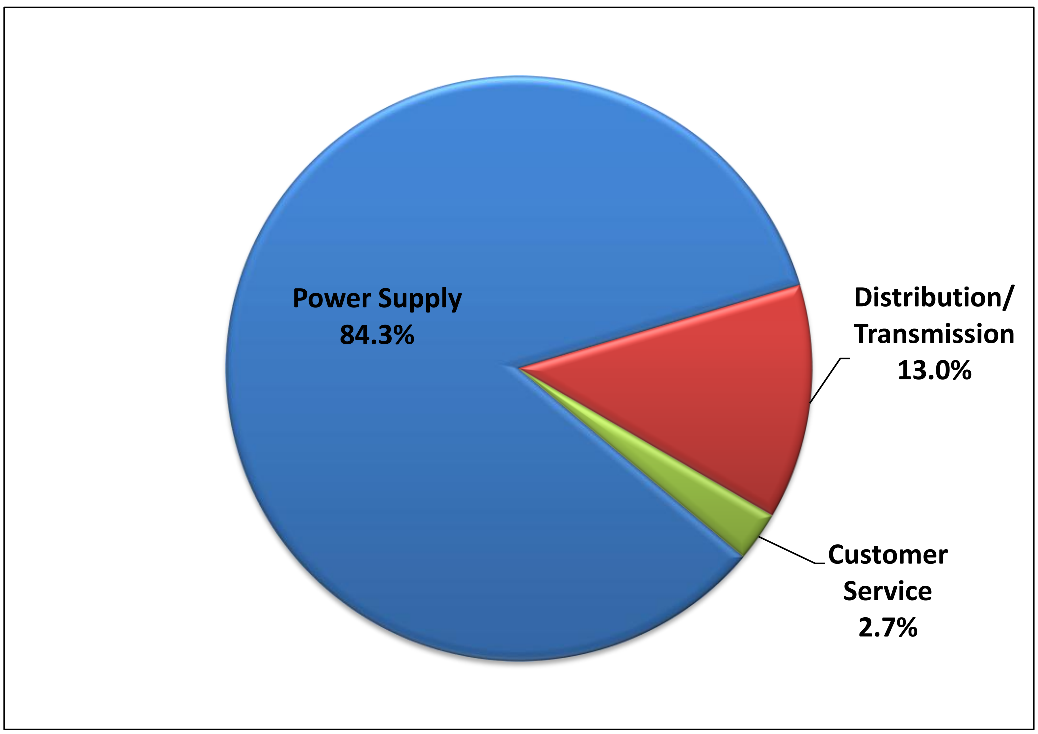
The cost of power supply, distribution, and customer services are identified as part of the unbundling process and are the first step in determining unbundled charges to customers. The total revenue requirements of $483.35M are separated into three categories identified in Table 16.

Table 16 – Breakdown of GPA Cost Structure

Expense Type	Amount	Percentage
Power Supply	$ 407,386,037	84.3%
Distribution/Transmission	62,809,339	13.0%
Customer Service	13,157,284	2.7%
Total	$ 483,352,660	100.0%

GPA is projected to expend 84.3% of its total costs toward power supply. Distribution/transmission-related costs are 13%; and customer service 2.7%. These components are broken down into each of the subcomponents and are identified in the following sections.

Figure 1 – Breakdown of Cost Structure



Power Supply Cost Breakdown

Production Costs (Excluding Fuel)

Production costs excluding fuel are projected to increase from $35.1M in 2024 to $71.0M by 2026. This increase is primarily driven by higher operating and maintenance expenses associated with new generation assets. However, with the shutdown of Cabras Units 1 & 2, production costs are expected to decline by approximately $6.0M in 2027. The table below is a summary of the historical and projected production costs.

Table 17 – Summary of Historical and Projected Production Costs

	FY 2027	FY 2026	FY 2025	FY 2024	FY 2023	FY 2022	FY 2021
Summary							
Other Production	$ 11,565,727	$ 11,228,861	$ 20,824,779	$ 20,218,232	$ 17,742,232	$ 19,101,287	$ 18,303,565
Energy Conversion Costs	10,815,000	18,705,634	21,244,361	13,843,588	10,185,615	9,355,771	10,712,059
Waste Treatment Costs (GWA)	1,751,000	1,751,000	1,063,386	1,032,413	1,002,343	1,858,287	1,620,960
Ukudu Lease O&M	40,458,330	39,279,932	-	-	-	-	-
Total Other Production	**$ 64,590,057**	**$ 70,965,427**	**$ 43,132,525**	**$ 35,094,233**	**$ 28,930,190**	**$ 30,315,346**	**$ 30,636,584**

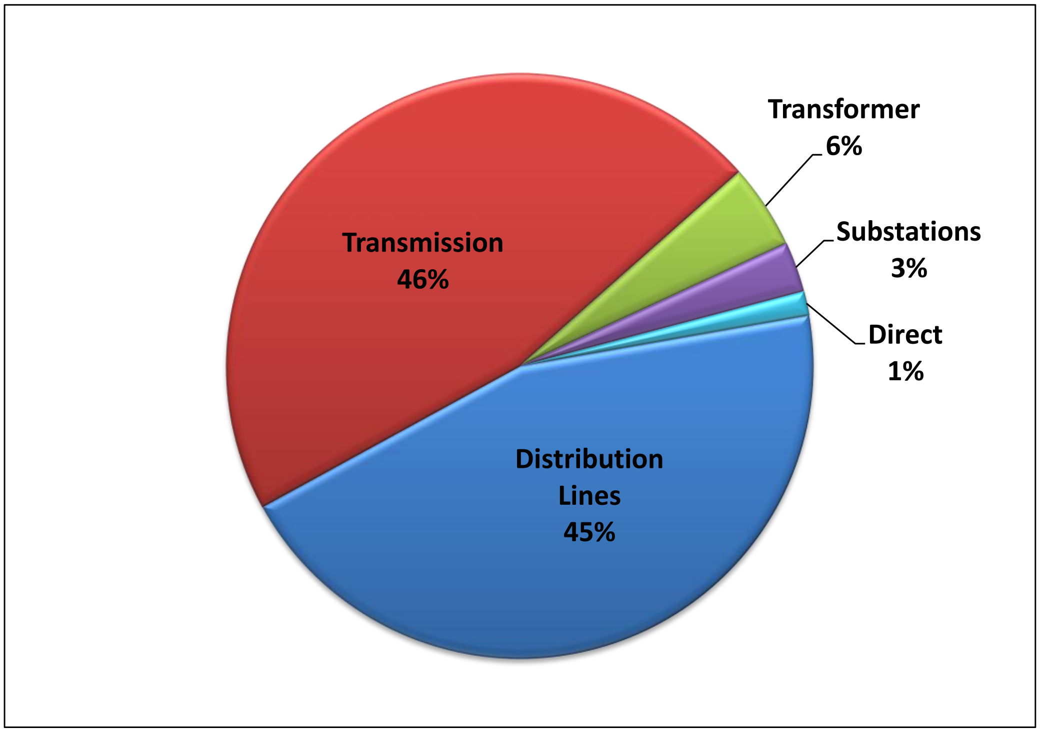
Fuel Costs

Fuel costs are projected to decline as the Ukudu facility comes online. Thanks to the plant's improved heat rate and overall efficiency, total fuel costs are expected to decrease from $350.0M to approximately $235.0M once the unit is fully operational. (Based on 2024 Fuel Costs)

Distribution Breakdown

Distribution rates consist of several different components. Total distribution-related costs of $62.81M for 2026 are broken down into the main components including substations, transformers, transmission, and distribution lines. Figure 2 shows the breakdown of distribution components identified in the study.

Figure 2 – Breakdown of Distribution Costs

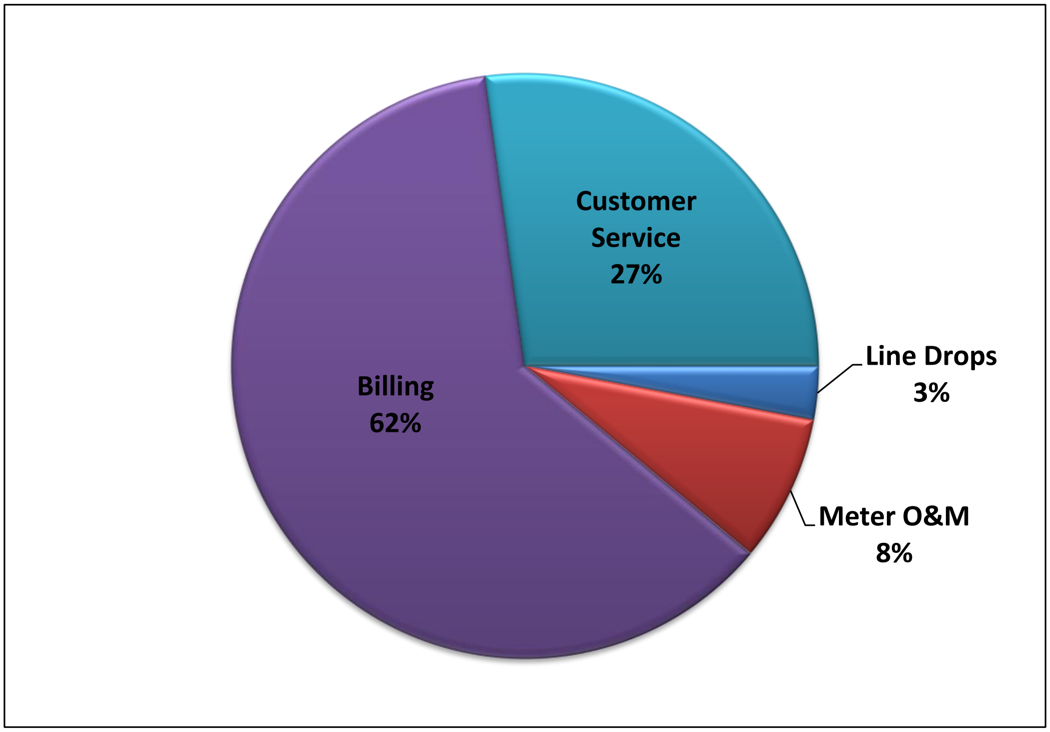


Each of these components is allocated to customer groups based on certain factors established in the study. These factors are based on the efficiency of each customer class and the time of day or the season the electricity is used. Other factors are also considered, such as the length of line extensions to reach certain customer classes.

Customer-Related Cost Breakdown

GPA total expenses for customer-related costs are $13.16M for 2026. The cost is broken down into the components identified in Figure 3.

Figure 3 – Breakdown of Customer Costs



5. Significant Assumptions

This section outlines the procedures used to develop the cost of service and unbundling study for GPA and the related significant assumptions.

Forecasted Operating Expenses

Forecasted expenses were based on 2022, 2023, 2024, and 2025 budget adjusted for power supply costs and inflation. The table below is a summary of the expenses used in the analysis. The projected operating expenses include an adjustment for any city contributions.

Table 18 – Projected Operating Expenses for 2026 – 2030

Description	Projected 2026	Projected 2027	Projected 2028	Projected 2029	Projected 2030
Operating Expenses:					
Purchases					
Renewables & Closings	$ 23,681,990	$ 23,918,810	$ 24,157,998	$ 24,399,578	$ 24,643,573
Fuel Costs	236,834,420	239,202,765	241,594,792	244,010,740	246,450,848
Other Fuel Handling	8,432,218	8,601,706	8,774,600	8,950,969	9,130,884
Production					
Other Production	11,228,861	11,565,727	11,912,699	12,270,080	12,638,182
Energy Conversion Costs	18,705,634	10,815,000	11,139,450	11,473,634	11,817,843
Ukudu Water Costs	1,700,000	1,751,000	1,803,530	1,857,636	1,913,365
Ukudu Lease O&M	39,279,932	40,458,330	41,672,080	42,922,242	44,209,909
Distribution					
Transmission	6,687,617	6,888,246	7,094,893	7,307,740	7,526,972
Distribution	7,910,478	8,147,792	8,392,226	8,643,993	8,903,313
Other Operating Expenses (Revenues)					
Customer Accounting	7,610,655	7,838,974	8,074,144	8,316,368	8,565,859
Administrative and General	40,452,523	41,666,098	42,916,081	44,203,564	45,529,671
Depreciation Expense	45,002,856	53,877,856	40,398,009	54,402,856	40,923,009
Total Operating Expenses	$ 447,527,184	$ 454,732,304	$ 447,930,502	$ 468,759,399	$ 462,253,428

Power supply costs from 2026 – 2030 are based on GPA's current charges adjusted for system growth factors and inflation.

Load Data

Load data is one of the most critical components of a cost of service study. Information from the billing statistics were used to determine the usage patterns of each customer class after reconciling revenues with financial statements to ensure a good basis for development of the study.

Annual Projection Assumptions

The kWh sales forecast is based on FY2023 actual adjusted for growth. Table 19 details growth, inflation of expenses, changes in purchase power costs, interest earned on investments.

Table 19 – Projection Annual Escalation Factors 2026 – 2030

Fiscal Year	Inflation	Growth	Fuel Change	Investment Income
2026	3.0%	1.0%	1.0%	3.0%
2027	3.0%	1.0%	1.0%	3.0%
2028	3.0%	1.0%	1.0%	3.0%
2029	3.0%	1.0%	1.0%	3.0%
2030	3.0%	1.0%	1.0%	3.0%

System Loss Factors

Losses occurring from the transmission and distribution of electricity can vary from year to year depending upon weather and system loading. The distribution loss factor used for the cost of service study was based on historic losses at 5.5%.

Revenue Forecast

The revenue forecast was based on FY2023 usages adjusted for growth rate assumptions.

6. Considerations and Additional Information

GPA Financial Considerations

1. GPA is projected to require an increase in rates charged to customers in FY2026 and is projected to work towards maintaining financial targets over the projection period.

Fiscal Year	Distribution Rate Adjustment	Rate Impact (after fuel savings)	Debt Coverage Ratio	Fixed Coverage Ratio	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2026	31.0%	-13.3%	1.72	1.41	$ 41,612,353	$ 36,644,853	$ 86,108,037	$ 107,606,754
2027	0.0%	0.0%	1.79	1.47	39,383,794	60,834,013	86,036,082	107,609,033
2028	0.0%	0.0%	1.76	1.45	51,213,634	60,669,308	84,309,711	108,640,594
2029	0.0%	0.0%	1.74	1.43	35,464,802	60,016,588	80,791,313	109,689,636
2030	0.0%	0.0%	1.72	1.41	47,103,420	59,801,704	75,322,886	110,757,713

2. Cash balances are decreasing and projected to be below the recommended minimums during the projection period, even with the proposed rate increase. This cash decrease could be off set with additional system growth or reduced capital expenditure.

3. Debt Coverage Ratio and Fixed Cost Coverage Ratio are below recommended minimum levels throughout the projection period without changes in rates. The recommended rates change is anticipated to result in coverage ratio's exceeding the minimum coverage levels.

4. Current rate-related revenues are projected to result in operating income below the target operating income for each year. Meeting the operating income target indicates current rates are fully funding system revenue requirements.

5. GPA system losses are below average resulting in lower power supply cost for customers. The average system losses and unaccounted for energy for GPA are approximately 5.5% compared to typical municipal system losses of approximately 5.4%.

Rate-Related Considerations

1. Customer charges are under-recovering and energy rates are over-recovering for most customer classes. The table below compares the current customer charges with the cost-based customer charge. It is recommended that movements toward the cost-based customer charge occur with the additional revenue used to lower the energy rates for customers in the class.

Customer Class	Current Average Customer Charge	COS Customer Charge
Residential (R)	$ 15.00	$ 27.85
Small General (G 1ϕ)	14.16	27.85
Small General (G 3ϕ)	14.16	55.14
Small Govt. (S 1ϕ)	14.16	27.83
Small Govt. (S 3ϕ)	14.16	55.18
Private Outdoor Lighting (H)	-	39.23
Public Street Lights (F)	-	235.43
General Service (J 1ϕ)	38.33	132.88
General Service (J 3ϕ)	38.33	134.81
Large Power (P)	59.25	277.83
Small Govt. (K 1ϕ)	38.33	132.91
Small Govt. (K 3ϕ)	38.33	134.84
Large Govt. (L)	59.25	276.72
Condo/Apartment (D)	59.25	189.97
Navy (N)	10,990.00	676.62

2. GPA may consider movements toward cost of service. The cost of service study indicates a variance exists between revenues and costs for certain rate classes. The study results are listed below:

Customer Class	Cost of Service	Projected Revenues	% Change
Residential (R)	$ 192,151,535	$ 144,279,507	33.2%
Small General (G 1ϕ)	11,525,603	11,133,050	3.5%
Small General (G 3ϕ)	13,376,443	11,646,477	14.9%
Small Govt. (S 1ϕ)	1,760,724	1,878,493	-6.3%
Small Govt. (S 3ϕ)	2,491,150	2,270,538	9.7%
Private Outdoor Lighting (H)	339,774	299,282	13.5%
Public Street Lights (F)	5,009,297	5,369,792	-6.7%
General Service (J 1ϕ)	3,374,791	3,559,664	-5.2%
General Service (J 3ϕ)	59,899,424	59,185,323	1.2%
Large Power (P)	64,418,298	65,078,335	-1.0%
Small Govt. (K 1ϕ)	538,199	577,589	-6.8%
Small Govt. (K 3ϕ)	28,851,696	30,655,041	-5.9%
Large Govt. (L)	15,320,491	18,300,724	-16.3%
Condo/Apartment (D)	2,159,633	1,961,581	10.1%
Navy (N)	82,135,602	76,420,434	7.5%
Total	$ 483,352,660	$ 432,615,828	11.7%

Appendix A

List of Electric Rate Studies Completed by Utility Financial Solutions, LLC over the past 10 years. UFS completed long-term financial projections, cost of service studies and rate designs.

1	Ainsworth NE - KBR Rural Public Power Dst
2	Alameda CA
3	Albany GA
4	Albemarle NC
5	Algona IA
6	Ames IA
7	AMP - American Municipal Power, Inc. OH
8	Anderson IN
9	Apex NC
10	APPA
11	Ashland OR
12	Austin Energy TX
13	Austin MN
14	Ava MO
15	Ayden NC
16	Barbados
17	Barton Village Inc. VT
18	Battle River REA - Camrose AB Canada
19	Bay City MI
20	Beaver City UT
21	Bedford VA
22	Belmont MA
23	Benton AR
24	Bentonville AR
25	Berea KY
26	Bermuda
27	Biggs CA
28	Blanding UT
29	Blue Ridge Power Agency
30	Boulder CO
31	Bozrah CT
32	Brainerd MN
33	Breese IL
34	Bryan OH
35	Burt County Public Power District NE
36	Bushnell IL
37	Butler Public Power District NE
38	Cedar- Knox NE

39 Cedar Falls IA
40 Central Municipal Power Agency Services
41 Charlevoix MI
42 Chaska MN
43 Chelsea MI
44 Cherryville NC
45 Clallam County WA
46 Cleveland Public Power OH
47 CMEEC
48 Cody WY
49 Coffeyville KS
50 Coldwater MI
51 Colorado Springs CO
52 Columbia MO
53 Columbia TN
54 Concord NC
55 Conway AR
56 Cornelius NC
57 Cornhusker NE
58 Crisp County Power Commission GA
59 Cuming County Public Power District NE
60 Custer Public Power District NE
61 Cuyahoga Falls OH
62 Danvers MA
63 Danville VA
64 DEMEC Inc.
65 DNV Energy Insights USA Inc.
66 East Norwalk CT
67 Easton MD
68 Eaton Rapids MI
69 Edenton NC
70 EDP Renewables North America LLC
71 ElectriCities
72 Elizabeth City NC
73 Elkhorn NE
74 Energy Northwest - Richland WA
75 Ephraim City UT
76 Escanaba MI
77 Fairview City UT
78 Farmville NC
79 Fillmore UT
80 Forest Grove OR
81 Fort Collins CO
82 Freeburg IL
83 Front Royal VA

84 Fulton County REMC - Rochester IN
85 Gastonia NC
86 Geneseo IL
87 Georgetown Utility Systems TX
88 Gladstone MI
89 Grand Electric Cooperative SD
90 Grand Haven MI
91 Granite Falls NC
92 GRDA - Grand River Dam Authority OK
93 Greenup IL
94 Gridley CA
95 Groton CT
96 Guam
97 Guernsey WY
98 Hamilton NC
99 Hannibal MO
100 Harbor Springs MI
101 Hart MI
102 Haskins OH
103 Hastings NE
104 Heber City UT
105 Hertford NC
106 Highland IL
107 Hillsdale MI
108 Hingham MA
109 Holland BPW MI
110 Homestead FL
111 Hometown Connections, LLC
112 Hope AR
113 Hope Enterprise Corporation
114 Howard Greeley NE
115 Hubbard OH
116 Hudson MA
117 Hudson OH
118 Huntersville NC
119 Huntsville AL
120 Hurricane UT
121 Hutchinson MN
122 Hyde Park VT
123 Imperial CA - IID
124 IMUA IL
125 Independence MO
126 Indiana Municipal Power Agency
127 Ipswich MA
128 Jacksonville Village VT

129 Jasper IN
130 Kasson MN
131 Kaukauna WI
132 Kennett MO
133 Kenyon MN
134 Kerrville TX
135 Keys Energy Services FL
136 Kings Mountain NC
137 Knoxville TN
138 Lake Worth FL
139 Landis NC
140 Lansing MI
141 Laurens SC
142 Laurinburg NC
143 Lewes DE
144 Lexington NC
145 Lincoln NE - MEAN - NMPP
146 Linden IN - Tipmont REMC
147 Lodi OH
148 Lompoc CA
149 Los Alamos NM
150 Louisburg NC
151 Loup Valleys NE
152 Loveland CO
153 Lowell MI
154 Lumberton NC
155 Lusk WY
156 Maiden NC
157 Manassas VA
158 Mansfield MO
159 Marblehead MA
160 Marquette MI
161 Martinsville VA
162 Mascoutah IL
163 McCook NE
164 McMinnville OR
165 Memphis TN
166 Merced Irrigation District CA
167 Middle Tennessee EMC TN
168 Middletown DE
169 Milford DE
170 Milltown NJ
171 Mishawaka IN
172 Missouri River Energy Services SD
173 MMEA MI

174 Modesto Irrigation District CA
175 Monroe NC
176 Monroe UT
177 Morganton NC
178 Mt. Pleasant UT
179 Murfreesboro TN
180 Naperville IL
181 Nashville TN
182 Nebraska Electric Gen & Transmission NE
183 New Bern NC
184 New Carlisle IN
185 New Castle DE
186 Newark DE
187 Newberry SC
188 Newton Falls OH
189 Newton IL
190 Newton NC
191 Niles MI
192 Niles OH
193 NIMPA IL
194 Niobrara Valley NE
195 North Attleborough MA
196 North Central Public Power District NE
197 North Little Rock AR
198 Northeast Public Power Association NEPPA
199 Northern California Power Agency CA
200 Norwich CT
201 Norwood MA
202 Oberlin OH
203 Oglesby IL
204 OMEA OH
205 OMPA OK
206 Orrville OH
207 Owatonna MN
208 Owensboro KY
209 Painesville OH
210 Palmyra MO
211 Parowan UT
212 Paw Paw Village MI
213 Payson UT
214 Perennial Power District NE
215 Peru IL
216 Petoskey MI
217 Philippi WV
218 Pikeville NC

219 Pine Bluffs WY
220 Pineville NC
221 Pioneer Community Energy CA
222 Plainview NE
223 Platte River CO
224 PMEA PA
225 Polk County Public Power District NE
226 Poplar Bluff MO
227 Portland MI
228 Powell WY
229 PREMA NE
230 Pulaski Electric System TN
231 Rancho Cucamonga CA
232 Rantoul IL
233 Red Bud IL
234 Richland MO
235 Richlands VA
236 Richmond IN
237 Riverside CA
238 Riviera Utilities AL
239 Robersonville NC
240 Rochelle IL
241 Rochester MN
242 Rock Falls IL
243 Rosebud Electric Cooperative SD
244 Roseville CA
245 Salem MO
246 San Luis Valley REC CO
247 Santa Clara UT
248 Santee Cooper SC
249 Scotland Neck NC
250 SCPPA CA
251 Sebewaing MI
252 Selma NC
253 Seville OH
254 Shasta Lake CA
255 Shelby NC
256 Shelby OH
257 Sikeston MO
258 Sitka AK
259 Sleepy Eye MN
260 Smithfield NC
261 SMUD - Sacramento Municipal Utility Dist
262 Smyrna DE
263 South Bend Hydro

264 South Central PPD NE
265 South Haven MI
266 South River NJ
267 South San Joaquin Irrigation District CA
268 South Utah Valley UT
269 Southern Public Power District NE
270 Southport NC
271 Spring City UT
272 St. Louis MI
273 Stanton NE
274 Statesville NC
275 Stillwater OK
276 Stilwell OK
277 Sturgis MI
278 Sullivan IL
279 Tahlequah OK
280 Town of Lyndon VT
281 Traverse City MI
282 Turlock CA
283 Twin Valleys NE
284 UAMPS
285 UPPCO MI
286 VPPSA VT
287 Wadsworth OH
288 Wagoner OK
289 Wakefield MI
290 Walkerton IN
291 Washington City NC
292 Washington City UT
293 Watertown SD
294 Waverly IA
295 West Boylston MA
296 West Kentucky RECC KY
297 Westerville OH
298 Westfield MA
299 Wheatland WY
300 Winfield KS
301 Winnetka IL
302 Winona MO
303 WMPA WY
304 WPPI Energy
305 Wyandotte MI
306 Yazoo City MS
307 Zeeland BPW MI
308 Apex NC

309 Ayden NC
310 Cherryville NC
311 Corneliius NC
312 Edenton NC
313 Elizabeth City NC
314 Farmville NC
315 Gastonia NC
316 Granite Falls NC
317 Hertford NC
318 Huntersville NC
319 Kings Mountain NC
320 Landis NC
321 Laurinburg NC
322 Lexington NC
323 Lousiburg NC
324 Lumberton NC
325 Maiden NC
326 Monroe NC
327 Morganton NC
328 Newton NC
329 Pikeville NC
330 Pineville NC
331 Robersonville NC
332 Scotland Neck NC
333 Selma NC
334 Shelby NC
335 Smithfield NC
336 Southport NC
337 Statesville NC
338 Tarboro NC
339 Washington NC